Agenda
Reliability and Security Technical Committee

September 11, 2024 | 8:30 a.m. – 4:30 p.m. Eastern
Hybrid

ALT HOTEL MONTREAL
120, Rue Peel,
Montréal, Québec,
H3C 0L8

Webex

Call to Order

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

Introduction and Chair's Remarks

Agenda

1. **Administrative items**
   a. Arrangements
   b. Announcement of Quorum
   c. Reliability and Security Technical Committee (RSTC) Resources
      i. RSTC Membership Roster
      ii. RSTC Newsletter
      iii. RSTC Charter
   d. Actions taken between meetings
      i. LLTF/EVTF Scope Approval and leadership appointments
         (1) LLTF: Chair – Matt Veath (AEP), Vice Chair – Agee Springer (ERCOT)
         (2) EVTF: Chair – Uzma Siddiqi (Seattle City)
      ii. RSTC Executive Committee (EC) Approved SPCWG Work Plan addition: Annual Protection System Misoperation Analysis
      iii. RSTC EC Approved the Electric Vehicle Task Force Work Plan
      iv. RSTC EC Approved the Large Loads Task Force Work Plan

Consent Agenda

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

Regular Agenda

3. **Remarks and Reports**
   a. Subcommittee Reports*
   b. RSTC Work Plan
   c. Report of August 14, 2024 Member Representatives Committee (MRC) Meeting and August 14, 2024 Board of Trustees Meeting
4. **RSTC Charter Revisions* – Approve –** Candice Castaneda, NERC Staff
5. **Risk and Mitigations for Losing EMS Functions Reference Document* – Approve –** Wei Qiu, NERC Staff
6. **Frequency Response Annual Analysis (FRAA)* – Accept –** Greg Park, RS Chair | Rich Hydzik, Sponsor
7. **Technical Reference Document: Balancing Authority Area Footprint Change* – Accept to post for 30-day Comment Period –** Greg Park, RS Chair | Rich Hydzik, Sponsor
8. **PRC-024 Inverter-Based Resources Whitepaper* – Approve –** Manish Patel, SPCWG Vice Chair | David Mulcahy, Sponsor
9. **Technical Reference Document: Transmission System Phase Backup Protection – Approve –** Manish Patel, SPCWG Vice Chair | David Mulcahy, Sponsor
10. **SPCWG Review of Reliability Guideline: Electromagnetic Transient Studies for Interconnection of Inverter-Based Resources (EMTTF Work Item #2)* – Information –** Manish Patel, SPCWG Vice Chair | David Mulcahy, Sponsor
11. RSTC HIGH PRIORITY **SAR: Revisions to FAC-001 and FAC-002* – Endorse –** Alex Shattuck, NERC Staff | Jody Green, Sponsor
12. **White Paper: Sampling as Part of an Effective Facility Ratings Program* – Approve –** Jennifer Flandermeyer, Chair FRTF | Ian Grant, Sponsor
13. **Revised Implementation Guidance: Reliability Standard FAC-008-5* – Endorse –** Robert Reinmuller, FRTF Team Lead | Ian Grant, Sponsor
14. **Review of Cold Weather Events Recommendations – Information –** Elsa Prince, NERC Staff
15. **Short Term Load Forecasting Panel Session – Information –** Elsa Prince/Matt Lewis, NERC Staff and Industry Experts
16. **Technical Reference Document - Clarity of DERs in Operational Planning Assessments and Real-Time Assessments* – Request RSTC Reviewers –** Shayan Rizvi, SPIDERWG Chair | Wayne Guttormson, Sponsor
17. **Balancing Authority Regulating Reserves – Information –** Greg Park, RS Chair | Rich Hydzik, Sponsor
18. **Interregional Transfer Capability Study (ITCS) – Information –** Saad Malik, NERC Staff
19. **Chair's Closing Remarks and Adjournment**

*Background materials included.

Addition to SPCWG Work Plan

Since 2009, the ERO has identified Protection System Misoperations as a risk to the reliability of the Bulk Electric System. The rate of Protection System Misoperations has been a reliability indicator since the inception of Adequate Level of Reliability (ALR) metrics. Each year, protection system misoperations are reported in the State of Reliability Report. The annual SOR document speaks to the statistical analysis of the misoperation rates year to year but can only speak to the causes of misoperations at a high level.

The NERC Planning Committee convened a Protection System Misoperation Task Force (PSMTF) in 2013 to perform deeper analysis on the causes of protection system misoperations. NERC staff produced Misoperation Analysis Reports in 2014 and 2015. Those reports also did more in-depth analysis of the causes of misoperations. Since 2015, the ERO has not produced an in-depth report on protection system misoperations.

In the 2013 PSMTF report, the task force stated: "The PSMTF and SPCS recommend that misoperation analysis be continued on an annual basis by the respective protection system subcommittees within the Regions. This analysis shall be forwarded to the NERC SPCS and NERC PAS for trending and metrics reporting."

The SPCWG believes that this is an important activity that should be done. The SPCWG would like to undertake this task and coordinate protection system misoperation analysis with the Regional protection system working groups/committees and produce an annual report that could be used by the Performance Analysis Subcommittee (PAS) for their annual State of Reliability Report.

Therefore, the SPCWG is requesting to add annual protection system misoperation analysis to it's work plan.

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 Motor Vehicle 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	**White Paper: Risk Mitigation Strategies to Manage Motor Vehicle Electrification** *A white paper on the focused high priority risks from the prioritization white paper also on the EVTF work plan. This paper is to provide recommended risk mitigation strategies that could be employed for all the risks as well as expand upon how utilities and EV manufacturers can ensure*	Q2 - 2025	In draft.
3	**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. This document will also cover model improvements to represent charging and discharging behavior of EVs and EV service equipment that the RSTC LMWG can build upon.*	Q4 – 2025	In draft.

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Large Loads Task Force (LLTF)

Draft Work Plan

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

#	Task Description	Target Completion	Status
1	**White Paper: Characteristics and Risks of Emerging Large Loads** *White Paper on the unique characteristics and risks associated with emerging large loads. This paper will leverage the NERC Framework to address known and emerging reliability and security risks to identify, validate, and prioritize potential reliability risks related to the integration of emerging large loads.*	Q2 – 2025	Not Started
2	**White Paper: Assessment of gaps in existing practices, requirements, and Reliability Standards for Emerging Large Loads** *White Paper assessing whether existing engineering practices, requirements, and Reliability Standards can adequately capture and mitigate reliability impact(s) of large loads interconnected to the BPS. The paper will also highlight gaps in load modeling practices that LMWG can leverage to take further action to improve load modeling.*	Q4 – 2025	Not Started
3	**Reliability Guideline: Risk Mitigation for Emerging Large Loads** *Reliability Guideline identifying risk mitigation including improvements to existing planning, and operation processes and interconnection requirements for large loads. Guidance may include recommended improvements to modeling practices, analyses, coordination and data collection efforts, real time monitoring and event analysis.*	Q2 – 2026	Not Started

RSTC Status Report 6 GHZ Task Force (6GHZTF)

Chair: Jennifer Flandermeyer
Vice Chair: Larry Butts
September 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

- Develop transition plan for TF

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 Transition Plan to Potential TWG or Disband	On Track	December 2024

EAS Status Report

RSTC Status Report – Event Analysis Subcommittee (EAS)

Chair: Chris Moran
Vice-Chair: James Hanson
September 11-12, 2024

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

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

Items for RSTC Action:

- None

Recent 2024 Activity

- Development of Lessons Learned – 2 published; 2 in development
- Development of FMM Diagrams – 3 approved; 3 in development
- FMMWG Scope Document Revised & Approved
- Conducted (2) EAP v5 Industry Webinars

Ongoing & Upcoming Activities

- Development of Lessons Learned
- Development of Lessons Learned Webinar(s) in 2024
- FMMWG Development of Failure Mode & Mechanism Diagrams
- Conduct Winter Weather Preparation Industry Webinar

Workplan Status *(6 month look-ahead)*

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

EGWG Status Report

RSTC Status Report – Electric Gas Working Group (EGWG)

Chair: Mike Knowland
Vice-Chair: Daniel Farmer
September 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:

- None

Workplan Status *(6 month look-ahead)*

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

Recent Activity

- RSTC approved the EGWG Scope on June 11, 2024
- EGWG meeting was held July 25, 2024.
- Argonne National Labs updated the group on their pilot project, Fuel Availability for Regional Flexible Resources to Support System Variability. The pilot will cover a small portion of the PJM footprint.
- PJM highlighted the paper that identifies key strategic issues revealed through event analysis.
- There were no actionable items.

Upcoming Activity

- The next EGWG engagement will be a joint hybrid meeting with the ERAWG and RAS on October 23, 2024 at NERC in Washington D.C.

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

Co-Chairs: Adam Sparacino, Miguel Acosta

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

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

Items for RSTC Approval/Discussion:

- Informational: Feedback on NERC Reliability Guideline on EMT Modeling for BPS-connected IBR – Recommended Model Requirements and Verification Practices (2023)

Recent Activity

- Technical Presentation: Challenges with Quality of EMT Model Submissions – Joy Brake, Nova Scotia Power
- Technical Presentation: IESO's EMT Adoption Roadmap – Dr. Mohamed ElNozahy, IESO
- ORNL-DOE-NERC EMT Workshop

Upcoming Activity

Workplan Status *(6 month look-ahead)*

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

Energy Reliability Assessment Working Group (ERAWG)

Chair: Mike Knowland
Vice Chair: David Mulcahy
September 2024

On Track
Schedule at risk
Milestone delayed

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

Recent Activity:

- The Tiger Team completed Volume 2 - a technical reference document with detailed scenarios on conducting energy reliability assessments in a variety of time horizons.

Items for RSTC Approval/Discussion:

- *None*

Upcoming Activity:

- At the conclusion of the 60-day comment period (6/17 – 8/16), the *Tiger Team* will reconvene to address the comments received on the technical reference document (Volume 2) and update as necessary.
- Provide technical assistance for the Project 2022-03 DT as needed.
- Next ERAWG meeting scheduled for September 18, 2024 | 1-2 p.m. ET

Workplan Status *(6 month look-ahead)*

Milestone	Status	Comments
Supporting DT for Project 2022-03.	On Track (green)	On Track
The Tiger Team will finalize the technical reference document (Volume 2).	On Track (green)	On Track
ERAWG to have a joint meeting with EGWG in October 2024.	On Track (green)	On Track

Facility Ratings Task Force (FRTF)

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

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

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

Items for RSTC Action:

- Approve: Whitepaper "Sampling as Part of an Effective Facility Ratings Program"
- Endorse: Implementation Guidance for FAC-008-5

Recent Activity:

- Held a leadership meeting to discuss progress and strategy on deliverables.
- Sub-teams 1 & 3 addressed comments received during the 30-day RSTC-approved postings.

Upcoming Activity:

- Sub-team 2: Support for Project 2021-08 Modifications to FAC-008 DT will continue 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.
- Next FRTF meeting scheduled for September 27, 2024 | 2-3 p.m. ET

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

Milestone	Status	Comments
Item 1 – Implementation Guidance on sustaining accurate Facility Ratings	Green	Complete
Item 2 – Support Project 2021-08 Modifications to FAC-008 DT	Green	On Track
Item 3 – Whitepaper on sampling for Facility Rating Programs	Green	Complete

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:

- Item 16: SAR for FAC-001 and FAC-002 Enhancements
  - Approve SAR

Recent Activity

- Approval of Item 22: Grid Forming White Paper

Upcoming Activity

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

Workplan Status *(6 month look-ahead)*

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

RSTC Status Report: Load Modeling Working Group (LMWG)

Chair: Kannan Sreenivasachar
Vice Chair: Robert J O'Keefe
September 11, 2024

On Track
Schedule at risk
Milestone delayed

Purpose: The LMWG is developing more effective modeling for the large 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

- Identified key concerns with the existing electronic load modeling and introduced some modeling considerations that will lead to more effective electronic load modeling.
- Identified challenges associated with large load interconnections and the associated modeling considerations.

Upcoming Activities

- Conduct Reliability Studies with EV Unidirectional EV Charger Model and Bidirectional EV Charger Model.
- Continue Review of Responses to Data Center Questionnaire
- Reviewing dynamic modeling / lab testing / disturbance monitoring for large loads

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 – Performance Analysis Subcommittee (PAS)

Chair: Heide Caswell
Vice-Chair: Peter Ashcroft
September 1, 2024

- On Track (green)
- Schedule at risk (yellow)
- Milestone delayed (red)
- Not started (white)
- Complete (blue)

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

Items for RSTC Approval/Discussion:

- TADS Section 1600 proposed update (Information)

Recent Activity

- Issuance of the 2024 State of Reliability Report.

Upcoming Activity

- 45-Day Public Comment Period for TADS Section 1600 proposed update

Workplan Status *(6 month look-ahead)*

Milestone	Status	Comments
2024 State of Reliability Report	Complete	2024 SOR was published in June 2024.
TADS Section 1600 update	On Track	*TADS Section 1600 is proposed to be updated to include load loss data, geographical locations, and equipment sub-codes*

RSTC Status Report – Probabilistic Assessment Working Group (PAWG)

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

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

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 (green)	Plan to complete by Q3 2024

Recent Activity

- Met August 06, 2024, and will meet in August 27-28 (2nd day is joint PAWG/RAS meeting) to go through initial set of results for 2024 ProbA .
- Initiated a sub-team to work on PAWG Work Plan Item to review/refresh PAWG Documents
- Started planning for 2025 Probabilistic Analysis Forum (PAF2025) by brainstorming on the topics to consider

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
- The sub-team of PAWG members will continue working on review PAWG documents and refresh them to align with enhanced ProbA/added Energy assessment component
- Continue on the planning of PAF2025

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
- Coordination with RTOS on work plan items

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: Dan Baker
September 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.

Recent Activity

- Quarterly review of interconnection performance
- Balancing Authority "High Speed Measurements" survey report reviewed.
- BASS User Guide being reviewed for possible updates
- RS identified a possible decline in interconnection CPS1 For the WI and EI during shoulder months. (RSTC Presentation)

Items for RSTC Approval/Discussion:

- BAA Footprint Change Reference Document – approval to post for industry comment

Upcoming Activity

- *In Person/Hybrid Meetings Scheduled*
  - *October 30th and 31st*
  - *Location: NERC Offices, Washington DC*
- *Joseph Marcrum will assume Chair of Frequency Working Group.*
- *Eastern Interconnection is performing a survey of Balancing Authority's Primary Inadvertent accumulation to determine trends for persistent high frequency*
- *BASS User Guide being reviewed for possible updates*
- *Guidelines Review*
  - *Operating Reserve Management – Draft by October 2024*
  - *Inadvertent Interchange – Draft by April 2025*

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

Milestone	Status	Comments
Support ERSWG Measures 1,2,4, and 6	On Track	Periodic review and consultation with NERC staff ongoing
Support FRAA Report development and endorse	On Track	Sent for RSTC acceptance at September meeting.

RSTC Status Report – Real Time Operating Subcommittee (RTOS)

Chair: Christopher Wakefield
Vice-Chair: Derek Hawkins
September 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

- Continued work related to the Cold Weather Report.

Items for RSTC Approval/Discussion:

N/A

Upcoming Activity

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

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:

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

Upcoming Activity

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

Workplan Status *(6 month look-ahead)*

Milestone	Status	Comments
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 Standards Committee response to RSTC letter regarding SCWG proposals	On Track	In Progress

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

Chair: Karl Perman
Vice Chair: Thomas Peterson
September 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:
- None

Recent Work Plan Activity
- Whitepaper: New Technology Enablement & Field Testing in RSTC comment period through Aug 31st.
- Security Guideline for Inverter-Based Resources launched and writing outline
- Security Guideline for Distributed Energy Resource Aggregators launched and writing outline

Upcoming Activity
- Launch of SITES sub-team and volunteer recruitment for AI/ML value gap analysis and Whitepaper development

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

Milestone	Status	Comments
Whitepaper: New Tech Enablement	Green (On Track)	Collecting / Incorporating RSTC Comments
Security Guideline for Inverter-Based Resources	Green (On Track)	Meeting bi-weekly. Writing Outline
Security Guideline for Distributed Energy Resource Aggregators	Green (On Track)	Meeting bi-weekly. Writing Outline

RSTC Status Report – Synchronized Measurement Working Group (SMWG)

Chair: Clifton Black
Vice-Chair: Open
September 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:

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

Recent Activity

- Held April SMWG Hybrid Meeting (4/18).
- Held July SMWG Virtual Meeting (7/30).

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.

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

Chair: Lynn Schroeder
Vice-Chair: Manish Patel
As of August 8, 2024

On Track
Schedule at risk
Milestone delayed

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

Items for RSTC Approval/Discussion:

Accept: PRC-024-3 white paper
Accept: Tech. Ref. Doc. Transmission System Phase Backup Protections
Accept: Comments on EMT Studies for Interconnection of Inverter-Based Resources

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
- Working to develop White paper on TPL-001-5.1 Footnote 13
- If work plan item was approved by the RSTC EC, begin work on a report analyzing misoperations
- Developing comments on the FERC ANOPR regarding implementation of Dynamic Line Ratings

Workplan Status *(6 month look-ahead)*

Milestone	Status	Comments
Ethernet P&C TRD	On Track	The outline is complete, and the writing portion continues
Review and update Transmission System Phase Backup Protections	On Track	Being submitted for acceptance
TPL-001-5.1 footnote 13	On Track	Team developing Implementation guidance
Steady-state approach for PRC-024-3 Evaluation for Inverter-Based Resources" white paper	On Track	Being submitted for acceptance
Misoperations Analysis Report	On Track	Working to identify appropriate dates and content based on current schedule

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

Chair: Shayan Rizvi (Jan 2024-2026)
Vice-Chair: John Schmall (Jan 2024-2026)
September 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.*

Recent Activity
- Met in July 2024 to update work products.
- Drafting comments from past RSTC and industry reviews
- Received RTOS favorable consensus for EOP-005 SAR work.

Items for RSTC Approval/Discussion:
- **RSTC Review**: *Technical Reference Document: Clarity of DERs in Operational Planning Assessments and Real-Time Assessments*

Upcoming Activity
- *Continue drafting of Reliability Guidelines from Standards Review White Paper*
- *Continue collaboration among the RSTC groups for SARs*
- *Respond to comment for White Paper on DER Aggregator Modeling*
- *Continue drafting response to RSTC on EOP-005 SAR.*

Workplan Status *(6 month look-ahead)*

See next slide for details

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

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	🟢	Received many technical comments. Anticipated return Q4 2024
C11 – White Paper: Variability, Uncertainty, and Data Collection for the BPS with DER Aggregators	🟢	Comment period ended and responding to comments. Returning Q4 2024
A3 – White Paper: Modeling of DER Aggregator and DERMS Functional Impacts	🟢	Seeking RSTC review in Q4 2024
Reliability Guideline: Detection of Aggregate DER Response during Grid Disturbances	🔴	In scoping and draft. Delayed to respond to other RG comments. Anticipated Q1 2025
Reliability Guideline: DER Forecasting	🟢	Comment period ends 8/15/24. Responding to comments after.
Reliability Guideline: Aggregate DER in Emergency Operations	🔴	In draft. Delayed to review operational work. Anticipated Q1 2025
Technical Reference Document: DERs and OPA-RTAs	🟢	On RSTC September Agenda

Work Look Ahead - SAR

- On Track
- Schedule at risk
- Milestone delayed

Workplan Status (6 month look-ahead)

Milestone	Status	Comments
C16 – SAR EOP-005	On Track	In draft. RTOS consensus activities ended Q2-Q3 2024. Anticipated return Q4 2024 or Q1 2025

RSTC Status Report – Security Working Group (SWG)

Co-Chair: Brent Sessions
Co-Chair: John Tracy
September 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
- Work Plan Updates
  - Removed potential Work Plan item Communication Protection System Guideline
- New Activity
  - Physical Security Sub-team formed

Items for RSTC Approval/Discussion:

- N / A

On-going Activity

- Continuation of Physical Security sub-team
  - Re-write of 2019 Physical Security Guideline
- CIP Implementation Guidance for Synchrophasors
  - Entity presentations continue at sub-team meetings for Synchrophasor use-cases
  - Both CIP and non-CIP approaches
- OLIR Mapping NIST800-53 to NERC CIP
  - Working through control families
  - Quality assurance of data
- Evidence Request Tool
  - Sub-team continues working revisions / updates to the ERT

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

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

Proposed RSTC Charter Revisions

Action

- Review revised RSTC Charter based on comments
- Approve the revised RSTC Charter for presentation of the NERC Board of Trustees (Board)
  - Clean Proposed RSTC Charter
  - Redline of Proposed RSTC Charter to Approved Version
  - Redline of Proposed RSTC Charter to May 2024 Version
  - Clean RSTC Nomination and Election Process
  - Redline RSTC Nomination and Election Process
  - Comment Matrix

Background

In November 2019, the NERC 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 at present provides that if a sector receives no nominations during the election process, the seat would 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 therefore developed targeted draft revisions to the RSTC Charter to address concerns with respect to balanced sector membership based on such lessons learned. These revisions were discussed on June 11, 2024 and sent to the RSTC for comment between June 12-July 22, 2024.

Five sets of comments were provided on the proposed changes. These comments fall within the following three overarching themes:

- Eliminate At-Large Conversion and Create Opportunity to Request Special Election: One commenter proposed that in lieu of the numerical cap on At Large Members from a particular sector, we eliminate the At Large conversion process and institute an opportunity for a special election if a Sector seeks one to fill an open seat.
- Numerical Cap in At Large Member Selection Process: All five commenters objected to the numerical cap on the number of representatives from a sector that could serve as At Large Members, on the basis that it would either be unnecessary if the Nominating Subcommittee selection criteria adds prioritization of sector balance and that this numerical limitation would hamper flexibility.
- Clarifications: These comments also include recommendations to (i) clarify how a Sector nomination for an open seat might be submitted during the At-Large nomination period, (ii) include the language prioritizing sector balance as part of the Nominating Subcommittee selection criteria rather than another sentence, and (iii) move NERC Staff notice to an existing Sector representative that their open Sector election has received no nominations to the RSTC Nomination and Election Process posted online.

Based on comments provided, the revised draft RSTC Charter would (i) eliminate the At Large conversion process and provide an opportunity for a Sector to seek a special election in writing if it has an open seat; (ii) provide the clarifications requested; (iii) remove the numerical cap on the number of representatives from a certain sector that may be recommended for At Large membership; and (iv) include a reference and citation to Section 1302 of the NERC Rules of Procedure ("ROP") stating that the recommended slate would not cause any two stakeholder Sectors to control the vote on any matter, and that no single Sector is able to defeat a matter. This would ensure that the RSTC Charter memorializes the existing expectation from the ROP to help safeguard balanced stakeholder representation.

The RSTC Nomination and Election Process that supports the RSTC's practical execution of the Charter's nomination and election requirements has also been updated for conforming changes, as well as to: (i) reflect NERC Staff notice to existing sector representatives if there has been no nomination during the election cycle for an open sector seat as this was thought to be more appropriate in the process document; and (ii) to help give color to the reference to Section 1302 of the NERC ROP by explaining that "For purposes of the ROP Section 1302 calculation, this means that if the Committee has a total of 34 voting members as contemplated in the Charter, no two sectors (when all seats, including at-large seats, are combined) should have more than 11 votes."

Summary

The proposed revisions would modify Section 3 Membership – Member Selection as follows:

- (2) Election of Sector Members:

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 seat will remain open~~s to at-large seats~~ until the end of the term unless a late sector nomination for the recent election is received prior to the end of the at-large nomination period. The RSTC Executive Committee (RSTC EC) may also call a special election for an open sector seat if requested in writing by the relevant sector.

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.

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 unless a special election is called by the RSTC EC based on a written request by the relevant sector. Interim sector vacancies will not be filled with an at-large representative.

These proposed revisions to the RSTC Charter would enhance the sector election process by: (i) eliminating the present At-Large conversion process which has caused this group of Members to swell; (ii) adding an opportunity for a sector to seek a special election if it has an open seat; and (iii) providing a longer grace period prior to conversion of an open sector seat to an at-large seat. NERC Staff's notification to underrepresented sectors that their sector has received no nominations for an open seat would be placed in the RSTC Nomination and Election Process on the RSTC website as recommended by one commenter.

- (4) Selection of At-Large Members

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~~. 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; and (d) sector balance. The RSTC NS selection process shall also ensure that consistent with Section 1302 of the NERC Rules of Procedure, the Nominating Subcommittee's recommended slate would not cause any two stakeholder Sectors to control the vote on any matter, and that no single Sector is able to defeat a matter.[4]

~~The Board votes to appoint the at-large members.~~

Fn. 4 would cite:

[4] *See*, NERC Rules of Procedure, at Section 1302 (stating in relevant part, "All committees and other subgroups (except for those organized on other than a Sector basis because Sector representation will not bring together the necessary diversity of opinions, technical knowledge and experience in a particular subject area) must ensure that no two stakeholder Sectors are able to control the vote on any matter, and no single Sector is able to defeat a matter.").

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. The recommended language would also memorialize the existing rule in Section 1302 of the ROP to help ensure balanced stakeholder representation.

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. *See also*, attached Charter and RSTC Nomination and Election Process redlines.

Next Steps
Request for approval of the RSTC Charter for presentation to the NERC Board.

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

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

Table of Contents

Preface

Electricity is a key component of the fabric of modern society and the Electric Reliability Organization (ERO) Enterprise serves to strengthen that fabric. The vision for the ERO Enterprise, 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 empty sector seat will remain open until the end of the term, unless a late sector nomination for the recent election is received prior to the end of the at-large nomination period. The RSTC Executive Committee (RSTC EC) may also call a special election for an open sector seat if requested in writing by a member from relevant sector with an empty seat, accompanied by supporting rationale for the RSTC EC's consideration.

   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 Notwithstanding the foregoing, upon written request from a member from relevant sector with an empty seat, accompanied by supporting rationale, the RSTC EC may hold an additional special in an attempt to fill the vacancy. 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 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. 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; (c) experience and expertise from an organization in the sector relevant to the RSTC; and (d) sector balance. The RSTC NS selection process shall be consistent with Section 1302 of the NERC Rules of Procedure such that the Nominating Subcommittee's recommended slate would not cause any two stakeholder Sectors to control the vote on any matter, and that no single Sector is able to defeat a matter.[4]

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.

[4] *See,* NERC Rules of Procedure, at Section 1302 (stating in relevant part, "All committees and other subgroups (except for those organized on other than a Sector basis because Sector representation will not bring together the necessary diversity of opinions, technical knowledge and experience in a particular subject area) must ensure that no two stakeholder Sectors are able to control the vote on any matter, and no single Sector is able to defeat a matter.").

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[5] and Participant Conduct Policy[6];
- 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**

---

5 https://www.nerc.com/pa/Stand/Resources/Documents/NERC_Antitrust_Compliances_Guidelines.pdf

6 https://www.nerc.com/gov/Annual%20Reports/NERC_Participant_Conduct_Policy.pdf

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 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. [7]

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.

[7] 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.[8]

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:

[8] 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[9] and Participant Conduct Policy[10].

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.

[9] https://www.nerc.com/pa/Stand/Resources/Documents/NERC_Antitrust_Compliances_Guidelines.pdf
[10] 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[11]

- 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.

[11] 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[12]

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.

[12] 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

Approved by the NERC Board of Trustees: February __, 2025

RELIABILITY | RESILIENCE | SECURITY




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

Table of Contents

Preface

Electricity is a key component of the fabric of modern society and the Electric Reliability Organization (ERO) Enterprise serves to strengthen that fabric. The vision for the ERO Enterprise, 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~~seat will remain open until the end of the term unless a ~~valid~~late sector nomination for the recent election 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~~The RSTC Executive Committee (RSTC EC) may also call a special election for an open sector seat if requested in writing by a member from relevant sector with an empty seat, accompanied by supporting rationale for the RSTC EC's consideration.

[3] Upon recognition of NERC as the ERO, Mexican Government representation will be equitable and based approximately on proportionate Net Energy for Load.

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.

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. Notwithstanding the foregoing, upon written request from a member from relevant sector with an empty seat, accompanied by supporting rationale, the RSTC EC may hold an additional special in an attempt to fill the vacancy. 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; and (d) sector balance. The RSTC NS selection process shall be~~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.~~consistent with Section 1302 of the NERC Rules of Procedure such that the Nominating Subcommittee's recommended slate would not cause any two stakeholder Sectors to control the vote on any matter, and that no single Sector is able to defeat a matter.[4]

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

[4] *See,* NERC Rules of Procedure, at Section 1302 (stating in relevant part, "All committees and other subgroups (except for those organized on other than a Sector basis because Sector representation will not bring together the necessary diversity of opinions, technical knowledge and experience in a particular subject area) must ensure that no two stakeholder Sectors are able to control the vote on any matter, and no single Sector is able to defeat a matter.").

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~~5] and Participant Conduct Policy[~~5~~6];
- 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**

[~~4~~5] https://www.nerc.com/pa/Stand/Resources/Documents/NERC_Antitrust_Compliances_Guidelines.pdf
[~~5~~6] https://www.nerc.com/gov/Annual%20Reports/NERC_Participant_Conduct_Policy.pdf

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 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~~7]

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.

[~~6~~7] 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~~8]

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~~8] 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[89] and Participant Conduct Policy[910].

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.

[89] https://www.nerc.com/pa/Stand/Resources/Documents/NERC_Antitrust_Compliances_Guidelines.pdf
[910] 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~~11]

- 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~~11] 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~~12]

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~~12] 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 20254

Approved by the NERC Board of Trustees: February __~~5~~, 20254

RELIABILITY | RESILIENCE | SECURITY




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

Table of Contents

Preface

Electricity is a key component of the fabric of modern society and the Electric Reliability Organization (ERO) Enterprise serves to strengthen that fabric. The vision for the ERO Enterprise, 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 seat will remain open ~~s~~ ~~to at-large seats~~ until the end of the term, unless a late sector nomination for the recent election is received prior to the end of the at-large nomination period. The RSTC Executive Committee (RSTC EC) may also call a special election for an open sector seat if requested in writing by a member from relevant sector with an empty seat, accompanied by supporting rationale for the RSTC EC's consideration.

   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 ~~.~~ Notwithstanding the foregoing, upon written request from a member from relevant sector with an empty seat, accompanied by supporting rationale, the RSTC EC may hold an additional special in an attempt to fill the vacancy. 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~~. 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; and (d) sector balance. ~~-~~The RSTC NS selection process shall be consistent with Section 1302 of the NERC Rules of Procedure such that the Nominating Subcommittee's recommended slate would not cause any two stakeholder Sectors to control the vote on any matter, and that no single Sector is able to defeat a matter.[4]

~~The Board votes to appoint the at-large members.~~

~~6.~~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.

~~7.~~6. International Representation

International representation on the RSTC shall be consistent with Article VIII Section 4 of the NERC Bylaws.

[4] *See,* NERC Rules of Procedure, at Section 1302 (stating in relevant part, "All committees and other subgroups (except for those organized on other than a Sector basis because Sector representation will not bring together the necessary diversity of opinions, technical knowledge and experience in a particular subject area) must ensure that no two stakeholder Sectors are able to control the vote on any matter, and no single Sector is able to defeat a matter.").

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[5] and Participant Conduct Policy[6];
- 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**

[5] https://www.nerc.com/pa/Stand/Resources/Documents/NERC_Antitrust_Compliances_Guidelines.pdf
[6] https://www.nerc.com/gov/Annual%20Reports/NERC_Participant_Conduct_Policy.pdf

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 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.[7]

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.

[7] 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.[8]

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:

[8] 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[9] and Participant Conduct Policy[10].

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.

[9] https://www.nerc.com/pa/Stand/Resources/Documents/NERC_Antitrust_Compliances_Guidelines.pdf
[10] 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[11]

- 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.

[11] 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[12]

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.

[12] 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.

Reliability and Security Technical Committee Nomination and Election Process

This document provides information on the Reliability and Security Technical Committee (RSTC) Sector election process, At-Large member selection process and the Chair and Vice Chair election process. The 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.

The RSTC has a hybrid representation model consisting of the following types of memberships:

- Sector members;
- At-Large members; and,
- Non-voting members.

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 empty sector seat will remain open until the end of the term unless a late sector nomination for the recent election is received prior to the end of the at-large nomination period. The RSTC Executive Committee (RSTC EC) may also call a special election for an open sector seat if requested in writing by a member from relevant sector with an empty seat, accompanied by supporting rationale for the RSTC EC's consideration.

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 its approval at its annual February meeting.

For the Sector election cycle, one voting member shall be elected to each of the following membership sectors:

- Sector 1 - Investor-owned Utility;
- Sector 2 - State/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.

Any Sector seat previously converted to an At-Large seat (Per the prior version of Section 3 of the RSTC Charter) with an expiring term will revert to the Sector seat for nominations and election.

A notice will be sent to industry with specific dates for individuals to self-nominate or nominate another individual for a specific Sector. Nominations will be vetted by NERC Staff to ensure that the nominees qualify for the stated Sector.

Sector elections will be conducted as follows:

1. Sector nominations will occur annually mid-October - mid-November.
2. NERC Staff will notify each RSTC member whose term is to expire in February for awareness prior to the nomination period.
3. 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
4. If more than one nominee is submitted for a Sector, elections will be held mid-to-late November. The election process is as follows:
   a. An announcement is made identifying the candidates and the voting dates.
   b. Each sector voter will rank order their preferences for the sector representatives. For example, if there are four candidates, a voter will assign a 1, 2, 3, or 4 to each candidate with 1 being their most preferred candidate and 4 being their least preferred candidate.

      Once all votes are cast, the number assigned by sector voters for each candidate will be calculated as a weighted score. For example, there are three nominees in a sector. If 10 sector members vote, the results would be:

	1st ranking	2nd ranking	3rd ranking	Total votes	Weighted Score
Nominee 1	5	4	1	10	2.40
Nominee 2	2	3	5	10	1.70
Nominee 3	3	3	4	10	1.90

Weighted score = (# 1st ranking*3) + (# 2nd ranking*2) + (# 3rd ranking *1)

Total Votes

For Nominee 1, the weighted score is 2.4 = {5*3) + (4*2) 1*1)

10

The candidate with the highest weighted score will be elected.

c. If there is a tie, there will be a runoff election between the tied candidates. This step will be repeated, if necessary, until there is a winner.

d. If a candidate is elected and withdraws their nomination prior to Board appointment, the second ranked candidate will be the elected candidate.

5. The sector nominations/elections will follow newly approved NERC Bylaws[1].

Selection of At-Large Members

After sector elections, the RSTC Nominating Subcommittee (NS) will evaluate the attributes of all sector reps to determine the additional expertise/diversity we need to seek for the At-Large nominees to meet the goals of the Charter:

- Selection of At-Large members will allow for better balancing of representation on the RSTC of the following:[2]
  - 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.);
  - Sector balance and,
  - North American countries, consistent with the NERC bylaws (Canada, Mexico, and U.S.).

This evaluation will occur late November to early December. The number of At-Large seats will be determined by:

- At-Large members whose terms expire in February
- Any vacant At-Large seat up to the ten contemplated in the Charter

The NS will announce the expertise/diversity they are seeking via e-mail (industry-wide) and seek nominations for At-Large members. The nomination period will be in December.

Once the At-Large nomination period ends, the NS will review all nominations and develop a slate of recommended candidates by mid-January to be presented to NERC Board of Trustees for appointment. In developing the slate or recommendations, the NS will consider the following:

---

[1] https://www.nerc.com/gov/Annual%20Reports/Amended%20and%20Restated%20Bylaws%204-5-21.pdf

[2] *See,* NERC Sector 13 in the NERC Bylaws (2021).

- All nominations that are from the same company or affiliate of any sector representative will be discarded per RSTC Charter provisions. (Section 3, Affiliates: "A company, including its affiliates, may not have more than one member on the RSTC.")
    - If there are two or more nominees from the same company or affiliate, they will be requested to coordinate on which one individual will be the At-Large nominee from that company.
- Review each nomination for the expertise/diversity as noted in the solicitation for At-Large nominations:
    - Ensure Regional Entity and Interconnection diversity (i.e., goal of having at least one representative from each Interconnection and Regional Entity footprint);
    - Ensure diverse subject matter expertise (Planning, Operating, or Security);
    - Ensure diverse representation of organizational types (Cooperatives, Investor-Owned Utilities, Public Power, Power Marketing Agencies, etc.);
    - Sector balance and,
    - Ensure appropriate level of Canadian representation
- Review each nomination for any additional information that is submitted with their nomination such as:
    - Current or prior technical committee membership
    - Current or prior ERO committee membership
    - Current or prior standard drafting team membership

Further, the selection process shall be consistent with Section 1302 of the NERC Rules of Procedure ("ROP") as stated in the Charter. For purposes of the ROP Section 1302 calculation, this means that if the Committee has a total of 34 voting members as contemplated in the Charter, no two sectors (when all seats, including at-large seats, are combined) should have more than 11 votes

At the February Board meeting, sector and At-Large members will be appointed. The first RSTC meeting for newly appointed Sector and At-Large members will be in March (specific dates TBD).

Selection of Officers

The RSTC will have two officers – one chair and one vice-chair. Officers shall be selected per the procedure in Section 5 of the RSTC Charter.

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Reliability and Security Technical Committee Nomination and Election Process

This document provides information on the Reliability and Security Technical Committee (RSTC) Sector election process, At-Large member selection process and the Chair and Vice Chair election process. The 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.

The RSTC has a hybrid representation model consisting of the following types of memberships:

- Sector members;
- At-Large members; and,
- Non-voting members.

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 empty sector seat will remain open until the end of the term unless a late sector nomination for the recent election is received prior to the end of the at-large nomination period. The RSTC Executive Committee (RSTC EC) may also call a special election for an open sector seat if requested in writing by a member from relevant sector with an empty seat, accompanied by supporting rationale for the RSTC EC's consideration. ~~In the event that a sector has no nominations for one or both sector seats at the annual election, the RSTC will convert those empty sector seats to At-Large seats until the end of the term.~~

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 its approval at its annual February meeting.

For the Sector election cycle, one voting member shall be elected to each of the following membership sectors:

- Sector 1 - Investor-owned Utility;

- Sector 2 - State/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.

Any Sector seat previously converted to an At-Large seat (Per the prior version of Section 3 of the RSTC Charter) with an expiring term will revert to the Sector seat for nominations and election.

A notice will be sent to industry with specific dates for individuals to self-nominate or nominate another individual for a specific Sector. Nominations will be vetted by NERC Staff to ensure that the nominees qualify for the stated Sector.

Sector elections will be conducted as follows:

1. Sector nominations will occur annually mid-October - mid-November.
2. NERC Staff will notify each RSTC member whose term is to expire in February for awareness prior to the nomination period.
~~2.~~3. 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
~~3.~~4. If more than one nominee is submitted for a Sector, elections will be held mid-to-late November. The election process is as follows:
   a. An announcement is made identifying the candidates and the voting dates.
   b. Each sector voter will rank order their preferences for the sector representatives. For example, if there are four candidates, a voter will assign a 1, 2, 3, or 4 to each candidate with 1 being their most preferred candidate and 4 being their least preferred candidate.

      Once all votes are cast, the number assigned by sector voters for each candidate will be calculated as a weighted score. For example, there are three nominees in a sector. If 10 sector members vote, the results would be:

	1st ranking	2nd ranking	3rd ranking	Total votes	Weighted Score
Nominee 1	5	4	1	10	2.40
Nominee 2	2	3	5	10	1.70

Nominee 3	3	3	4	10	1.90

Weighted score = (# 1st ranking*3) + (# 2nd ranking*2) + (# 3rd ranking *1)

Total Votes

For Nominee 1, the weighted score is 2.4 = {5*3) + (4*2) 1*1)

10

The candidate with the highest weighted score will be elected.

c. If there is a tie, there will be a runoff election between the tied candidates. This step will be repeated, if necessary, until there is a winner.

d. If a candidate is elected and withdraws their nomination prior to Board appointment, the second ranked candidate will be elected candidate.

~~4.~~5. The sector nominations/elections will follow newly approved NERC Bylaws[1].

Selection of At-Large Members

After sector elections, the RSTC Nominating Subcommittee (NS) will evaluate the attributes of all sector reps to determine the additional expertise/diversity we need to seek for the At-Large nominees to meet the goals of the Charter:

- Selection of At-Large members will allow for better balancing of representation on the RSTC of the following:[2]
  - 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.);
  - Sector balance and,
  - North American countries, consistent with the NERC bylaws (Canada, Mexico, and U.S.).

This evaluation will occur late November to early December. The number of At-Large seats will be determined by:

- ~~Five current~~ At-Large members whose terms expire in February
- Any vacant At-Large seat up to the ten contemplated in the Charter
- ~~Any vacant Sector seat that was converted to an At-Large seat with a term expiring in February~~

The NS will announce the expertise/diversity they are seeking via e-mail (industry-wide) and seek nominations for At-Large members. The nomination period will be in December.

[1] https://www.nerc.com/gov/Annual%20Reports/Amended%20and%20Restated%20Bylaws%204-5-21.pdf

[2] *See,* NERC Sector 13 in the NERC Bylaws (2021).

Once the At-Large nomination period ends, the NS will review all nominations and develop a slate of recommended candidates by mid-January to be presented to NERC Board of Trustees for appointment. In developing the slate or recommendations, the NS will consider the following:

- All nominations that are from the same company or affiliate of any sector representative will be discarded per RSTC Charter provisions. (Section 3, Affiliates: “A company, including its affiliates, may not have more than one member on the RSTC.”)
  - If there are two or more nominees from the same company or affiliate, they will be requested to coordinate on which one individual will be the At-Large nominee from that company.
- Review each nomination for the expertise/diversity as noted in the solicitation for At-Large nominations:
  - Ensure Regional Entity and Interconnection diversity (i.e., goal of having at least one representative from each Interconnection and Regional Entity footprint);
  - Ensure diverse subject matter expertise (Planning, Operating, or Security);
  - Ensure diverse representation of organizational types (Cooperatives, Investor-Owned Utilities, Public Power, Power Marketing Agencies, etc.);
  - Sector balance and,
  - Ensure appropriate level of Canadian representation
- Review each nomination for any additional information that is submitted with their nomination such as:
  - Current or prior technical committee membership
  - Current or prior ERO committee membership
  - Current or prior standard drafting team membership

Further, the selection process shall be consistent with Section 1302 of the NERC Rules of Procedure (“ROP”) as stated in the Charter. For purposes of the ROP Section 1302 calculation, this means that if the Committee has a total of 34 voting members as contemplated in the Charter, no two sectors (when all seats, including at-large seats, are combined) should have more than 11 votes

At the February Board meeting, sector and At-Large members will be appointed. The first RSTC meeting for newly appointed Sector and At-Large members will be in March (specific dates TBD).

Selection of Officers

The RSTC will have two officers – one chair and one vice-chair. Officers shall be selected per the procedure in Section 5 of the RSTC Charter.

Risks and Mitigation for Losing EMS Functions Reference Document

Action
Approve

Background
To identify the risks of losing EMS functions and share mitigation strategies to reduce these risks, the NERC Energy Management System Working Group (EMSWG) published the reference document Risk and Mitigations for Losing EMS Functions in December 2017. A second and third versions were endorsed by the RSTC in March 2021 and September 2022, respectively. Since the reference document is published biennially, the NERC EMSWG conducted an update in 2024 by analyzing the causes of EMS events reported through the ERO Event Analysis Process (EAP) from 2019–2023. The document includes identifying and discussing reliability and security risks due to the loss of EMS functions and presents risk mitigation strategies used by the industry.

Summary
The EMSWG updated the EMS reference document by analyzing the causes of EMS events reported through the ERO EAP from 2019–2023. The EMSWG is seeking the RSTC's approval of the document.

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Risks and Mitigations for Losing EMS Functions Reference Document

Version 4

September 2024

RELIABILITY | RESILIENCE | SECURITY

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

Table of Contents

Preface

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

Executive Summary

Loss of situational awareness is 1 of the 11 risks identified in the *2023 ERO Reliability Risk Priorities Report*.[1] Loss or degradation of situational awareness challenges the BPS by affecting the ability of personnel or automatic control systems to perceive and anticipate reductions of system reliability and take pre-emptive action.

An energy management system (EMS) is a computer-aided tool used by system operators to monitor, control, and optimize the performance of generation and/or transmission systems. The primary objective of an EMS is to provide situational awareness for system operators and allow remote control of devices to provide secure and stable operation of the Bulk Electric System (BES).

To identify the risks of losing EMS functions and share mitigation strategies to reduce these risks,[2] the NERC Energy Management System Working Group (EMSWG) published the reference document *Risk and Mitigations for Losing EMS Functions* in December 2017. The second version was published in March 2020 and the third[3] in September 2022.

Since the reference document is published biennially, the NERC EMSWG conducted an update in 2024 by analyzing the causes of EMS events reported through the ERO Event Analysis Process (EAP) between 2019 and 2023. The document includes identification and discussion of reliability and security risks due to the loss of EMS functions and presents risk mitigation strategies used by industry.

Conclusion

Based on data and information collected for this reference document, the following can be concluded:

- EMSs were highly reliable from 2019 to 2023. During this period, the loss of EMS functions did not lead to the loss of generators, transmission lines, or customer load.
- EOP-004-4 continues to affect EMS event reporting. In April 2019, EOP-004-4 was revised to require the reporting of the complete loss of monitoring or control capability at a BES control center for 30 continuous minutes or more. Loss of state estimator/real-time contingency analysis reporting has been declining since 2019. The complete loss of monitoring or control capability has been the most prevalent reported event failure since 2020. However, the ERO encourages partial-loss EMS reporting through the EAP for trending of potential reliability risks/impacts to the BES as some entities continue to do.
- Software is the major contributor to loss of state estimator/real-time contingency, and communications/maintenance are the major contributors to the complete loss of monitoring or control capability.
- Mitigating actions have been effectively applied during EMS events to manage risks within acceptable levels.
- The ERO EAP is used to analyze, track, and trend these outages. Lessons learned and best practices are shared with industry to improve overall EMS performance.
- The NERC Monitoring and Situational Awareness Technical Conference[4] provides a forum for vendor involvement to share knowledge and collaborate with industry to minimize the frequency and duration of EMS outages.

---

[1] *2023 ERO Reliability Risk Priorities Report:* https://www.nerc.com/comm/RISC/Related%20Files%20DL/RISC_ERO_Priorities_Report_2023_Board_Approved_Aug_17_2023.pdf
[2] This reference document is provided for guidance and does not reflect binding norms or mandatory requirements.
[3] *Risk and Mitigations for Losing EMS Functions Reference Document*—Version 3: https://www.nerc.com/comm/RSTC_Reliability_Guidelines/Risks_and_Mitigations_for_Losing_EMS_Functions_v3.pdf
[4] https://www.nerc.com/pa/rrm/Resources/Pages/Conferences-and-Workshops.aspx

Chapter 1: Energy Management System

An EMS is a system of advanced computer applications used by system operators to monitor, control, and optimize the performance of the generation and/or transmission system. An EMS that encompasses supervisory control and data acquisition (SCADA), telecommunications, and real-time reliability support tools is vital for situational awareness as well as making and implementing well-informed operating decisions. An EMS consists of both hardware and software. An EMS's hardware component consists of remote terminal units (RTU) at the substations, servers at the data centers, wired and wireless telecommunications systems, and the system control centers, including all the computers used to monitor and control the BES. An EMS's software component consists of application programs for the data acquisition, control, alarming, real-time calculations, and network analysis of power systems, including state estimation and contingency analysis.

The primary objective of an EMS is to provide situational awareness for system operators and allow remote control of devices to secure and stable operation of the BES. Situational awareness includes, but is not limited to, the following:

- The ability to monitor/control the frequency within the system operator's area
- The ability to monitor/control the status (open or closed) of switching devices as well as real and reactive power flows on generators, BES tie-lines, and transmission facilities within the system operator's areas
- The ability to monitor/control voltage and reactive resources
- The ability to monitor the status of applicable EMS applications, such as real-time contingency analysis (RTCA) and/or alarm management

System operators can use this information pertaining to situational awareness to take actions that affect the reliability and resiliency of the BES. Generation can be dispatched or taken off-line to prevent overloads and improve the voltage in an area. Capacitor banks, shunt devices, synchronous condensers, or other voltage-controlling tools can be utilized to maintain voltage limits. Transmission breakers and remote-controlled switches can be opened or closed as needed to address real-time and contingency conditions.

In an EMS, application programs run in a real-time or extended real-time environment to keep the power system in a secure operating condition. These EMS applications include SCADA, alarm processing, automatic generation control (AGC), network applications (including state estimation), power flow, contingency analysis or security analysis, and data historians. **Figure 1.1** shows a simplified EMS configuration.

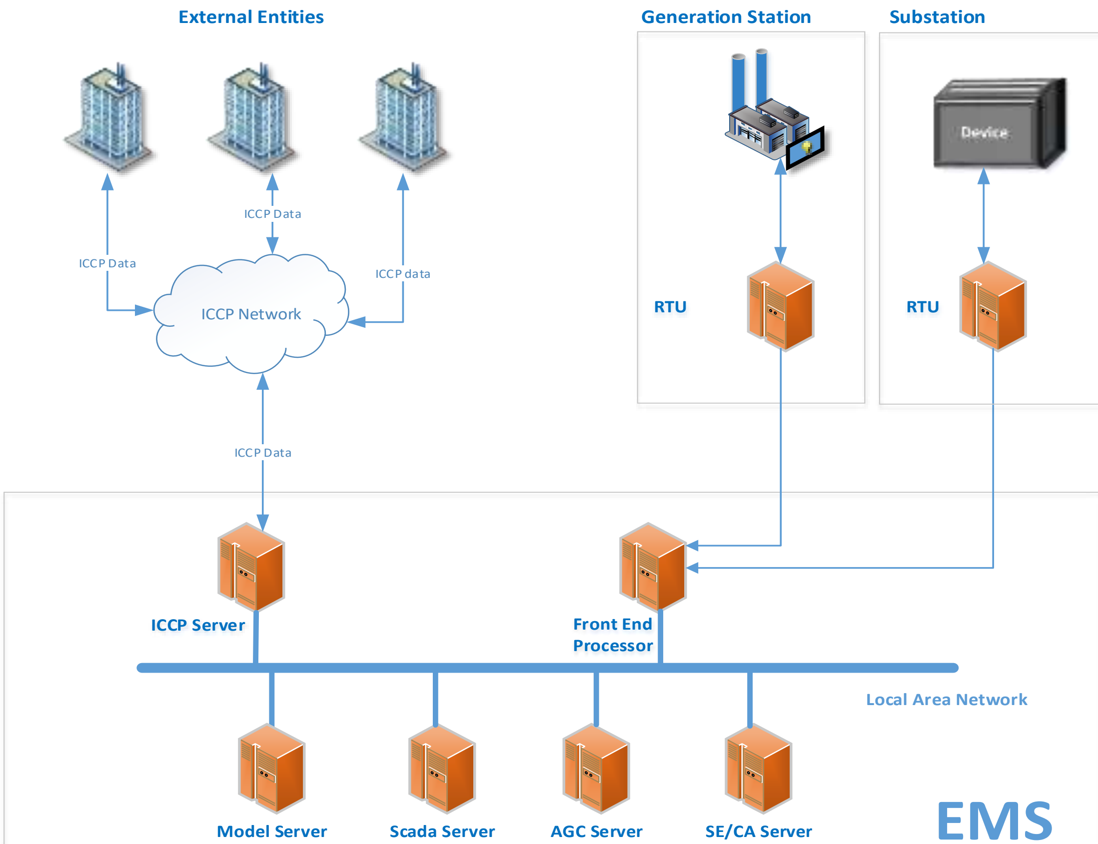


Figure 1.1: A Simplified EMS Configuration

Inter-Control Center Protocol (ICCP): ICCP has been standardized under the IEC 60870-6 specifications and allows the exchange of real-time and historical power system monitoring and control data, including measured values, data quality codes, scheduling data, energy accounting data, and operator messages. Data exchange can occur over wide-area networks between utility control centers, utilities, power pools, regional control centers, and non-utility generators.

SCADA: SCADA is a category of software application programs for process control and the gathering of data in real time from remote locations in order to control devices and monitor conditions. SCADA sends and receives telemetered data between the RTU or ICCP link and the control center. Control signals are sent from the operator's desk at the control center back to the field to change the status of devices (e.g., open or close breakers) or adjust generation.

RTU: An RTU is a microprocessor-controlled electronic device that interfaces devices in the physical world with a distributed control system or SCADA system by transmitting telemetry data to a master system and by using messages from the master supervisory system to control connected devices.

Front End Processor (FEP): An FEP interfaces the host computer to a number of networks, such as systems network architecture or a number of peripheral devices (e.g., RTUs, terminals, disk units, printers, and tape units). Data is transferred between the host computer and the front-end processor by using a high-speed parallel interface. The FEP communicates with peripheral devices by using slower serial interfaces, usually also through communication networks. The purpose is to offload the work of managing the peripheral devices, transmitting and receiving messages, packet assembly and disassembly, error detection, and error correction from the host computer.

AGC: An AGC is an application for adjusting the power output of multiple generators at different power plants in response to changes in interchange, load, generation, and frequency error. AGC software uses real-time data, such as frequency, actual generation, tie-line load flows, and plant controller status, to determine generation changes.

State Estimator (SE): An SE is an application that calculates the current state of the electric system (the voltage magnitudes and angles at every bus) by using a network model and telemetered measurements. The purpose is to provide a consistent base case for use by other network applications programs, such as power flow and contingency analysis. While SCADA relies on direct telemetered values from the RTUs, the state estimator is able to calculate and predict non-metered values to provide additional situational awareness to the system operators.

RTCA: An RTCA is an application used to predict electric system conditions after simulating specific contingencies. It relies on a base case from an SE or power flow case.

In an EMS, voltage magnitudes and power flows through equipment are continuously monitored through SCADA, SE, and RTCA to check for voltage/thermal exceedance. The EMS system is programmed with limits on the BES equipment being monitored. These limits are used with alarm processing to send visual and audio alarms to the system operators when monitored quantities are approaching or exceeding the threshold of an operating limit. AGC computes a balancing area's area control error (ACE) from interchange and frequency data. ACE determines whether a system is in balance or adjustments need to be made to generation. AGC software also determines the required output for generating resources while observing energy balance and frequency control by sending set-points to generators. The scheduled tie-line power flows are maintained by adjusting the real power output of the AGC-controlled generators to accommodate fluctuating load demands.

The typical dependency between the main EMS applications is illustrated in **Figure 1.2**.

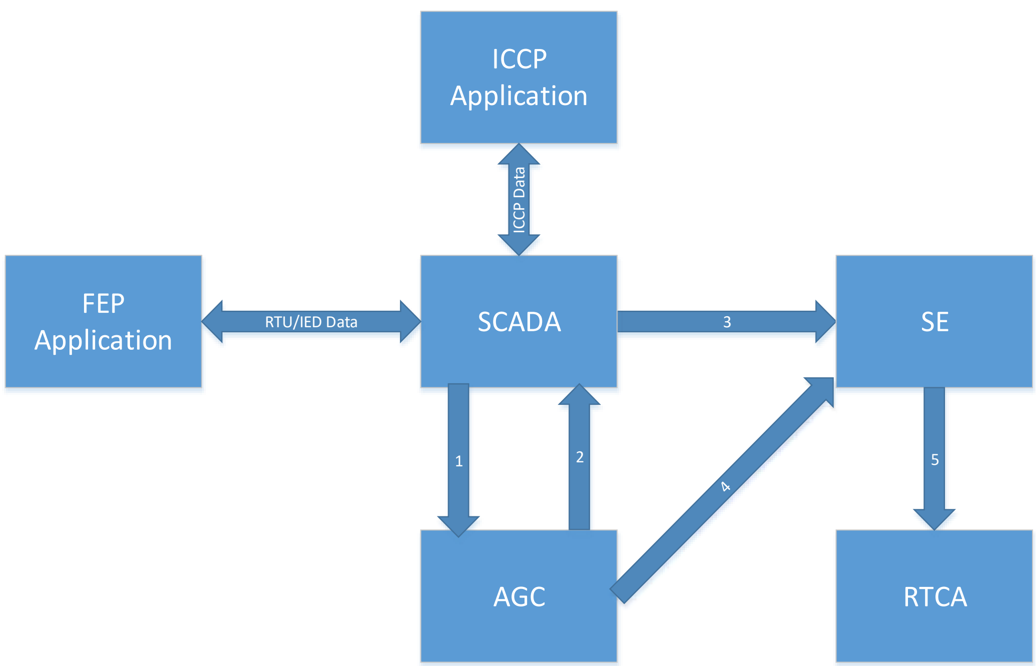


Figure 1.2: Typical Dependency Between Main EMS Applications

The data flows between the EMS functions shown in **Figure 1.2** are described below:

- **ICCP Data** (between ICCP application and SCADA): Real-time and historical power system monitoring and control data, including measured values, data quality codes, scheduling data, energy accounting data, generator set-point controls, and operator messages
- **RTU Data** (between FEP application and SCADA): Data from substation devices and commands to substation devices. This data includes the following:
  - Measured values
  - Position indication
  - Positioning commands
  - Alarms
- **Path 1** (from SCADA to AGC): Telemetered status data and analogue value data that includes the following:
  - Area frequency
  - Tie-line MW
  - Generator unit on-line/off-line
  - Generator unit control local or remote
  - Generator unit MW output
  - Generator unit MW set-point feedback
  - Generator unit MW limits
- **Path 2** (from AGC to SCADA): New set-point controls calculated by AGC
- **Path 3** (from SCADA to SE): The data typically consists of the following:
  - Breaker status (open or closed)
  - Switch status (open or closed)
  - Transformer tap settings
  - MW flow measurements
  - MVAR flow measurements
  - Voltage magnitude measurements
  - Current magnitude measurements
  - Phase angle difference measurements
  - High-voltage direct current (HVDC) operating modes
  - Tagging status
  - Special measurements defined by users
- **Path 4** (from AGC to SE): The data typically consists of the following:
  - Generator unit control (local or remote)
  - Generator unit MW output
  - Generator unit MW limits

- **Path 5** (from SE to RTCA): A base-case solution typically consists of the following:
  - System topology
  - Voltage magnitudes and angles at each bus
  - Transformer tap settings
  - Generator unit control status
  - Generator unit MW limits
  - HVDC operating modes
  - VAR status

Chapter 2: Analysis of Loss of EMS Functions

This section discusses the risks of losing EMS functions, analyzes reasons for the loss of EMS functions based on EMS events reported by 132 NERC compliance registries (NCR) between 2019 and 2023, and presents mitigation strategies to reduce the risk when one or more EMS functions are temporarily lost or disabled.

Risks of Loss of EMS Functions

The BES operates in a dynamic environment, and its physical properties are constantly changing. Situational awareness is necessary to maintain reliability, anticipate events, and respond appropriately when or before events occur.

Without the appropriate tools and data, system operators may have degraded situational awareness to make decisions that ensure reliability for a given condition of the BES. Certain essential functional capabilities must be in place with up-to-date information for staff to make informed decisions. An essential component of monitoring and situational awareness is the availability of information when needed. Unexpected outages of functions or planned outages without appropriate coordination or oversight can leave system operators with impaired visibility. While failure of a decision-support tool has not directly led to the loss of generators, transmission lines, or customer load, such failures may hinder the decision-making capabilities of the system operators during a disturbance. NERC has analyzed data and identified that short-term outages of tools and monitoring systems are not uncommon, and the industry is committed to reducing the frequency and duration of these types of events.

The BES reliability risk due to EMS function failures varies depending on the function that is lost and the duration of that outage. Some examples are listed below:

- **Complete Loss of Monitoring or Control Capability including Loss of SCADA**
  The complete loss would likely be the most impactful EMS failure. The system operators would not have indication of the status of devices or key data points, such as MW, MVAR, current, voltage, or frequency from the RTUs. Furthermore, the system operators would not be able to open and close breakers or switches remotely from the control center. SCADA data feeds AGC and SE/RTCA applications; loss of quality data would compromise their functionality.
- **Loss of ICCP**
  The loss of ICCP would disrupt the information that is shared between Transmission Operators (TOP), Balancing Authorities (BA), Generation Operators (GOP), and Reliability Coordinators (RC). The RCs rely on information from their BAs and TOPs to monitor the wider area, and an ICCP outage may remove real-time updates from the affected section of the model.
- **Loss of RTU**
  RTU loss would involve the system operators losing information on devices and control of the devices. The situation could be mitigated by staffing the substation in order to provide manual updates.
- **Loss of AGC**
  The loss of AGC prevents the system operator from automatically maintaining system frequency, net tie-line interchanges, and optimal generation levels close to scheduled (or specified) values.
- **Loss of SE**
  The loss of SE would involve the system operators losing the situational awareness not directly provided by the SCADA system. While the system operators would still have SCADA, which would provide control and indication of all telemetered devices, the loss of SE would eliminate other key data values that help the system operators monitor the system as well as limit the predictive analysis that the EMS provides. The loss of SE would also cause the loss of the associated contingency analysis tool since that tool relies on a valid SE solution to run.

- **Loss of RTCA**
  The loss of RTCA would prevent alerting the system operators if a contingency presents a potential reliability issue, compromising situational awareness and reliability and increasing the complexity of performing real-time assessments.

Reasons for Loss of EMS Functions

There were 263 EMS events reported between 2019 and 2023 through the EAP. These include the loss of SCADA, ICCP, RTU, AGC, SE, RTCA, or a combination of these functions for 30 or more continuous minutes. Figure 2.1 shows a trend of the reported EMS events by loss of EMS functions over the 2019–2023 period. Partial-loss events (i.e., loss of SE/RTCA, loss of ICCP, loss of RTU, and loss of AGC) have been declining since 2019.

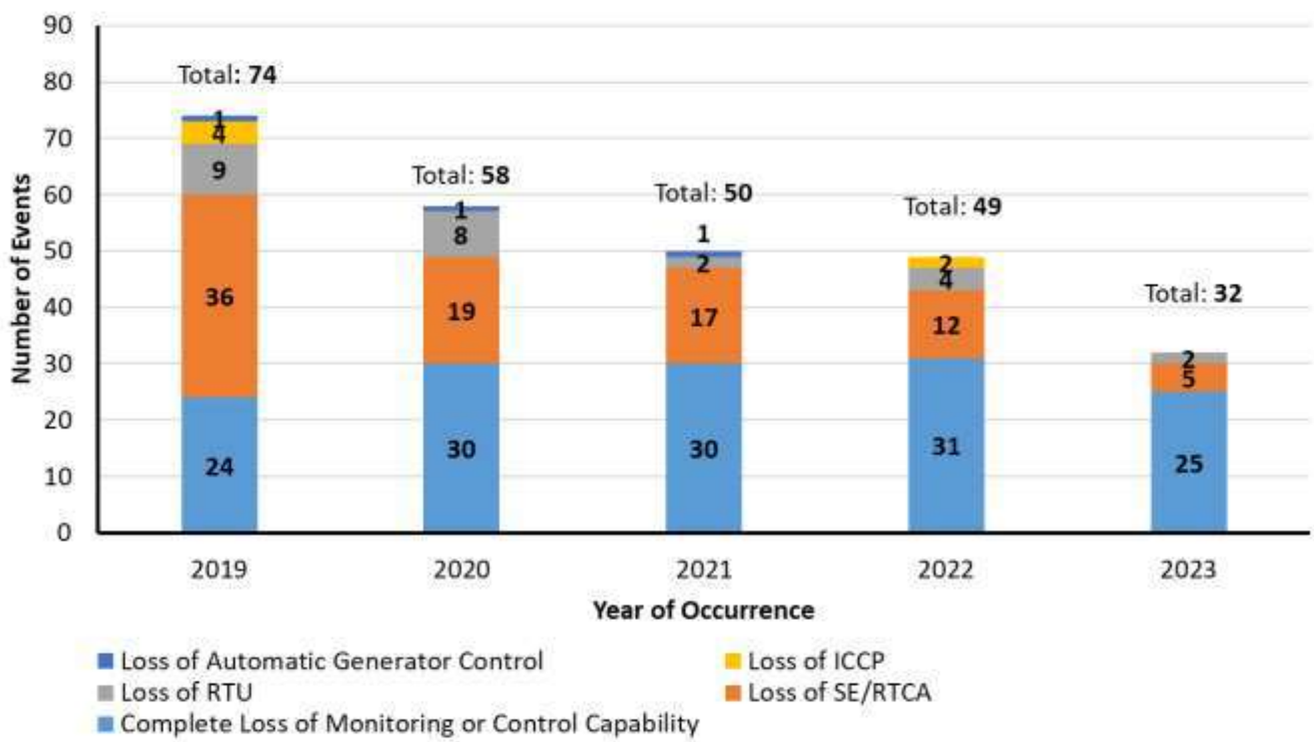


Figure 2.1: Number of EMS-Related Events (2019–2023)

There are two reasons for the declining trend of partial-loss events:

- Partial-loss events are no longer captured as part of EOP-004-4 mandatory reporting. NERC standard EOP-004-4 was modified to require the reporting of the complete loss of monitoring or control capability at a BES control center for 30 continuous minutes or more. The modified NERC Reliability Standard went into effect on April 1, 2019, in the United States and some Canadian provinces. However, the ERO encourages partial-loss EMS reporting through the EAP for trending of potential reliability risks/impacts to the BES as some entities continue to do.
- The industry has made significant efforts to enhance EMS reliability and resilience. For example, many entities built a 24x7 onsite team that works along with system operators and provides dedicated support for SE and RTCA. This action has significantly reduced the outage duration, rendering many SE/RTCA issues not reportable.

The complete loss of monitoring or control capability events increased from 2019 to 2022 but dropped back to 25 in 2023. Improvements to the database and system configuration/settings in 2023 contributed to the decrease.

Settings: Periodic review of system parameters and settings with vendor support has been shown to reduce settings errors. Different flags and weighting levels may need to be adjusted as models are expanded or system conditions change.

Skill Development: Hiring more skilled in-house personnel who can troubleshoot and correct these issues can decrease outage durations, including additional knowledge transfer from the vendor to the in-house staff.

The reported EMS events can be grouped by the following attributes:

- **Software:** Software defects, modeling issues, database corruption, memory issues, etc.
- **Communications:** Device issues (e.g., RTU failure, FEP failure, fiber failure, network router failure), changes made (e.g., firewall failure), or less-than-adequate system interactions (e.g., bad telemetered data quality)
- **Maintenance:** System upgrades, job scoping, change management, risk identification, and other themes, such as testing in a controlled environment and implementing the change (e.g., system/software configuration or settings failure, patch change, or implementation that causes EMS functions to crash)
- **Facility:** Loss of power to the control center or data center, fire alarm, ac power failure, etc.

Table 2.1 breaks down the attributes in each EMS function failure. Software is the major contributor to loss of SE/RTCA, while communications/maintenance are the two major contributors to the complete loss of monitoring or control capability.

Table 2.1: Contributors to Loss of EMS Functions

Failure	Software	Communications	Maintenance	Facility	Total
Complete loss of monitoring or control capability	31	49	39	21	**140**
Loss of SE/RTCA	49	10	27	3	**89**
Loss of RTU	2	11	5	7	**25**
Loss of ICCP		5		1	**6**
Loss of AGC	1		2		**3**
Total	**83**	**75**	**73**	**32**	**263**

Based on the analysis of the EMS events reported, the following recommendations are made to reduce the loss of situational awareness risks due to loss of EMS functions:

- **Maintaining Models**
  The models of the electric grid are critical for EMS functions. Models should be periodically maintained but promptly updated after BES changes have been completed in the field, such as when new transmission or generation device(s) are put into service or when devices are retired. Otherwise, EMS functions cannot present proper real-time changes (e.g., topology, MW output) related to these devices and sequentially yield

unsolved or incorrect solutions.[5] For a major model release,[6] entities should perform front- and back-end data validations and field-by-field comparisons of all databases that are not limited to fields or areas with previously identified issues. Entities should run regression testing with new models in a comprehensive test environment and ensure the applications can consume the new models and yield similar or improved results.

- **Looking Beyond Geographic Diversity Alone for Data Communications Redundancy**
  When contracting with multiple vendors for redundancy in data communications services, one should never assume that geographic diversity alone provides redundancy. This is because there is a point of convergence that may exist at a common hub that becomes a single point of failure. To ensure redundant physical circuit separation and independence of supporting equipment and power, the duration of the service should be specified in the contract. Also, to validate independence, testing should be performed that simulates this failure to ensure that the redundancy in place covers this scenario. More details on this topic are provided in the lessons learned titled *Telecom Provider Failure Induced Loss of ICCP from Regional Neighbors*[7] and *Intermittent Network Connection Causes EMS Disruption*.[8]

- **Network Communications Configuration**
  EMS-related communications networks are moving from point-to-point serial communication infrastructures to packet-based networks. The main advantage of packet-based networks is that data can be transmitted from node to node while avoiding a communications system failure caused by the breakdown of a single (or few) intermediate link(s). Consequently, the correct configuration is critical to ensure that the communications network functions as designed. This led to the following recommendations:
  - Establish standardized settings for network devices.
  - Complete physical separation between SCADA operations networks and business networks, voice over internet protocol, and external-facing networks is preferred over virtual local area networks to avoid network traffic congestion and security issues.[9]
  - Work with switch vendors to configure a firewall health check that continuously confirms the ability to reach devices beyond the directly connected switch. The firewall health check should allow for an automated firewall high-availability failover in the event of a similar "half failure" of the directly connected switch in the future.[10]

- **Alarming**
  Alarming has not initiated any EMS events; however, an improper configuration can degrade the system operator's situational awareness. A risk assessment should be performed to determine any gaps in alarming. Alarming quantity, visualization, and even sound effects vary widely. It is essential for the entity to not only determine what alarms are needed but also to assess what can cause them to fail or otherwise go

[5] Lessons learned *Model Data Error Impacts State Estimator and Real-Time Contingency Analysis Results* https://www.nerc.com/pa/rrm/ea/Lessons%20Learned%20Document%20Library/LL20220403_Model_Data_Error_Impacts_SE_and_RTCA.pdf

[6] Lessons Learned *EMS Pausing During Database Deployment* https://www.nerc.com/pa/rrm/ea/Lessons%20Learned%20Document%20Library/LL20220801_EMS_pausing_during_database_deployment.pdf

[7] Lessons learned *Telecom Provider Failure Induced Loss of ICCP from Regional Neighbors*: https://www.nerc.com/pa/rrm/ea/Lessons%20Learned%20Document%20Library/20190503_Loss_of_ICCP_from_Regional_Neighbors.pdf

[8] Lessons learned *Intermittent Network Connection Causes EMS Disruption* https://www.nerc.com/pa/rrm/ea/Lessons%20Learned%20Document%20Library/LL20220406_Intermittent_Network_Connection_Causes_EMS_Disruption.pdf

[9] Lessons learned *Networking Packet Broadcast Storms:* https://www.nerc.com/pa/rrm/ea/Lessons%20Learned%20Document%20Library/LL20181001_Networking_Packet_Broadcast_Storms.pdf

[10] Lessons learned *Loss of Monitoring due to a "Half Failed" High Availability Switch Pair* https://www.nerc.com/pa/rrm/ea/Lessons%20Learned%20Document%20Library/LL20230801_Loss_of_Monitoring_Half_Failed_High_Availability_Switch_Pair.pdf

unnoticed.[11] The NERC Standards TOP-010 R4 and IRO-018 R3 require a separate alarm process monitor. This helps increase operator situational awareness and reduce significant events when the alarm processor fails.

- **Power Supply**
  Stable and secure power supplies are critical to control rooms, data centers, and substations. Although the redundant power supply was installed at the control rooms, data centers, and substations, it is essential for the backup generator, uninterruptible power supply, and associated power switches to be tested and maintained monthly. More recommendations are provided in the lesson learned titled *Loss of Monitoring or Control Capability due to Power Supply Failure*.[12]

- **Dealing with Abnormal Working Environment**
  In 2020, entities implemented work-from-home policies for nonessential employees. Many tasks (like maintenance, software/database deployment, etc.) that were normally conducted onsite had to be executed remotely. Job scoping needs improvement to involve all potentially impacted groups and departments and strengthen peer review of design, implementation, and testing. Many entities also implemented working split shifts both at the primary and backup control centers in order to practice social distancing. It is recommended to improve appropriate materials/tools that allow working shifts to monitor and control the BES from backup control centers.

- **EMS Platform Upgrade**
  The challenges that entities usually face during an EMS upgrade are primarily due to the confluence of change from the EMS upgrade and the model tool/application implementation. Entities should ensure the following actions concerning EMS upgrades:
  - Entities should develop a more holistic approach to aligning the models with EMS revisions.
  - Entities should strengthen communications with vendors and increase knowledge transfer from vendors.
  - Vendors should document all new data fields in their release packages, and the entity should understand their impacts and modify or create in-house tools accordingly.

- **Completed Software Testing Process**
  Systems and software assurance requires a process model for formal testing based upon the software development framework within which the software was created. The scope of the test should provide an assurance case for operation of the software under test for both known and unknown operating conditions with the inclusion of a data integrity check of the module. In general, the process is considered to have four components:[13]
  - **Test Scope:** Define the test environment requirements and setup, features/functions that need to be tested, documentation and produce as output, approval workflows, etc.
  - **Test Design:** Design the test cases that are necessary to validate the system/functions/features being built compared to its design requirements (regression and incremental testing typically necessary)
  - **Test Execution:** Execute tests in many different ways
  - **Test Closure:** Consider the exit criteria for signaling completion of the test cycle and readiness for release

[11] Lessons learned *Enhanced Alarming Can Help Detect State Estimator and Real-Time Contingency Analysis Issues:* https://www.nerc.com/pa/rrm/ea/Lessons%20Learned%20Document%20Library/20190502_Enhanced_Alarming_helps_detect_SE_RTCA_issues.pdf

[12] Lessons learned *Loss of Monitoring or Control Capability due to Power Supply Failure:* https://www.nerc.com/pa/rrm/ea/Lessons%20Learned%20Document%20Library/20190801_Loss_of_Monitoring_Control_due_to_Power_Supply_Failure.pdf

[13] Lessons learned *Loss of Automatic Generation Control During Routine Update* https://www.nerc.com/pa/rrm/ea/Lessons%20Learned%20Document%20Library/LL20200403_Loss_of_AGC_During_Routine_Update.pdf

Mitigations for the Risk of Loss of EMS Functions

Out of all the reported events from 2019 to 2023, no EMS event that led to the loss of generation, transmission lines, or customer load was reported. The 263 reported EMS events during this span were approximately 73 minutes in duration on average. The following mitigations have been effectively applied to manage the risks within acceptable levels:

- Enhanced system restoration plans that include drills and training on the procedures and real-life practice implementing the procedures
- Overlapping coverage of situational awareness with RCs and neighboring TOPs and BAs so that the system is being continuously monitored by additional entities outside of that immediate footprint. (This is further strengthened by additional ICCP data points from generators and tie-lines that can provide visibility.)
  - The RC notifies adjacent RCs, TOPs, and BAs within its RC area when it loses essential real-time tools capability. Once notified by an RC of problems with the RC real-time tools, RC area TOPs and BAs or adjacent RC(s) will report any detected BES outages or abnormal BES conditions, including abnormal conditions related to generation, loads or tie-line flows, or SOL exceedances, to their (or the affected) RC until normal monitoring capabilities are restored. During this same time period, TOPs and BAs also report any significant real-time or post-contingent overloads or voltage limit deviations to their RC.
  - With an extended and continued loss of essential real-time tools, a BA/TOP notifies their RC and their neighboring entities (known impacted interconnected entities) of the tool problem or degradation being experienced as soon as practical but generally within 30 minutes of the loss. The notification generally includes the following:
    - A single point of contact and preferred method of communication
    - Extent of the real-time tool loss and systems impacted (to understand the magnitude)
    - Plan and status for corrective actions to restore lost functionality
    - Any requested assistance and plan for maintaining system monitoring and control
    - Estimated time for restoration of functionality (if known)
    - An agreed-upon schedule for periodic updates
- Off-line tools (studies) that can be used for analyzing contingencies plus other contingency-analysis, including day-ahead studies, seasonal and standing operating guides, and system operator training
- Backup tools and functionality that include backup EMS systems, backup control centers, and other additional redundancy
- Collaboration with vendors to build comprehensive testing procedures and/or troubleshoot the cause of the failure to minimize the system recovery time
- Manning substations during EMS events so that system operators and field personnel can take actions as needed (e.g., open/close breakers), verify status of devices, and verify power flows and voltages
- Internally defined conservative operations procedures used during EMS events (e.g., no switching, additional monitoring, staffing substations, and asking neighbors for assistance)
- Periodic routines that regularly test and maintain the backup generator, uninterruptible power supply, and associated power switches to verify and ensure that power supply redundancy has been implemented in control rooms, data centers, and substations
- Dedicated and skilled in-house personnel who can troubleshoot/correct issues with real-time tools and training provided to improve/increase knowledge transfer from the vendor

- Different mechanisms that have been built or set up for notifications:
  - Normal phone communication capabilities (e.g., phones, cell phones, satellite, radio)
  - Emergency hotline system or "blast call" system
  - NERC Reliability Coordinator Information System[14]
  - WECC-wide messaging system[15]

The Federal Energy Regulatory Commission (FERC) and NERC conducted the *Planning Restoration Absent SCADA or EMS (PRASE report)* study,[16] which focused on the potential impact of the loss of EMS, SCADA, or ICCP functionality on system restoration and the manner in which such impact could be mitigated. The objective of the study was to assess entities' system restoration plan steps in the absence of EMS, SCADA, and/or ICCP data and identify viable resources, methods, or practices that would expedite system restoration despite the loss of such systems. The following was concluded in the PRASE report:

- All volunteer registered entities have made significant investments in their SCADA and EMS infrastructures, including leveraging redundancies to increase availability and functionality.
- All volunteer registered entities would remain capable of executing their restoration plan without SCADA/EMS availability.
- Five recommendations are provided for all entities responsible for system restoration, as follows:
  - Planning for backup communications measures
  - Planning for personnel support during system restoration absent SCADA
  - Planning backup power supplies for an extended period of time
  - Analysis tools for system restoration
  - Incorporating loss of SCADA or EMS scenarios in system restoration training

TOPs and RCs have been requested to perform real-time assessments since NERC Standards TOP-001-5, Requirement R13, IRO-008-2, and Requirement R4. The ERO Enterprise has endorsed compliance implementation guidance (CIG)[17] to help NERC registered entities establish a common understanding of the practices and processes surrounding the completion of a real-time assessment. This guidance also offers examples for managing real-time assessments with or without the use of RTCA tools or other support applications.

To avoid single points of failure in primary control center data exchange infrastructure, the redundant and diversely routed data exchange infrastructure within the primary control center and associated tests for redundant functionality are required by NERC Reliability Standards TOP-001-6, Requirements R20, R21, R23, and R24, and IRO-002-7 Requirements R2 and R3. The NERC Data Exchange Infrastructure Requirements Task Force developed a CIG[18] from the perspective of the Reliability Standards. The CIG discusses data exchange infrastructure reference models

[14] The system the RCs use to post messages and share operating information in Real-time is called the Reliability Coordinator Information System.
[15] AESO, BC Hydro RC, and RC West will use the Grid Messaging System (GMS); SPP will use the Reliability Communication Tool.
[16] *FERC-NERC-Regional Entity Joint Review of Restoration and Recovery Plans:* https://www.ferc.gov/legal/staff-reports/2017/06-09-17-FERC-NERC-Report.pdf
[17] TOP-001-3 R13 and IRO-008-2 R4 *NERC Operating Committed Compliance Implementation Guidance Real-time Assessments*: https://www.nerc.com/pa/comp/guidance/EROEndorsedImplementationGuidance/TOP-001-3%20R13%20and%20IRO-008-2%20R4%20Real%20Time%20Assessments%20(OC).pdf
[18] TOP-001-4 and IRO-002-5 *NERC Operating Committed Compliance Implementation Guidance Data Exchange Infrastructure and Testing*: https://www.nerc.com/pa/comp/guidance/EROEndorsedImplementationGuidance/TOP-001-4%20and%20IRO-002-5%20Data%20Exchange%20Infrastructure%20and%20Testing%20(OC).pdf

and associated examples of redundant functionality tests and identifies ways to avoid single points of failure in primary control center data exchange infrastructure that could halt the flow of real-time data and result in loss of situational awareness.

Real-time assessments are evaluations of system conditions using real-time data to assess existing (pre-contingency) and potential (post-contingency) operating conditions. To understand the strategies and techniques that RCs and TOPs use to perform real-time assessments, FERC, NERC, and the Regional Entities engaged in on-site discussions with nine participating RCs and TOPs (participants) in 2019. The joint staff review team focused on real-time assessments during events where the participant or its RC/TOP experienced a loss or degradation of real-time data or of the primary tools used to perform real-time assessments. A joint report, the *FERC and ERO Enterprise Joint Report on Real-time Assessments*,[19] was released in July 2021. In a new report, FERC and the ERO Enterprise detailed recommendations for utilities to improve the performance of their real-time assessments.

[19] *FERC and ERO Enterprise Joint Report on Real-time Assessments*
https://www.ferc.gov/media/ferc-and-ero-enterprise-joint-report-real-time-assessments

Chapter 3: Event Analysis Process

The ERO EAP was launched in October 2010 and is intended to promote a structured and consistent approach for event analyses in North America. Through the ERO EAP, the ERO strives to develop a culture of reliability excellence that promotes aggressive self-critical review and analysis of operations, planning, and critical infrastructure protection processes. The ERO EAP also serves an integral function for the industry by providing insight and guidance via its identification and dissemination of valuable information to owners, operators, and users of the BPS who enable improved and more reliable operation. EMS events are defined in Cat 1h[20] events.

1h: *Loss of monitoring[21] and/or control[22] at a Control Center such that it degrades[23] the entity's ability to make Real-time operating decisions that are necessary to maintain reliability of the BES in the entity's footprint for 30 continuous minutes or more.*

Some examples that should be considered for EA reporting include but are not limited to the following:

- *i. Loss of operator ability to remotely monitor or control BES elements*
- *ii. Loss of communications from SCADA Remote Terminal Units (RTU)*
- *iii. Unavailability of ICCP links, which reduces BES visibility*
- *iv. Loss of the ability to remotely monitor and control generating units via AGC*
- *v. Unacceptable state estimator or real time contingency analysis solutions*

The process involves identifying what happened, why it happened, and what can be done to prevent reoccurrence. Identification of the sequence of events answers the "what happened" question, and determination of the root cause of an event answers the "why" question. The process also allows for events to be assigned cause codes or characteristics and attributes, which can then be used by the Event Analysis Subcommittee to identify trends. Trends may identify the need to take actions, such as a NERC alert, or may support changes to Reliability Standards.

The events analyzed in the ERO EAP come from mandatory processes (e.g., EOP-004, OE-417) and a process that encourages entities to share their EMS events that do not meet the reporting threshold of the mandatory processes but meet the Category 1h event definition in the ERO EAP. NERC standard EOP-004-4 was revised to require the reporting of the complete loss of monitoring or control capability at a BES control center for 30 continuous minutes or more. The revised NERC Reliability Standard went into effect on April 1, 2019, in the United States and some Canadian provinces. Therefore, the NERC EMSWG conducted an assessment and published *NERC Energy Management System Performance Special Assessment (2018–2019)*[24] in March 2021. The ERO Event Analysis Program later identified a need to continue the analysis by adding 2020 EMS events reported through the ERO EAP into the study period and published a revision[25] in December 2021. The two documents assessed three factors (outage duration, EMS functions, and entity reliability functions) and examined associated trends, event root causes, and contributing causes identified through the ERO Cause Code Assignment Process.

---

[20] For the latest category definition: http://www.nerc.com/pa/rrm/ea/Pages/EA-Program.aspx

[21] The ability to accurately receive relevant information about the BES in Real Time and evaluate system conditions using Real-time data to assess existing (pre-Contingency) and potential (post-Contingency) operating conditions to maintain reliability of the BES

[22] The ability to take and/or direct actions to maintain the reliability of the BES in Real Time via entity actions or by issuing Operating Instructions

[23] For purposes of 1h categorization "degrades" means less-than required functioning of any monitoring/control component, process, or capability

[24] *NERC Energy Management System Performance Special Assessment (2018–2019)*: https://www.nerc.com/pa/rrm/ea/PapersDocumentsAssessmentsDL/EMS_Special_Assessment_March2021.pdf

[25] *Analysis and Risk Mitigation for Loss of EMS functions (2018–2020)*: https://www.nerc.com/pa/rrm/ea/PapersDocumentsAssessmentsDL/Analysis_and_Risk_Mitigations_2018-2020.pdf

More than 180 entities have reported EMS events and participated in the ERO EAP since 2010. To date, more than 200 lessons learned[26] documents have been posted and shared with the industry with more than 60 lessons learned specifically dealing with EMS-related issues. The ERO EAP has proven to be an effective method for analyzing EMS outages, and the industry has readily participated without a NERC Reliability Standard. Focusing on the root and contributing causes helps to determine the appropriate mitigating actions, and these lessons are then shared with industry. The information gathered is disseminated and shared with industry at the annual NERC Monitoring and Situational Awareness Technical Conference, highlighted in the next chapter.

[26] http://www.nerc.com/pa/rrm/ea/Pages/Lessons-Learned.aspx

Chapter 4: NERC Monitoring and Situational Awareness Technical Conference

As the ERO, NERC is committed to continuous learning and improvement of BPS reliability. Since 2013, NERC has hosted an annual Technical Conference for Monitoring and Situational Awareness. The conference creates awareness of common problems observed by utilities, promotes an exchange of ideas, shares good industry practices, and brings together expertise from various utilities and vendors in a collaborative, educational atmosphere. The ERO EAP captures lessons learned and common trends for EMS outages and makes them available to industry by creating awareness and involving stakeholders in a collaborative process. The ultimate goal is to minimize the outages, in terms of both EMS outage duration and frequency, to maintain the highest levels of situational awareness.

The themes of the conferences since 2013 are listed in **Table 4.1**, and the presentations are available on NERC's website.[27]

Table 4.1: Themes of the Monitoring and Situational Awareness Technical Conference

Year	Theme
2013	Industry Practices for Reducing the EMS Outages, Alleviating Risks Involved when Outages Occur, and Maintaining Situational Awareness
2014	Sustaining EMS Reliability
2015	The Tools and Monitoring Capabilities of both EMS/SCADA Systems and Third-Party Software that Gives System Operator's the Real-Time "Bird's Eye" View of System Conditions
2016	EMS Resiliency with an Emphasis on the Capacity to Recover Quickly from Difficulties
2017	EMS Solution Quality (Modeling and Real-Time Assessment)
2018	The Evolution of EMS Systems
2019	Solutions for Emerging Changes
2020	Energy Management System Reliability and Resiliency in the Pandemic
2021	New Normal in Energy Management Systems
2022	Post Pandemic—New Normal in Energy Management System
2023	The Ever-Changing Landscape of the Energy Management Systems

[27] http://www.nerc.com/pa/rrm/Resources/Pages/Conferences-and-Workshops.aspx

Chapter 5: Conclusion

This reference document describes EMS functions and components. Its primary contribution is to identify and discuss BES reliability risks due to the loss of EMS functions, analyze causes of loss of EMS functions based on EMS events reported between 2019 and 2023, and present mitigations used by industry to reduce the number and impact of EMS events. This reference document also highlights the ERO EAP's work to analyze these events and share this information with industry. These lessons learned and trends are also shared at the annual NERC Monitoring and Situational Awareness Technical Conference. This conference is a collaboration with industry and vendors to minimize the duration and frequency of EMS outages and their potential reliability impacts to the BES.

The following can be concluded:

- EMSs were highly reliable from 2019 to 2023. During this period, the loss of EMS functions did not lead to the loss of generators, transmission lines, or customer load.
- EOP-004-4 continues to affect EMS event reporting. NERC Reliability Standard EOP-004-4 went into effect on April 1, 2019, in the United States and several Canadian provinces. One major modification to the standard is that the reporting is now clearly required only for complete loss of monitoring or control capability at a BES control center for 30 continuous minutes or more. Partial loss of monitoring or control is no longer considered. Entities appear to be now interpreting that partial-loss events (such as loss of SE/RTCA and loss of ICCP) no longer require reporting. This change in interpretation will likely reduce the data available for trending through the ERO EAP.
- The complete loss of monitoring or control capability has been the most prevalent reported event failure since 2020 but started decreasing in 2023 thanks to the improvement in database and system configuration/settings. Partial-loss events (i.e., loss of SE/RTCA, loss of ICCP, loss of RTU, and loss of AGC) have been declining since 2019 due to EOP-004-4's impact on partial loss of EMS functions reporting and the industry effort to enhance EMS reliability and resilience.
- Software is the major contributor to loss of SE/RTCA, while communications/maintenance are the major contributors to the complete loss of monitoring or control capability.
- The ERO EAP is used to analyze, track, and trend these outages. Lessons learned and best practices are shared with industry to improve overall EMS performance
- Good utility practice mitigations have been effectively applied during EMS events to manage risks within acceptable levels. The industry has made significant efforts to enhance EMS reliability and resilience. For example, many entities implemented a 24x7 onsite team that works along with system operators and provides dedicated support to SE and RTCA. This action has significantly reduced the outage duration, rendering many SE/RTCA issues not reportable.
- Overlapping coverage of situational awareness with the RCs and neighboring TOPs and BAs facilitates continuous monitoring of the system by additional entities outside of that immediate footprint. This is further strengthened by additional ICCP data points from generators and tie-lines that can provide visibility.

Considering the average outage time (73 minutes) of the 263 events reported by 132 NCRs between 2019 and 2023, it was observed that the actual EMS availability was 99.99%[28] during the term. Therefore, the mitigation strategies

[28] Considering the average outage time (73 minutes) of the 263 reported events from 2019 to 2023,
Total down time (in minutes) = 263 events * 73 minutes/event = 19,199 minute.

Assuming that any distinct NCRs submitting a report regarding EMS outage has an EMS system,
Total time (in minutes) =132 entities * 60 min/hr * 24hr/day * 1,826 days = 347,086,080 minutes.

Therefore, System Availability = (Total Time – Total Downtime)/Total Time = (347,086,080– 19,199) / 347,086,080 = 0.99994469 ~ 99.99%

described above have been proven effective. To both continue to maintain and further enhance EMS availability, the ERO will work directly with the stakeholders to sustain the EAP momentum, continue data gathering, track and trend the risk, conduct analysis, develop solutions, and share the information.

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Risks and Mitigations for Losing EMS Functions Reference Document

Version ~~3~~4

September ~~2022~~2024

RELIABILITY | RESILIENCE | SECURITY




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

Table of Contents

Preface

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

Reliability | Resilience | Security

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

The North American BPS is made up of six Regional ~~Entity boundaries~~Entities as shown ~~in~~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.

Formatted: Space After: 12 pt

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

Executive Summary

Loss of situational awareness is ~~one~~1 of ~~eleven~~the 11 risks identified in the *~~2021~~2023 ERO Reliability Risk Priorities Report*.[1] Loss or degradation of situational awareness ~~poses BPS~~ challenges ~~as it affects~~the BPS by affecting the ability of personnel or automatic control systems to perceive and anticipate ~~degradation~~reductions of system reliability and take pre-emptive action.

An energy management system (EMS) is a computer-aided tool used by system operators to monitor, control, and optimize the performance of generation and/or transmission systems. The primary objective of an EMS is to provide situational awareness ~~to the~~for system operators and allow remote control of devices to provide secure and stable operation of the Bulk Electric System (BES).

To identify the risks of losing EMS functions and share mitigation strategies to reduce these risks,[2] the NERC Energy Management System Working Group (EMSWG) published the reference document *Risk and Mitigations for Losing EMS Functions* in December 2017~~ and the~~. The second version~~[3]~~ was published in March 2020 and the third[4] in September 2022.

Since the reference document is published biennially, the NERC EMSWG conducted an update in ~~2022~~2024 by analyzing the causes of EMS events reported through the ERO Event Analysis Process (EAP) ~~from 2017–2021~~between 2019 and 2023. The document includes identification and discussion of reliability and security risks due to the loss of EMS functions and presents risk mitigation strategies used by industry.

Conclusion

Based on data and information collected for this reference document, the following can be concluded:

- EMSs were highly reliable from ~~2017–2021~~2019 to 2023. During this period, the loss of EMS functions ~~has~~did not ~~led~~lead to the loss of ~~generation~~generators, transmission lines, or customer load.
- EOP-004-4 ~~is affecting~~continues to affect EMS event reporting. In April 2019, EOP-004-4 was revised to require the reporting of the complete loss of monitoring or control capability at a BES control center for 30 continuous minutes or more~~ since April 2019.~~. Loss of state estimator/real-time contingency analysis reporting has been declining since ~~2018~~2019. The complete loss of monitoring or control capability has been the most prevalent reported event failure since 2020. However, the ERO encourages partial~~-~~ loss EMS reporting through the EAP for trending of potential reliability risks/impacts to the BES as some entities continue to do.
- Software is the major contributor to loss of state estimator/real-time contingency, and communications ~~failure~~/maintenance are the major contributors to the ~~loss of EMS functions, encompassing approximately 68%~~complete loss of ~~reported EMS events~~monitoring or control capability.
- Mitigating actions have been effectively applied during EMS events to manage risks within acceptable levels.
- The ERO EAP is used to analyze, track, and trend these outages. Lessons learned and best practices are shared with industry to improve overall EMS performance.

Formatted: Kern at 11 pt
Formatted: Kern at 11 pt
Formatted: Kern at 11 pt
Formatted: Kern at 11 pt
Formatted: Kern at 11 pt
Formatted: Kern at 11 pt
Formatted: Kern at 11 pt
Formatted: Kern at 11 pt
Formatted: Kern at 11 pt
Formatted: Kern at 11 pt
Formatted: Kern at 11 pt
Formatted: Kern at 11 pt
Formatted: Kern at 11 pt
Formatted: Kern at 11 pt
Formatted: Kern at 11 pt
Formatted: Kern at 11 pt
Formatted: Kern at 11 pt
Formatted: Kern at 11 pt

---

[1] *~~2021~~2023 ERO Reliability Risk Priorities Report:* ~~https://www.nerc.com/comm/RISC/Documents/RISC%20ERO%20Priorities%20Report_Final_RISC_Approved_July_8_2021_Board_Submitted_Copy.pdf~~ https://www.nerc.com/comm/RISC/Related%20Files%20DL/RISC_ERO_Priorities_Report_2023_Board_Approved_Aug_17_2023.pdf

[2] This reference document is provided for guidance and does not reflect binding norms or mandatory requirements.

~~[3] *Risk and Mitigations for Losing EMS Functions Reference Document*—Version 2: https://www.nerc.com/comm/OC/ReferenceDocumentsDL/Risks_and_Mitigations_for_Losing_EMS_Functions_v2.pdf~~

[4] *Risk and Mitigations for Losing EMS Functions Reference Document*—Version 3: https://www.nerc.com/comm/RSTC_Reliability_Guidelines/Risks_and_Mitigations_for_Losing_EMS_Functions_v3.pdf

- The NERC Monitoring and Situational Awareness Technical Conference[5] provides a forum for vendor involvement to share knowledge and collaborate with industry to minimize the frequency and duration of EMS outages.

Formatted: Kern at 11 pt

Formatted: Kern at 11 pt

[5] https://www.nerc.com/pa/rrm/Resources/Pages/Conferences-and-Workshops.aspx

~~Introduction~~

~~The NERC EMSWG published the reference document in December 2017 and the second version in March 2020. The second version contained analysis of 521 EMS events reported through the voluntary ERO EAP between October 2013 and April 2019. Since the reference document is published biennially, the NERC EMSWG decided to publish the third version by analyzing the causes of EMS events reported through the ERO EAP from 2017–2021. The document identifies and discusses reliability and security risks due to the loss of EMS functions as well as presents risk mitigation strategies used by industry.~~

~~The goal of minimizing the frequency and duration of EMS outages is achieved by the following:~~

- ~~Utilizing the ERO EAP as an effective tool for analyzing the reported events and for identifying the risks~~
- ~~Through the EAP, the registered entities, and with the help of NERC and the Regional Entities, identifying the root and contributing causes of EMS events~~
- ~~Sharing this information with industry through the development and publishing of lessons learned and best practices~~
- ~~Culminating in the collaborative effort of industry and vendors experts gathering at the annual NERC Monitoring and Situational Awareness Conference to discuss how to best address the root and contributing causes identified~~

Chapter 1: Energy Management System

An EMS is a system of advanced computer~~-aided tools~~ applications used by system operators to monitor, control, and optimize the performance of the generation and/or transmission system. An EMS that encompasses supervisory control and data acquisition (SCADA), telecommunications, and real-time reliability support tools is vital for situational awareness as well as making and implementing well-informed operating decisions. An EMS consists of both hardware and software. ~~The~~An EMS's hardware ~~part of an EMS~~ component consists of remote terminal units (~~RTUs~~RTU) at the substations, servers at the data centers, ~~the~~wired and wireless telecommunications systems~~ both wired and wireless~~, and the system control centers, including all the computers used to monitor and control the BES. ~~The~~An EMS's software component~~ of an EMS~~ consists of application programs for the data acquisition, control, alarming, real-time calculations, and network analysis of power systems, including state estimation and contingency analysis.

The primary objective of an EMS is to provide situational awareness for ~~the~~ system operators[6] and allow remote control of devices to ~~provide~~ secure and stable operation of the BES. Situational awareness includes, but is not limited to, the following:

- The ability to monitor/control the frequency within the system operator's area
- The ability to monitor/control the status (open or closed) of switching devices as well as real and reactive power flows on generators, BES tie-lines, and transmission facilities within the system operator's areas
- The ability to monitor/control voltage and reactive resources
- The ability to monitor the status of applicable EMS applications, such as real-time contingency analysis (RTCA) and/or alarm management

~~Using~~System operators can use this information pertaining to situational awareness~~, the system operators can make decisions~~ to take actions that affect the reliability and resiliency of the BES. Generation can be dispatched or taken off-line to prevent overloads and improve the voltage in an area. Capacitor banks, shunt devices, synchronous condensers, or other voltage-controlling tools can be utilized to maintain voltage limits. Transmission breakers and remote-controlled switches can be opened or closed as needed to address real-time and contingency conditions.

In an EMS, application programs run in a real-time or ~~in an~~ extended real-time environment to keep the power system in a secure operating condition. These EMS applications include SCADA, alarm processing, automatic generation control (AGC), network applications (including state estimation), power flow, contingency analysis or security analysis, and data historians~~, among others.~~. **Figure 1.1** shows a simplified EMS configuration.

~~[6] NERC Reliability Guideline: *Situational Awareness for the System Operator*: http://www.nerc.com/comm/OC_Reliability_Guidelines_DL/SA_for_System_Operators.pdf.~~

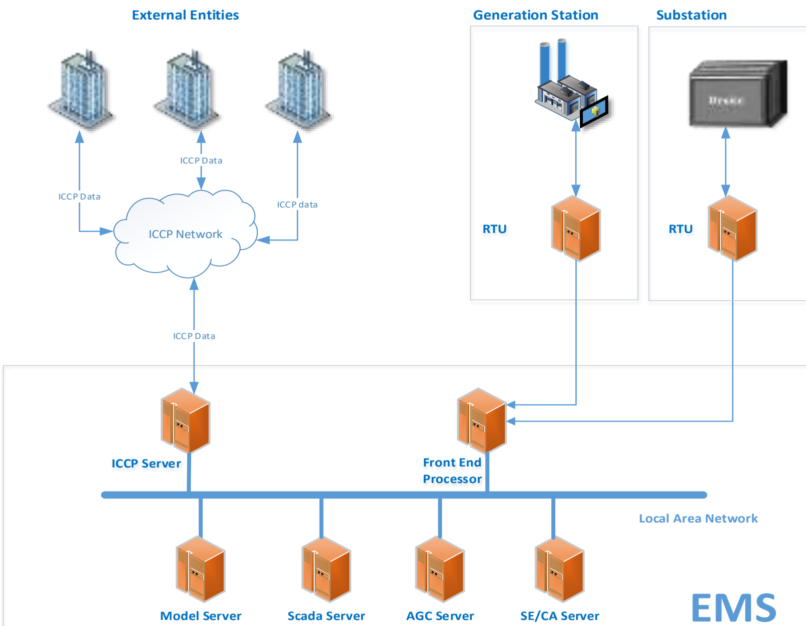


Figure 1.1: A Simplified EMS Configuration

Inter~~-~~-Control Center Protocol (ICCP): ICCP has been standardized under the IEC 60870-6 specifications and allows the exchange of real-time and historical power system monitoring and control data, including measured values, data quality codes, scheduling data, energy accounting data, and operator messages. Data exchange can occur over wide-area networks between utility control centers, utilities, power pools, regional control centers, and non-utility generators.

SCADA: SCADA is a category of software application programs for process control and the gathering of data in real-time from remote locations in order to control devices and monitor conditions. SCADA sends and receives telemetered data between the RTU or ICCP link and the control center. Control signals are sent from the operator's desk at the control center back to the field to change the status of devices (e.g., open or close breakers) or adjust generation.

RTU: An RTU is a microprocessor-controlled electronic device that interfaces devices in the physical world with a distributed control system or SCADA system by transmitting telemetry data to a master system and by using messages from the master supervisory system to control connected devices.

Front End Processor (FEP): An FEP interfaces the host computer to a number of networks, such as systems network architecture or a number of peripheral devices (e.g., ~~RTU's~~RTUs, terminals, disk units, printers, and tape units). Data is transferred between the host computer and the front-end processor by using a high-speed parallel interface. The FEP communicates with peripheral devices by using slower serial interfaces, usually also through communication networks. The purpose is to ~~off-load~~offload the work of managing the peripheral devices, transmitting and receiving messages, packet assembly and disassembly, error detection, and error correction from the host computer.

Formatted: Font: Bold

Formatted: Font: Bold

Formatted: Font: Bold

Formatted: Font: Bold

AGC: An AGC is an application for adjusting the power output of multiple generators at different power plants in response to changes in interchange, load, generation, and frequency error. AGC software uses real-time data, such as frequency, actual generation, tie-line load flows, and plant controller status, to determine generation changes.

Formatted: Font: Bold

State Estimator (SE): An SE is an application that calculates the current state of the ~~electrical~~electric system (the voltage magnitudes and angles at every bus) by using a network model and telemetered measurements. The purpose is to provide a consistent base case for use by other network applications programs, such as power flow and contingency analysis. While SCADA relies on direct telemetered values from the RTUs, the state estimator is able to calculate and predict non-metered values to provide additional situational awareness to the system operators.

Formatted: Font: Bold

RTCA: An RTCA is an application used to predict ~~electrical~~electric system conditions after simulating specific contingencies. It relies on a base case from ~~a~~an SE or ~~Power Flow~~power flow case.

Formatted: Font: Bold

In an EMS, voltage magnitudes and power flows ~~over the lines~~through equipment are continuously monitored through SCADA, SE, and RTCA to check for voltage/thermal exceedance. The EMS system is programmed with limits on the BES equipment~~.~~ being monitored. These limits are used with ~~Alarm Processing~~alarm processing to send visual and audio alarms to the system operators when monitored quantities are approaching or exceeding the threshold of an operating limit. AGC computes a ~~Balancing Area's Area Control Error~~balancing area's area control error (ACE) from interchange and frequency data. ACE determines whether a system is in balance or adjustments need to be made to generation. AGC software also determines the required output for generating resources while observing energy balance and frequency control by sending set-points to generators. The scheduled tie~~-~~-line power flows are maintained by adjusting the real power output of the AGC~~-~~-controlled generators to accommodate fluctuating load demands.

The typical dependency between the main EMS applications is illustrated in **Figure 1.2**.

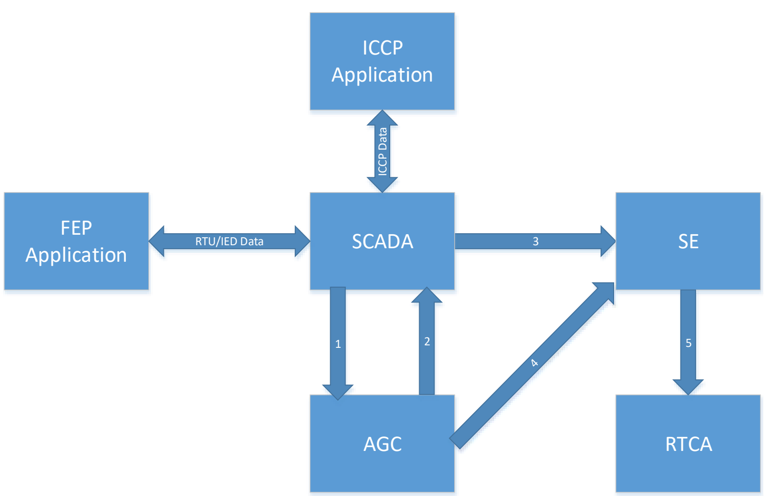


Figure 1.2: Typical ~~dependency between main~~Dependency Between Main EMS Applications

The data flows between the EMS functions shown in **Figure 1.2** are described below:

- **ICCP Data** (between ICCP ~~Application~~application and SCADA): Real-time and historical power system monitoring and control data, including measured values, data quality codes, scheduling data, energy accounting data, generator set-point controls, and operator messages
- **RTU Data** (between FEP ~~Application~~application and SCADA): Data from substation devices and commands to substation devices. This data includes the following:
  - Measured ~~Values~~values
  - Position ~~Indication~~indication
  - Positioning ~~Commands~~commands
  - Alarms
- **Path 1** (from SCADA to AGC): Telemetered status data and analogue value data that includes the following:
  - Area frequency
  - Tie~~-~~-line MW
  - Generator unit on-line/off-line
  - Generator unit control local or remote
  - Generator unit MW output
  - Generator unit MW set-point feedback
  - Generator unit MW limits
- **Path 2** (from AGC to SCADA): New set-point controls calculated by AGC
- **Path 3** (from SCADA to SE): The data typically consists of the following:
  - Breaker status (open or closed)
  - Switch status (open or closed)
  - Transformer tap settings
  - MW flow measurements
  - MVAR flow measurements
  - Voltage magnitude measurements
  - Current magnitude measurements
  - Phase angle difference measurements
  - High-voltage direct current (HVDC) operating modes
  - Tagging status
  - Special measurements defined by users
- **Path 4** (from AGC to SE): ~~the~~The data typically consists of the following:
  - Generator unit control (local or remote)
  - Generator unit MW output
  - Generator unit MW limits

- **Path 5** (from SE to RTCA): A base~~-~~-case solution typically consists of the following:
  - System topology
  - Voltage magnitudes and angles at each bus
  - Transformer tap settings
  - Generator unit control status
  - Generator unit MW limits
  - HVDC operating modes
  - VAR status

Chapter 2: Analysis of Loss of EMS Functions

This section ~~will identify and discuss~~discusses the risks of losing EMS functions, ~~analyze~~analyzes reasons for the loss of EMS functions based on EMS events reported by ~~144~~132 NERC compliance registries (~~NCRs~~NCR) between ~~2017~~2019 and 2023, and ~~2021, and present~~presents mitigation strategies ~~that~~to reduce the risk when one or more EMS functions are temporarily lost or disabled.

Risks of Loss of EMS Functions

The BES operates in a dynamic environment, and its physical properties are constantly changing. Situational awareness is necessary to maintain reliability, anticipate events, and respond appropriately when or before ~~they~~events occur.

Without the appropriate tools and data, system operators may have degraded situational awareness ~~for making~~to make decisions that ensure reliability for a given condition of the BES. Certain essential functional capabilities must be in place with up-to-date information for staff to make informed decisions. An essential component of monitoring and situational awareness is the availability of information when needed. Unexpected outages of functions or planned outages without appropriate coordination or oversight can leave system operators with impaired visibility. While failure of a decision-support tool has not directly led to the loss of ~~generation~~generators, transmission lines, or customer load, such failures may hinder the decision-making capabilities of the system operators during a disturbance. NERC has analyzed data and identified that short-term outages of tools and monitoring systems are not uncommon, and the industry is committed to reducing the frequency and duration of these types of events.

The BES reliability risk due to EMS function failures varies depending on the function that is lost and the duration of that outage. Some examples are listed below:

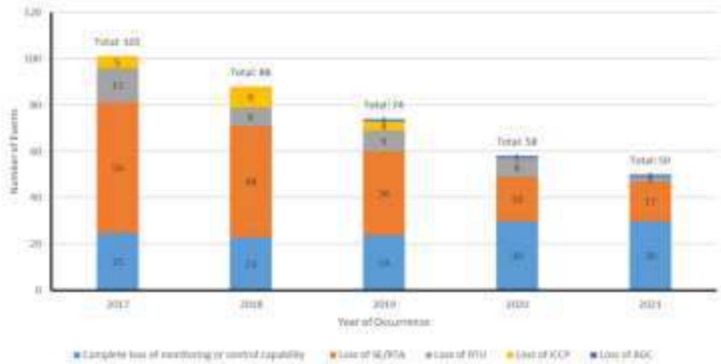
- **Complete Loss of Monitoring or Control Capability including Loss of SCADA**
  The complete loss~~ of SCADA~~ would likely be the most impactful EMS failure. The system operators would not have indication of the status of devices or key data points, such as MW, MVAR, current, voltage, or frequency from the RTUs. Furthermore, the system operators would not be able to open and close breakers or switches remotely from the control center. SCADA data feeds AGC and SE/RTCA applications; loss of quality data would compromise their functionality.
- **Loss of ICCP**
  The loss of ICCP would disrupt the information that is shared between Transmission Operators (TOP), Balancing Authorities (BA), Generation Operators~~,~~ (GOP), and Reliability Coordinators (RC). The RCs rely on information from ~~its~~their BAs and TOPs to monitor the wider area, and an ICCP outage may remove real-time updates from the affected section of the model.
- **Loss of RTU**
  ~~The~~RTU loss~~ of RTU~~ would involve the system operators losing information ~~of~~on devices and control of the devices. The situation could be mitigated by staffing the substation in order to provide manual updates.
- **Loss of AGC**
  The loss of AGC prevents the system operator from automatically maintaining system frequency, net tie-line interchanges, and optimal generation levels close to scheduled (or specified) values.
- **Loss of SE**
  The loss of SE would involve the system operators losing the situational awareness not directly provided by the SCADA system. While the system operators would still have SCADA, which would provide control and indication of all telemetered devices, the loss of SE would eliminate other key data values that help the system operators monitor the system as well as limit the predictive analysis that the EMS provides. The loss

Formatted: Indent: Left: 0.5", Space Before: 0 pt of SE would also cause the loss of the associated contingency analysis tool since that tool relies on a valid SE solution to run.

- **Loss of RTCA**
  The loss of RTCA ~~may~~would prevent alerting the system operators ~~when the next~~if a contingency presents a potential reliability issue, compromising situational awareness and reliability and increasing the complexity of performing real~~-~~-time assessments.

Reasons for Loss of EMS Functions

There were ~~371~~263 EMS events reported between ~~2017~~2019 and ~~2021~~2023 through the EAP. These include the loss of SCADA, ICCP, RTU, AGC, SE, RTCA, or a combination of these functions for 30 or more continuous minutes. **Figure 2.1** shows a trend of the reported EMS events by loss of EMS functions over the ~~2017–2021~~2019–2023 period. ~~Both~~Partial-loss events (i.e., loss of SE/RTCA, loss of ICCP, loss of RTU, and ~~ICCP events~~loss of AGC) have been declining since ~~2018. The complete loss of monitoring or control capability events was stable from 2017 to 2019 but increased in 2020 and stable in 2021~~2019.



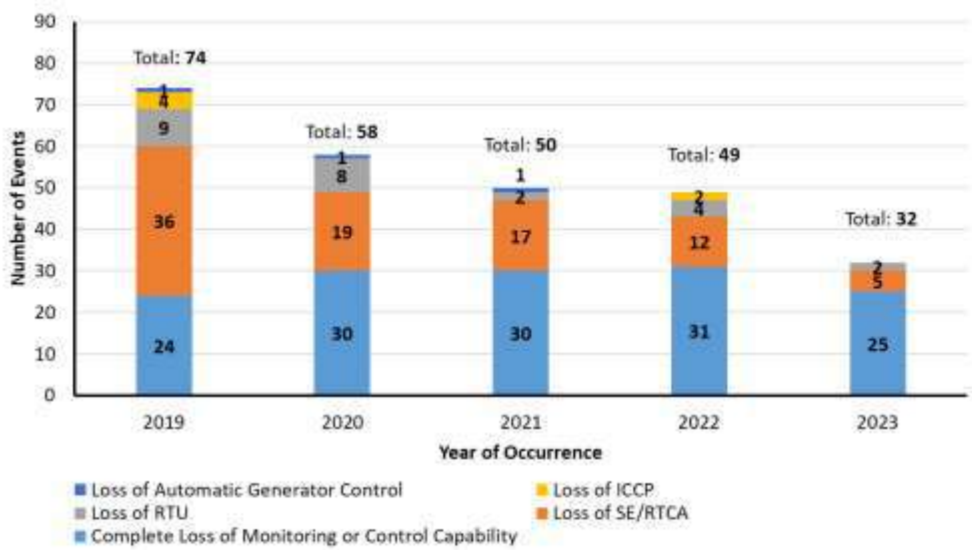


Figure 2.1: Number of EMS-Related Events (~~2017–2021~~2019–2023)

There are two reasons for the declining trend of partial-loss ~~of SE/RTCA and ICCP~~events:

- Partial-~~-~~loss events~~ (i.e, loss of SE/RTCA, loss of ICCP, loss of RTU, and loss of AGC)~~ are no longer captured as part of EOP-004-4 mandatory reporting. NERC standard EOP-004-4 was modified to require the reporting of the complete loss of monitoring or control capability at a BES control center for 30 continuous minutes or more. The modified NERC Reliability Standard went into effect on April 1, 2019, in the United States and some Canadian provinces. However, the ERO encourages partial~~-~~-loss EMS reporting through the EAP for trending of potential reliability risks/impacts to the BES as some entities continue to do.
- The industry has made significant ~~effort~~efforts to enhance EMS reliability and resilience. For example, many entities built a 24x7 onsite team that works along with system operators and provides dedicated support for SE and RTCA. This action has significantly reduced the outage duration~~ resulting in~~, rendering many SE/RTCA issues not~~ being~~ reportable.

The complete loss of monitoring or control capability events increased from 2019 to 2022 but dropped back to 25 in 2023. Improvements to the database and system configuration/settings in 2023 contributed to the decrease.

> **Settings:** Periodic review of system parameters and settings with vendor support has been shown to reduce settings errors. Different flags and weighting levels may need to be adjusted as models are expanded or system conditions change.
>
> **Skill Development:** Hiring more skilled in-house personnel who can troubleshoot and correct these issues can decrease outage durations, including additional knowledge transfer from the vendor to the in-house staff.

The reported EMS events can be grouped by the following attributes:

- **Software:** ~~software~~Software defects, modeling issues, database corruption, memory issues, etc.

Formatted: Font: Bold

- **Communications:** ~~devices~~Device issues (e.g., RTU failure, FEP failure, fiber failure, network router failure~~) or~~), changes made (e.g., firewall failure~~)~~), or less~~-~~than~~-~~adequate system interactions (e.g., bad telemetered data quality)
- **Maintenance:** ~~system~~System upgrades, job~~-~~ scoping, change~~-~~ management, risk identification, and other themes, such as testing in a controlled environment and implementing the change (e.g., system/software configuration or settings failure, patch change, or implementation that causes EMS functions to crash)
- **Facility:** ~~loss~~Loss of power to the control center or data center, fire alarm, ac power failure, etc.

Formatted: Font: Bold

Formatted: Font: Bold

Formatted: Font: Bold

Table 2.1 ~~shows the breakdown of~~breaks down the attributes in each EMS function failure. Software ~~and~~is the major contributor to loss of SE/RTCA, while communications/maintenance are the two major contributors to the complete loss of ~~EMS functions, encompassing approximately 68% of reported EMS events~~monitoring or control capability.

Table 2.1: Contributors to Loss of EMS ~~functions~~Functions

Failure	Software	Communications	Maintenance	Facility	Total
~~Loss of SE/RTCA~~Complete loss of monitoring or control capability	~~116~~31	~~21~~49	~~33~~39	~~6~~21	**~~176~~140**
~~Complete loss of monitoring or control capability~~Loss of SE/RTCA	~~34~~49	~~38~~10	~~38~~27	~~22~~3	**~~132~~89**
Loss of RTU	~~8~~2	~~18~~11	~~8~~5	~~8~~7	**~~42~~25**
Loss of ICCP		~~14~~5	~~2~~	~~2~~1	**~~18~~6**
Loss of AGC	1		2		**3**
Total	**~~159~~83**	**~~91~~75**	**~~83~~73**	**~~38~~32**	**~~371~~263**

Based on the analysis of the EMS events reported, the following recommendations are made to reduce the loss of situational awareness risks due to loss of EMS functions:

- **Maintaining Models**
  The models of the ~~electrical~~electric grid are critical for EMS functions. Models should be periodically maintained but promptly updated after BES changes have been completed in the field, such as when new transmission or generation device(s) are put into service or when devices are retired. Otherwise, EMS functions cannot present proper real-time changes (e.g., topology, MW output) related to these devices and sequentially yield unsolved or incorrect solutions.[7] For a major model release,[8] entities should perform front- and back-end data validations and field-by-field comparisons of all databases that are not limited to fields or areas with previously identified issues. Entities should run regression testing with new models in a

[7] Lessons learned *Model Data Error Impacts State Estimator and Real-Time Contingency Analysis Results* https://www.nerc.com/pa/rrm/ea/Lessons%20Learned%20Document%20Library/LL20220403_Model_Data_Error_Impacts_SE_and_RTCA.pdf

[8] Lessons Learned *EMS Pausing During Database Deployment* https://www.nerc.com/pa/rrm/ea/Lessons%20Learned%20Document%20Library/LL20220801_EMS_pausing_during_database_deployment.pdf

comprehensive test environment and ensure the applications can consume the new models and yield similar or improved results.

- **Looking ~~beyond~~Beyond Geographic Diversity Alone for Data Communications Redundancy**
When contracting with multiple vendors for redundancy in data communications services, one should never assume that geographic diversity alone provides redundancy. This is because there is a point of convergence that may exist at a common hub that becomes a single point of failure. To ensure redundant physical circuit separation and independence of supporting equipment and power, ~~it is recommended that~~ the duration of the service ~~is~~should be specified in the contract. Also, to validate independence, ~~it is recommended that~~ testing ~~is~~should be performed that simulates this failure to ensure that the redundancy in place covers this scenario. More details on this topic ~~can be found~~are provided in the ~~lesson~~lessons learned titled~~,~~ *Telecom Provider Failure Induced Loss of ICCP from Regional Neighbors*~~.~~[9] [10] and *Intermittent Network Connection Causes EMS Disruption*.[11]

- ~~**External Modeling**~~
~~Many entities have expanded their EMS models to monitor the impact of events and outages outside of their footprint. This has increased potential exposure to bad data points and inaccurate topology modeling and introduced communication issues that may cause EMS events. Entities should communicate BES changes (including new substations, new facilities, and removed facilities) to neighboring entities in advance. This will enable neighboring entities to update their external EMS models in a timely manner and ensure that the data received through ICCP links is accurately matched to the appropriate data points in the model.~~[12]

- **Network Communications Configuration**
EMS-related communications networks are moving from point-to-point serial communication infrastructures to packet-based networks. The main advantage of packet-based networks is that data can be transmitted from ~~one~~ node to ~~another~~ node while avoiding a communications system failure caused by the breakdown of a single (or few) intermediate link(s). Consequently, the correct configuration is critical to ensure that the communications network functions as designed. ~~Reporting included four complete loss events due to networking packet broadcast storms caused by improper network configurations.~~ This led to the following recommendations:
  - Establish standardized settings for network devices.
  - Complete physical separation between SCADA operations networks and business networks, voice over internet protocol, and external~~-~~facing networks ~~are~~is preferred over virtual local area networks to avoid network traffic congestion and security issues.[13]
  - Work with switch vendors to configure a firewall health check that continuously confirms the ability to reach devices beyond the directly connected switch. The firewall health check should allow for an automated firewall high-availability failover in the event of a similar “half failure” of the directly connected switch in the future.[14]

~~[9] Lessons learned *Telecom Provider Failure Induced Loss of ICCP from Regional Neighbors*:~~
~~https://www.nerc.com/pa/rrm/ea/Lessons%20Learned%20Document%20Library/20190503_Loss_of_ICCP_from_Regional_Neighbors.pdf~~
[10] Lessons learned *Telecom Provider Failure Induced Loss of ICCP from Regional Neighbors*:
https://www.nerc.com/pa/rrm/ea/Lessons%20Learned%20Document%20Library/20190503_Loss_of_ICCP_from_Regional_Neighbors.pdf
[11] Lessons learned *Intermittent Network Connection Causes EMS Disruption*
https://www.nerc.com/pa/rrm/ea/Lessons%20Learned%20Document%20Library/LL20220406_Intermittent_Network_Connection_Causes_EMS_Disruption.pdf
~~[12] Lessons learned *External Model Data Causing State Estimator to Not Converge*:~~
~~https://www.nerc.com/pa/rrm/ea/Lessons%20Learned%20Document%20Library/LL20180602_External_Model_Data_Causing_State_Estimator_to_Not_Converge.pdf~~
[13] Lessons learned *Networking Packet Broadcast Storms:*
https://www.nerc.com/pa/rrm/ea/Lessons%20Learned%20Document%20Library/LL20181001_Networking_Packet_Broadcast_Storms.pdf
[14] Lessons learned *Loss of Monitoring due to a “Half Failed” High Availability Switch Pair*

Formatted: Font: Italic

- **Alarming**
  Alarming has not initiated any EMS events; however, an improper configuration can degrade the system ~~operator's~~operator's situational awareness. A risk assessment should be performed to determine any gaps in alarming. Alarming quantity, visualization, and even sound effects vary widely ~~vary~~. It is essential for the entity to not only determine what alarms are needed but also to assess what can cause them to fail or otherwise go unnoticed.[15] The NERC Standards TOP-010 R4 and IRO-018 R3 require a separate alarm process monitor. This helps increase operator situational awareness and reduce significant events when the alarm processor fails.

- **Power Supply**
  Stable and secure power supplies are critical to control rooms, data centers, and substations. ~~Sixteen EMS events were due to loss of power supply.~~ Although the redundant power supply was installed at the control rooms, data centers, and substations, it is essential ~~that routines be established for monthly testing and maintenance of~~for the backup generator, uninterruptible power supply, and associated power switches~~.~~ to be tested and maintained monthly. More recommendations ~~can be found~~are provided in the lesson learned titled~~,~~ *Loss of Monitoring or Control Capability due to Power Supply Failure*~~[16] and *Loss of SCADA Operating and Monitoring Ability*~~.[17]

- **Dealing with Abnormal Working Environment**
  In 2020, entities implemented work-from-home policies for nonessential employees. Many tasks (like maintenance, software/database deployment, etc.) that were normally ~~were~~ conducted onsite had to be executed ~~in a remote fashion~~remotely. Job scoping needs improvement to involve all potentially impacted groups and departments and strengthen peer review of design, implementation, and testing. Many entities also implemented working split shifts both at the primary ~~control center~~ and backup control ~~center~~centers in order to practice social distancing. It is recommended to improve appropriate materials/tools that allow working shifts to monitor and control the BES from backup control centers.

- **EMS Platform Upgrade**
  The challenges that entities usually face during an EMS upgrade are primarily due to the confluence of change from the EMS upgrade and the model tool/application implementation. Entities should ensure the following actions concerning EMS upgrades:
  - Entities should develop a more holistic approach to aligning the models with EMS revisions.
  - Entities should strengthen communications with vendors and increase knowledge transfer from vendors.
  - Vendors should document all new data fields in their release packages, and the entity should understand their impacts and modify or create in-house tools accordingly.

- **Completed Software Testing Process**

---

https://www.nerc.com/pa/rrm/ea/Lessons%20Learned%20Document%20Library/LL20230801_Loss_of_Monitoring_Half_Failed_High_Availability_Switch_Pair.pdf

[15] Lessons learned *Enhanced Alarming Can Help Detect State Estimator and Real-Time Contingency Analysis Issues:* https://www.nerc.com/pa/rrm/ea/Lessons%20Learned%20Document%20Library/20190502_Enhanced_Alarming_helps_detect_SE_RTCA_issues.pdf

~~[16] Lessons learned *Loss of Monitoring or Control Capability due to Power Supply Failure:* https://www.nerc.com/pa/rrm/ea/Lessons%20Learned%20Document%20Library/20190801_Loss_of_Monitoring_Control_due_to_Power_Supply_Failure.pdf~~

[17] Lessons learned *Loss of ~~SCADA Operating and~~ Monitoring ~~Ability~~or Control Capability due to Power Supply Failure:* ~~https://www.nerc.com/pa/rrm/ea/Lessons%20Learned%20Document%20Library/LL20170503_Loss_of_SCADA_Operating_and_Monitoring_Ability.pdf~~ https://www.nerc.com/pa/rrm/ea/Lessons%20Learned%20Document%20Library/20190801_Loss_of_Monitoring_Control_due_to_Power_Supply_Failure.pdf

Systems and software assurance requires a process model for formal testing based upon the software development framework within which the software was created. The scope of the test should provide an assurance case for operation of the software under test for both known and unknown operating conditions with the inclusion of a data integrity check of the module. In general, the process is considered to have four components:[18]

- **Test Scope:** Define the test environment requirements and setup, features/functions that need to be tested, documentation and produce as output, approval workflows, etc.
- **Test Design:** Design the test cases that are necessary to validate the system/functions/features being built compared to its design requirements (regression and incremental testing typically necessary)
- **Test Execution:** Execute tests in many different ways
- **Test Closure:** Consider the exit criteria for signaling completion of the test cycle and readiness for release

Mitigations for the Risk of Loss of EMS Functions

~~In~~Out of all ~~of~~ the reported events from ~~2017~~2019 to ~~2021, there has been~~2023, no EMS event that led to the loss of generation, transmission lines, or customer load~~.~~ was reported. The ~~371~~263 reported EMS events ~~from 2017 to 2021~~during this span were approximately ~~70~~73 minutes in duration on average. The following mitigations have been effectively applied to manage the risks within acceptable levels:

- Enhanced system restoration plans that include drills and training on the procedures and real-life practice implementing the procedures
- Overlapping coverage of situational awareness with ~~RC's~~RCs and neighboring TOPs and BAs so that the system is being continuously monitored by additional entities outside of that immediate footprint. (This is further strengthened by additional ICCP data points from generators and tie-lines that can provide visibility.)
  - The RC notifies adjacent RCs, TOPs, and BAs within its RC area when it loses essential real-time tools capability. Once notified by an RC of problems with the RC real-time tools, RC area TOPs and BAs or adjacent RC(s) will report any detected BES outages or abnormal BES conditions, including abnormal conditions related to generation, loads or tie-line flows, or SOL exceedances, to their (or the affected) RC until normal monitoring capabilities are restored. During this same time period, TOPs and BAs also report any significant real-time or post-contingent overloads or voltage limit deviations to their RC.
  - With an extended and continued loss of essential real-time tools, a BA/TOP notifies their RC and their neighboring entities (known impacted interconnected entities) of the tool problem or degradation being experienced as soon as practical~~,~~ but generally within 30 minutes of the loss. The notification generally includes the following:
    - A single point~~-~~ of~~-~~ contact and preferred method of communication
    - Extent of the real~~-~~-time tool loss and systems impacted (to understand the magnitude)
    - Plan and status for corrective actions to restore lost functionality
    - Any requested assistance and plan for maintaining system monitoring and control
    - Estimated time for restoration of functionality (if known)
    - An agreed~~-~~-upon schedule for periodic updates
- ~~Offline~~Off-line tools (studies) that can be used for analyzing contingencies plus other contingency-analysis, including day-ahead studies, seasonal and standing operating guides, and system operator training

[18] Lessons learned *Loss of Automatic Generation Control During Routine Update* https://www.nerc.com/pa/rrm/ea/Lessons%20Learned%20Document%20Library/LL20200403_Loss_of_AGC_During_Routine_Update.pdf

- ~~Enhanced preventive controls that include limits and bounds on external data where the SE/CA can converge around the erroneous data~~
- Backup tools and functionality that include backup EMS systems, backup control centers, and other additional redundancy
- Collaboration with vendors to build comprehensive testing procedures and/or troubleshoot the cause of the failure ~~in order~~ to minimize the system recovery time
- Manning substations during EMS events so that system operators and field personnel can take ~~action~~actions as needed (e.g., open/close breakers), verify status of devices, ~~plus~~and verify power flows and voltages
- Internally defined conservative operations procedures used during EMS events (e.g., no switching, additional monitoring, ~~manning~~staffing substations, and asking neighbors for assistance)
- Periodic routines that regularly test and maintain the backup generator, uninterruptible power supply, and associated power switches to verify and ensure that power supply redundancy has been implemented in control rooms, data centers, and substations
- Dedicated and skilled in-house personnel who can troubleshoot/correct issues with real-time tools and training provided to improve/increase knowledge transfer from the vendor
- Different mechanisms that have been built or set up for notifications:
  - Normal phone communication capabilities (e.g., phones, cell phones, satellite, radio)
  - Emergency ~~hot line~~hotline system or "blast call" system
  - NERC Reliability Coordinator Information System[19]
  - WECC-wide messaging system[20]

The Federal Energy Regulatory Commission (FERC) and NERC conducted the ~~study~~ *Planning Restoration Absent SCADA or EMS (PRASE report*~~),~~) study,[21] which focused on the potential impact of the loss of EMS, SCADA, or ICCP functionality on system restoration and the manner in which such impact could be mitigated. The objective of the study was to assess entities' system restoration plan steps in the absence of EMS, SCADA, and/or ICCP data~~,~~ and identify viable resources, methods, or practices that would expedite system restoration despite the loss of such systems. The following was concluded in the PRASE report:

- All volunteer registered entities have made significant investments in their SCADA and EMS infrastructures, including leveraging redundancies to increase availability and functionality.
- All volunteer registered entities would remain capable of executing their restoration plan without SCADA/EMS availability.
- Five recommendations are provided for all entities responsible for system restoration, ~~stated in the following~~as follows:
  - Planning for backup communications measures
  - Planning for personnel support during system restoration absent SCADA
  - Planning backup power supplies for an extended period of time

Formatted: Font: Not Italic

[19] The system the RCs use to post messages and share operating information in Real-time is called the Reliability Coordinator Information System.
[20] AESO, BC Hydro RC, and RC West will use the Grid Messaging System (GMS); SPP will use the Reliability Communication Tool.
[21] *FERC-NERC-Regional Entity Joint Review of Restoration and Recovery Plans:* https://www.ferc.gov/legal/staff-reports/2017/06-09-17-FERC-NERC-Report.pdf

- Analysis tools for system restoration
- Incorporating loss of SCADA or EMS scenarios in system restoration training

TOPs and RCs ~~are~~have been requested to perform real-time assessments ~~per~~since NERC Standards TOP-001-5, Requirement R13, IRO-008-2, and Requirement R4. ~~A~~ The ERO Enterprise has endorsed compliance implementation guidance~~[22]~~ (CIG)~~ has been endorsed by the ERO Enterprise~~ [23] to ~~assist~~help NERC registered entities ~~in establishing~~establish a common understanding of the practices and processes surrounding the completion of a real-time assessment. This guidance also offers examples for managing real-time assessments with or without the use of RTCA tools or other support applications.

To avoid single points of failure in primary ~~Control Center~~control center data exchange infrastructure, the redundant and diversely routed data exchange infrastructure within the primary ~~Control Center~~control center and associated tests for redundant functionality are required by NERC Reliability Standards TOP-001-~~5~~6, Requirements R20, R21, R23, and R24, and IRO-002-7 Requirements R2 and R3. The NERC Data Exchange Infrastructure Requirements Task Force developed a CIG[24] from the perspective of the Reliability Standards. The CIG discusses data exchange infrastructure reference models and associated examples of redundant functionality tests and identifies ways to avoid single points of failure in primary ~~Control Center~~control center data exchange infrastructure that could halt the flow of real-time data and result in loss of situational awareness.

~~[22] TOP-001-3 R13 and IRO-008-2 R4 *NERC Operating Committed Compliance Implementation Guidance Real-time Assessments*: https://www.nerc.com/pa/comp/guidance/EROEndorsedImplementationGuidance/TOP-001-3%20R13%20and%20IRO-008-2%20R4%20Real%20Time%20Assessments%20(OC).pdf~~

[23] TOP-001-3 R13 and IRO-008-2 R4 *NERC Operating Committed Compliance Implementation Guidance Real-time Assessments*: https://www.nerc.com/pa/comp/guidance/EROEndorsedImplementationGuidance/TOP-001-3%20R13%20and%20IRO-008-2%20R4%20Real%20Time%20Assessments%20(OC).pdf

[24] TOP-001-4 and IRO-002-5 *NERC Operating Committed Compliance Implementation Guidance Data Exchange Infrastructure and Testing*: ~~https://www.nerc.com/pa/comp/guidance/DraftImplementationGuidanceDL/TOP-001-4%20and%20IRO-002-5%20Data%20Exchange%20Infrastructure%20and%20Testing%20(OC).pdf~~ https://www.nerc.com/pa/comp/guidance/EROEndorsedImplementationGuidance/TOP-001-4%20and%20IRO-002-5%20Data%20Exchange%20Infrastructure%20and%20Testing%20(OC).pdf

Real-time assessments are evaluations of system conditions using real-time data to assess existing (pre-contingency) and potential (post-contingency) operating conditions. To understand the strategies and techniques that RCs and TOPs use to perform real-time assessments, FERC, NERC, and the Regional Entities engaged in on-site discussions with nine participating RCs and TOPs (participants) in 2019. The joint staff review team focused on real-time assessments during events where the participant or its RC/TOP experienced a loss or degradation of real-time data or of the primary tools used to perform real-time assessments. A joint report, the *FERC and ERO Enterprise Joint Report on Real-time Assessments*,[25] was released in July 2021. In a new report, FERC and the ERO Enterprise detailed recommendations for utilities to improve the performance of their real-time assessments.

[25] *FERC and ERO Enterprise Joint Report on Real-time Assessments*
https://www.ferc.gov/media/ferc-and-ero-enterprise-joint-report-real-time-assessments

Chapter 3: Event Analysis Process

The ERO EAP was launched in October 2010~~. The ERO EAP~~ and is intended to promote a structured and consistent approach ~~to performing~~for event analyses in North America. Through the ERO EAP, the ERO strives to develop a culture of reliability excellence that promotes aggressive self-critical review and analysis of operations, planning, and critical infrastructure protection processes. The ERO EAP also serves an integral function ~~as a learning opportunity~~ for the industry by providing insight and guidance ~~by identifying~~via its identification and ~~disseminating~~dissemination of valuable information to owners, operators, and users of the BPS who enable improved and more reliable operation. EMS events are defined in Cat 1h[26] events.

1h: *Loss of monitoring[27] and/or control[28] at a Control Center such that it ~~significantly affects~~degrades[29] the entity's ability to make Real-time operating decisions that are necessary to maintain reliability of the BES in the entity's footprint for 30 continuous minutes or more.*

Some examples that should be considered for EA reporting include but are not limited to the following:

- *i. Loss of operator ability to remotely monitor or control BES elements*
- *ii. Loss of communications from SCADA Remote Terminal Units (RTU)*
- *iii. Unavailability of ICCP links, which reduces BES visibility*
- *iv. Loss of the ability to remotely monitor and control generating units via AGC*
- *v. Unacceptable state estimator or real time contingency analysis solutions*

The process involves identifying what happened, why it happened, and what can be done to prevent reoccurrence. Identification of the sequence of events answers the "what happened" question, and determination of the root cause of an event answers the "why" question. ~~It~~The process also allows for events to ~~have~~be assigned cause codes or characteristics and attributes~~ assigned~~, which can then be used by the Event Analysis Subcommittee to identify trends. Trends may identify the need to take ~~action~~actions, such as a NERC alert, or may support changes to Reliability Standards.

The events analyzed in the ERO EAP come from mandatory processes (e.g., EOP-004, OE-417) and a ~~voluntary~~ process that encourages entities to share their EMS events that do not meet the reporting threshold of the mandatory processes but meet the Category 1h event definition in the ERO EAP. NERC standard EOP-004-4 was revised to require the reporting of the complete loss of monitoring or control capability at a BES control center for 30 continuous minutes or more. The revised NERC Reliability Standard went into effect on April 1, 2019, in the United States and some Canadian provinces. ~~Since then, the standard may potentially modify entity interpretation of the need to provide visibility on partial EMS functions loss that is used for trending analysis and reported through the ERO EAP as defined by Category 1h.~~ Therefore, the NERC EMSWG conducted an assessment and published *NERC Energy Management System Performance Special Assessment (2018–2019)*[30] in March 2021. ~~Later, the~~The ERO Event Analysis Program later identified a need to continue the analysis by adding 2020 EMS events reported through the

Formatted: Font: Not Italic

Formatted: Font: Not Italic

Formatted: Font: Not Italic

[26] For the latest category definition: http://www.nerc.com/pa/rrm/ea/Pages/EA-Program.aspx

[27] The ability to accurately receive relevant information about the BES in Real Time and evaluate system conditions using Real-time data to assess existing (pre-Contingency) and potential (post-Contingency) operating conditions to maintain reliability of the BES

[28] The ability to take and/or direct actions to maintain the reliability of the BES in Real Time via entity actions or by issuing Operating Instructions

[29] For purposes of 1h categorization "degrades" means less-than required functioning of any monitoring/control component, process, or capability

[30] *NERC Energy Management System Performance Special Assessment (2018–2019)*: https://www.nerc.com/pa/rrm/ea/PapersDocumentsAssessmentsDL/EMS_Special_Assessment_March2021.pdf

ERO EAP into the study period and published a revision[31] in December 2021. The two documents assessed three factors (~~i.e.,~~ outage duration, EMS functions, and entity reliability functions) and examined associated trends, event root causes, and contributing causes identified through the ERO Cause Code Assignment Process.

More than 180 entities have reported EMS events and participated in the ERO EAP since 2010. To~~-~~ date, more than ~~190~~200 lessons learned[32] documents have been posted and shared with the industry with more than ~~55 Lessons Learned~~60 lessons learned specifically dealing with EMS-related issues. The ERO EAP has proven to be an effective method for analyzing EMS outages, and the industry has readily participated without a NERC Reliability Standard. Focusing on the root and contributing causes helps to determine the appropriate mitigating actions, and these lessons are then shared with industry. The information gathered is disseminated and shared with industry at the annual NERC Monitoring and Situational Awareness Technical Conference, highlighted in the next chapter.

[31] *Analysis and Risk Mitigation for Loss of EMS functions (2018–2020)*:
https://www.nerc.com/pa/rrm/ea/PapersDocumentsAssessmentsDL/Analysis_and_Risk_Mitigations_2018-2020.pdf
[32] http://www.nerc.com/pa/rrm/ea/Pages/Lessons-Learned.aspx

Chapter 4: NERC Monitoring and Situational Awareness Technical Conference

As the ERO, NERC is committed to continuous learning and improvement of BPS reliability. ~~Beginning in~~Since 2013, NERC has hosted an annual Technical Conference for Monitoring and Situational Awareness~~ Conference~~. The conference creates awareness of common problems observed by utilities, promotes an exchange of ideas, shares good industry practices, and brings together expertise from various utilities and vendors in a collaborative, educational atmosphere. The ERO EAP captures lessons learned and common trends for EMS outages and makes them available to industry by creating awareness and involving stakeholders in a collaborative process. ~~Therefore, many challenges can be effectively mitigated.~~ The ultimate goal is to minimize the outages, in terms of both EMS outage duration and frequency~~; with the objective of maintaining~~, to maintain the highest levels of situational awareness.

The themes of the conferences since 2013 are listed in **Table 4.1**, and the presentations are available on NERC's website.[33]

Table 4.1: Themes of the Monitoring and Situational Awareness Technical Conference

Year	Theme
2013	Industry ~~practices~~Practices for ~~reducing~~Reducing the EMS ~~outages, alleviating risks involved~~Outages, Alleviating Risks Involved when ~~outages occur~~Outages Occur, and ~~maintaining situational awareness~~Maintaining Situational Awareness
2014	Sustaining EMS ~~reliability~~Reliability
2015	The ~~tools~~Tools and ~~monitoring capabilities~~Monitoring Capabilities of both EMS/SCADA ~~systems~~Systems and ~~third party software~~Third-Party Software that ~~gives system operator's~~Gives System Operator's the ~~real-time "bird's eye" view~~Real-Time "Bird's Eye" View of ~~system conditions~~System Conditions
2016	EMS ~~resiliency~~Resiliency with an ~~emphasis~~Emphasis on the ~~capacity~~Capacity to ~~recover quickly~~Recover Quickly from ~~difficulties~~Difficulties
2017	EMS ~~solution quality~~Solution Quality (Modeling and Real-~~time~~Time Assessment)
2018	The ~~evolution~~Evolution of EMS ~~systems~~Systems
2019	Solutions for ~~emerging changes~~Emerging Changes
2020	Energy ~~management system reliability~~Management System Reliability and ~~resiliency~~Resiliency in the ~~pandemic~~Pandemic
2021	New ~~normal~~Normal in ~~energy management systems~~Energy Management Systems
2022	Post Pandemic—New Normal in Energy Management System
2023	The Ever-Changing Landscape of the Energy Management Systems

[33] http://www.nerc.com/pa/rrm/Resources/Pages/Conferences-and-Workshops.aspx

Chapter 5: Conclusion

This reference document describes EMS functions and components. Its primary contribution is to identify and discuss BES reliability risks due to the loss of EMS functions, analyze causes of loss of EMS functions based on EMS events reported between ~~2017~~2019 and ~~2021~~2023, and present mitigations used by industry to reduce the number and impact of EMS events. This reference document also highlights the ERO EAP’s work ~~the ERO EAP does with analyzing~~to analyze these events and ~~sharing~~share this information with industry. These lessons learned and trends are also shared at the annual NERC Monitoring and Situational Awareness Technical Conference. This conference is a collaboration with industry and vendors to minimize the duration and frequency of EMS outages and their potential reliability impacts to the BES.

The following can be concluded:

- EMSs were highly reliable from ~~2017–2021. The~~2019 to 2023. During this period, the loss of EMS functions ~~has~~did not ~~directly led~~lead to the loss of ~~generation~~generators, transmission lines, or customer load.
- EOP-004-4 ~~is affecting~~continues to affect EMS event reporting. NERC Reliability Standard EOP-004-4 went into effect on April 1, 2019, in the United States and several Canadian provinces. One major modification to the standard is that the reporting is now clearly required only for complete loss of monitoring or control capability at a BES control center for 30 continuous minutes or more. Partial loss of monitoring or control is no longer considered. ~~It appears entities are~~Entities appear to be now interpreting that partial~~-~~-loss events (such as loss of SE/RTCA~~,~~ and loss of ICCP) no longer require reporting. This change in interpretation will likely reduce the data available for trending through the ~~voluntary ERO EAP and ERO Cause Code Assignment Process~~ERO EAP.
- The complete loss of monitoring or control capability has been the most prevalent reported event failure since 2020~~,~~ but ~~the~~started decreasing in 2023 thanks to the improvement in database and system configuration/settings. Partial-loss events (i.e., loss of SE/RTCA ~~is the most prevalent one over the evaluation period from 2017–2021. Both loss of SE/RTCA events and~~, loss of ICCP ~~events~~, loss of RTU, and loss of AGC) have been declining since ~~2018~~2019 due to ~~the~~ EOP-004-~~4~~4’s impact on partial loss of EMS functions reporting and the industry effort to enhance EMS reliability and resilience.
- Software ~~and communication failures~~is the major contributor to loss of SE/RTCA, while communications/maintenance are the major contributors to the ~~loss of EMS functions, encompassing approximately 68%~~complete loss of ~~reported EMS events~~monitoring or control capability.
- The ERO EAP is ~~an effective process for analyzing~~used to analyze, track, and trend these ~~risks by identifying the root~~outages. Lessons learned and ~~contributing causes and sharing this information~~best practices are shared with industry~~.~~ to improve overall EMS performance
- Good utility practice mitigations have been effectively applied during EMS events to manage risks within acceptable levels. The industry has made significant efforts to enhance EMS reliability and resilience. For example, many entities implemented a 24x7 onsite team that works along with system operators and provides dedicated support to SE and RTCA. This action has significantly reduced the outage duration, ~~resulting in~~rendering many SE/RTCA issues not ~~being~~ reportable.
- Overlapping coverage of situational awareness with the ~~RC’s~~RCs and neighboring TOPs and BAs ~~helps~~facilitates continuous monitoring of the system ~~to be continuously monitored~~ by additional entities outside of that immediate footprint. This is further strengthened by additional ICCP data points from generators and tie-lines that can provide visibility.

Formatted: Kern at 11 pt

Formatted: Kern at 11 pt

Formatted: Kern at 11 pt

Formatted: Kern at 11 pt

Considering the average outage time (~~70~~73 minutes) of the ~~371~~263 events reported by ~~144~~132 NCRs ~~from 2017 to 2021~~between 2019 and 2023, it was observed that the actual EMS availability was 99.99%[34] during the term. Therefore, the mitigation strategies described above have been proven ~~to work effectively.~~effective. To both continue to maintain and further enhance EMS availability, the ERO will work directly with the stakeholders to sustain the EAP momentum, continue data gathering, track and trend the risk, conduct analysis, develop solutions, and share the information.

[34] Considering the average outage time (~~70~~73 minutes) of the ~~371~~263 reported events from ~~2017~~2019 to ~~2021~~2023,
Total down time (in minutes) = ~~371~~263 events * ~~70~~73 minutes/event = ~~25,970~~19,199 minute.

Assuming that any distinct NCRs submitting a report regarding EMS outage has an EMS system,
Total time (in minutes) =~~144~~132 entities * 60 min/hr * 24hr/day * 1,826 days = ~~378,639,360~~347,086,080 minutes.

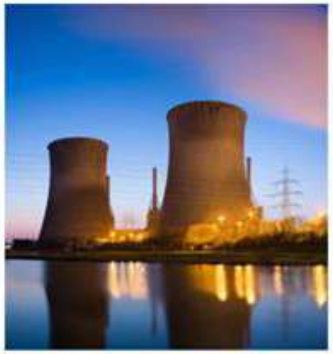
Therefore, ~~-~~System Availability = (Total Time – Total Downtime)/Total Time = (~~378,639,360 – 25,970) / 378,639,360~~347,086,080– 19,199) / 347,086,080 = 0.~~99993141~~99994469 ~ 99.99%

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

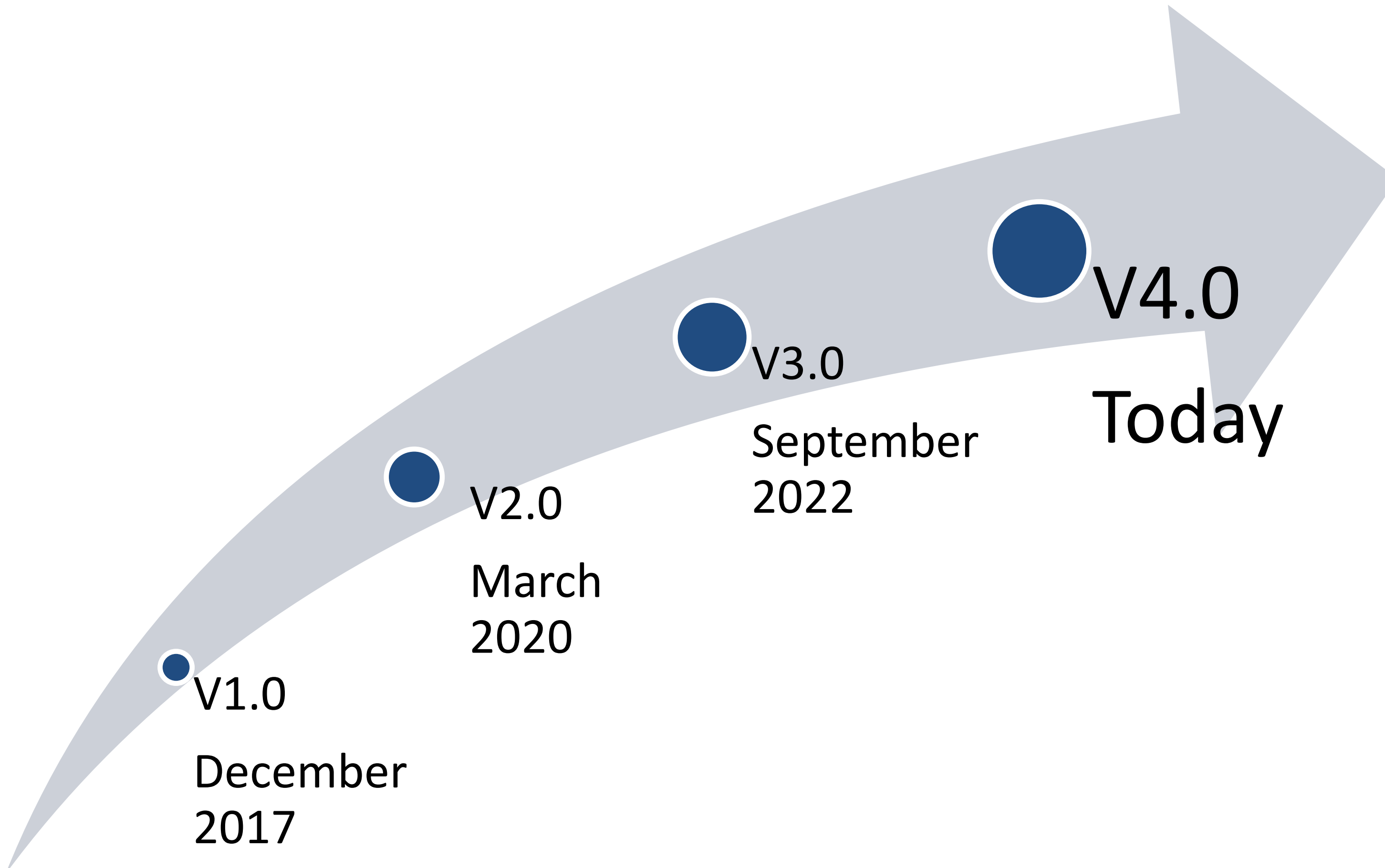
Risks and Mitigations for Losing EMS Functions Reference Document (v2.0)

Wei Qiu, Lead Engineer of Event Analysis
RSTC Meeting
September 11, 2024

RELIABILITY | RESILIENCE | SECURITY

History

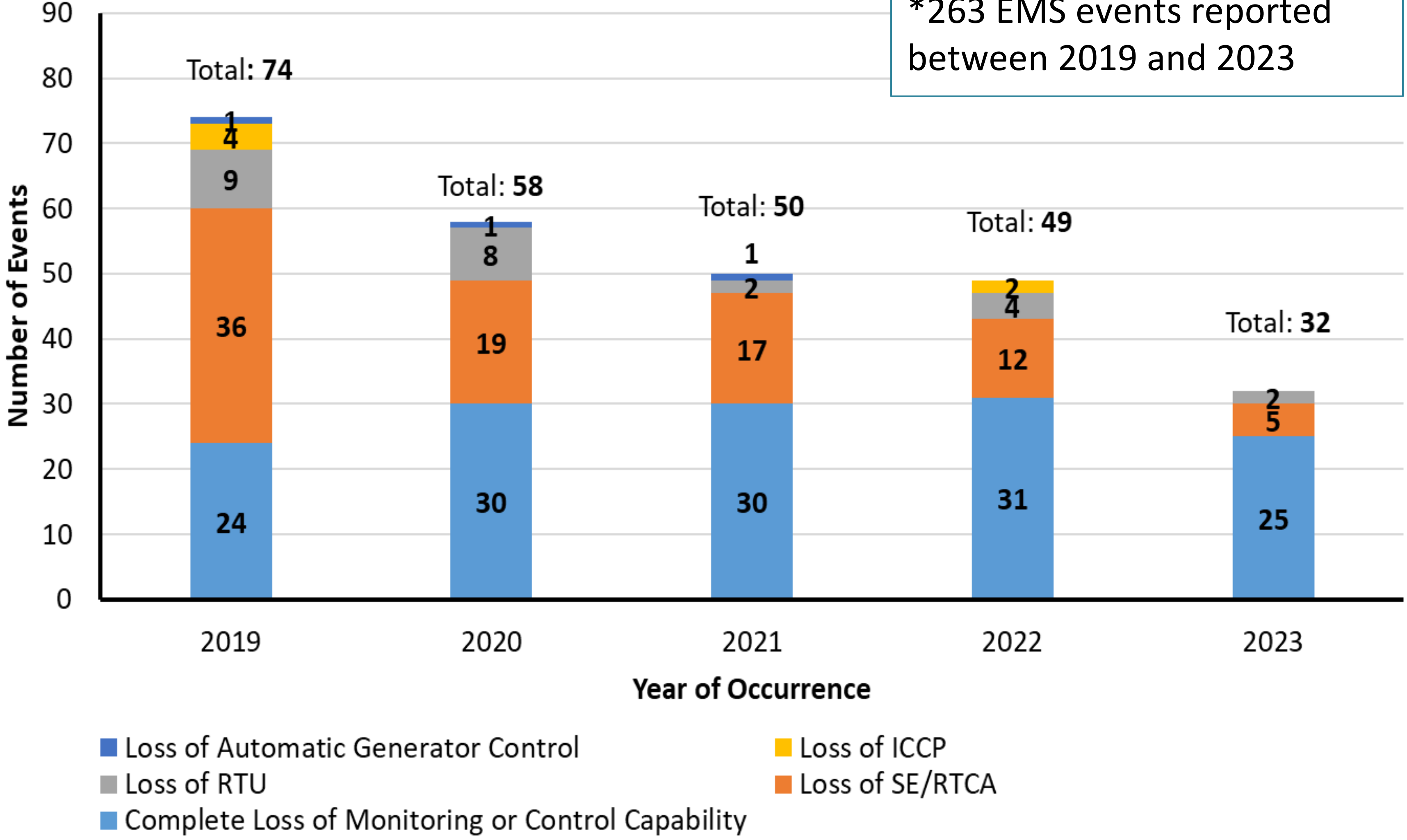

V1.0
December 2017
V2.0
March 2020
V3.0
September 2022
V4.0
Today

Purposes

- High level discussion of what an EMS is and the various parts EMS
- Identify and discuss the risk of losing EMS functions
- Analyze the causes of EMS events reported through the Electric Reliability Organization (ERO) Event Analysis Process (EAP)
- Share mitigation strategies to reduce these risks

EMS Events Trend

*263 EMS events reported between 2019 and 2023



NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Contributors to Loss of EMS functions

Failure	Software	Communications	Maintenance	Facility	Total
Complete loss of monitoring or control capability	31	49	39	21	**140**
Loss of SE/RTCA	49	10	27	3	**89**
Loss of RTU	2	11	5	7	**25**
Loss of ICCP		5		1	**6**
Loss of AGC	1		2		**3**
Total	**83**	**75**	**73**	**32**	**263**

- Software failure is the major contributor to the loss of SE/RTCA
- Communications and maintenance are the major ones to the complete loss

Mitigations for the Risk of Loss of EMS Functions

- Enhanced system restoration plans, including drills and training on the procedures, plus real-life practice implementing the procedures
- Overlapping coverage of situational awareness with RCs and neighboring TOPs and BAs
- Offline tools (studies)
- Backup tools and functionality
- Dedicated and skilled in-house personnel
- More in the document…

Conclusions

- Loss of EMS functions has not directly led to the loss of generators, transmission lines, or customer load
- Mitigating actions have been effectively applied during EMS events to manage risks within acceptable levels
- EAP is used to analyze, track, and trend these outages
- Lessons learned and best practices shared with industry
- NERC Monitoring and Situational Awareness Technical Conference provides a forum to share knowledge and collaborate with industry to minimize the frequency and duration of EMS outages

Questions and Answers

Frequency Response Annual Analysis (FRAA)

Action
Accept

Summary
The FRAA report is published annually and includes the annual analysis of frequency response performance for the administration and support of NERC Reliability Standard BAL-003-2 – Frequency Response and Frequency Bias Setting, 1 , effective December 1, 2020. It provides an update to the statistical analyses and calculations contained in the 2012 Frequency Response Initiative Report that was approved by the NERC Resources Subcommittee and the technical committee, which predated the Reliability and Security Technical Committee (RSTC) and was accepted by the NERC Board of Trustees.

This report is prepared by NERC staff2 and contains the annual analysis, calculation, and recommendations for the interconnection frequency response obligation (IFRO) for each of the four electrical Interconnections of North America for the operating year (OY) 2024 (December 2023 through November 2024).

We are seeking acceptance from the RSTC at this time.

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

2024 Frequency Response Annual Analysis

November 2024

This report was endorsed by the Resources Subcommittee on August 8th 2024.

RELIABILITY | RESILIENCE | SECURITY




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

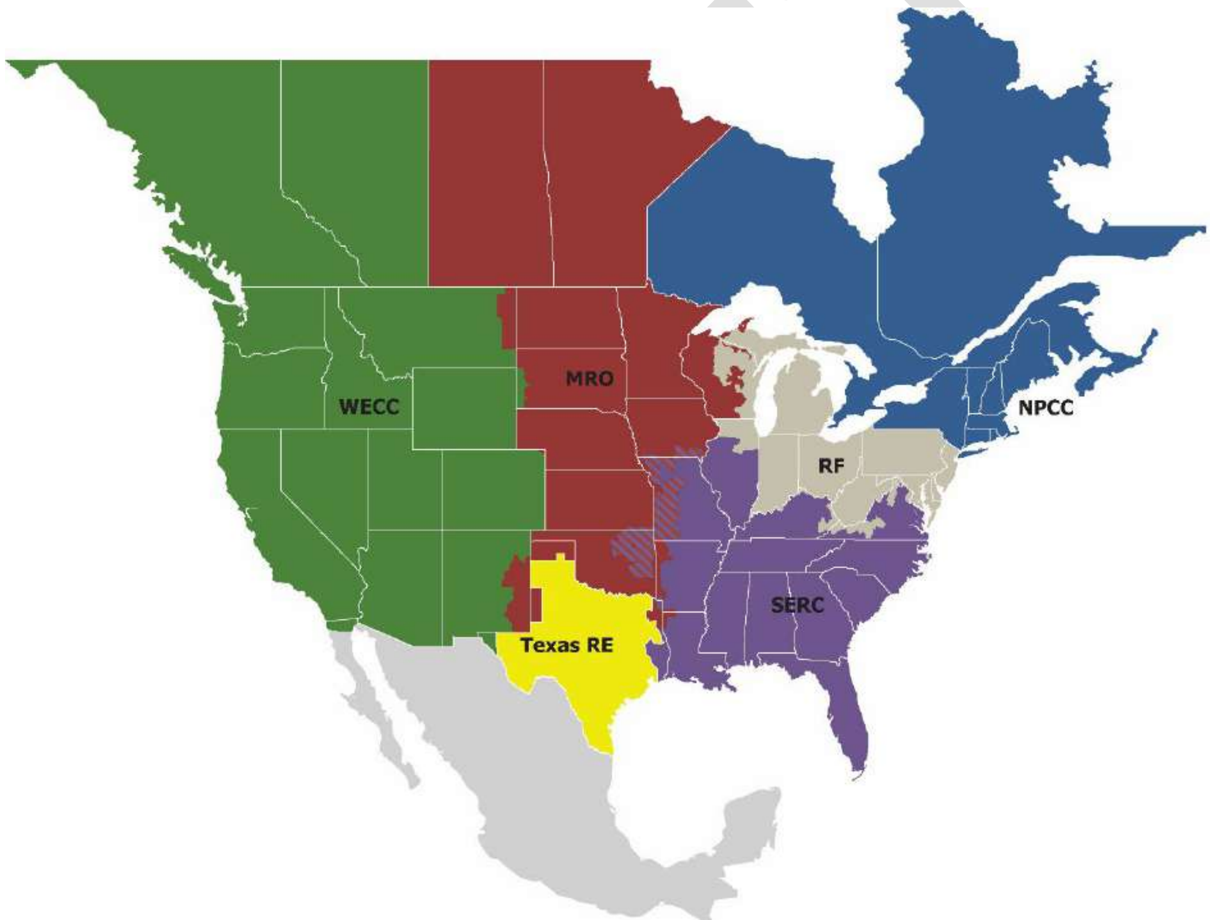
Table of Contents

Preface

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

Executive Summary

This report is the 2024 annual analysis of frequency response performance for the administration and support of *NERC Reliability Standard BAL-003-2 – Frequency Response and Frequency Bias Setting,*[1] effective December 1, 2020. It provides an update to the statistical analyses and calculations contained in the *2012 Frequency Response Initiative Report*[2] that was approved by the NERC Resources Subcommittee (RS) and the technical committee, which predated the Reliability and Security Technical Committee (RSTC) and was accepted by the NERC Board of Trustees (Board).

This report is prepared by NERC staff[3] and contains the annual analysis, calculation, and recommendations for the interconnection frequency response obligation (IFRO) for each of the four electrical Interconnections of North America for the operating year (OY) 2025 (December 2024 through November 2025). Below are the key findings and recommendations contained in this report.

Key Findings

Starting Frequency

The starting frequency for the calculation of IFROs, shown in **Table 1.1**, is the fifth percentile of the 5-year probability distribution of the respective interconnection frequency, representing a 95% chance that frequencies will be at or above that value at the start of any frequency event. The starting frequency remained the same for all interconnections, with the Eastern Interconnection (EI) at 59.971 Hz, the Western Interconnection (WI) at 59.970 Hz, the Texas Interconnection (TI) at 59.970 Hz, and Québec Interconnection (QI) at 59.965 Hz.

Frequency Probability Density Functions

The standard deviation is a measure of the dispersal of frequency values around the mean value; a smaller standard deviation indicates tighter concentration around the mean value and more stable performance of Interconnection frequency. Analysis of the frequency probability density functions shows that standard deviations have been flat (Eastern and Western) or fluctuating within a small range (Texas and Québec). Comparisons of annual frequency profiles for each Interconnection are shown in **Figure 1.6**, Figure 1.7, Figure 1.8, and **Figure 1.9**.

Interconnection Performance and the Comparison of Mean Value A, B, and Point C

Table 2.6 shows a comparison of mean Value A, mean Value B, and mean Point C that is illustrative of Interconnection performance during low frequency events over the previous OY and as compared to the 2016 OY in which the IFRO values were frozen. Loss of load events have been excluded from the data in **Table 2.6**. Eastern, Western, and Texas Interconnections show an increase in mean Value B and a decrease in the mean (A-B), indicating improved performance during the stabilizing period of frequency events. Quebec showed an increase in mean Value B up until OY 2023, where it declined slightly. Eastern, Western, and Texas Interconnections show either an increase or no change in mean Point C as well as a decrease or no change in mean (A–C), indicating improved performance during the arresting period of frequency events. Quebec shows a decrease in mean Value C as well as an increase in mean Value A-C. This performance data demonstrates that the higher calculated IFROs are due to improved stabilizing period performance and not due to a decline in the performance of the Point C nadir.

[1] http://www.nerc.com/pa/Stand/Reliability%20Standards/BAL-003-2.pdf
[2] http://www.nerc.com/docs/pc/FRI_Report_10-30-12_Master_w-appendices.pdf
[3] Prepared by the NERC Advanced System Analytics and Modeling department.

Recommendations

NERC provides the following recommendation for the administration of *Standard BAL-003-2*[1] for OY 2025 (December 1, 2024, through November 30, 2025):

- The IFRO value for the TI will change by **-60 MW/0.1 Hz** due to a decrease in Credit for Load Resources (CLR). Therefore, the recommended IFRO for TI **is -455 MW/0.1 Hz**.

NERC requests that the Recommended IFRO values calculated in this report in accordance with BAL-003-2 and shown in **Table ES.1** be approved for implementation in OY 2025. NERC, in collaboration with the RS, shall continue to monitor and evaluate the impacts on BPS reliability as a result of changes in IFRO values.

Table ES.1: Recommended IFROs for OY 2025

	Eastern (EI)	Western (WI)	Texas (TI)	Québec (QI)	Units
MDF[4]	0.420	0.280	0.405	0.947	Hz
RLPC[5]	3,875	2,918	2,805	2,000	MW
CLR	N/A	N/A	962	N/A	MW
Calculated IFRO	-923	-1,042	-455	-211	MW/0.1 Hz
Recommended IFROs[6]	**-923**	**-1,042**	**-455**	**-211**	**MW/0.1 Hz**

[4] The Procedure for ERO Support of Frequency Response and Frequency Bias Setting Standard, Version II, provided in the approved ballot for BAL-003-2, specifies that, "MDF is the Maximum Delta Frequency for the specific interconnection as determined in the 2017 Frequency Response Annual Analysis (FRAA)."

[5] BAL-003-2, Attachment A specifies that Resource Loss Protection Criteria (RLPC) be based on the two largest potential resource losses in an interconnection. This value is required to be evaluated annually.

[6] BAL-003-2 requires that the EI IFRO will be stepped down to its calculated value over three years. The maximum reduction is limited to 100 MW/0.10 Hz annually.

Introduction

This report, prepared by NERC staff,[7] contains the annual analysis, calculation, and recommendations for the IFRO for each of the four Interconnections of North America for the OY 2025 (December 2024 through November 2025). This analysis includes the following information:

- Statistical analysis of Interconnection frequency characteristics for the OYs 2019 through 2023 (December 1, 2018, through November 30, 2023)
- Analysis of frequency profiles for each Interconnection
- Calculation of adjustment factors from BAL-003-2 frequency response events

This year's frequency response analysis builds upon the work and experience from performing such analyses since 2013. As such, there are several important things that should be noted about this report:

- The University of Tennessee–Knoxville FNET[8] data used in the analysis has seen significant improvement in data quality, simplifying and improving annual analysis of frequency performance and ongoing tracking of frequency response events. In addition, NERC uses data quality checks to flag additional bad one-second data, including bandwidth filtering, least squares fit, and derivative checking.
- As with the previous year's analysis, all frequency event analysis uses sub-second data from the FNET system frequency data recorders (FDRs). This eliminates the need for the CC_{ADJ} factor originally prescribed in the *2012 Frequency Response Initiative Report*[9] because the actual frequency nadir was accurately captured.
- The Frequency Response Analysis Tool[10] is being used by the NERC Power System Analysis group for frequency event tracking in support of the NERC Frequency Working Group and RS. The tool has streamlined interconnection frequency response analysis. The tool provides an effective means of determining frequency event performance parameters and generating a database of values necessary for calculation of adjustment factors.

This report contains numerous references to Value A, Value B, and Point C, which are defined in NERC *BAL-003-2*.[1] As such, it is important to understand the relationship between these variables and the basic tenants of primary and secondary frequency control.

The Arresting, Rebound, Stabilizing, and Recovery Periods of a frequency event following the loss of a large generation resource are shown in **Figure ES.1**. Value A and Value B are average frequencies from t-16 to t-2 seconds and t+20 to t+52 seconds, respectively, as defined in NERC *BAL-003-2*. Point C is the lowest frequency experienced within the first 20 seconds following the start of a frequency event. A Point C' value may exist if frequency falls below the original Point C nadir or Value B after the end of the 20–52 second Stabilizing Period.

---

[7] Prepared by the NERC Advanced System Analytics and Modeling department.

[8] Operated by the Power Information Technology Laboratory at the University of Tennessee, FNET is a low-cost, quickly deployable GPS-synchronized wide-area frequency measurement network. High-dynamic accuracy FDRs are used to measure the frequency, phase angle, and voltage of the power system at ordinary 120 V outlets. The measurement data are continuously transmitted via the Internet to the FNET servers hosted at the University of Tennessee and Virginia Tech.

[9] http://www.nerc.com/docs/pc/FRI_Report_10-30-12_Master_w-appendices.pdf

[10] Developed by Pacific Northwest National Laboratory.

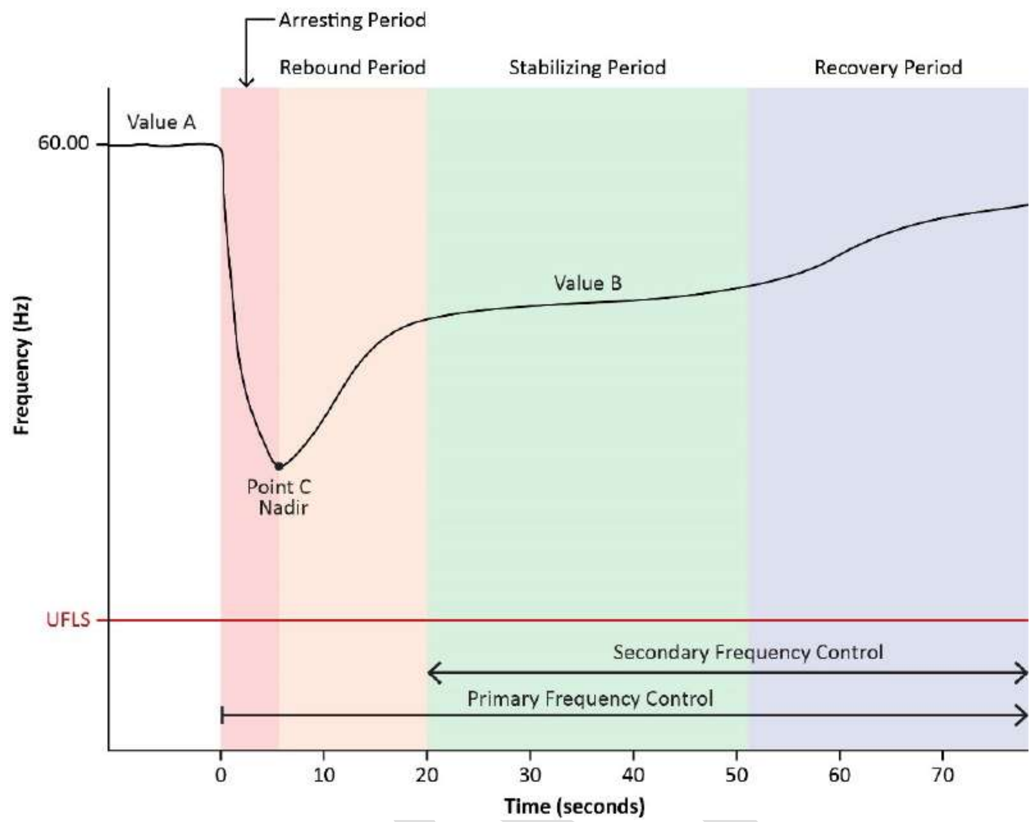


Figure ES.1: Primary and Secondary Frequency Control

Primary Frequency Control: This is the action by the Interconnection to arrest and stabilize frequency in response to frequency deviations and has three-time components: the Arresting Period, Rebound Period, and Stabilizing Period. These terms are defined below:

- **Arresting Period:** This is the time from time zero (Value A) to the time of the nadir (Point C) and is the combination of system inertia, load damping, and the initial primary control response of resources acting together to limit the duration and magnitude of frequency change. It is essential that the decline in frequency is arrested during this period to prevent activation of automatic under-frequency load shedding (UFLS) schemes in the Interconnection.
- **Rebound Period:** This includes the effects of governor response in sensing the change in turbine speed as frequency increases or declines, causing an adjustment to the energy input of the turbine's prime mover. This can also be impacted by end-user customers or other loads that are capable of self-curtailment due to local frequency sensing and control during frequency deviations.
- **Stabilizing Period:** This is the third component of primary frequency control following a disturbance when the frequency stabilizes following a frequency excursion. Value B represents the interconnected system frequency at the point immediately after the frequency stabilizes primarily due to governor action but before the contingent control area takes corrective automatic generation control action.

Chapter 1: Interconnection Frequency Characteristic Analysis

Annually, NERC staff performs a statistical analysis, as detailed in the *2012 Frequency Response Initiative Report,*[11] of the frequency characteristics for each of the four Interconnections. That analysis is performed to monitor the changing frequency characteristics of the Interconnections and to statistically determine each Interconnection's starting frequency for the respective IFRO calculations. For this report's analysis, one-second frequency data[12,13] from OYs 2019–2023 (December 1, 2018, through November 30, 2023) was used.

Frequency Variation Statistical Analysis

The 2024 frequency variation analysis was performed on one-second frequency data for 2019–2023 and is summarized in **Table 1.1**. This variability accounts for items like time-error correction (TEC), variability of load, interchange, and frequency over the course of a normal day. It also accounts for all frequency excursion events.

The starting frequency is calculated and published in this report for comparison and informational purposes. Starting frequencies are evaluated annually and indicate no need to change the Maximum Delta Frequency (MDF) for OY 2025.

Table 1.1: Interconnection Frequency Variation Analysis 2019-2023

Value	Eastern	Western	Texas	Québec
Number of Samples	157,020,269	156,980,095	155,531,801	150,869,719
Filtered Samples (% of total)	99.53	99.50	98.58	95.63
Expected Value (Hz)	59.999	59.999	59.999	60.000
Variance of Frequency (σ^2)	0.00027	0.00030	0.00029	0.00045
Standard Deviation (σ)	0.01638	0.01745	0.01694	0.02123
50% percentile (median)[13]	59.999	59.999	60.004	59.998
Starting Frequency (F_{START}) (Hz)	59.971	59.970	59.970	59.965

The starting frequency is the fifth percentile of the 5-year probability distribution of the respective interconnection frequency based on the statistical analysis, representing a 95% chance that frequencies will be at or above that value at the start of any frequency event. Since the starting frequencies encompass all variations in frequency, including changes to the target frequency during TECs, the need to expressly evaluate TEC as a variable in the IFRO calculation is eliminated.

[11] https://www.nerc.com/docs/pc/FRI_Report_10-30-12_Master_w-appendices.pdf

[12] One-second frequency data for the frequency variation analysis is provided by UTK. The data is sourced from FDRs in each Interconnection. The median value among the higher-resolution FDRs is down-sampled to one sample per second, and filters are applied to ensure data quality.

[13] Note regarding the EI median frequency that: with fast time error corrections the median value is around but slightly below 60 Hz. Without these corrections the median would be above 60 Hz.

Figure 1.1, **Figure 1.2**, **Figure 1.3**, and **Figure 1.4** show the probability density function (PDF) of frequency for each Interconnection. The vertical black line indicates the fifth-percentile frequency; the interconnection frequency will statistically be greater than that value 95% of the time; this value is used as the starting frequency.

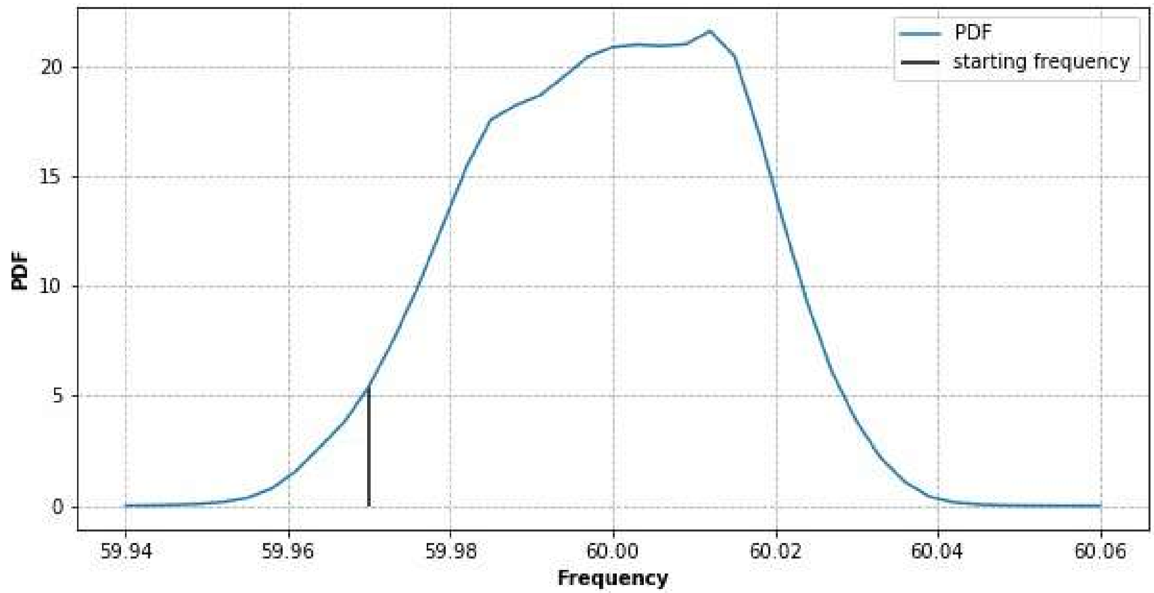


Figure 1.1: Eastern Interconnection 2019–2023 Probability Density Function of Frequency

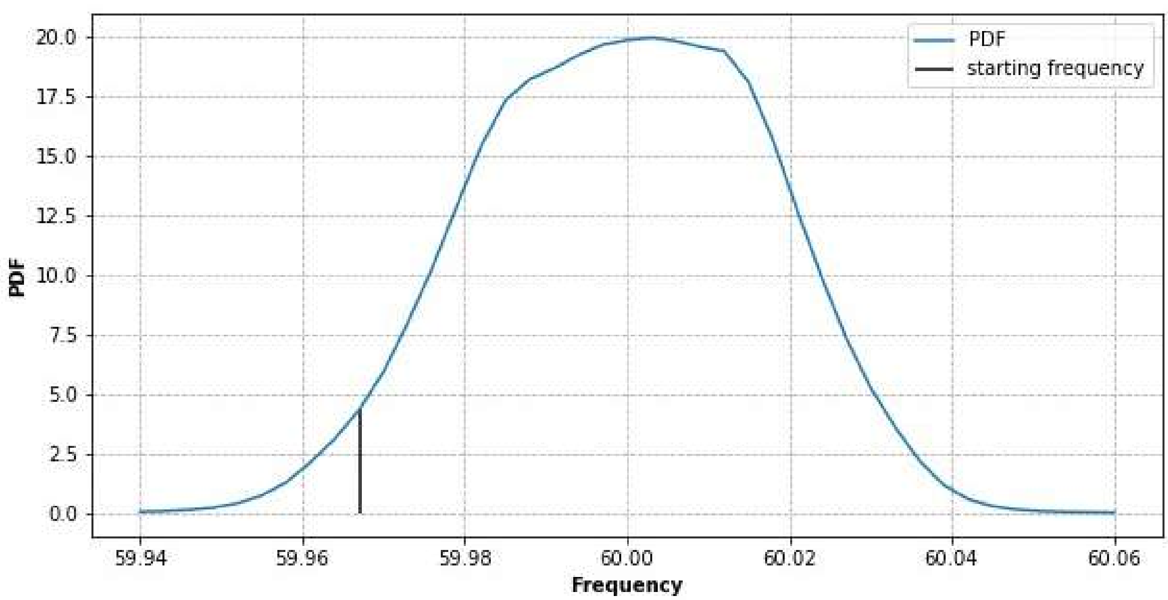


Figure 1.2: Western Interconnection 2019–2023 Probability Density Function of Frequency

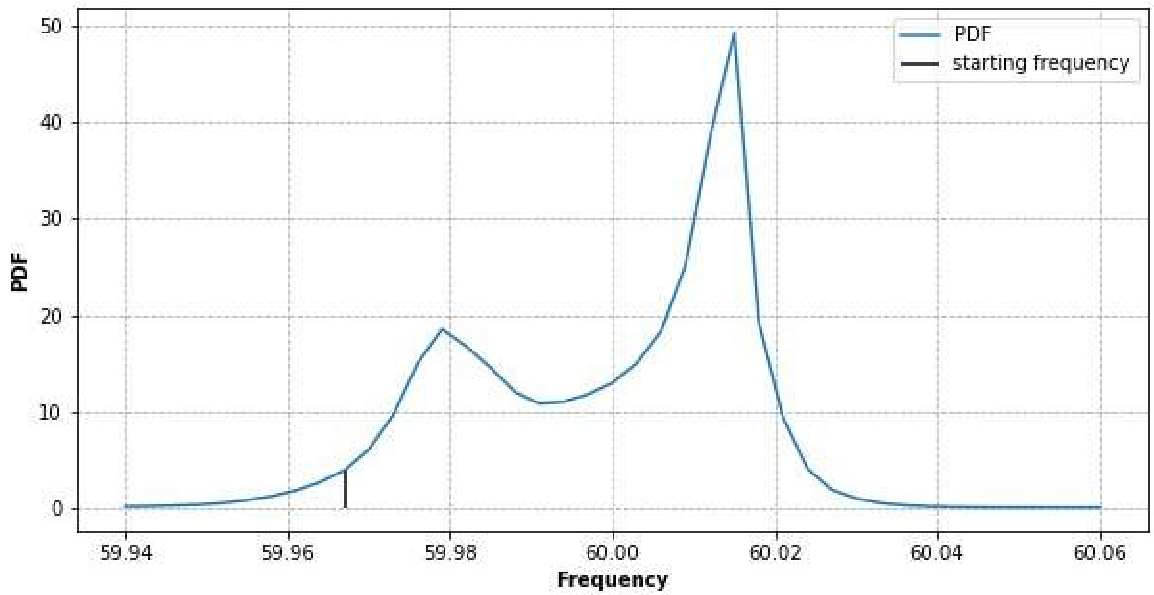


Figure 1.3: Texas Interconnection 2019–2023 Probability Density Function of Frequency

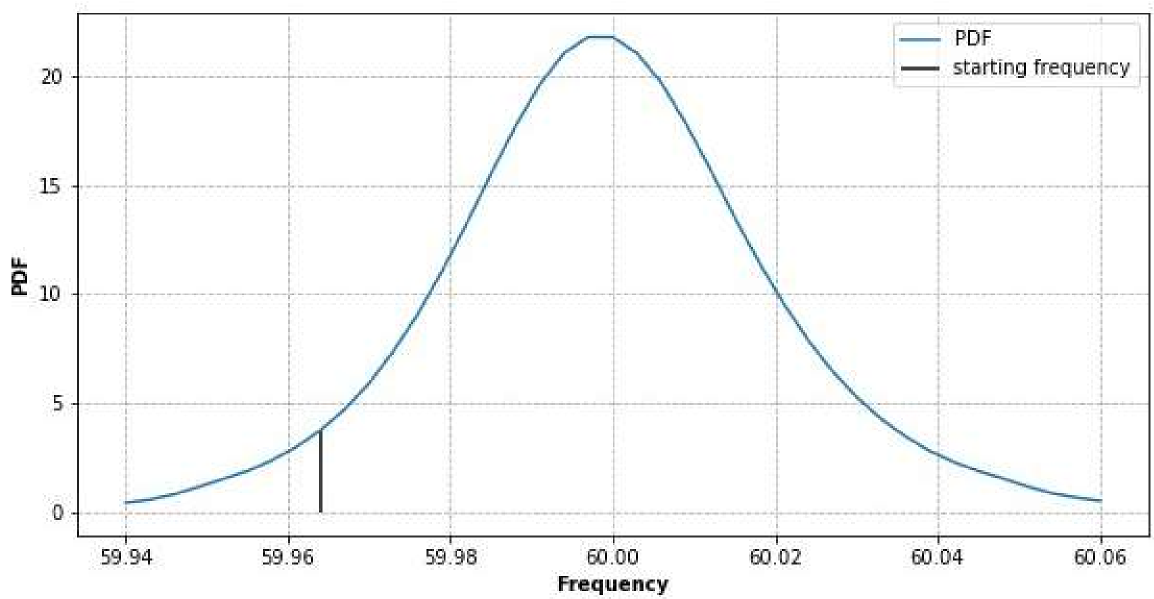


Figure 1.4: Québec Interconnection 2019–2023 Probability Density Function of Frequency

Figure 1.1, Figure 1.2, Figure 1.3, and Figure 1.4 show the PDF of frequency for each Interconnection. The Interconnection frequency will statistically be greater than that value 95% of the time; this value is used as the starting frequency. Figure 1.5 shows a comparison of the PDF for all Interconnections.

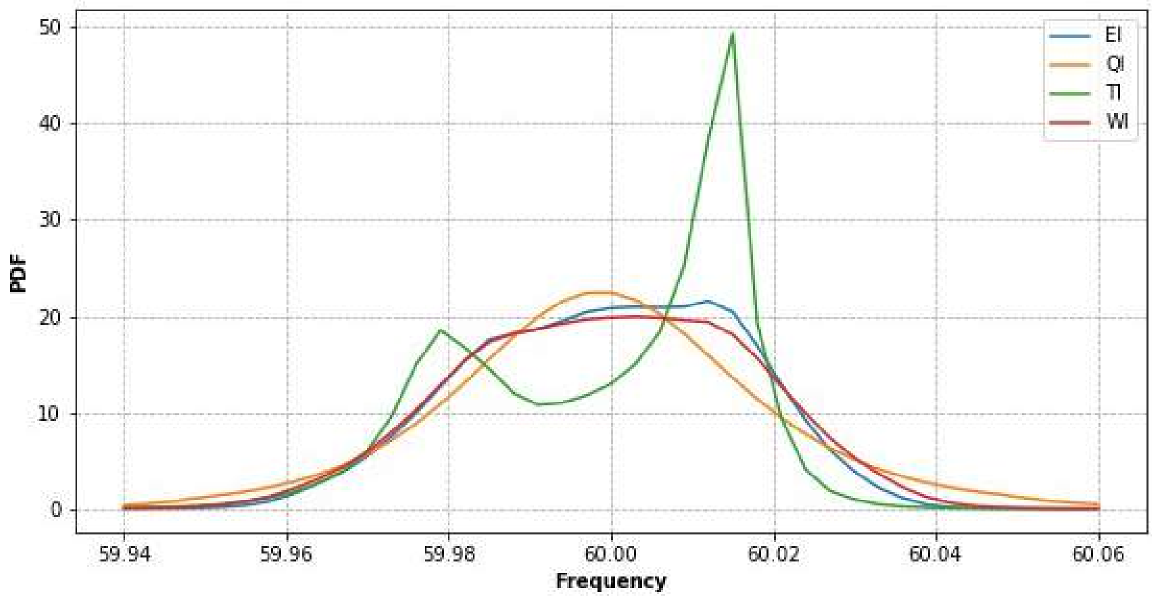


Figure 1.5: Comparison of 2019–2023 Interconnection Frequency PDFs

Variations in Probability Density Functions

The following is an analysis of the variations in probability density functions of the annual distributions of Interconnection frequency for years 2019–2023. Table 1.2 lists the standard deviation of the annual Interconnection frequencies.

Table 1.2: Interconnection Standard Deviation by Year

Interconnection	2019	2020	2021	2022	2023
Eastern	0.0162	0.0163	0.0164	0.0164	0.0167
Western	0.0174	0.0176	0.0174	0.0172	0.0177
Texas	0.0165	0.0174	0.0176	0.0169	0.0163
Québec	0.0204	0.0208	0.0223	0.0206	0.0220

In the EI, the standard deviation continued to increase in 2023 compared to 2019–2022. The standard deviation increased in the QI and the WI in 2023 compared to 2022. As standard deviation is a measure of dispersion of values around the mean value, the increasing standard deviations indicate reduced concentration around the mean value and less stable performance of the interconnection frequency. Comparisons of annual frequency profiles for each Interconnection are shown in Figure 1.6, Figure 1.7, Figure 1.8, and Figure 1.9.

Eastern Interconnection Frequency Characteristic Changes

The increase in standard deviation for the EI frequency characteristic in 2023 is shown in **Figure 1.6**. Statistical skewness (S)[14] decreased in 2022 (S = -0.15) as compared to 2020 and 2021 (S = -0.17 and -0.16, respectively). NERC, in coordination with its technical committees, continues to evaluate this phenomenon and its impact, if any, on BPS reliability.

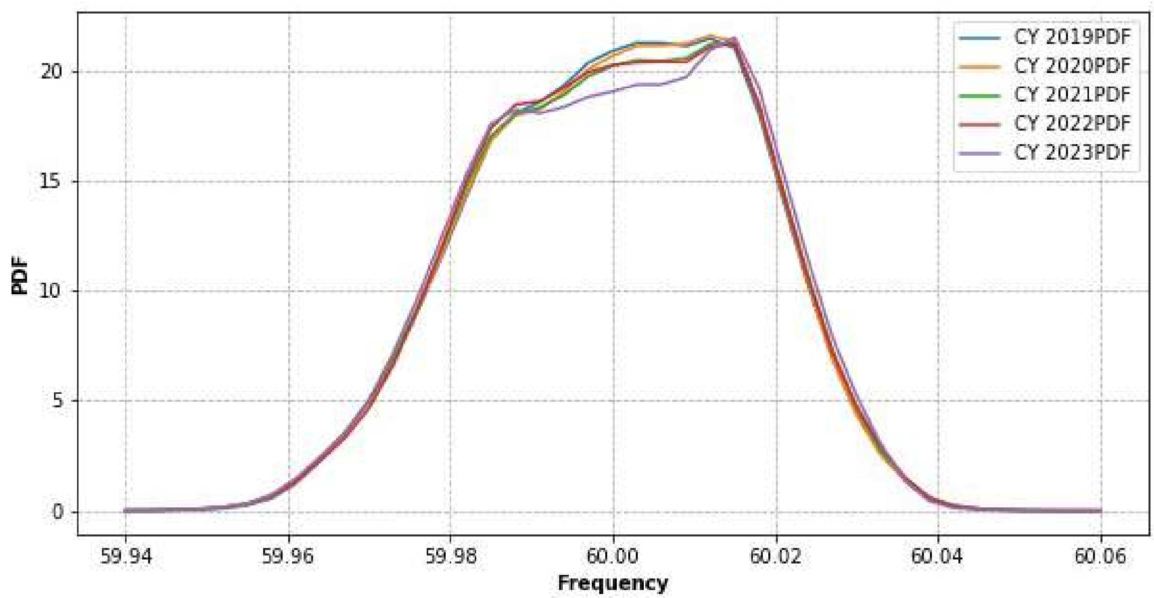


Figure 1.6: Eastern Interconnection Frequency Probability Density Function by Year

[14] The skewness (S) is a measure of asymmetry of a distribution. A perfectly symmetric distribution has S=0. The sign indicates where a longer tail of the distribution is. The negatively-skewed distribution has a longer left tail, and its curve leans to the opposite direction (to the right). Algebraically, it means that the frequency values that are smaller than its mean are spread farther from the mean than the values greater than the mean or that there is more variability in lower values of the frequency than in higher values of the frequency.

Western Interconnection Frequency Characteristic Changes

There was an observable change in the frequency distribution for the WI in 2021 that includes some skewness as shown in **Figure 1.7**.

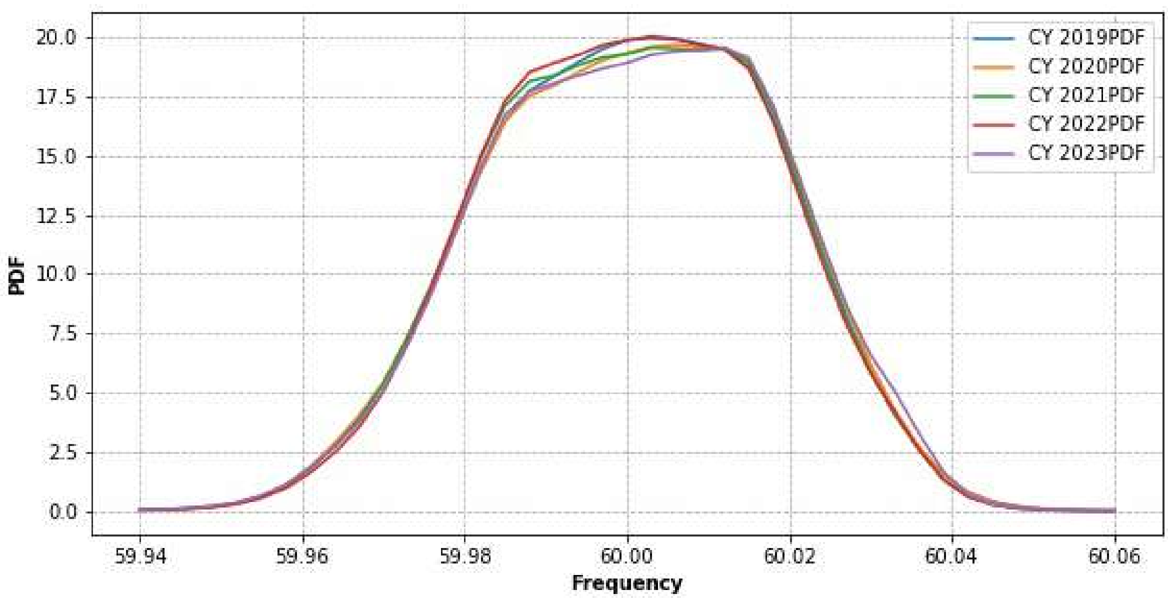


Figure 1.7: Western Interconnection Frequency Probability Density Function by Year

Texas Interconnection Frequency Characteristic Changes

Standard BAL-001-TRE-1[15] went into full effect in April 2015 and caused a dramatic change in the probability density function of frequency for Texas Interconnection in 2015 and 2016. This standard requires all resources in Texas Interconnection to provide proportional, nonstep primary frequency response with a ±17 mHz dead-band. As a result, any time frequency exceeds 60.017 Hz, resources automatically curtail themselves. That has resulted in far less operation in frequencies above the dead-band since all resources, including wind and solar, are backing down. It is exhibited in **Figure 1.8** as a probability concentration around 60.015 Hz. Similar behavior is not exhibited at the low dead-band of 59.983 Hz because most wind and solar resources are operated at maximum output and cannot increase output when frequency falls below the dead-band.

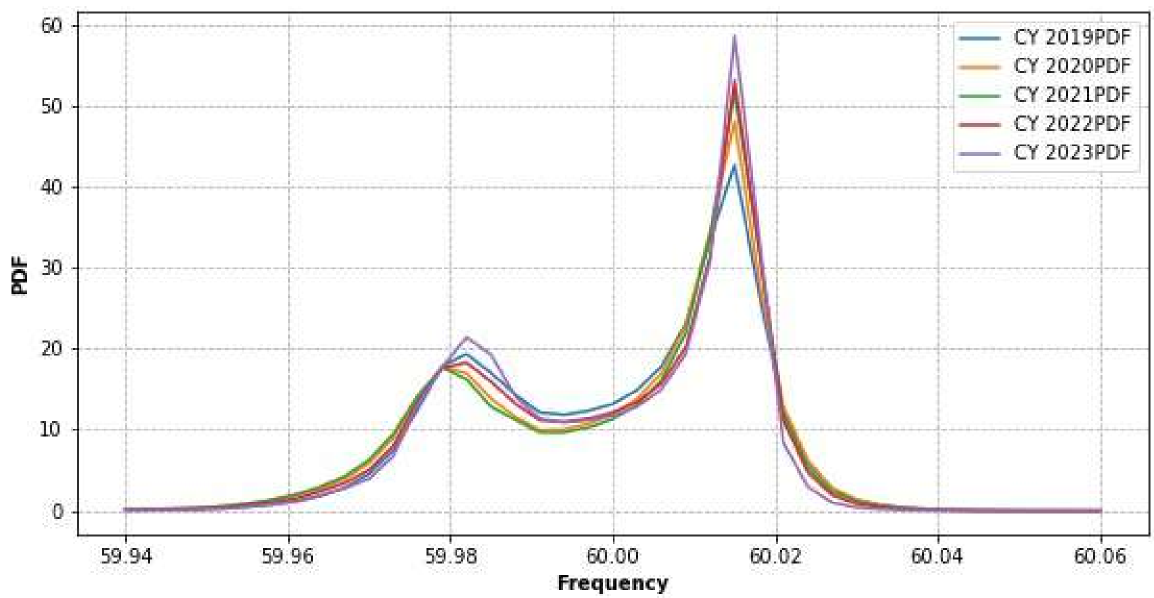


Figure 1.8: Texas Interconnection Frequency Probability Density Function by Year

15 http://www.nerc.com/pa/Stand/Reliability%20Standards/BAL-001-TRE-1.pdf

Quebec Interconnection Frequency Characteristic Changes

There were no observable changes in the shape of the distribution for the QI as shown in **Figure 1.9**.

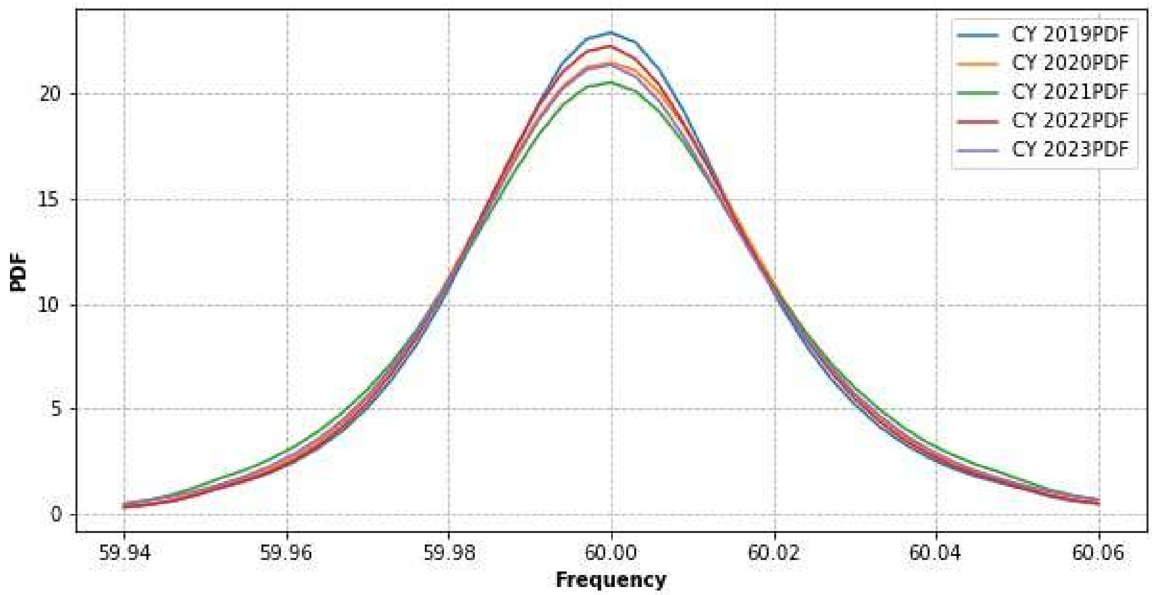


Figure 1.9: Québec Interconnection Frequency Probability Density Function by Year

Chapter 2: Determination of Interconnection Frequency Response Obligations

With this report the calculation of the IFROs is determined by BAL-003-2. Previously, the calculation involved a multifaceted process that employed statistical analysis of past performance; analysis of the relationships between measurements of Value A, Point C, and Value B; and other adjustments to the allowable frequency deviations and resource losses used to determine the recommended IFROs. Refer to the *2012 Frequency Response Initiative Report* for additional details on the development of the IFRO and the adjustment calculation methods.[16] This report includes information that serves to transition from the old to the new method.

Tenets of IFRO

The IFRO is the minimum amount of frequency response that must be maintained by an Interconnection. Each Balancing Authority (BA) in the Interconnection is allocated a portion of the IFRO that represents its minimum annual median performance responsibility. To be sustainable, BAs susceptible to islanding may need to carry additional frequency-responsive reserves to coordinate with their UFLS plans for islanded operation.

A number of methods to assign the frequency response targets for each Interconnection can be considered. Initially, the following tenets should be applied:

- A frequency event should not activate the first stage of regionally approved UFLS systems within the Interconnection.
- Local activation of first-stage UFLS systems for severe frequency excursions, particularly those associated with delayed fault-clearing or in systems on the edge of an Interconnection, may be unavoidable.
- Other frequency-sensitive loads or electronically coupled resources may trip during such frequency events as is the case for photovoltaic (PV) inverters.
- It may be necessary in the future to consider other susceptible frequency sensitivities (e.g., electronically coupled load common-mode sensitivities).

UFLS is intended to be a safety net to prevent system collapse due to severe contingencies. Conceptually, that safety net should not be utilized for frequency events that are expected to happen on a relatively regular basis. As such, the resource loss protection criteria were selected in accordance with BAL-003-2 to avoid violating regionally approved UFLS settings.

Interconnection Resource Loss Protection Criteria (RLPC)

BAL-003-2 introduced the Interconnection Resource Loss Protection Criteria (RLPC) to replace the Resource Contingency Protection Criteria used previously. It is based on resource loss in accordance with the following process:

NERC will request BAs to provide their two largest resource loss values and largest resource loss due to an N-1 or N2 remedial action scheme (RAS) event or largest resource as described above. This will facilitate comparison between the existing Interconnection RLPC values and the RLPC values in use. This data submission will be needed to complete the calculation of the RLPC and IFRO.

[16] https://www.nerc.com/comm/OC/BAL0031_Supporting_Documents_2017_DL/FRI_Report_10-30-12_Master_wappendices.pdf#search=Frequency%20Response%20Initiative%20Report

BAs determine the two largest resource losses for the next OY based on a review of the following items:

- The two largest balancing contingency events due to a single contingency identified using system models in terms of loss measured by megawatt loss in a normal system configuration (N-0) (An abnormal system configuration is not used to determine the RLPC).
- The two largest units in the BA area, regardless of shared ownership/responsibility
- The two largest RAS resource losses (if any) that are initiated by single (N-1) contingency events.

The BA provides these two numbers determined above as Resource Loss A and Resource Loss B in the FR Form 1.

The BA should then provide the largest resource loss due to RAS operations (if any) that are initiated by a multiple contingency (N-2) event (RLPC cannot be lower than this value). If this RAS impacts more than a single BA, one BA is asked to take the lead and sum all resources lost due to the RAS event and provide that information.

The calculated RLPC should meet or exceed any credible N-2 resource loss event.

The host BA (or planned host BA) where jointly owned resources are physically located should be the only BA to report that resource. The full ratings of the resource, not the fractional shares, should be reported.

Direct current (dc) ties to asynchronous resources (such as dc ties between Interconnections, or the Manitoba Hydro Dorsey bi-pole ties to their northern asynchronous generation) should be considered as resource losses. DC lines such as the Pacific DC Intertie, which ties two sections of the same synchronous Interconnection together, should not be reported. A single pole block with normal clearing in a monopole or bi-pole high-voltage direct current system is a single contingency.

Calculation of IFRO Values

The IFRO is calculated using the RLPC above (Table 1 from BAL-003-2).

$$IFRO = \frac{RLPC - CLR}{MDF * 10}\ \mathrm{MW/0.1Hz}$$

As specified in the *Procedure for ERO Support of Frequency Response and Frequency Bias Setting*[17] standard, "MDF is the Maximum Delta Frequency for the specific interconnection as determined in the 2017 Frequency Response Annual Analysis (FRAA)." The BAL-003-2 revision alleviated the adverse impacts of an improving CB_R.

The IFRO for each Interconnection is calculated in this report in **Table 2.5**; note that the calculated value for the EI IFRO is estimated by BAL-003-2 to be stepped down over three years with a reduction of IFRO not to exceed -100 MW/0.10 Hz per year in accordance with BAL-003-2. Collected RLPC data exceeded the estimate at the time BAL003-2 balloted, and EI IFRO should meet the actual calculated value in only two OYs as a result. That determines the difference between the calculated EI IFRO in **Table 2.5** and the recommended IFRO shown in **Table ES.1** and **Table 2.7**.

[17] https://www.nerc.com/pa/Stand/Frequency%20Response%20Project%20200712%20Related%20Files%20DL/BAL-003-1_Procedure-Clean_20120210.pdf

Determination of Adjustment Factors

The C-to-B ratio (CB_R) is no longer used in the IFRO method and has been eliminated.

Adjustment for Primary Frequency Response Withdrawal (BC'_{ADJ})

Point C is normally the frequency nadir during the event; however, point C and the nadir may differ if the nadir occurs more than 20 seconds after the start of the event[18]. This lower nadir is symptomatic of primary frequency response withdrawal or squelching by unit-level or plant-level outer loop control systems. Withdrawal is most prevalent in the EI.

To track frequency response withdrawal in this report, the later-occurring nadir is termed Point C,' which is defined as occurring after the Value B averaging period and must be lower than either Point C or Value B.

Primary frequency response withdrawal is important depending on the type and characteristics of the generators in the resource dispatch, especially during light-load periods. Therefore, an additional adjustment to the maximum allowable delta frequency for calculating the IFROs was statistically developed. This adjustment is used whenever withdrawal is a prevalent feature of frequency events.

The statistical analysis is performed on the events with C' value lower than Value B to determine the adjustment factor BC'_{ADJ} to account for the statistically expected Point C' value of a frequency event. These results correct for the influence of frequency response withdrawal on setting the IFRO. **Table 2.1** shows a summary of the events for each Interconnection where the C' value was lower than Value B (averaged from T+20 through T+52 seconds) and those where C' was below Point C for OYs 2019 through 2023 (December 1, 2018, through November 30, 2023).

Table 2.1: Statistical Analysis of the Adjustment for C' Nadir (BC'adj)

Interconnection	Number of Events Analyzed	C' Lower than B	C' Lower than C	Mean Difference Between B and C'	Standard Deviation	BC'ADJ (95% Quantile)
EI	100	39	11	0.009	0.005	0.011
WI	100	61	1	N/A	N/A	N/A
TI	80	50	8	N/A	N/A	N/A
QI	136	45	16	-0.025	0.018	-0.017

The 16 events detected for QI are for load-loss events; this is indicated by the negative values for the mean difference and the BC'_{ADJ}. The adjustment is not intended to be used for load-loss events.

Although one event with C' lower than Point C was identified in the WI, an adjustment factor is not warranted; only the adjustment factor of 11 mHz for the EI is necessary. Of the 100 frequency events analyzed in the EI, there were 39 events that exhibited a secondary nadir where Point C' was below Value B and 11 events where Point C' was lower than the initial frequency nadir (Point C). These secondary nadirs occur beyond 52 seconds after the start of the event,[19] which is the time frame for calculating Value B.

[18] The "*Procedure for ERO Support of Frequency Response and Frequency Bias Setting Standard*" defines Point C to occur within T+20 seconds.

[19] The timing of the C' occurrence is consistent with outer-loop plant and unit controls, causing withdrawal of inverter-based resource frequency response.

Therefore, a BC'_{ADJ} is only needed for the EI; no BC'_{ADJ} is needed for the other three Interconnections. This will continue to be monitored moving forward to track these trends in C' performance.

Low-Frequency Limit

The low-frequency limits to be used for the IFRO calculations (**Table 2.2**) should be the highest step in the Interconnection for regionally approved UFLS systems. These values have remained unchanged since the *2012 Frequency Response Initiative Report*.

Table 2.2: Low-Frequency Limits (Hz)

Interconnection	Highest UFLS Trip Frequency
EI	59.5
WI	59.5
TI	59.3
QI	58.5

The highest UFLS set point in the EI is 59.7 Hz in SERC-Florida Peninsula (FP), which was previously FRCC, while the highest set point in the rest of the Interconnection is 59.5 Hz. The SERC-FP 59.7 Hz first UFLS step is based on internal stability concerns and is meant to prevent the separation of the FP from the rest of the Interconnection. SERC-FP concluded that the IFRO starting point of 59.5 Hz for the EI is acceptable in that it imposes no greater risk of UFLS operation for an Interconnection resource loss event than for an internal SERC-FP event.

Protection against tripping the highest step of UFLS does not ensure generation that has frequency-sensitive boiler or turbine control systems will not trip, especially in electrical proximity to faults or the loss of resources. Severe system conditions might drive the combination of frequency and voltage to levels that present some generator and turbine control systems to trip the generator. Similarly, severe rates-of-change occurring in voltage or frequency might actuate volts-per-hertz relays; this would also trip some generators, and some combustion turbines may not be able to sustain operation at frequencies below 59.5 Hz.

Inverter-based resources may also be susceptible to extremes in frequency. Laboratory testing by Southern California Edison of inverters used on residential and commercial scale PV systems revealed a propensity to trip at about 59.4 Hz, about 200 mHz above the expected 59.2 Hz prescribed in IEEE Standard 1547 for distribution-connected PV systems rated at or below 30 kW (57.0 Hz for larger installations). This could become problematic in the future in areas with a high penetration of inverter-based resources.

Credit for Load Resources

The TI depends on contractually interruptible (an ancillary service) demand response that automatically trips at 59.7 Hz by under-frequency relays to help arrest frequency declines. A CLR is made for the resource contingency for the TI.

The amount of CLR available at any given time varies by different factors, including its usage in the immediate past. NERC performed statistical analysis on hourly available CLR over a two-year period from December 2022 through November 2023, like the approach used in the *2015 FRAA* and in the *2016 FRAA*. Statistical analysis indicated that 962 MW of CLR is available 95% of the time. Therefore, a CLR adjustment of 962 MW is applied in the calculation of the TI IFRO as a reduction to the RLPC.

TI Credit for Load Resources

Prior to April 2012, the TI was procuring 2,300 MW of responsive reserve service, of which up to 50% could be provided by the load resources with under-frequency relays set at 59.70 Hz. Beginning April 2012, due to a change in market rules, the responsive reserve service requirement was increased from 2,300 MW to 2,800 MW for each hour, meaning load resources could potentially provide up to 1,400 MW of automatic primary frequency response.

Determination of Maximum Allowable Delta Frequencies

Because of the measurement limitation[20] of the BA-level frequency response performance, IFROs must be calculated in "Value B space." Protection from tripping UFLS for the Interconnections based on Point C, Value B, or any nadir occurring after Point C, within Value B, or after T+52 seconds must be reflected in the maximum allowable delta frequency for IFRO calculations expressed in terms comparable to Value B.

Table 2.3 shows the calculation of the maximum allowable delta frequencies for each of the Interconnections. All adjustments to the maximum allowable change in frequency are made to include the following:

- Adjustments for the differences between Point C and Value B
- Adjustments for the event nadir being below Value B or Point C due to primary frequency response withdrawal measured by Point C'

Table 2.3: Determination of Maximum Allowable Delta Frequencies

	EI	WI	TI	QI	Units
Starting Frequency	59.971	59.970	59.970	59.965	Hz
Minimum Frequency Limit	59.500	59.500	59.300	58.500	Hz
Base Delta Frequency	0.471	0.470	0.670	1.465	Hz
BC'_{ADJ20}	0.011	N/A	N/A	-0.017	-
Calculated Max. Allowable Delta Frequency	0.460	0.470	0.670	1.482	Hz
Max. Delta Frequency Per *Procedure for ERO Support of Frequency Response and Frequency Bias Setting Standard*	0.420	0.280	0.405	0.947	Hz

[20] Due to use of 1–6 second scan-rate in BA's EMS systems to calculate the BA's Frequency Response Measures for frequency events under BAL-003-1

Calculated IFROs

Table 2.4 shows the determination of IFROs for OY 2025 (December 2024 through November 2025) under standard BAL-003-2 based on a resource loss equivalent to the recommended criteria in each Interconnection. The maximum allowable delta frequency values have already been modified to include the adjustments for the differences between Value B and Point C (CB_R), the differences in measurement of Point C using one-second and subsecond data (CC_{ADJ}), and the event nadir being below the Value B (BC'_{ADJ}).

Table 2.4: Initial Calculation of OY 2025 IFROs					
	Eastern	**Western**	**Texas**	**Québec**	**Units**
Starting Frequency	59.971	59.970	59.970	59.965	Hz
Max. Delta Frequency Per *Procedure for ERO Support of Frequency Response and Frequency Bias Setting Standard*	0.420	0.280	0.405	0.947	Hz
Resource Loss Protection Criteria	3,875	2,918	2,805	2,000	MW
Credit for Load Resources	N/A	N/A	962	N/A	MW
Calculated IFRO using 2017 MDF	-923	-1042	-455	-211	MW/0.1 Hz
Recommended IFRO					
IFRO per *Procedure for ERO Support of Frequency Response and Frequency Bias Setting Standard*	-923[21]	-1042	-455	-211	MW/0.10 Hz

Comparison to Previous IFRO Values

The IFROs were first calculated and presented in the *2012 Frequency Response Initiative Report*. Table 2.5 compares the current IFROs and their key component values to those presented in the *2016 FRAA* report.

[21] BAL-003-2 requires that the EI IFRO will be stepped down to its calculated value over three years. The maximum reduction is limited to 100 MW/0.10 Hz annually.

Table 2.5: Interconnection IFRO Comparison						
	OY 2016 Calc.[22]	OY 2024 In Use[23]	OY 2025 Calc.[24]	OY 2016 Calc. to OY 2024 In Use Change	OY 2024 In Use to 2025 Calc. Change	Units
Eastern Interconnection						
Starting Frequency	59.974	59.971	59.971	-0.003	0.000	Hz
Max. Allowable Delta Frequency	0.443	0.420	0.460	-0.023	0.040	Hz
Resource Contingency Protection Criteria	4500	3,875	3,875	-625	0	MW
Credit for Load Resources	0	0	0	0	0	MW
Absolute Value of IFRO	**1015**	**923**	**842**	-92	-81	MW/0.1 Hz
Western Interconnection						
Starting Frequency	59.967	59.970	59.970	0.003	0.000	Hz
Max. Allowable Delta Frequency	0.292	0.280	0.470	-0.012	0.190	Hz
Resource Loss Protection Criteria	2626	2918	2918	292	0	MW
Credit for Load Resources	0	0	0	0	0	MW
Absolute Value of IFRO	**858**	**1042**	**621**	184	-421	MW/0.1 Hz
Texas Interconnection						
Starting Frequency	59.971	59.970	59.970	-0.001	0.000	Hz
Max. Allowable Delta Frequency	0.405	0.405	0.670	0.000	0.265	Hz
Resource Loss Protection Criteria	2805	2805	2805	0	0	MW
Credit for Load Resources	1136	1204	962	68	242	MW

[22] Calculated in the 2015 FRAA report. Average frequency values were for OYs 2012–2014.
[23] Calculated in the 2023 FRAA report. Average frequency values were for OYs 2018–2022.
[24] Calculated in the 2024 FRAA report. Average frequency values were for OYs 2019–2023.

Table 2.5: Interconnection IFRO Comparison						
	OY 2016 Calc.[22]	OY 2024 In Use[23]	OY 2025 Calc.[24]	OY 2016 Calc. to OY 2024 In Use Change	OY 2024 In Use to 2025 Calc. Change	Units
Absolute Value of IFRO	**412**	**395**	**275**	-17	60	MW/0.1 Hz
Québec Interconnection						
Starting Frequency	59.969	59.965	59.965	-0.004	0.000	Hz
Max. Allowable Delta Frequency	0.948	0.947	1.482	-0.001	0.000	Hz
Resource Loss Protection Criteria	1700	2000	2000	300	0	MW
Credit for Load Resources	0	0	0	0	0	MW
Absolute Value of IFRO	**179**	**211**	**135**	32	-76	MW/0.1 Hz

Key Findings

Table 2.6 shows a comparison of mean Value A, mean Value B, and mean Point C that is illustrative of Interconnection performance over the previous OY and as compared to the 2016 OY in which the IFRO values were frozen. Loss of load events have been excluded from the data in Table 2.6. Eastern, Western, and Texas Interconnections show an increase in mean Value B and a decrease in the mean (A-B), indicating improved performance during the stabilizing period of frequency events. Quebec showed an increase in mean Value B up until OY 2023, where it declined slightly. Eastern, Western, and Texas Interconnections show either an increase or no change in mean Point C as well as a decrease or no change in mean (A–C), indicating improved performance during the arresting period of frequency events. Quebec shows a decrease in mean Value C as well as an increase in mean Value A-C. Texas showed an increase or no change in the mean Point C as well as a decrease or no change in mean (A-C), indicating improved performance during the Arresting Period of frequency events. QI showed decreasing mean Point C and increasing mean (A-C).

Table 2.6: Year over Year Comparison Value A, Value B, and Point C (Loss of Load Events Excluded)					
	OY2016	OY2023	OY2024	Difference OY 2023–2016	Difference OY 2024–2023
Eastern Interconnection					
Mean Value A (Hz)	59.998	60.000	60.001	0.002	0.001
Mean Value B (Hz)	59.947	59.956	59.957	0.009	0.001
Mean Point C (Hz)	59.947	59.948	59.948	0.001	0
Mean A – B (Hz)	0.051	0.045	0.044	-0.006	-0.001
Mean A – C (Hz)	0.051	0.052	0.053	0.001	0.001
Western Interconnection					

Table 2.6: Year over Year Comparison Value A, Value B, and Point C (Loss of Load Events Excluded)

	OY2016	OY2023	OY2024	Difference OY 2023–2016	Difference OY 2024–2023
Mean Value A (Hz)	60	59.996	59.998	-0.004	0.002
Mean Value B (Hz)	59.923	59.949	59.952	0.026	0.003
Mean Point C (Hz)	59.887	59.898	59.901	0.011	0.003
Mean A – B (Hz)	0.076	0.047	0.046	-0.029	-0.001
Mean A – C (Hz)	0.112	0.098	0.097	-0.014	-0.001
Texas Interconnection					
Mean Value A (Hz)	59.996	59.999	60.000	0.003	0.001
Mean Value B (Hz)	59.889	59.924	59.931	0.035	0.007
Mean Point C (Hz)	59.84	59.858	59.866	0.018	0.008
Mean A – B (Hz)	0.107	0.074	0.070	-0.033	-0.004
Mean A – C (Hz)	0.156	0.141	0.134	-0.015	-0.007
Québec Interconnection					
Mean Value A (Hz)	60.003	60.005	60.005	0.002	0
Mean Value B (Hz)	59.843	59.876	59.869	0.033	-0.007
Mean Point C (Hz)	59.433	59.515	59.484	0.082	-0.031
Mean A – B (Hz)	0.160	0.129	0.135	-0.031	0.006
Mean A – C (Hz)	0.570	0.490	0.521	-0.080	0.031

Recommended IFROs for OY 2025

Consistent with the requirements of BAL-003-2, the IFRO values shown in **Table 2.7** for OY 2025 (December 2024 through November 2025) are recommended as follows:

Table 2.7: Recommended IFROs for OY 2025

	EI	WI	TI	QI	Units
MDF[25]	0.420	0.280	0.405	0.947	Hz
RLPC[26]	3875	2918	2805	2000	MW
CLR	0	0	962	0	MW
Calculated IFRO	-923	-1042	-455	-211	MW/0.1 Hz
Recommended IFRO[27]	**-923**	**-1042**	**-455**	**-211**	MW/0.1 Hz

[25] The Procedure for ERO Support of Frequency Response and Frequency Bias Setting Standard, Version II, provided in the approved ballot for BAL-003-2, specifies that, "MDF is the Maximum Delta Frequency for the specific interconnection as determined in the 2017 Frequency Response Annual Analysis (FRAA).

[26] BAL-003-2, Attachment A specifies that Resource Loss Protection Criteria (RLPC) be based on the two largest potential resource losses in an interconnection. This value is required to be evaluated annually.

[27] BAL-003-2 requires that the EI IFRO will be stepped down to its calculated value over three years. The maximum reduction is limited to 100 MW/0.10 Hz annually.

Chapter 3: Dynamics Analysis of Recommended IFROs

Because the IFROs for the EI, WI, and TI have only been calculated upon issue of this report, they have not been changed as governed by BAL-003-2. Additional dynamic validation analyses were not done for this report.

Refer to the dynamics validation in the *2017 FRAA*[28] report for details. No analysis was performed for the QI.

Further supporting dynamic studies accompanied the development and filing of BAL-003-2.

[28] https://www.nerc.com/comm/OC/Documents/2017_FRAA_Final_20171113.pdf

Technical Reference Document: Balancing Authority Area Footprint Change

Action
Approve

Background
The Resources Subcommittee (RS) has recently revised the Technical Reference Document: Balancing Authority Area Footprint Change. This important document is designed to provide a standardized method for Balancing Authorities (BAs), working in cooperation with NERC staff, to accurately calculate the Frequency Bias Setting (FBS). This calculation is based on the real contributions of primary frequency response to an Interconnection, which is known as the Frequency Response Measure (FRM).

Summary
The RS is requesting approval from the RSTC to publish the Technical Reference Document: Balancing Authority Area Footprint Change for a 30-day commenting period.

Balancing Authority Area Footprint Change Tasks

Reference Document

Background

Since the implementation and enforcement of NERC Reliability Standard BAL-003-1 in April 2016, Balancing Authorities (BAs) have experienced several changes in their footprint, particularly those in multi-BA Interconnections. The intent of the existing BAL-003-1 standard is to measure an Interconnection's ability to 1) arrest sudden changes in system frequency and 2) contribute primary frequency response to prevent activation of under frequency load shedding (UFLS). One of the many goals achieved by the standard was establishing a methodology for BAs to measure performance over time against a defined calculated target, i.e., Frequency Response Obligation (FRO). Another goal accomplished was to establish a standard methodology for BAs, in coordination with NERC staff, to calculate Frequency Bias Setting (FBS) based on actual primary frequency response contributions to an Interconnection, i.e., Frequency Response Measure (FRM). Nonetheless, adjustments BAs need to make, to both the FRO and the FBS, as a result of changes in footprint within a BAL-003 operating year, was not contemplated or simply not in scope at that time. There were some unanswered questions, such as:

- What do BAs need to do when reallocating assets to another BA?
- What is going to happen to the FRO?
- How is a BA going to meet its FRO if it no longer has those assets within its BA footprint?
- What is going to be the impact to my existing FBS?
- How is my BA going to manage BA ACE Limits (BAAL) with more resources and the same FBS?
- What else needs to be coordinated with other entities with every change in footprint (i.e. recertification, revisions models, etc.)?

To address those questions or concerns the NERC Resources Subcommittee (RS) has revised this Reference Document to assist BAs with the tasks associated with BAs footprint changes. Especially, how BAs may agree on transfer of responsibilities. <u>This document includes several scenarios of historical BA footprint changes. Since these scenarios cannot address every possible scenario, BAs are encouraged to contact their regional NERC RS representative at balancing@NERC.com for further assistance.</u>

Applicability:

The tasks, roles and responsibilities in this reference document apply to entities typically involved in BA footprint changes, such as BAs, Reliability Coordinators (RCs), Regional Entities (REs), NERC and Regional Inadvertent Survey Contacts.

Notification Timeline:

A BA that will be experiencing changes in footprint should notify all the applicable groups no less than ninety (90) calendar days prior to the effective implementation date. Proper coordination to transfer responsibilities is essential for the BAs to operate and meet their obligations.

Scope

The following are the more common changes that occur to BAs, especially to those that operate in multi–BA Interconnections (e.g., Western Interconnection (WI) and Eastern Interconnection (EI)):

1. **Total Merge** – at least two BAAs participate. One or more remain as registered BA(s), while the other(s) proceed to deregister from NERC. See Diagram 1 and Diagram 5.

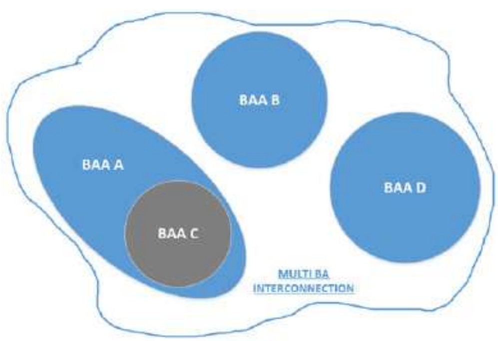


DIAGRAM 1

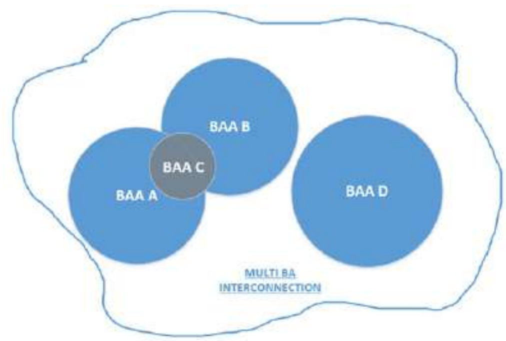


DIAGRAM 5

2. **Partial Merge** – A portion of generation and/or load is moved from one or more existing BAA(s) to one or more new or existing BAA(s). Transferring BA remains registered with NERC. This may include Pseudo Ties moving generation from one BA to another. See Diagram 2.

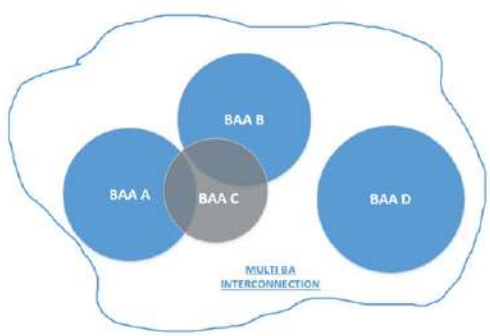


DIAGRAM 2

3. **New BA** – It did not exist previously (i.e., recently registered and certified). See Diagram 3.

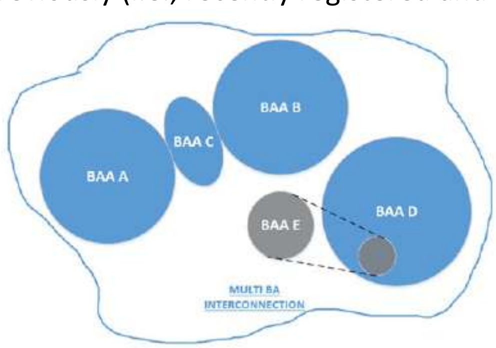


DIAGRAM 3

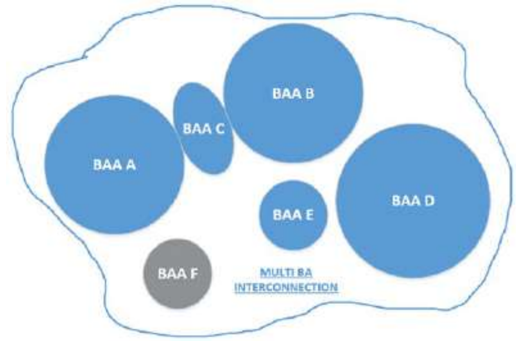


DIAGRAM 4

a. New generation and/or load to the Interconnection forming a new BA. See Diagram 4.

b. Existing generation and/or load operating in the Interconnection that are forming a new BA. A mix of new and existing generation and/or load in the Interconnection forming a new BA.

4. **Deregistered BA** – A BA planning to discontinue operations transferring generation and/or load into one or more receiving BAA(s).

5. **Receiving BA (Successor)** – A BA changes name or turns over responsibility to another entity.

BA footprint changes between interconnections are not in scope.

Process Steps

I. NERC Certification Process

Each NERC RE[1] has registration information posted on its website regarding how to start the NERC certification process. The certification process may take up to nine (9) months to complete. Refer to Appendix 5A – Organization Registration and Certification Manual (Section 500 of the Rules of Procedures) **– New BA Task**

II. Obtain BA ID

Obtain BA ID from the North American Energy Standards Board (NAESB)[2] Electric Industry Registry (EIR) – 4-character maximum label **– New BA Task**

III. BA Map Bubble Diagram

Add new BA, or updated BAA footprint, to the NERC BAs bubble diagram – **NERC RS Task**

III. Model Revision

Notify groups or entities responsible for making update(s) to power flow representations applicable to their area.

- Interchange Distribution Calculator (IDC)[3]– Eastern Interconnection
- Enhanced Curtailment Calculator (ECC)[4] – Western Interconnection,
- Multi Regional Modeling Working Group Model (MMWG) – Eastern Interconnection

– **EIDSN, ECCTF, MMGW, BA Task**

---

[1] Regional Entity Registration and Certification information: FRCC | MRO | NPCC | RF | SERC | SPP RE | Texas RE | WECC

[2] The EIR is maintained by the North American Energy Standards Board

[3] The IDC is maintained by the Eastern Interconnection Data Sharing Network, Inc.

[4] The ECC is maintained by PEAK Reliability RC

IV. Inadvertent Interchange

For merged BAs, the BA that is deregistering needs to transfer its Inadvertent balance to the receiving BA. For BAs that are splitting or transferring, they may allocate Inadvertent Interchanges as the parties deem appropriate, but the net balance between the remaining BAs must remain the same **– Deregistering BA, Receiving BA, and Regional Inadvertent Survey Contact Task**

V. Submit FERC 714 Data Schedule II Part III or Similar

From BAs experiencing changes in footprint will complete and submit a BA to BA General 714 data submittal form (or its successor) to NERC RS staff support via the Balancing Authority Submittal Site (BASS) or its successor. The FERC 714 data (or similar _see Attachment C) will apply for the two years prior and year to date - once available. Data must be provided separate by calendar year (2 complete and 1 partial year) – **Transferring and Receiving BA Task**

IV. Frequency Response Obligation (FRO)

Although intra-year reallocation of FRO between receiving and transferring BA is not in scope in the current BAL-003-1 NERC Reliability Standard under enforcement, this reference document shows the two options BAs experiencing changes in footprint may agree to follow.

Option 1 – **No change in FRO Appl**y – In this case the transferring BA retains any primary frequency response measure (FRM) contributed by the assets being transferred through the end of the operating year. The receiving BA, on the other hand, will not use any primary FRM contributed by the assets being transferred towards its FRO. Transferring and receiving BA(s) should follow the **No Change in FRO Apply** process below.

Option 2 – Change in FRO Apply – The other option for both the transferring and receiving BA(s) is for both to agree to reallocate FRO retroactive to the beginning of BAL-003 operating year. Transferring and receiving BA(s) should follow the **Change in FRO Apply** process below.

1. **No Change in FRO Apply**
   As described in Option 1 above, the BA(s) will retain both its originally allocated FRO and any primary FRM contributed by the assets being transferred. In this case, the BAs experiencing changes in footprint are responsible for:
   a. Documenting and reporting changes in footprint to NERC through its (their) Regional Entity (RE)
   b. Communicating to NERC through the RE the agreements between BA(s), or lack of, that will indicate or result in retention of both FRO and FRM by transferring BA through the end of the operating year; especially when the assets in transition are forming a new BA where the new BA will not have an FRO allocated until the following operating year.
2. **Change in FRO Apply**
   If any agreements or exemptions as described on Option 2 above apply, then a reallocation of FRO, ***<u>retroactive to the beginning of the operating year</u>***, will be calculated and officially communicated

by NERC to the BAs experiencing changes in footprint. In this case, the transferring BA(s) and receiving BA(s) will be responsible for the following:

a. Communicating agreements between BAs that will result in transferring BA(s) subtracting any primary FRM contributed by those assets from its(their) FRS Form 1 and FRS Form 2 – **Both a transferring and receiving BA(s) Task**

b. Transferring the data subtracted from FRS Form 1 and FRS Form 2 to the receiving BA(s) **– Transferring BA Task**

c. Completing FRS Form 1 and FRS Form 2 from the data received from the Transferring BA for submission to NERC at the end of the operating year **– Receiving BA Task**

Scenarios for when Change in FRO Apply
The following hypothetical scenarios will guide the involved parties on the necessary steps to be completed when retroactive reallocation of FRO applies. The changes may be due to total merges, partial merges or creation of new BA(s).

1. **Total Merge – At Least Two BA Involved**
   At least one BA remains a registered BA while the other(s) will deregister.

   In this example (see Diagram 1), BA C merges to BA A. Therefore, BA A becomes the receiving BA while BA C becomes the transferring (deregistering) BA. Here are the steps that both BA A and BA C should follow:

   a. BA A, receiving generating assets and/or load from the transferring (deregistering) BA C, will report and document taking over BA C's existing FRO retroactive to the beginning of the BAL-003 Operating Year – **Receiving BA A Task**

   b. BA A should obtain *FERC 714 data Schedule II Part III* (or similar) from BA C to complete and submit a *BA to BA General 714 data submittal form* (or its successor) to NERC RS support staff – **Deregistering BA C and Receiving BA A Task**

   c. NERC staff, once it has received the BA to BA General 714 data submittal form(s) (or its successor) from BA A and BA C via the BASS (or its successor), will then calculate FRO reallocations for the current operating year and upcoming operating year (if already calculated or in process) – **NERC Staff Task**

   d. The NERC staff supporting the NERC RS will document the BA FRO reallocation for the current operating year and for the upcoming operating year (if applicable). The official document will be posted in the NERC BASS (or its successor) – **NERC Staff Task**

2. **Partial Merge - BA Footprint Changes Between At Least Two Existing BAs**
   A partial merge occurs when at least one BA merges with at least one other BA. All BAs remain registered. Only a portion of generation and/or load gets transferred to at least one other BA.

   In this example, BA C transfers a portion of its generation and/or load to BA A and BA B (see Diagram 2).

The following are the steps that BA A, BA B and BA C should follow:

a. BA A and BA B, receiving generating assets and/or load from the transferring BA C, will report and document taking over the applicable calculated portion of BA C's FRO retroactive to the beginning of the BAL-003 Operating Year – **Receiving BA A and BA B Task**

b. BA A and BA B, receiving generating assets and/or load into their respective BAA from BA C, will obtain all applicable *FERC 714 Schedule II Part III* data (or similar) from BA C to complete and submit a *BA to BA General 714 data submittal form* (or its successor) via NERC BASS (or its successor) to NERC for FRO reallocation purposes – **Receiving BA A and BA B Task**

c. BA C will also submit a *BA to BA General 714 data submittal form* with the net generation and/or and NEL that will remain in its BAA – **Transferring BA C Task**

d. Once all BA to BA General 714 data submittal forms (or its successor) are received by NERC from the BAs involved in the partial merge via NERC BASS (or its successor), NERC will initiate the reallocation of FRO for the operating year in enforcement – **NERC Staff Task**

e. NERC will update the *BA FRO Allocation* report for the BAL-003 operating year in enforcement and reissue making the transfer of FRO official. The official document will be posted in NERC BASS (or its successor) – **NERC Staff Task**

3. Partial Merge - BA Footprint Changes Between Existing BA(s) and New BA(s) –
Like the previous scenario, a partial merge occurs when at least one BA merges with at least one other BA. In this case, the BA receiving generation and/or load is a newly registered BA (see Diagram 3).

For instance, the source data for the reallocation of the new BA's FRO will be from a subset of transferring BA D's *FERC 714 Schedule II Part III (or similar),* applicable to the assets and/or load being transferred. Once again, FERC 714 data will apply for the two years prior up until the last day the transferred generating assets and/or load were within BA D's BAA. Data must be provided separate by calendar year (2 complete and 1 partial year).

Here are the steps that BA D and BA E should follow:

a. The existing BA D is transferring generation and/or load to the newly created BA E. Therefore, BA E will obtain all applicable portion of its *FERC 714 Schedule II Part III* data (or similar) from BA D to complete a *BA to BA General 714 data submittal form* (or its successor) for submittal to NERC RS support staff via NERC BASS (or its successor). Similarly, BA D will submit a *BA to BA General 714 data submittal form* with net generation and/or load that will remain in its BAA – **Transferring BA D and Receiving BA E Task**

b. NERC Staff, once it has received the BA to BA General 714 data submittal form(s) (or its successor) from the BAs involved in the partial merge, will then calculate FRO reallocations for both the new BA E and transferring BA D – **NERC Staff Task**

c. NERC will update the *BA FRO Allocation* report for the BAL-003 operating year in enforcement and reissue making the transfer of FRO official. The official document will be posted in NERC BASS (or its successor) – **NERC Staff Task**

New Assets Forming a New BA (Gen Only BA or Load Only BA) - No Initial FRO allocated

If new generation and/or load intends to interconnect to the BES and form a new BAA, none of the above scenarios apply. In this case, the only data source for the allocation of the new BA's FRO comes from non-BA quality data. Instead, the source for the calculation of FRO will come either from testing data, transmission planning studies, contracts, or generation and/or load forecast from the new BA F's registration (see Diagram 4).

These are the steps that BA F and other applicable entities may follow:

1. Estimate net generation and/or load from testing and/or contracts to calculate an estimated and potentially non-enforceable FRO. The estimated FRO will be in place for BA F to operate with a baseline while BA quality data is collected and validated for the following two BAL-003 operating years – **NERC Staff Task**
2. Estimated generation or load will be reviewed and approved by NERC staff and the Regional Entity as a best estimate to allocate an estimated FRO - **Regional Entity and NERC Staff Task**
3. NERC staff may update the *BA FRO Allocation* report to add the new BA and reissue. Effective date for implementation should not change since the FRO is just estimated for the new BA. Therefore, there is no need for altering the previously allocated and published FRO for not affected BAs in the interconnection. The official document may be posted in NERC BASS (or its successor) – **NERC Staff Task**

V. Calculation and Reallocation of Frequency Bias Setting (FBS) and L_{10}

BAs may do a risk analysis on the potential impact of changes to their FBS. Especially, any impact to key BA operating reliability metrics such as CPS1, BAAL and ATEC (WI Only). Once completed, the BA may decide to either:

1. Leave their elected FBS "as is" for the remainder of the BAL-003 operating year. Mainly, if the amount of generation and/or load being transferred does not represent a significant impact to the reliable operation of their BAA. Especially if one or more of the BAs involved in the transfer is using Variable Non-Linear FBS.

   a. BA(s) using Variable Non-Linear FBS should adjust generation and/or load assets transferred from/to receiving/transferring BA(s) from automatic generation control (AGC) on the Energy Management System (EMS).

   Note: Once the adjustments are made, the EMS will start auto calculating all the input variables for the calculation of Variable Non-Linear FBS. Refer to Attachment D for more information.

2. Recalculate a new FBS by completing prior year's FRS Form 2 and FRS Form 1 adding/removing the data from generation and/or load being transferred (BA quality data).

   Note: This methodology only applies to BA(s) using Fixed-Linear FBS.

3. Calculate the lowest absolute fixed FBS (based on the interconnection's peak demand/generation from FERC 714 data or similar for the corresponding generation and/or load being transferred) and add/subtract from the BA's elected FBS as posted on NERC BASS.

   Note: This addition/subtraction methodology applies to BA(s) using either Fixed-Linear or Variable-Non-Linear FBS.

4. Transfer a mutually agreed portion of the transferring BA's FBS to the receiving BA by either:
   a. Calculating the actual primary frequency response median from the assets being transferred, or
   b. Calculate the absolute lowest absolute fixed frequency bias setting (based on the interconnection's peak demand/generation from the corresponding generation and/or load being transferred).
   c. Agree on an estimated percentage of net generation and/or load from BA C's *FERC 714 Schedule II Part III* data being relocated into each Receiving BA's BAA. Then use the estimated percentage to reallocate BA C's elected FBS to each Receiving BA.

   Note: This addition/subtraction methodology applies to BA(s) using either Fixed-Linear or Variable-Non-Linear FBS. The intra-year reallocation of FBS should not alter the interconnection's allocated FBS. In other words, the reallocation should not affect other BAs previously elected FBS and allocated L_{10}.

Below are the same or similar scenarios to the ones used to illustrate FRO reallocation in Section V above. The BA(s) may follow these steps when experiencing a total merge, partial merge or the creation of a new BA.

1. **Total Merge Methodology –Two BAs Involved**
   a. In this scenario, a total merge occurs between BA A and BA C. BA C is the receiving BA while BA C is the transferring/deregistering BA (see Diagram 1 below). The methodology in this case is simple. Deregistering BA C's elected FBS may be reallocated in its entirety to BA A for the remainder of BAL-003 operating year. This methodology applies to BAs using either Fixed-Linear or Variable-Non-Linear FBS **– Deregistering BA and NERC Staff Task**
   b. BA A should obtain FERC 714 data Schedule II Part III (or similar) from BA C to complete and submit a BA to BA General 714 data submittal form (or its successor) to NERC RS support staff via NERC BASS (or its successor) – **Deregistering BA C and Receiving BA A Task**

      Note: The FERC 714 data (or similar) from BA C should consist of the last two annual filings with FERC plus year-to-date monthly generation and/or load not yet filed. The data will be used by NERC staff to calculate BA A's minimum FBS for the next two years.

2. **Total Merge Methodology – At Least Three BAs Involved**
   If a total merge occurs between three or more BAs where two or more are receiving and one is deregistering (see diagram 5), the following steps should be followed:

a. Both BA A and BA B should obtain, from deregistering BA C, the last two *FERC 714 Schedule II Part III* data submissions (or similar) plus any year-to-date monthly net generation and/or load. The data obtained will be required to complete a *BA to BA General 714 data submittal form* (or its successor) for submittal to NERC RS support staff **– Receiving BA(s) Task**

   Important**:** Dynamic transfers where BA C was the source BA claimed by sinking BA(s) as net generation per FERC 714 reporting instructions, may be included by BA C as native generation for an accurate reallocation of Frequency Bias Setting (FBS) to BA A and BA B.

b. Update the FERC 714 data for the applicable BA(s) and recalculate the absolute minimum FBS allocation for receiving BA A and BA B – **NERC Staff Task**

   Both BA A and BA B may decide to either follow steps c through d (BA using Fixed Linear FBS) or just step f (BA using Fixed Linear or Variable Non-Linear FBS) as described below:

c. Resubmit new FRS Form 2 (or its successor) for each one of the events posted on prior year's BAL-003 FRS Form 1 (or its successor). This time incorporating actual frequency response from the generation and/or load received from BA C - **Receiving BA(s) Task (using Fixed Linear FBS)**

d. BA A and BA B will select the Form 1 Summary Data worksheet on the FRS Form 2 (or its successor), to then copy and then paste the frequency response data calculated for each event to the BA Form 2 Event Data worksheet on their respective FRS Form 1 (or its successor) – **Receiving BA(s) Task (using Fixed Linear FBS)**

e. Once primary frequency response data has been imported to the FRS Form 1 (or its successor) for each event, the following values should be calculated automatically for BA A and BA B in the worksheet:

   i. New lowest fixed FBS based on 100% of FRM Median and the BA's highest fixed FBS based on 125% of FRM Median

   ii. BA minimum absolute fixed FBS based on interconnections non-coincident peak demand/generation

   iii. Compare the product of step i. and ii. If the product of step i. is greater than the product of step ii., for either BA A or BA B, then the BA will be allowed to select their desired FBS (between 100% of FRM and 125% of FRM) if not currently using Variable Non-Linear FBS.

   iv. If, on the contrary, the product of step i. is less than the product of step ii., then BA A and/or BA B will be allocated an absolute minimum fixed frequency bias setting based on interconnection's peak demand/generation by NERC, if not currently using Variable Non-Linear FBS.

f. Agree on an estimated percentage of net generation and/or load from BA C's *FERC 714 Schedule II Part III* data being relocated into each Receiving BA's BAA. Then use the estimated percentage to reallocate BA C's elected FBS to each Receiving BA. For instance, if 70% and 30% of the generation and/or load is transferred from BA C to BA A and BA B respectively, the FBS to be reallocated should equal the existing elected BA C's FBS times .7 to BA A while the rest (i.e., BA C's FBS times .3) will go to BA B **– Receiving BA(s) Task (using either Fixed Linear or Variable Non-Linear FBS)**

g. Update the Frequency Bias Setting and L_{10} Values report for the applicable operating year and reissue with an effective date (if necessary). The official document will reside in the NERC BASS site – **NERC Staff Task**

3. **Partial Merge Methodology - BA Footprint Change Between At Least Three Existing BAs**
This scenario is like scenario 2, which is represented in Diagram 5 above. The only difference is that all BAs remain registered BAs and only a partial merge occurs from BA C to BA A and BA B. See Diagram 2. Therefore, all steps in scenario 2 may be followed by all BAs to calculate the new FBS.

4. **Partial Merge - BA Footprint Changes Between Existing BA(s) and New BA(s)**
This scenario is like scenarios 2 and 3 above. In this instance, transferring BA D remains a registered BA and BA E is the new registered BA. A partial merge occurs between BA D and BA E. BA E may be a generation and load BA, generation only BA or load only BA. See Diagram 3.

All steps in scenario 2 may be followed by both BAs to calculate their new FBS. However, depending on the amount of generation and/or load being transferred to BA E, the transferring BA D (as mentioned in section VI above) may decide to either maintain the same FBS (option i.) or mutually agree to transfer a representative portion of its elected FBS to BA E (option iv.). If option iv. is agreed upon by both BAs, BA E will use the transferred FBS as its starting FBS for current and following year's BAL-003 operating year.

5. **New BA with New Generation and/or Load**
This scenario 5 is different than the aforementioned scenarios. In this case, new generation and/or load have been added to the interconnection and, instead of joining the BA operating in the area, an entity decides to form its own BA. See Diagram 4.

These are the steps that may be followed by the new BA:

a. If no BA quality data exist from new resources forming the new BA, then the new BA should use estimated annual net generation and/or load values from testing prior to commissioning and submit to NERC via NERC BASS (or its successor) to allocate an initial FRO – **New BA and NERC Staff Task**

b. Use the allocated FRO from NERC and calculate an initial FBS based on lowest absolute frequency bias setting based on interconnection's peak demand/generation. Submit to NERC via NERC BASS for approval – **New BA Task**

c. Update the Frequency Bias Setting and L10 Values report adding the new BA for the existing operating year and reissue and updated version with the effective date for implementation. The official document will reside in the NERC BASS site – **NERC Staff Task**

VII. Reliability Coordinator IROL Operating Procedure(s)

Update and communicate any new roles and responsibilities identified in the RC's IROL operating process as a result of changes in BA(s) footprint. The RC(s) and BA(s) experiencing changes in footprint are responsible for updating, communicating and training the receiving entities on the revised operating process which defines their new role(s) and responsibilities in the mitigation of IROL exceedances in the RC area. – **RC and Transferring BA Task**

VIII. Reporting
Update BAL-003 BA listing on the Frequency Bias Setting and L10 Settings Report and update CERTS[5] reliability tools (e.g., Resource Adequacy) with elected BA FBS, FRO, and L_{10} – **NERC Staff Task**

IX. Update NERC BASS
Add new BA to the NERC BASS, identify BA's primary and secondary contacts and grant them access for periodic upload of CPS1, BAAL and BAL-003 data – **NERC Staff and New BA Task**

X. Support the ACE
Reporting application with real time ACE on ICCP link – **BA Task, RC Task, NERC Staff Task, and EPG Task**

XI. Obtain accounts for CERTS tools including the Inadvertent Interchange Accounting application
Add interfaces for adjacent BAs in Inadvertent tool and the NERC BASS for BAL-003 metrics and control performance reporting (CPS 1) **– New BA Task, NERC Staff Task**

XII. Obtain Services from a Reliability Coordinator (RC)
NERC Rules of Procedure Section 500, paragraph 1.4.2 require that all BAs be under the responsibility of an RC[6] **- New BA Task**

XIII. Coordination of Adjacent BAs and RC
Update the following as applicable:

- Reliability Plan (RC and Operating Reliability Subcommittee)
- NERC Certification and Registration
- Coordination on reporting for NERC Assessments and,
- Net Energy for Load (NEL) reporting to NERC for appropriate allocation of billing

– **NERC Staff and NERC Certification Task**

XV. Remove Access
Lock out from access to NERC reliability applications, as applicable – **NERC Staff Task**

[5] The Consortium Of Electric Reliability Technology Solutions (CERTS) maintains a suite of reliability tools for BAs to use
[6] NERC Rules of Procedure can be found at NERC.com

ATTACHMENT A

PRIMARY INADVERTENT INTERCHANGE REALLOCATION WESTERN INTERCONNECTION ONLY

Purpose

This section of the document is created to provide BAs in the Western Interconnection with a recommended blueprint on how to mutually agree to manage the potential reallocation of Accumulated Primary Interchange between BAs.

I. Accumulated Primary Inadvertent Interchange (PII_{Accum})

We will use the same scenarios shown in section VI of this document to assist BAs in the calculation of new PII_{Accum} balances (On-Peak and Off-Peak), as well as PII_{Accum} limits. This section only applies to BAs in the Western Interconnection.

1. **Total Merge Scenario – Two BAs Involved**

   When a total merge occurs between two BAs, the PII_{Accum} balances (On/Off-Peak) and PII_{Accum} limits must get transferred in complete coordination and cooperation between the transferring BA, the receiving BA and the WECC Interchange Tool[7] (WIT) administrator. Meaning, the day of the month and the hour when the BA ceases operations must be coordinated, so that the final balances get properly transferred to the receiving BA in WIT (or its successor) on the exact date and hour-ending the merge becomes official.

Table 1 below shows the deregistering BA's (BA B) last hour-ending PII_{Accum} On-Peak balance, PII_{Accum} Off-Peak balance and PII_{Accum} limits before the merge, while Table 1A shows the algebraic sum of BA A's and BA B's adjusted PII_{Accum} On/Off-Peak balances (on Table 1) after the merge, to be carried and paid back by receiving BA A going forward, via Automatic Time Error Correction (ATEC).

BEFORE MERGE Hour-Ending Balances (MWh)			
BA	PII_{Accum} On-Peak	PII_{Accum} Off-Peak	PII limits
A	-150	-120	200
B	250	140	300

Table 1

AFTER MERGE Hour-Ending Balances (MWh)			
BA	PII_{Accum} On-Peak	PII_{Accum} Off-Peak	PII limits
A	100	20	500
B	0	0	0

Table 1A

In this case BA B's 250 MWh and 140 MWh of PII_{Accum} On-Peak and Off-Peak balances, respectively, get transferred by performing an algebraic sum to BA A's last hour-ending balances. BA B's PII limits (300 MWh) are also transferred to BA A's previous limit (200 MWh) effective the end of the month after the merge occurs.

[7] https://www.wit.oati.com/tes_wit/tes-login-new.wml

2. Total Merge Scenario – At Least Two BAs Involved
In this example, BA A and BA B will be absorbing a portion of generation and or load from the deregistering BA C. Refer to Diagram 5.

Table 2 below shows the deregistering BA C's before merge last hour-ending PII_{Accum} On-Peak balance, PII_{Accum} Off-Peak balance and PII limits. Once again, the day of the month and the hour when the BA ceases operations must be coordinated, so that the final balances get properly transferred to the receiving BA in WIT (or its successor) on the exact date and hour-ending the merge becomes official.

Table 2A below shows the algebraic sum of BA A's and BA B's adjusted PII_{Accum} On/Off-Peak balances (on Table 1) to be carried and paid back by receiving BA A and BA B going forward, via Automatic Time Error Correction (ATEC).

BEFORE MERGE Hour-Ending Balances (MWh)			
BA	PII_{Accum} On-Peak	PII_{Accum} Off-Peak	PII limits
A	-150	-120	200
B	250	140	300
C	200	-100	500

Table 2

AFTER MERGE Hour-Ending Balances (MWh)			
BA	PII_{Accum} On-Peak	PII_{Accum} Off-Peak	PII limits
A	100	-160	400
B	400	80	600
C	0	0	0

Table 2A

Here are the steps that needed to be completed by the BAs (deregistering and receiving) to come up with the after-merge hour-ending adjusted balances:

a. Calculate the amount of PII_{Accum} (On-Peak and Off-Peak) contributed by each individual asset being transferred to the receiving BA A and BA B – **Deregistering BA Task.**

b. Transfer the PII_{Accum} balances (On-Peak and Off-Peak) contributed by each individual asset transferred to their respective receiving BA A and BA B – **Deregistering BA Task.**

c. Identify the amount of generation or load that each asset contributed towards the calculation of prior calendar year's integrated hourly peak demand or generation – **Deregistering BA Task.**

d. Transfer generation and or load data from each individual asset to receiving BA A and BA B for future calculation of PII limits based on prior calendar year's integrated hourly peak demand or generation – **Deregistering BA.**

e. Update the newly adjusted PII_{Accum} balances and PII limits in WIT (or its successor) – **Receiving BAs and WIT Administrator.**

3. Partial Merge Methodology - BA Footprint Change Between At Least Two Existing Bas
Like the total merge methodology in the previous example, this time BA A and BA B will be absorbing only a portion of generation and or load from transferring BA C, which will remain a registered BA. Refer to Diagram 2.

Table 3 below shows the transferring BA C's before merge last hour-ending PII_{Accum} On-Peak balance, PII_{Accum} Off-Peak balance and PII limits. Once again, the day of the month and the hour when the BA ceases operations must be coordinated, so that the final balances get properly transferred to the receiving BA in WIT (or its successor) on the exact date and hour-ending the merge becomes official. Table 2A below shows the algebraic sum of BA A's and BA B's PII_{Accum} On/Off-Peak balances (on Table 1) to be carried and paid back by receiving BA A and BA B going forward, via Automatic Time Error Correction (ATEC).

BEFORE MERGE Hour-Ending Balances (MWh)			
BA	PII_{Accum} On-Peak	PII_{Accum} Off-Peak	PII limits
A	-150	-120	200
B	250	140	300
C	760	-600	800

Table 3

AFTER MERGE Hour-Ending Balances (MWh)			
BA	PII_{Accum} On-Peak	PII_{Accum} Off-Peak	PII limits
A	50	-170	400
B	350	40	500
C	460	-450	400

Table 3A

Here are the steps that needed to be completed by the BAs (deregistering and receiving) to come up with the after-merge hour-ending adjusted balances:

a. Calculate the amount of PII_{Accum} (On-Peak and Off-Peak) contributed by each individual asset being transferred to the receiving BA A and BA B – **Deregistering BA Task**

b. Transfer PII_{Accum} balances (On-Peak and Off-Peak) contributed by each individual asset transferred to their respective receiving BA A and BA B – **Deregistering BA Task**

c. Identify the amount of generation or load that each asset contributed towards the calculation of prior calendar year's integrated hourly peak demand or generation – **Deregistering BA Task**

d. Transfer generation and or load data from each individual asset to receiving BA A and BA B for future calculation of PII limits based on prior calendar year's integrated hourly peak demand or generation – **Deregistering BA**

e. Update the newly adjusted PII_{Accum} balances and PII limits in WIT (or its successor) – **Transferring BA, Receiving BAs and WIT Administrator**

If transferring or receiving BA's newly adjusted PII_{Accum} balances are greater than the recalculated PII Limits, the BA(s) may request the Regional Entity to maintain the previous PII limits before BAL-004-WECC -02 R1 becomes fully enforceable with the new PII limits. For instance, let's assume that BA C's newly adjusted PII_{Accum} balances On/Off Peak are 460 MWh and -450 MWh respectively. Also, the PII_{Accum} limits, because of the change, decreased by half from 800 MWh to 400 MWh (see Table 3A). BA C, therefore, based on the results from the after-merge adjustments, may opt for requesting a 90-day extension to continue using the previous PII_{Accum} limits while it works towards bringing its PII_{Accum} balances down – **Transferring BA, Receiving BA and Regional Entity Task.**

4. **Partial Merge - BA Footprint Changes Between Existing BA(s) and New BA(s) –**
   When a partial merge occurs between existing BA D and new BA E (see Diagram 3), the receiving BA E and or the transferring BA D may opt for either:

   a. Following the steps on the previous scenario to calculate both BA D's and BA E's adjusted PII_{Accum} balances and limits (see tables 4 and 4A). or **– Transferring BA and New BA Task**

   b. Maintaining the PII_{Accum} balances incurred by the assets being transferred thus retain its PII_{Accum} limits through the end of the current operating calendar year (see tables 4B and 4C) **– Transferring BA Task**

   c. If both BAs agree to opt for option b, then, the transferring BA will provide the previous calendar year's integrated peak demand data (load serving BAs) or integrated hourly peak generation data (generation only BAs) to the newly created BA E for the calculation of its PIIAccum limits, per BAL-004-WECC-02 R1, 1.1 or 1.2 (see table 4C) - **– Transferring BA and New BA Task**

BEFORE MERGE Hour-Ending Balances (MWh)			
BA	PII_{Accum} On-Peak	PII_{Accum} Off-Peak	PII limits
D	300	-110	500
E	0	0	0

Table 4

AFTER MERGE Hour-Ending Balances (MWh)			
BA	PII_{Accum} On-Peak	PII_{Accum} Off-Peak	PII limits
D	280	-100	450
E	20	-10	50

Table 4A

BEFORE MERGE Hour-Ending Balances (MWh)			
BA	PII_{Accum} On-Peak	PII_{Accum} Off-Peak	PII limits
D	300	-110	500
E	0	0	0

Table 4B

AFTER MERGE Hour-Ending Balances (MWh)			
BA	PII_{Accum} On-Peak	PII_{Accum} Off-Peak	PII limits
D	300	-110	500
E	0	0	50

Table 4C

   d. Contact the WIT administrator to add the new BA E in WIT (or its successor) to start recording hourly PII_{Accum} balances as well as FBS, L_{10}, etc. **– New BA Task**

5. **New BA with New Generation**
   Like in the calculation and allocation of FRO and FBS, a new BA needs to calculate a PII_{Accum} limit to operate in the Western Interconnection and track in WIT. In the case of a new BA, an estimation of maximum generating capacity is used to establish its PII_{Accum} limit.

For instance, a new generator has decided to create the new gen only BA (BA F on Diagram 6). The generator inside the new BA F has committed to deliver 100 MWh, via a long term structured deal, to a load serving entity operating inside BA C. In addition, the new generator has an additional 100 MWh of generating capacity available to sell in the day ahead and real-time market operating inside BA A. The sum of both, committed and available extra generating capacity, will be its PII_{Accum} limit. See table 5 below.

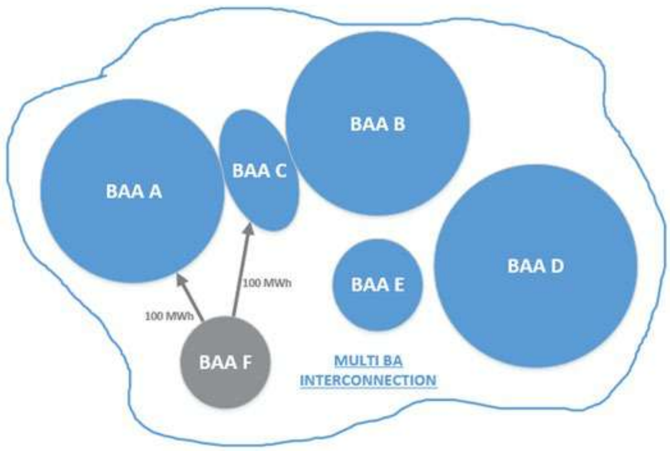


DIAGRAM 6

Hourly Generation	MWh
Committed	100
Available	100
Hourly Peak Gen	**200**

Table 5

ATTACHMENT B

BA Housekeeping Tasks Checklist

Task	Balancing Authorities			NERC Staff	Regional Entity	Reliability Coordinator	Check Box
	Transferring	Receiving	New				
NERC Certification Process			R	A	I		☐
Obtain BA ID			R	I	I		☐
BA Map Bubble Diagram				R	I	I	☐
Model Revision				R	I	I	☐
Inadv. Interchange Transfers on NERC Inadvertent Portal	R	R		I	I	I	☐
FRO Calculation							
FERC 714 Sched II Part III Data or Similar	R	R		I			☐
BA-to-BA General 714 Data Submittal Form		R		I			☐
OY XXXX Report for BAL-003	I	I	I	R	I		☐
FBS Calculation							
FERC 714 Sched II Part III Data or Similar	R	R		I			☐
BA-to-BA General 714 Data Submittal Form		R		I			☐
FRS Form 1 FERC 714 Data Worksheet				R			☐
FRS Form 1	R/O	R/O	R/O	R			☐
FRS Form 2	R/O	R/O	R/O	R			☐
NERC BASS Updates				R			☐
Elect FBS if: -FRM Median>FRO and, -FRM Median>Min Abs. Fixed FBS Based on Interconnection Peak Demand	R	R		A			☐
FBS and L_{10} Values Report for BAL-003 OY	I	I	I	A/R	I	I	☐
Accumulated PII (WI)							
On/Off Peak PII_{Accum} Balances	R	R			I		☐
PII_{Accum} Limits/Extensions	R	R	R		I		☐
WIT FBS Changes and PII_{Accum} Balance Transfers	R	R	R		R		☐

R – Responsible   A – Approve   I - Informed   R/O – Responsible/Optional

ATTACHMENT C

BA to BA General 714 Data Submittal Form

balancing@nerc.com

Energy and Demand Data for BAL-003

FERC Form 714 Part II Schedule III Data

Data Year | **Select**

Instructions:

1. Enter your contact information.
2. Select your Interconnection - drop down list
3. Select the year of the data - drop-down list
4. Select your BA acronym - the drop-down list is dependent on which Interconnection is selected.
5. Enter your BA's data on the form on the left. As filed with FERC, or equivalent, and after merge occurs
6. Enter comments about the change in footprint. For instance, if the BA(s) is transferring or receiving data. From what BA(s). Etc.
7. Submit through the BA Submittal Site (BASS) in the Non-714 Submittals file for your BA.

Submitter's Contact Information

Technical Contact Name	Email	Telephone	Date Submitted (mm/dd/yyyy)

Interconnecton		BA		Effective Date:	mm/dd/yyyy

	BAA Net Generation (c) (MWh)		BA Net Energy for Load (e) (MWh)		BA Net Gen + BA NEL (MWh)		Monthly Peak Demand (j) (MW)	
	As Filed	Adjusted	As Filed	Adjusted	As Filed	Adjusted	As Filed	Adjusted
JAN						-		
FEB						-		
MAR						-		
APR						-		
MAY						-		
JUN						-		
JUL						-		
AUG						-		
SEP						-		
OCT						-		
NOV						-		
DEC						-		
Total	-	-	-	-	-	-	-	-

Comments:

Revision History		
Date	**Version**	**Comment**
2/28/2019	1.0	Initial document – addressed comments received from 45-day industry comment period.
1/23/2024	1.1	Added references to NERC Balancing Authority Submittal Site (BASS) for BAs to submit information and requests to NERC Staff.

Balancing Authority Area Footprint Change Tasks

Reference Document

Background

Since the implementation and enforcement of NERC Reliability Standard BAL-003-1 in April 2016, Balancing Authorities (BAs) have experienced several changes in their footprint, particularly those in multi-BA Interconnections. The intent of the existing BAL-003-1 standard is to measure an Interconnection's ability to 1) arrest sudden changes in system frequency and 2) contribute primary frequency response to prevent activation of under frequency load shedding (UFLS). One of the many goals achieved by the standard was establishing a methodology for BAs to measure performance over time against a defined calculated target, i.e., Frequency Response Obligation (FRO). Another goal accomplished was to establish a standard methodology for BAs, in coordination with NERC staff, to calculate Frequency Bias Setting (FBS) based on actual primary frequency response contributions to an Interconnection, i.e., Frequency Response Measure (FRM). Nonetheless, adjustments BAs need to make, to both the FRO and the FBS, as a result of changes in footprint within a BAL-003 operating year, was not contemplated or simply not in scope at that time. There were some unanswered questions, such as:

- What do BAs need to do when reallocating assets to another BA?
- What is going to happen to the FRO?
- How is a BA going to meet its FRO if it no longer has those assets within its BA footprint?
- What is going to be the impact to my existing FBS?
- How is my BA going to manage BA ACE Limits (BAAL) with more resources and the same FBS?
- What else needs to be coordinated with other entities with every change in footprint (i.e. recertification, revisions models, etc.)?

To address those questions or concerns the NERC Resources Subcommittee (RS) has revised this Reference Document to assist BAs with the tasks associated with BAs footprint changes. Especially, how BAs may agree on transfer of responsibilities. This document includes several scenarios of historical BA footprint changes. Since these scenarios cannot address every possible scenario, BAs are encouraged to contact their regional NERC RS representative at balancing@NERC.com for further assistance.

Applicability:

The tasks, roles and responsibilities in this reference document apply to entities typically involved in BA footprint changes, such as BAs, Reliability Coordinators (RCs), Regional Entities (REs), NERC and Regional Inadvertent Survey Contacts.

Notification Timeline:

A BA that will be experiencing changes in footprint should notify all the applicable groups no less than ninety (90) calendar days prior to the effective implementation date. Proper coordination to transfer responsibilities is essential for the BAs to operate and meet their obligations.

Scope

The following are the more common changes that occur to BAs, especially to those that operate in multi–BA Interconnections (e.g., Western Interconnection (WI) and Eastern Interconnection (EI)):

1. **Total Merge** – at least two BAAs participate. One or more remain as registered BA(s), while the other(s) proceed to deregister from NERC. See Diagram 1 and Diagram 5.

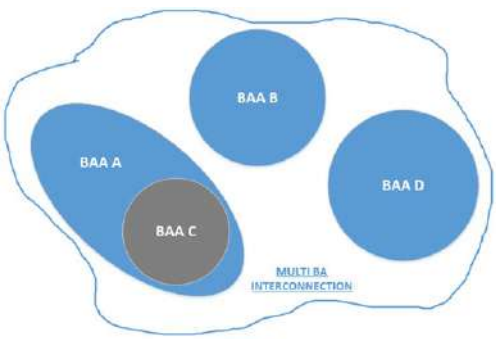


DIAGRAM 1

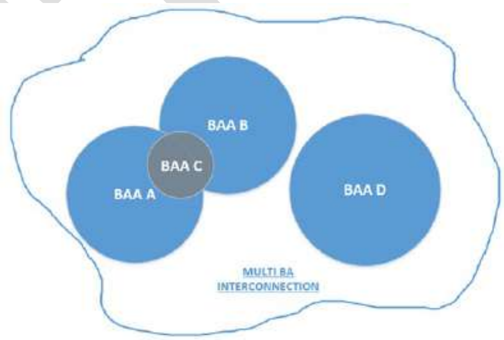


DIAGRAM 5

2. **Partial Merge** – A portion of generation and/or load is moved from one or more existing BAA(s) to one or more new or existing BAA(s). Transferring BA remains registered with NERC. This may include Pseudo Ties moving generation from one BA to another. See Diagram 2.

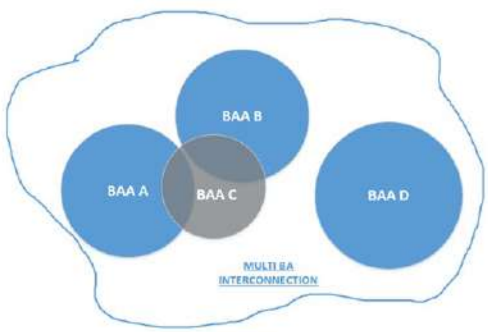


DIAGRAM 2

3. **New BA** – It did not exist previously (i.e., recently registered and certified). See Diagram 3.

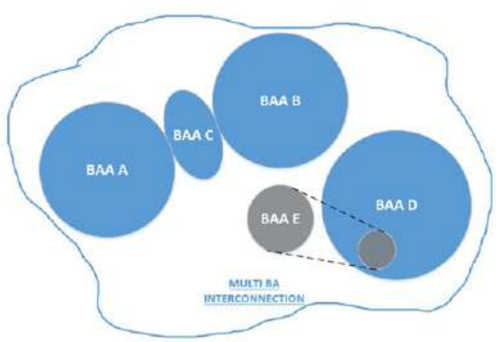


DIAGRAM 3

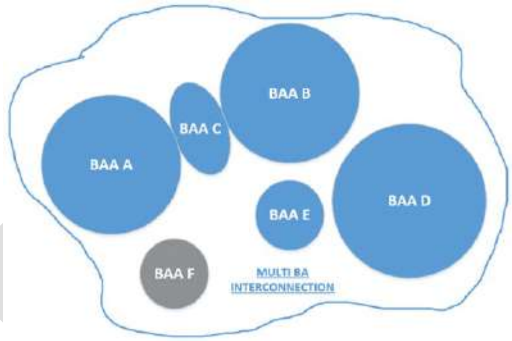


DIAGRAM 4

   a. New generation and/or load to the Interconnection forming a new BA. See Diagram 4.
   b. Existing generation and/or load operating in the Interconnection that are forming a new BA. A mix of new and existing generation and/or load in the Interconnection forming a new BA.

4. **Deregistered BA** – A BA planning to discontinue operations transferring generation and/or load into one or more receiving BAA(s).
5. **Receiving BA (Successor)** – A BA changes name or turns over responsibility to another entity.

BA footprint changes between interconnections are not in scope.

Process Steps

I. NERC Certification Process

Each NERC RE[1] has registration information posted on its website regarding how to start the NERC certification process. The certification process may take up to nine (9) months to complete. Refer to Appendix 5A – Organization Registration and Certification Manual (Section 500 of the Rules of Procedures) **– New BA Task**

II. Obtain BA ID

Obtain BA ID from the North American Energy Standards Board (NAESB)[2] Electric Industry Registry (EIR) – 4-character maximum label **– New BA Task**

III. BA Map Bubble Diagram

Add new BA, or updated BAA footprint, to the NERC BAs bubble diagram – **NERC RS Task**

III. Model Revision

Notify groups or entities responsible for making update(s) to power flow representations applicable to their area.

- Interchange Distribution Calculator (IDC)[3]– Eastern Interconnection
- Enhanced Curtailment Calculator (ECC)[4] – Western Interconnection,
- Multi Regional Modeling Working Group Model (MMWG) – Eastern Interconnection

– **EIDSN, ECCTF, MMGW, BA Task**

[1] Regional Entity Registration and Certification information: FRCC | MRO | NPCC | RF | SERC | SPP RE | Texas RE | WECC
[2] The EIR is maintained by the North American Energy Standards Board
[3] The IDC is maintained by the Eastern Interconnection Data Sharing Network, Inc.
[4] The ECC is maintained by PEAK Reliability RC

IV. Inadvertent Interchange

For merged BAs, the BA that is deregistering needs to transfer its Inadvertent balance to the receiving BA. For BAs that are splitting or transferring, they may allocate Inadvertent Interchanges as the parties deem appropriate, but the net balance between the remaining BAs must remain the same **– Deregistering BA, Receiving BA, and Regional Inadvertent Survey Contact Task**

V. Submit FERC 714 Data Schedule II Part III or Similar

From BAs experiencing changes in footprint will complete and submit a BA to BA General 714 data submittal form (or its successor) to NERC RS staff support via the Balancing Authority Submittal Site (BASS) or its successor. The FERC 714 data (or similar _see Attachment C) will apply for the two years prior and year to date - once available. Data must be provided separate by calendar year (2 complete and 1 partial year) – **Transferring and Receiving BA Task**

IV. Frequency Response Obligation (FRO)

Although intra-year reallocation of FRO between receiving and transferring BA is not in scope in the current BAL-003-1 NERC Reliability Standard under enforcement, this reference document shows the two options BAs experiencing changes in footprint may agree to follow.

Option 1 – **No change in FRO Appl**y – In this case the transferring BA retains any primary frequency response measure (FRM) contributed by the assets being transferred through the end of the operating year. The receiving BA, on the other hand, will not use any primary FRM contributed by the assets being transferred towards its FRO. Transferring and receiving BA(s) should follow the **No Change in FRO Apply** process below.

Option 2 – Change in FRO Apply – The other option for both the transferring and receiving BA(s) is for both to agree to reallocate FRO retroactive to the beginning of BAL-003 operating year. Transferring and receiving BA(s) should follow the **Change in FRO Apply** process below.

1. **No Change in FRO Apply**
   As described in Option 1 above, the BA(s) will retain both its originally allocated FRO and any primary FRM contributed by the assets being transferred. In this case, the BAs experiencing changes in footprint are responsible for:
   a. Documenting and reporting changes in footprint to NERC through its (their) Regional Entity (RE)
   b. Communicating to NERC through the RE the agreements between BA(s), or lack of, that will indicate or result in retention of both FRO and FRM by transferring BA through the end of the operating year; especially when the assets in transition are forming a new BA where the new BA will not have an FRO allocated until the following operating year.
2. **Change in FRO Apply**
   If any agreements or exemptions as described on Option 2 above apply, then a reallocation of FRO, ***<u>retroactive to the beginning of the operating year</u>***, will be calculated and officially communicated by NERC to the BAs experiencing changes in footprint. In this case, the transferring BA(s) and receiving BA(s) will be responsible for the following:

a. Communicating agreements between BAs that will result in transferring BA(s) subtracting any primary FRM contributed by those assets from its(their) FRS Form 1 and FRS Form 2 – **Both a transferring and receiving BA(s) Task**

b. Transferring the data subtracted from FRS Form 1 and FRS Form 2 to the receiving BA(s) **– Transferring BA Task**

c. Completing FRS Form 1 and FRS Form 2 from the data received from the Transferring BA for submission to NERC at the end of the operating year **– Receiving BA Task**

Scenarios for when Change in FRO Apply

The following hypothetical scenarios will guide the involved parties on the necessary steps to be completed when retroactive reallocation of FRO applies. The changes may be due to total merges, partial merges or creation of new BA(s).

1. **Total Merge – At Least Two BA Involved**

   At least one BA remains a registered BA while the other(s) will deregister.

   In this example (see Diagram 1), BA C merges to BA A. Therefore, BA A becomes the receiving BA while BA C becomes the transferring (deregistering) BA. Here are the steps that both BA A and BA C should follow:

   a. BA A, receiving generating assets and/or load from the transferring (deregistering) BA C, will report and document taking over BA C's existing FRO retroactive to the beginning of the BAL-003 Operating Year – **Receiving BA A Task**

   b. BA A should obtain *FERC 714 data Schedule II Part III* (or similar) from BA C to complete and submit a *BA to BA General 714 data submittal form* (or its successor) to NERC RS support staff – **Deregistering BA C and Receiving BA A Task**

   c. NERC staff, once it has received the BA to BA General 714 data submittal form(s) (or its successor) from BA A and BA C via the BASS (or its successor), will then calculate FRO reallocations for the current operating year and upcoming operating year (if already calculated or in process) – **NERC Staff Task**

   d. The NERC staff supporting the NERC RS will document the BA FRO reallocation for the current operating year and for the upcoming operating year (if applicable). The official document will be posted in the NERC BASS (or its successor) – **NERC Staff Task**

2. **Partial Merge - BA Footprint Changes Between At Least Two Existing BAs**

   A partial merge occurs when at least one BA merges with at least one other BA. All BAs remain registered. Only a portion of generation and/or load gets transferred to at least one other BA.

In this example, BA C transfers a portion of its generation and/or load to BA A and BA B (see Diagram 2).

The following are the steps that BA A, BA B and BA C should follow:

- BA A and BA B, receiving generating assets and/or load from the transferring BA C, will report and document taking over the applicable calculated portion of BA C's FRO retroactive to the beginning of the BAL-003 Operating Year – **Receiving BA A and BA B Task**
- BA A and BA B, receiving generating assets and/or load into their respective BAA from BA C, will obtain all applicable *FERC 714 Schedule II Part III* data (or similar) from BA C to complete and submit a *BA to BA General 714 data submittal form* (or its successor) via NERC BASS (or its successor) to NERC for FRO reallocation purposes – **Receiving BA A and BA B Task**
- BA C will also submit a *BA to BA General 714 data submittal form* with the net generation and/or and NEL that will remain in its BAA – **Transferring BA C Task**
- Once all BA to BA General 714 data submittal forms (or its successor) are received by NERC from the BAs involved in the partial merge via NERC BASS (or its successor), NERC will initiate the reallocation of FRO for the operating year in enforcement – **NERC Staff Task**
- NERC will update the *BA FRO Allocation* report for the BAL-003 operating year in enforcement and reissue making the transfer of FRO official. The official document will be posted in NERC BASS (or its successor) – **NERC Staff Task**

3. **Partial Merge - BA Footprint Changes Between Existing BA(s) and New BA(s) –**
   Like the previous scenario, a partial merge occurs when at least one BA merges with at least one other BA. In this case, the BA receiving generation and/or load is a newly registered BA (see Diagram 3).

For instance, the source data for the reallocation of the new BA's FRO will be from a subset of transferring BA D's *FERC 714 Schedule II Part III (or similar),* applicable to the assets and/or load being transferred. Once again, FERC 714 data will apply for the two years prior up until the last day the transferred generating assets and/or load were within BA D's BAA. Data must be provided separate by calendar year (2 complete and 1 partial year).

Here are the steps that BA D and BA E should follow:

- The existing BA D is transferring generation and/or load to the newly created BA E. Therefore, BA E will obtain all applicable portion of its *FERC 714 Schedule II Part III* data (or similar) from BA D to complete a *BA to BA General 714 data submittal form* (or its successor) for submittal to NERC RS support staff via NERC BASS (or its successor). Similarly, BA D will submit a *BA to BA General 714 data submittal form* with net generation and/or load that will remain in its BAA – **Transferring BA D and Receiving BA E Task**
- NERC Staff, once it has received the BA to BA General 714 data submittal form(s) (or its successor) from the BAs involved in the partial merge, will then calculate FRO reallocations for both the new BA E and transferring BA D – **NERC Staff Task**

- NERC will update the *BA FRO Allocation* report for the BAL-003 operating year in enforcement and reissue making the transfer of FRO official. The official document will be posted in NERC BASS (or its successor) – **NERC Staff Task**

New Assets Forming a New BA (Gen Only BA or Load Only BA) - No Initial FRO allocated

If new generation and/or load intends to interconnect to the BES and form a new BAA, none of the above scenarios apply. In this case, the only data source for the allocation of the new BA's FRO comes from non-BA quality data. Instead, the source for the calculation of FRO will come either from testing data, transmission planning studies, contracts, or generation and/or load forecast from the new BA F's registration (see Diagram 4).

These are the steps that BA F and other applicable entities may follow:

1. Estimate net generation and/or load from testing and/or contracts to calculate an estimated and potentially non-enforceable FRO. The estimated FRO will be in place for BA F to operate with a baseline while BA quality data is collected and validated for the following two BAL-003 operating years – **NERC Staff Task**
2. Estimated generation or load will be reviewed and approved by NERC staff and the Regional Entity as a best estimate to allocate an estimated FRO - **Regional Entity and NERC Staff Task**
3. NERC staff may update the *BA FRO Allocation* report to add the new BA and reissue. Effective date for implementation should not change since the FRO is just estimated for the new BA. Therefore, there is no need for altering the previously allocated and published FRO for not affected BAs in the interconnection. The official document may be posted in NERC BASS (or its successor) – **NERC Staff Task**

V. Calculation and Reallocation of Frequency Bias Setting (FBS) and L_{10}

BAs may do a risk analysis on the potential impact of changes to their FBS. Especially, any impact to key BA operating reliability metrics such as CPS1, BAAL and ATEC (WI Only). Once completed, the BA may decide to either:

1. Leave their elected FBS "as is" for the remainder of the BAL-003 operating year. Mainly, if the amount of generation and/or load being transferred does not represent a significant impact to the reliable operation of their BAA. Especially if one or more of the BAs involved in the transfer is using Variable Non-Linear FBS.

   a. BA(s) using Variable Non-Linear FBS should adjust generation and/or load assets transferred from/to receiving/transferring BA(s) from automatic generation control (AGC) on the Energy Management System (EMS).

   Note: Once the adjustments are made, the EMS will start auto calculating all the input variables for the calculation of Variable Non-Linear FBS. Refer to Attachment D for more information.

2. Recalculate a new FBS by completing prior year's FRS Form 2 and FRS Form 1 adding/removing the data from generation and/or load being transferred (BA quality data).

   Note: This methodology only applies to BA(s) using Fixed-Linear FBS.

3. Calculate the lowest absolute fixed FBS (based on the interconnection's peak demand/generation from FERC 714 data or similar for the corresponding generation and/or load being transferred) and add/subtract from the BA's elected FBS as posted on NERC BASS.

   Note: This addition/subtraction methodology applies to BA(s) using either Fixed-Linear or Variable-Non-Linear FBS.

4. Transfer a mutually agreed portion of the transferring BA's FBS to the receiving BA by either:

   a. Calculating the actual primary frequency response median from the assets being transferred, or

   b. Calculate the absolute lowest absolute fixed frequency bias setting (based on the interconnection's peak demand/generation from the corresponding generation and/or load being transferred).

   c. Agree on an estimated percentage of net generation and/or load from BA C's *FERC 714 Schedule II Part III* data being relocated into each Receiving BA's BAA. Then use the estimated percentage to reallocate BA C's elected FBS to each Receiving BA.

   Note: This addition/subtraction methodology applies to BA(s) using either Fixed-Linear or Variable-Non-Linear FBS. The intra-year reallocation of FBS should not alter the interconnection's allocated FBS. In other words, the reallocation should not affect other BAs previously elected FBS and allocated L_{10}.

Below are the same or similar scenarios to the ones used to illustrate FRO reallocation in Section V above. The BA(s) may follow these steps when experiencing a total merge, partial merge or the creation of a new BA.

1. **Total Merge Methodology –Two BAs Involved**

   a. In this scenario, a total merge occurs between BA A and BA C. BA C is the receiving BA while BA C is the transferring/deregistering BA (see Diagram 1 below). The methodology in this case is simple. Deregistering BA C's elected FBS may be reallocated in its entirety to BA A for the remainder of BAL-003 operating year. This methodology applies to BAs using either Fixed-Linear or Variable-Non-Linear FBS **– Deregistering BA and NERC Staff Task**

   b. BA A should obtain FERC 714 data Schedule II Part III (or similar) from BA C to complete and submit a BA to BA General 714 data submittal form (or its successor) to NERC RS support staff via NERC BASS (or its successor) – **Deregistering BA C and Receiving BA A Task**

      Note: The FERC 714 data (or similar) from BA C should consist of the last two annual filings with FERC plus year-to-date monthly generation and/or load not yet filed. The data will be used by NERC staff to calculate BA A's minimum FBS for the next two years.

2. **Total Merge Methodology – At Least Three BAs Involved**
   If a total merge occurs between three or more BAs where two or more are receiving and one is deregistering (see diagram 5), the following steps should be followed:

   a. Both BA A and BA B should obtain, from deregistering BA C, the last two *FERC 714 Schedule II Part III* data submissions (or similar) plus any year-to-date monthly net generation and/or load.

The data obtained will be required to complete a *BA to BA General 714 data submittal form* (or its successor) for submittal to NERC RS support staff **– Receiving BA(s) Task**

Important**:** Dynamic transfers where BA C was the source BA claimed by sinking BA(s) as net generation per FERC 714 reporting instructions, may be included by BA C as native generation for an accurate reallocation of Frequency Bias Setting (FBS) to BA A and BA B.

b. Update the FERC 714 data for the applicable BA(s) and recalculate the absolute minimum FBS allocation for receiving BA A and BA B – **NERC Staff Task**

Both BA A and BA B may decide to either follow steps c through d (BA using Fixed Linear FBS) or just step f (BA using Fixed Linear or Variable Non-Linear FBS) as described below:

c. Resubmit new FRS Form 2 (or its successor) for each one of the events posted on prior year's BAL-003 FRS Form 1 (or its successor). This time incorporating actual frequency response from the generation and/or load received from BA C - **Receiving BA(s) Task (using Fixed Linear FBS)**

d. BA A and BA B will select the Form 1 Summary Data worksheet on the FRS Form 2 (or its successor), to then copy and then paste the frequency response data calculated for each event to the BA Form 2 Event Data worksheet on their respective FRS Form 1 (or its successor) – **Receiving BA(s) Task (using Fixed Linear FBS)**

e. Once primary frequency response data has been imported to the FRS Form 1 (or its successor) for each event, the following values should be calculated automatically for BA A and BA B in the worksheet:

   i. New lowest fixed FBS based on 100% of FRM Median and the BA's highest fixed FBS based on 125% of FRM Median

   ii. BA minimum absolute fixed FBS based on interconnections non-coincident peak demand/generation

   iii. Compare the product of step i. and ii. If the product of step i. is greater than the product of step ii., for either BA A or BA B, then the BA will be allowed to select their desired FBS (between 100% of FRM and 125% of FRM) if not currently using Variable Non-Linear FBS.

   iv. If, on the contrary, the product of step i. is less than the product of step ii., then BA A and/or BA B will be allocated an absolute minimum fixed frequency bias setting based on interconnection's peak demand/generation by NERC, if not currently using Variable Non-Linear FBS.

f. Agree on an estimated percentage of net generation and/or load from BA C's *FERC 714 Schedule II Part III* data being relocated into each Receiving BA's BAA. Then use the estimated percentage to reallocate BA C's elected FBS to each Receiving BA. For instance, if 70% and 30% of the generation and/or load is transferred from BA C to BA A and BA B respectively, the FBS to be reallocated should equal the existing elected BA C's FBS times .7 to BA A while the rest (i.e., BA C's FBS times .3) will go to BA B **– Receiving BA(s) Task (using either Fixed Linear or Variable Non-Linear FBS)**

g. Update the Frequency Bias Setting and L_{10} Values report for the applicable operating year and reissue with an effective date (if necessary). The official document will reside in the NERC BASS site – **NERC Staff Task**

3. **Partial Merge Methodology - BA Footprint Change Between At Least Three Existing BAs**
This scenario is like scenario 2, which is represented in Diagram 5 above. The only difference is that all BAs remain registered BAs and only a partial merge occurs from BA C to BA A and BA B. See Diagram 2. Therefore, all steps in scenario 2 may be followed by all BAs to calculate the new FBS.

4. **Partial Merge - BA Footprint Changes Between Existing BA(s) and New BA(s)**
This scenario is like scenarios 2 and 3 above. In this instance, transferring BA D remains a registered BA and BA E is the new registered BA. A partial merge occurs between BA D and BA E. BA E may be a generation and load BA, generation only BA or load only BA. See Diagram 3.

   All steps in scenario 2 may be followed by both BAs to calculate their new FBS. However, depending on the amount of generation and/or load being transferred to BA E, the transferring BA D (as mentioned in section VI above) may decide to either maintain the same FBS (option i.) or mutually agree to transfer a representative portion of its elected FBS to BA E (option iv.). If option iv. is agreed upon by both BAs, BA E will use the transferred FBS as its starting FBS for current and following year's BAL-003 operating year.

5. **New BA with New Generation and/or Load**
This scenario 5 is different than the aforementioned scenarios. In this case, new generation and/or load have been added to the interconnection and, instead of joining the BA operating in the area, an entity decides to form its own BA. See Diagram 4.

   These are the steps that may be followed by the new BA:

   a. If no BA quality data exist from new resources forming the new BA, then the new BA should use estimated annual net generation and/or load values from testing prior to commissioning and submit to NERC via NERC BASS (or its successor) to allocate an initial FRO – **New BA and NERC Staff Task**

   b. Use the allocated FRO from NERC and calculate an initial FBS based on lowest absolute frequency bias setting based on interconnection's peak demand/generation. Submit to NERC via NERC BASS for approval – **New BA Task**

   c. Update the Frequency Bias Setting and L10 Values report adding the new BA for the existing operating year and reissue and updated version with the effective date for implementation. The official document will reside in the NERC BASS site – **NERC Staff Task**

VII. Reliability Coordinator IROL Operating Procedure(s)

Update and communicate any new roles and responsibilities identified in the RC's IROL operating process as a result of changes in BA(s) footprint. The RC(s) and BA(s) experiencing changes in footprint are responsible for updating, communicating and training the receiving entities on the revised operating process which defines their new role(s) and responsibilities in the mitigation of IROL exceedances in the RC area. – **RC and Transferring BA Task**

VIII. Reporting

Update BAL-003 BA listing on the Frequency Bias Setting and L10 Settings Report and update CERTS[5] reliability tools (e.g., Resource Adequacy) with elected BA FBS, FRO, and L_{10} – **NERC Staff Task**

IX. Update NERC BASS

Add new BA to the NERC BASS, identify BA's primary and secondary contacts and grant them access for periodic upload of CPS1, BAAL and BAL-003 data – **NERC Staff and New BA Task**

X. Support the ACE

Reporting application with real time ACE on ICCP link – **BA Task, RC Task, NERC Staff Task, and EPG Task**

XI. Obtain accounts for CERTS tools including the Inadvertent Interchange Accounting application

Add interfaces for adjacent BAs in Inadvertent tool and the NERC BASS for BAL-003 metrics and control performance reporting (CPS 1) **– New BA Task, NERC Staff Task**

XII. Obtain Services from a Reliability Coordinator (RC)

NERC Rules of Procedure Section 500, paragraph 1.4.2 require that all BAs be under the responsibility of an RC[6] **- New BA Task**

XIII. Coordination of Adjacent BAs and RC

Update the following as applicable:

- Reliability Plan (RC and Operating Reliability Subcommittee)
- NERC Certification and Registration
- Coordination on reporting for NERC Assessments and,
- Net Energy for Load (NEL) reporting to NERC for appropriate allocation of billing

– **NERC Staff and NERC Certification Task**

XV. Remove Access

Lock out from access to NERC reliability applications, as applicable – **NERC Staff Task**

[5] The Consortium Of Electric Reliability Technology Solutions [(CERTS)](#) maintains a suite of reliability tools for BAs to use
[6] NERC Rules of Procedure can be found at NERC.com

ATTACHMENT A

PRIMARY INADVERTENT INTERCHANGE REALLOCATION WESTERN INTERCONNECTION ONLY

Purpose

This section of the document is created to provide BAs in the Western Interconnection with a recommended blueprint on how to mutually agree to manage the potential reallocation of Accumulated Primary Interchange between BAs.

I. Accumulated Primary Inadvertent Interchange (PII_{Accum})

We will use the same scenarios shown in section VI of this document to assist BAs in the calculation of new PII_{Accum} balances (On-Peak and Off-Peak), as well as PII_{Accum} limits. This section only applies to BAs in the Western Interconnection.

1. **Total Merge Scenario – Two BAs Involved**

   When a total merge occurs between two BAs, the PII_{Accum} balances (On/Off-Peak) and PII_{Accum} limits must get transferred in complete coordination and cooperation between the transferring BA, the receiving BA and the WECC Interchange Tool[7] (WIT) administrator. Meaning, the day of the month and the hour when the BA ceases operations must be coordinated, so that the final balances get properly transferred to the receiving BA in WIT (or its successor) on the exact date and hour-ending the merge becomes official.

Table 1 below shows the deregistering BA's (BA B) last hour-ending PII_{Accum} On-Peak balance, PII_{Accum} Off-Peak balance and PII_{Accum} limits before the merge, while Table 1A shows the algebraic sum of BA A's and BA B's adjusted PII_{Accum} On/Off-Peak balances (on Table 1) after the merge, to be carried and paid back by receiving BA A going forward, via Automatic Time Error Correction (ATEC).

Table 1. BEFORE MERGE Hour-Ending Balances (MWh)

BA	PII_{Accum} On-Peak	PII_{Accum} Off-Peak	PII limits
A	-150	-120	200
B	250	140	300

Table 1A. AFTER MERGE Hour-Ending Balances (MWh)

BA	PII_{Accum} On-Peak	PII_{Accum} Off-Peak	PII limits
A	100	20	500
B	0	0	0

In this case BA B's 250 MWh and 140 MWh of PII_{Accum} On-Peak and Off-Peak balances, respectively, get transferred by performing an algebraic sum to BA A's last hour-ending balances. BA B's PII limits (300 MWh) are also transferred to BA A's previous limit (200 MWh) effective the end of the month after the merge occurs.

[7] https://www.wit.oati.com/tes_wit/tes-login-new.wml

2. **Total Merge Scenario – At Least Two BAs Involved**
In this example, BA A and BA B will be absorbing a portion of generation and or load from the deregistering BA C. Refer to Diagram 5.

Table 2 below shows the deregistering BA C's before merge last hour-ending PII_{Accum} On-Peak balance, PII_{Accum} Off-Peak balance and PII limits. Once again, the day of the month and the hour when the BA ceases operations must be coordinated, so that the final balances get properly transferred to the receiving BA in WIT (or its successor) on the exact date and hour-ending the merge becomes official.

Table 2A below shows the algebraic sum of BA A's and BA B's adjusted PII_{Accum} On/Off-Peak balances (on Table 1) to be carried and paid back by receiving BA A and BA B going forward, via Automatic Time Error Correction (ATEC).

Table 2. BEFORE MERGE Hour-Ending Balances (MWh)			
BA	PII_{Accum} On-Peak	PII_{Accum} Off-Peak	PII limits
A	-150	-120	200
B	250	140	300
C	200	-100	500

Table 2A. AFTER MERGE Hour-Ending Balances (MWh)			
BA	PII_{Accum} On-Peak	PII_{Accum} Off-Peak	PII limits
A	100	-160	400
B	400	80	600
C	0	0	0

Here are the steps that needed to be completed by the BAs (deregistering and receiving) to come up with the after-merge hour-ending adjusted balances:

- Calculate the amount of PII_{Accum} (On-Peak and Off-Peak) contributed by each individual asset being transferred to the receiving BA A and BA B – **Deregistering BA Task.**
- Transfer the PII_{Accum} balances (On-Peak and Off-Peak) contributed by each individual asset transferred to their respective receiving BA A and BA B – **Deregistering BA Task.**
- Identify the amount of generation or load that each asset contributed towards the calculation of prior calendar year's integrated hourly peak demand or generation – **Deregistering BA Task.**
- Transfer generation and or load data from each individual asset to receiving BA A and BA B for future calculation of PII limits based on prior calendar year's integrated hourly peak demand or generation – **Deregistering BA.**
- Update the newly adjusted PII_{Accum} balances and PII limits in WIT (or its successor) – **Receiving BAs and WIT Administrator.**

3. **Partial Merge Methodology - BA Footprint Change Between At Least Two Existing Bas**
   Like the total merge methodology in the previous example, this time BA A and BA B will be absorbing only a portion of generation and or load from transferring BA C, which will remain a registered BA. Refer to Diagram 2.

Table 3 below shows the transferring BA C's before merge last hour-ending PII_{Accum} On-Peak balance, PII_{Accum} Off-Peak balance and PII limits. Once again, the day of the month and the hour when the BA ceases operations must be coordinated, so that the final balances get properly transferred to the receiving BA in WIT (or its successor) on the exact date and hour-ending the merge becomes official.

Table 2A below shows the algebraic sum of BA A's and BA B's PII_{Accum} On/Off-Peak balances (on Table 1) to be carried and paid back by receiving BA A and BA B going forward, via Automatic Time Error Correction (ATEC).

Table 3. BEFORE MERGE Hour-Ending Balances (MWh)			
BA	PII_{Accum} On-Peak	PII_{Accum} Off-Peak	PII limits
A	-150	-120	200
B	250	140	300
C	760	-600	800

Table 3A. AFTER MERGE Hour-Ending Balances (MWh)			
BA	PII_{Accum} On-Peak	PII_{Accum} Off-Peak	PII limits
A	50	-170	400
B	350	40	500
C	460	-450	400

Here are the steps that needed to be completed by the BAs (deregistering and receiving) to come up with the after-merge hour-ending adjusted balances:

- Calculate the amount of PII_{Accum} (On-Peak and Off-Peak) contributed by each individual asset being transferred to the receiving BA A and BA B – **Deregistering BA Task**
- Transfer PII_{Accum} balances (On-Peak and Off-Peak) contributed by each individual asset transferred to their respective receiving BA A and BA B – **Deregistering BA Task**
- Identify the amount of generation or load that each asset contributed towards the calculation of prior calendar year's integrated hourly peak demand or generation – **Deregistering BA Task**
- Transfer generation and or load data from each individual asset to receiving BA A and BA B for future calculation of PII limits based on prior calendar year's integrated hourly peak demand or generation – **Deregistering BA**
- Update the newly adjusted PII_{Accum} balances and PII limits in WIT (or its successor) – **Transferring BA, Receiving BAs and WIT Administrator**

If transferring or receiving BA's newly adjusted PII_{Accum} balances are greater than the recalculated PII Limits, the BA(s) may request the Regional Entity to maintain the previous PII limits before BAL-004-WECC -02 R1 becomes fully enforceable with the new PII limits. For instance, let's assume that BA C's newly adjusted PII_{Accum} balances On/Off Peak are 460 MWh and -450 MWh respectively. Also, the PII_{Accum} limits, because of the change, decreased by half from 800 MWh to 400 MWh (see Table 3A). BA C, therefore, based on the results from the after-merge adjustments, may opt for requesting a 90-day extension to continue using the previous PII_{Accum} limits while it works towards bringing its PII_{Accum} balances down – **Transferring BA, Receiving BA and Regional Entity Task.**

4. **Partial Merge - BA Footprint Changes Between Existing BA(s) and New BA(s) –**
   When a partial merge occurs between existing BA D and new BA E (see Diagram 3), the receiving BA E and or the transferring BA D may opt for either:

   a. Following the steps on the previous scenario to calculate both BA D's and BA E's adjusted PII_{Accum} balances and limits (see tables 4 and 4A). or **– Transferring BA and New BA Task**

   b. Maintaining the PII_{Accum} balances incurred by the assets being transferred thus retain its PII_{Accum} limits through the end of the current operating calendar year (see tables 4B and 4C) **– Transferring BA Task**

   c. If both BAs agree to opt for option b, then, the transferring BA will provide the previous calendar year's integrated peak demand data (load serving BAs) or integrated hourly peak generation data (generation only BAs) to the newly created BA E for the calculation of its PIIAccum limits, per BAL-004-WECC-02 R1, 1.1 or 1.2 (see table 4C) - **– Transferring BA and New BA Task**

Table 4. BEFORE MERGE Hour-Ending Balances (MWh)			
BA	PII_{Accum} On-Peak	PII_{Accum} Off-Peak	PII limits
D	300	-110	500
E	0	0	0

Table 4A. AFTER MERGE Hour-Ending Balances (MWh)			
BA	PII_{Accum} On-Peak	PII_{Accum} Off-Peak	PII limits
D	280	-100	450
E	20	-10	50

Table 4B. BEFORE MERGE Hour-Ending Balances (MWh)			
BA	PII_{Accum} On-Peak	PII_{Accum} Off-Peak	PII limits
D	300	-110	500
E	0	0	0

Table 4C. AFTER MERGE Hour-Ending Balances (MWh)			
BA	PII_{Accum} On-Peak	PII_{Accum} Off-Peak	PII limits
D	300	-110	500
E	0	0	50

   d. Contact the WIT administrator to add the new BA E in WIT (or its successor) to start recording hourly PII_{Accum} balances as well as FBS, L_{10}, etc. **– New BA Task**

5. New BA with New Generation

Like in the calculation and allocation of FRO and FBS, a new BA needs to calculate a PII_{Accum} limit to operate in the Western Interconnection and track in WIT. In the case of a new BA, an estimation of maximum generating capacity is used to establish its PII_{Accum} limit.

For instance, a new generator has decided to create the new gen only BA (BA F on Diagram 6). The generator inside the new BA F has committed to deliver 100 MWh, via a long term structured deal, to a load serving entity operating inside BA C. In addition, the new generator has an additional 100 MWh of generating capacity available to sell in the day ahead and real-time market operating inside BA A. The sum of both, committed and available extra generating capacity, will be its PII_{Accum} limit. See table 5 below.

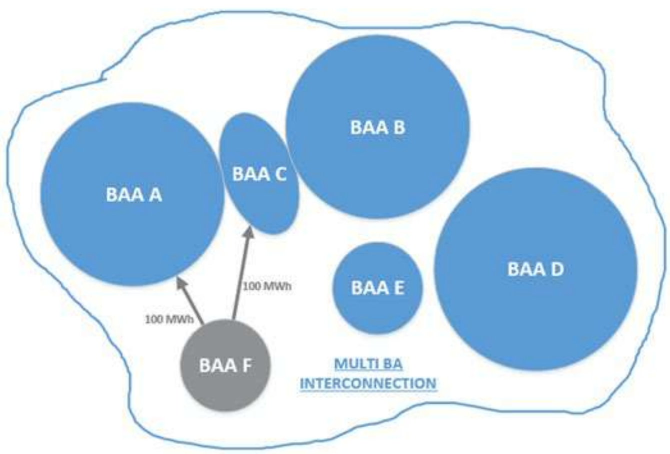


DIAGRAM 6

Table 5. Hourly Generation	MWh
Committed	100
Available	100
Hourly Peak Gen	**200**

ATTACHMENT B

BA Housekeeping Tasks Checklist

Task	Balancing Authorities			NERC Staff	Regional Entity	Reliability Coordinator	Check Box
	Transferring	Receiving	New				
NERC Certification Process			R	A	I		☐
Obtain BA ID			R	I	I		☐
BA Map Bubble Diagram				R	I	I	☐
Model Revision				R	I	I	☐
Inadv. Interchange Transfers on NERC Inadvertent Portal	R	R		I	I	I	☐
FRO Calculation							
FERC 714 Sched II Part III Data or Similar	R	R		I			☐
BA-to-BA General 714 Data Submittal Form		R		I			☐
OY XXXX Report for BAL-003	I	I	I	R	I		☐
FBS Calculation							
FERC 714 Sched II Part III Data or Similar	R	R		I			☐
BA-to-BA General 714 Data Submittal Form		R		I			☐
FRS Form 1 FERC 714 Data Worksheet				R			☐
FRS Form 1	R/O	R/O	R/O	R			☐
FRS Form 2	R/O	R/O	R/O	R			☐
NERC BASS Updates				R			☐
Elect FBS if: -FRM Median>FRO and, -FRM Median>Min Abs. Fixed FBS Based on Interconnection Peak Demand	R	R		A			☐
FBS and L_{10} Values Report for BAL-003 OY	I	I	I	A/R	I	I	☐
Accumulated PII (WI)							
On/Off Peak PII_{Accum} Balances	R	R			I		☐
PII_{Accum} Limits/Extensions	R	R	R		I		☐
WIT FBS Changes and PII_{Accum} Balance Transfers	R	R	R		R		☐

R – Responsible A – Approve I - Informed R/O – Responsible/Optional

ATTACHMENT C

BA to BA General 714 Data Submittal Form

balancing@nerc.com

Energy and Demand Data for BAL-003

FERC Form 714 Part II Schedule III Data

Data Year Select

Instructions:

1. Enter your contact information.
2. Select your Interconnection - drop down list
3. Select the year of the data - drop-down list
4. Select your BA acronym - the drop-down list is dependent on which Interconnection is selected.
5. Enter your BA's data on the form on the left. As filed with FERC, or equivalent, and after merge occurs
6. Enter comments about the change in footprint. For instance, if the BA(s) is transferring or receiving data. From what BA(s). Etc.
7. Submit through the BA Submittal Site (BASS) in the Non-714 Submittals file for your BA.

Submitter's Contact Information

Technical Contact Name	Email	Telephone	Date Submitted (mm/dd/yyyy)

Interconnecton		BA		Effective Date:	mm/dd/yyyy

	BAA Net Generation (c) (MWh)		BA Net Energy for Load (e) (MWh)		BA Net Gen + BA NEL (MWh)		Monthly Peak Demand (j) (MW)	
	As Filed	Adjusted	As Filed	Adjusted	As Filed	Adjusted	As Filed	Adjusted
JAN						-		
FEB						-		
MAR						-		
APR						-		
MAY						-		
JUN						-		
JUL						-		
AUG						-		
SEP						-		
OCT						-		
NOV						-		
DEC						-		
Total	-	-	-	-	-	-	-	-

Comments:

Revision History		
Date	**Version**	**Comment**
2/28/2019	1.0	Initial document – addressed comments received from 45-day industry comment period.
1/23/2024	1.1	Added references to NERC Balancing Authority Submittal Site (BASS) for BAs to submit information and requests to NERC Staff.

Review Acceptance for a PRC-024-3 IBR Implementation Document

Action

The SPCWG is requesting that the RSTC form a group to accept on the Steady-State Approach for PRC-024-3 Evaluation for Inverter-Based Resources document that examines the complexities of evaluating compliance with PRC-024-3 with respect to Inverter-Based Resources.

Background

This report illustrates how a Generator Owner (GO) of an inverter-based resource (IBR) may evaluate their compliance with Requirement R2 of the NERC Reliability Standard PRC-024-3. The example provided in this report is not exclusive as there are likely other methods for implementing a standard. This report provides an example of how NERC registered entities can project their IBR unit voltage protection settings to a corresponding main power transformer (MPT) high-side voltage or conversely project the MPT high-side voltages to the corresponding IBR unit voltage protection settings. They can then directly compare the voltage protection settings to the PRC-024-3 voltage boundary curve since both values are on the same basis.

As the examples in the paper show, there is a significant difference between the voltage setting at the IBR unit terminal and the corresponding voltage at the MPT high side in this example. This case highlights the importance of considering the voltage drop from the protection location to the MPT high side when evaluating compliance with PRC-024. The IBR-plant detailed model produces the most conservative results when used in calculations if the worst-case IBR unit for undervoltage and overvoltage settings are individually identified. Additionally, it can be observed that the difference in voltage drop between the two extreme IBR units can be significant. Only in the simplest collector system configurations will manual calculations be adequate for showing compliance with PRC-024.

This paper was reviewed by industry and the only comments were those that supported the document.

Summary

The SPCWG notes that while IBRs are being removed from PRC_024 in the future, the examples contained within the document are still technically valid and relevant. When the new versions of PRC-024 and PRC-029 are published in the future, this paper will just need minor renaming and updating for those new standards.

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Steady-State Approach for PRC-024-3 Evaluation for Inverter-Based Resources

September 2024

Statement of Purpose

This report illustrates how a Generator Owner (GO) of an inverter-based resource (IBR) may evaluate their compliance with Requirement R2 of the NERC Reliability Standard PRC-024-3. The example provided in this report is not exclusive as there are likely other methods for implementing a standard. This report provides an example of how NERC registered entities can project their IBR unit voltage protection settings to a corresponding main power transformer (MPT) high-side voltage or conversely project the MPT high-side voltages to the corresponding IBR unit voltage protection settings. They can then directly compare the voltage protection settings to the PRC-024-3 voltage boundary curve since both values are on the same basis.

Scope

This report applies to GOs who are evaluating compliance with PRC-024-3 Requirement R2 copied below.

> R2. Each Generator Owner shall set its applicable voltage protection in accordance with PRC-024 Attachment 2, such that the applicable protection does not cause the generating resource to trip or cease injecting current within the "no trip zone" during a voltage excursion at the high side of the GSU or MPT, subject to the following exceptions: *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*
>
> - If the Transmission Planner allows less stringent voltage protection settings than those required to meet PRC-024 Attachment 2, then the Generator Owner may set its protection within the voltage recovery characteristics of a location-specific Transmission Planner's study.
> - Applicable voltage protection may be set to trip or cease injecting current during a voltage excursion within a portion of the "no trip zone" for documented and communicated regulatory or equipment limitations in accordance with Requirement R3.

Figure 1 shows an example of a typical IBR plant. The high-side terminals of the MPT are referred to as point of measurement (POM) in this document. MPTs are also widely known as generator step-up (GSU) transformers. The individual wind turbine generators (WTG)/Inverters in the plant are referred to as IBR units and respective terminals to as point of coupling (POC).

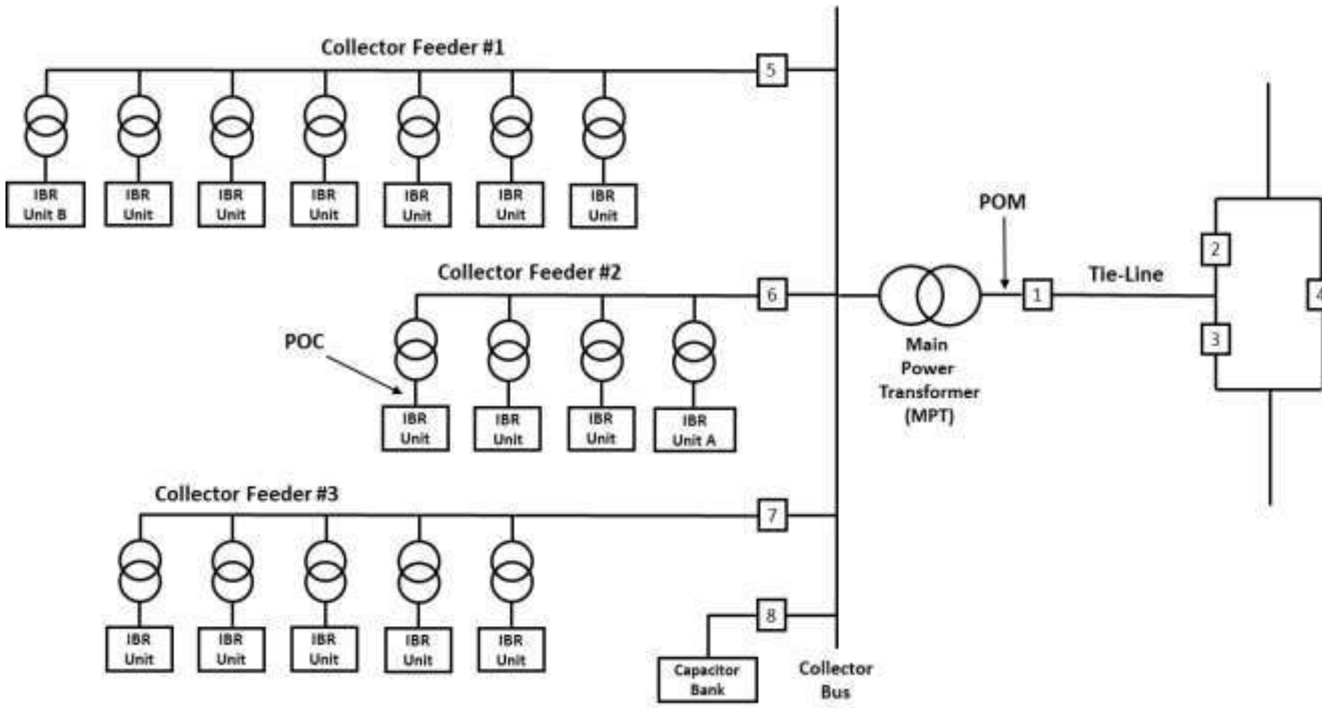


Figure 1: A Typical IBR Plant

Methodology

Attachment 2 of PRC-024-3 outlines how to evaluate protection settings.

Evaluating Protection Settings:

The voltage values in the Attachment 2 voltage boundaries are voltages at the high side of the GSU/MPT (i.e., POM). For generating resources with multiple stages of step up to reach interconnecting voltage, this is the high side of the transformer with a low side below 100 kV and a high side 100 kV or above. When evaluating protection settings, consider the voltage differences between where the protection is measuring voltage and the POM. A steady-state calculation or dynamic simulation may be used. If using a steady-state calculation or dynamic simulation, use the following conditions when evaluating protection settings:

- The most probable real and reactive power loading conditions for the IBR plant are under study.
- All installed IBR plant reactive power support (e.g., static VAR compensators, synchronous condensers, capacitors) equipment is available and operating normally.
- The actual tap settings of transformers between the IBR unit terminals and the high side of the GSU/MPT are accounted for.
- For dynamic simulations, the automatic voltage regulator[1] is in automatic voltage control mode with associated limiters in service.

The PRC-024-3 standard allows the use of either steady-state calculation or dynamic simulation to evaluate compliance. This report demonstrates a steady-state calculation method.

[1] In the context of IBR plant, the automatic voltage regulator is equivalent to the power plant controller.

Similar to what is provided in the *PRC-024-2 Implementation Guidance*, which gives examples for synchronous generators, this report provides an example of how NERC registered entities can project their IBR unit voltage protection settings to a corresponding MPT high-side voltage or conversely project the MPT high-side voltages to the corresponding protection system voltage. They can then directly compare the voltage protection settings to the PRC-024-3 voltage "no trip zone" boundary since both values are on the same basis.

Like an assessment for a synchronous resource, a steady-state PRC-024 assessment for IBR plant relies on steady-state voltage calculations. In addition, there are some added assessment considerations due to the nature of operation and configuration/design of IBR plants.

IBRs have two distinct characteristics compared to Synchronous resources:

- IBRs consist of multiple dispersed IBR units connected through the ac collector system.
- IBR units are dynamic devices and respond very rapidly to voltages at their ac terminals. They can change their power factor (PF) very quickly.

The steady-state calculation methodology shown in this report accounts for the dispersed nature of the IBR units and the collector system. In addition, the dynamic nature of IBR units has been partially considered in this report's calculations. Additional suggestions have been included to further account for the dynamic nature of the IBR units to be considered in steady-state calculations.

Steady State Calculations

A steady state assessment consists of the following steps:

1. Represent the plant.
2. Determine the most probable real and reactive power loading conditions.
3. Calculate voltage drops.
4. Translate voltages and determine PRC-024 compliance:
    a. IBR unit protection settings from the POC to the POM
    Compare with the PRC-024-3 voltage no-trip boundaries

    OR

    b. PRC-024-3 voltage no-trip boundaries from the POM to the POC
    Compare with the IBR unit voltage protection settings

Represent the Plant

An IBR plant typically has a number of IBR units (10's or 100's) all connected together by an ac collector system to one or more main power transformers as shown in **Figure 1**. An aggregated representation of the plant, consisting of one aggregated IBR unit and an equivalenced collector system, is often used in power flow and dynamic studies. Depending on the plant layout, it may be possible to use an aggregated representation for calculating voltage drops. However, an aggregated representation of an IBR plant is often not suitable for PRC-024 assessment as the variation in the collector system results in different total impedances and therefore different voltage drops from each IBR unit to the MPT high side, where the PRC-024 no-trip zone is defined. An aggregated representation of the collector system uses equivalent values that represent the IBR plant as a whole but do not represent the voltage drop to any actual IBR unit. Therefore, the aggregated representation does not represent the voltage drop experienced by the actual IBR unit protection levels. Analysis with the detailed IBR plant model requires a tool capable of solving a power flow.

Other IBR plant equipment should also be represented, such as the following:

- MVAR contribution from capacitor banks or other reactive support devices in their normal operating condition
- The actual tap positions of the IBR unit transformers and MPT

If the MPT uses an on-load tap changer, then the most probable tap position should be used. Another approach is to select a neutral tap position or the tap position that provides nominal voltage on the low side of the MPT for the 0.95 PF lagging on high side of the MPT.

Most Probable Real and Reactive Power Loading Conditions

The PRC-024-3 standard requires that the compliance assessment be done at the most probable real and reactive loading conditions.

For this report, the most probable loading condition for assessing both undervoltage and overvoltage was the plant producing rated real power at the POM at a power factor of 0.95 lagging (supplying vars) at the POM.

The rationale for this chosen loading condition is made up of the following:

- The undervoltage condition is most likely to occur during a system fault when the system voltage (and the voltage at the POM) is already low pre-fault due to high loading. In this case, the IBR unit will be trying to boost the voltage prior to the fault by supplying vars.
- During the undervoltage event, the IBR will continue to supply vars.
- The overvoltage condition is most likely to occur as the system voltage recovers after a fault clearance. Depending on the speed of voltage recovery, the depth of voltage dip during a fault, the voltage control characteristics of the IBR units during undervoltage events, and the dynamics of the IBR unit controllers, the IBR unit may still be supplying lagging vars as the voltage recovers and moves into the overvoltage condition upon fault clearance. Without considering the specific dynamics of a particular IBR, this report assumes that even an IBR operating at 0 PF lagging during a severe fault will be fast enough to change the PF back to pre-fault 0.95 lagging at the POM as the voltage recovers after a fault past the normal operating region into the overvoltage region.
- It is possible to further refine the above approach to evaluating overvoltage with the steady-state methodology with consideration of the dynamic nature of IBR units. For example, when evaluating overvoltage trip settings with delays of greater than 0.2 seconds, it may be appropriate to use unity or even a leading power factor at the POM. This is based on an assumption that a 0.2-second time delay offers enough time for IBR unit controls to change the power factor.

Calculate Voltage Drops

Assessment of the transferred protection levels does not need to be performed for every IBR unit within the IBR plant. For the assumptions outlined above, the voltage at the POC is always going to be higher than voltage at the POM. Only two worst-case IBR units need to be considered:

- For assessing undervoltage protection settings, the chosen IBR unit is the one with the lowest voltage difference between the POM and terminals of the IBR unit (e.g., IBR unit A on collector feeder #2 has the shortest length between collector bus and IBR unit terminals and least current.).
- For assessing overvoltage protection settings, the IBR unit chosen is the one with the highest voltage difference between the POM and the terminals of this IBR unit (e.g., IBR unit B on collector feeder #1 has the longest length between collector bus and IBR unit terminals and highest current.).

The first step is to identify the worst-case IBR unit for undervoltage and overvoltage protection assessment. To do so, the total voltage drop from each IBR unit to the MPT high side is calculated to identify the IBR unit with the lowest voltage drop, which is the worst case for undervoltage assessment, and the IBR unit with the greatest drop, which is the worst case for overvoltage assessment. The voltage drop is calculated for every segment between the POC and the POM by using a load flow model.

The voltage drop calculations are done by considering the IBR as a constant current source. This is different from the methodology in *Generator Voltage Protective Relay Settings*,[2] which outlines PRC-024-2 voltage drop calculations for a synchronous unit assessment. In the methodology used for synchronous units in the PRC-024-2 implementation guidance, the synchronous unit is considered a constant MVA source. The output current of the unit is adjusted as the voltage drop is calculated for different GSU high side bus voltage levels. However, unlike the synchronous case, IBR units are current limited devices and are considered a constant current source for the purpose of PRC-024 compliance evaluation. This means that current at rated or most probable POM voltage is used to calculate voltage drop between the POC and the POM. Additionally, since the IBR plant impedance does not change with voltage, the same voltage drop value can be applied for all MPT high side voltage levels.

The constant current and the constant voltage drop level should be determined with the IBR plant operating as follows:

- The MPT high side bus at rated or most probable voltage
- The most probable power factor at the MPT high side, which for this report is chosen to be of 0.95 lagging power factor
- The IBR plant output at its rated MW level

[2] Generator Voltage Protective Relay Settings is implementation guidance endorsed by the Electricity Reliability Organization.

Example: Wind Plant

The example wind plant in Table 1 includes six collector feeders below a single MPT. The number of WTGs (i.e., IBR units) connected to each collector feeder varies from 3–13.

Table 1: Wind Plant Information		
Plant Data		
Power Factor at POM	0.95 lagging	
Plant MW Rating	156	
POM Voltage Rating (kV)	230	
Capacitor Bank Location and Voltage	MPT Low Side, 34.5kV bus	
Capacitor Bank MVAR Rating	10	
WTG/IBR unit Data		
MVA Rating	2.083	
MW Rating	2	
Power Factor Range	+/-0.80	
Number of WTGs/IBR units	78	
Nominal Voltage (kV)	0.63	
WTG/IBR unit Transformer Data		
MVA Rating	2.3	
Low-Side Nominal Voltage (kV)	0.63	
High-Side Nominal Voltage (kV)	34.5	
Low-Side Tap Setting	0%	0.63kV
High-Side Tap Setting	0%	34.5kV
%Impedance	8.344	@2.3MVA
Main Power Transformer Data		
Base MVA Rating	96	
Low-Side Nominal Voltage (kV)	34.5	
High-Side Nominal Voltage (kV)	230	
Low-Side Voltage Tap	0%	34.5kV
High-Side Voltage Tap	0%	230kV
% Impedance	9.8	@96MVA

The over and undervoltage protection settings at the WTG/IBR unit level are included in **Table 2**.

Table 2: IBR Unit-Level Protection Settings		
Protection Level	**Voltage (pu)**	**Time Delay (s)**
UV1	0.55	0.20
UV2	0.76	0.50
UV3	0.83	2.00
OV1	1.30	0.00
OV2	1.26	0.20
OV3	1.24	0.75
OV4	1.20	2.00

Calculation Using a Detailed Collector System Model of Wind Plant

A detailed collector system power flow model of the plant is used to calculate the voltage drop between IBR units and the high side of the MPT. The plant power flow model includes the capacitor bank connected to the collector bus and is in-service since this is the normal operating condition of the plant. The tap position for IBR unit transformer(s) and the MPT is also reflected in the power flow model. The voltage drop is calculated for rated or most probable voltage and a 0.95 lagging power factor at the MPT high side while operating at rated power and remaining within the P-Q capabilities of the IBR unit. The 0.95 lagging power factor at the MPT high side is achieved by setting all IBR units in the plant to provide the same real and reactive power output, which is one approach for assessing compliance with PRC-024.

As described in the methodology section, the worst-case IBR units with the highest and lowest voltage drop are identified. Typically, for assessing undervoltage protection settings, the IBR unit chosen is the one with the lowest voltage difference between the POM and terminals of the IBR unit. Whereas, for assessing overvoltage protection settings, the IBR unit chosen is the one with the highest voltage difference between the POM and the terminals of this IBR unit. **Table 3** and **Table 4** show the voltage levels calculated by using a power flow model for the worst-case IBR units at different points within the IBR plant.

Table 3: Voltage Levels at Multiple Points within the IBR Plant – Highest Drop IBR unit			
IBR unit Setting Level	**IBR unit Setting (pu)**	**MPT Low Side (pu)**	**MPT High Side (pu)**
UV1	0.55	0.4980	0.4266
UV2	0.76	0.7080	0.6366
UV3	0.83	0.7780	0.7066
OV1	1.30	1.2480	1.1766
OV2	1.26	1.2080	1.1366
OV3	1.24	1.1880	1.1166
OV4	1.20	1.1480	1.0766

Table 4: Voltage Levels at Multiple Points within the IBR Plant–Lowest Drop IBR unit			
IBR unit Setting Level	IBR unit Setting (pu)	MPT Low Side (pu)	MPT High Side (pu)
UV1	0.55	0.4980	0.4579
UV2	0.76	0.7080	0.6679
UV3	0.83	0.7780	0.7379
OV1	1.30	1.2480	1.2079
OV2	1.26	1.2080	1.1679
OV3	1.24	1.1880	1.1479
OV4	1.20	1.1480	1.1079

Figure 2 shows undervoltage pickup settings at IBR unit terminals reflected to the high-side of the MPT (i.e., POM) along with the PRC-024 low voltage no-trip boundary. IBR units experiencing lowest and highest voltage drop between terminals and the POM are shown. As seen in **Figure 2**, the undervoltage pickup settings reflected to the high side of the MPT for an IBR unit with the lowest voltage drop between the terminals and the POM are higher than the same undervoltage settings for an IBR unit with the highest voltage drop between the terminals and the POM. Given that the trip settings applied in all IBR units are same within an IBR plant, the IBR unit with lowest voltage drop between the terminals and the POM should be used when evaluating undervoltage pickup settings.

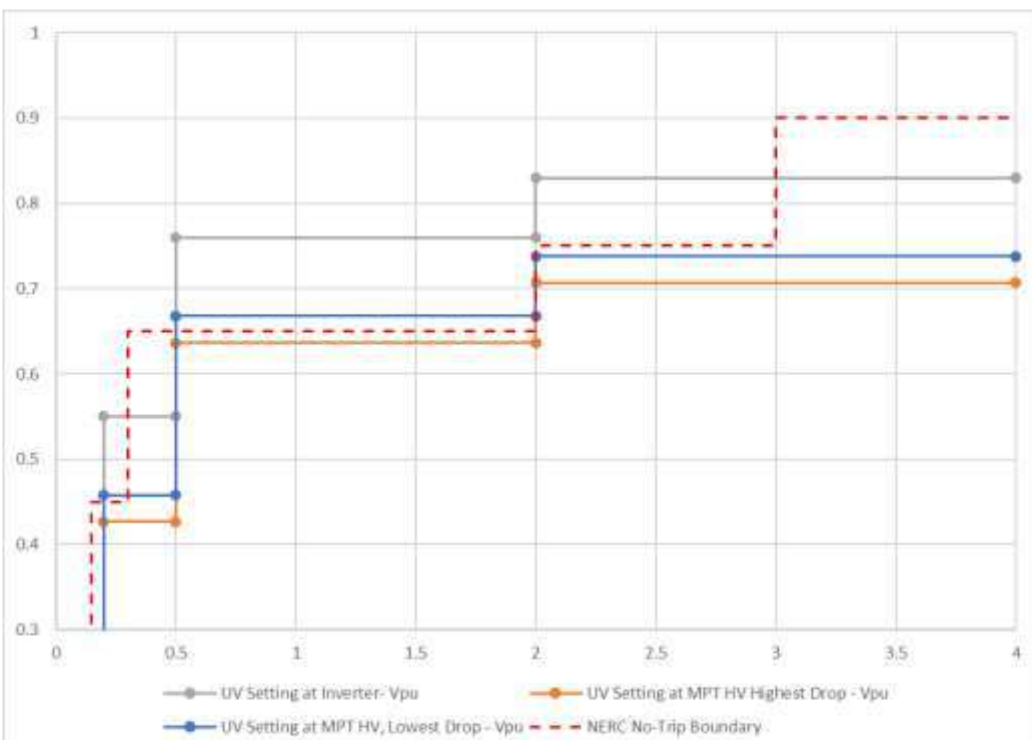


Figure 2: IBR Unit Undervoltage Settings Reflected to MPT High-Side Versus PRC-024 No-Trip Boundary

In this example, undervoltage levels UV1 and UV2 do not comply with the PRC-024 requirements. The undervoltage trip level UV3 barely meets the PRC-024 requirements. The pickup for UV1 and UV2 should be lowered so that the voltage of IBR unit (when reflected to POM) with lowest voltage drop between the terminals and the POM is below the low voltage no-trip boundary of the PRC-024. Note that, while lowering the protection level to meet this criteria will result in compliant settings, PRC-024 is not a comprehensive setting standard.

Figure 3 shows overvoltage pickup settings at IBR unit terminals reflected to the high-side of the MPT (i.e., POM) along with the PRC-024 high voltage no-trip boundary. IBR units experiencing lowest and highest voltage drop between terminals and the POM are shown. As seen in **Figure 3**, the overvoltage pickup settings reflected to the high side of the MPT for an IBR unit with the highest voltage drop between the terminals and the POM are lower than the same overvoltage pickup settings for an IBR unit with the lowest voltage drop between the terminals and the POM. Considering the IBR unit with highest voltage drop between the terminals and the POM, none of the overvoltage levels comply with the PRC-024 requirements. The pickup for all overvoltage levels should be raised so that voltage of IBR unit (when reflected to POM) with highest voltage drop between the terminals and the POM is above the high voltage no-trip boundary of the PRC-024.

Alternatively, the no-trip boundaries could be reflected from the MPT high side to the IBR unit level, as shown in **Figure 4** and **Figure 5**. Either reflection direction method will result in the same conclusions.

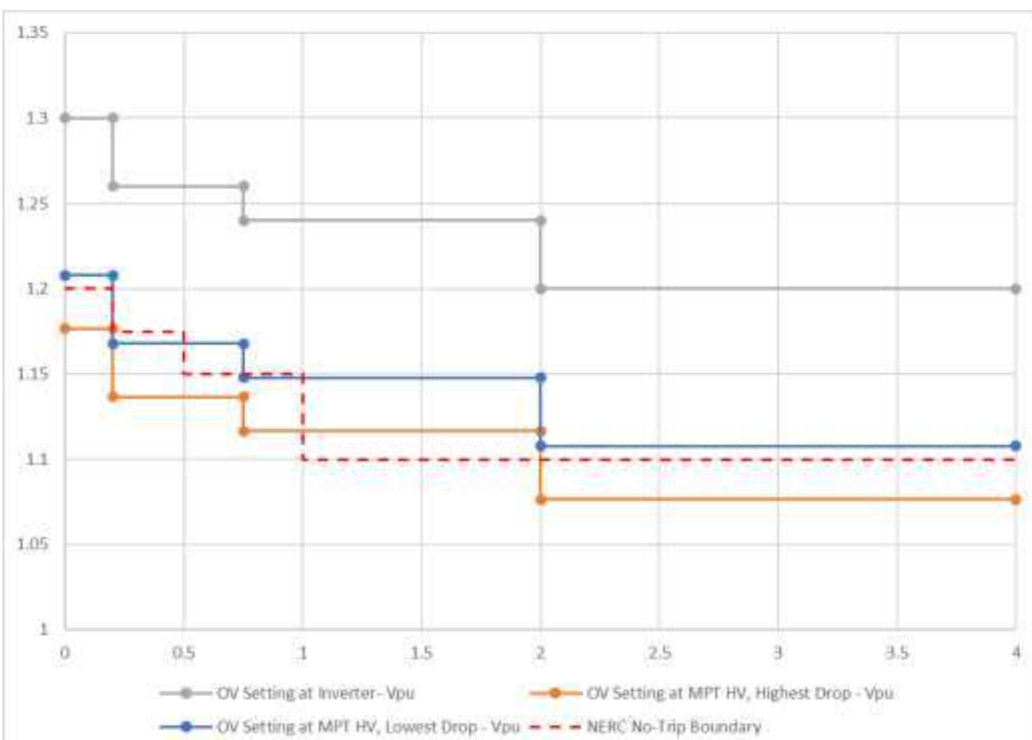


Figure 3: IBR Unit Overvoltage Settings Reflected to MPT High-Side Versus PRC-024 No-Trip Boundary

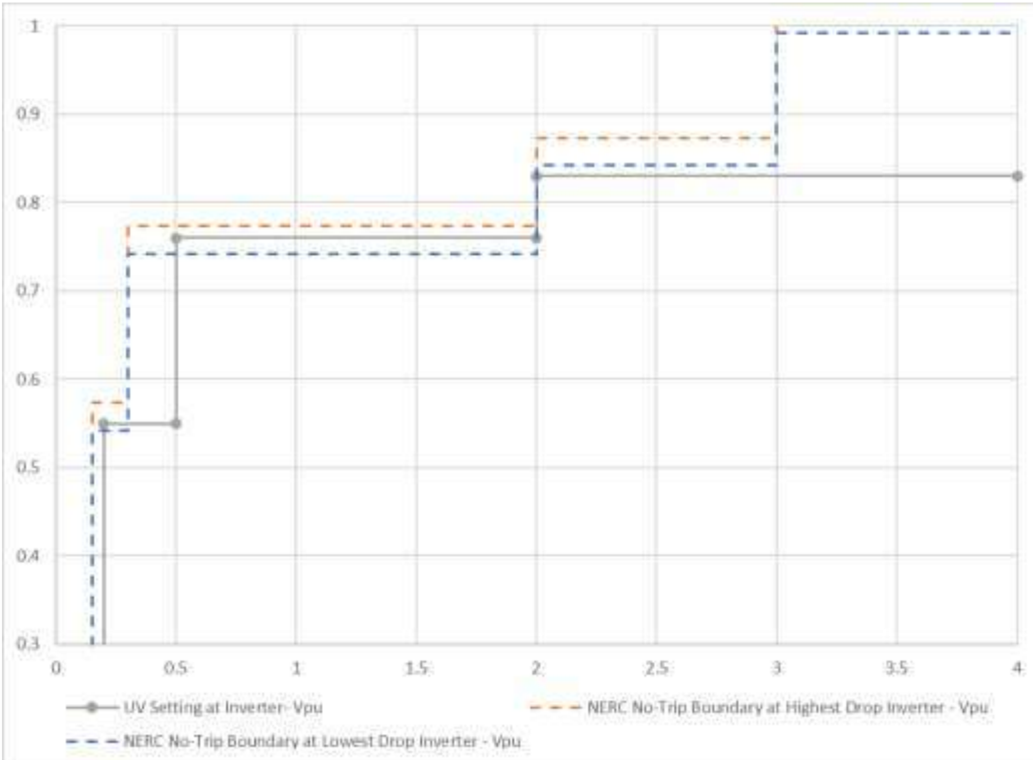


Figure 4: IBR unit Undervoltage Settings Versus PRC-024 No-Trip Boundary Reflected to IBR unit Terminal

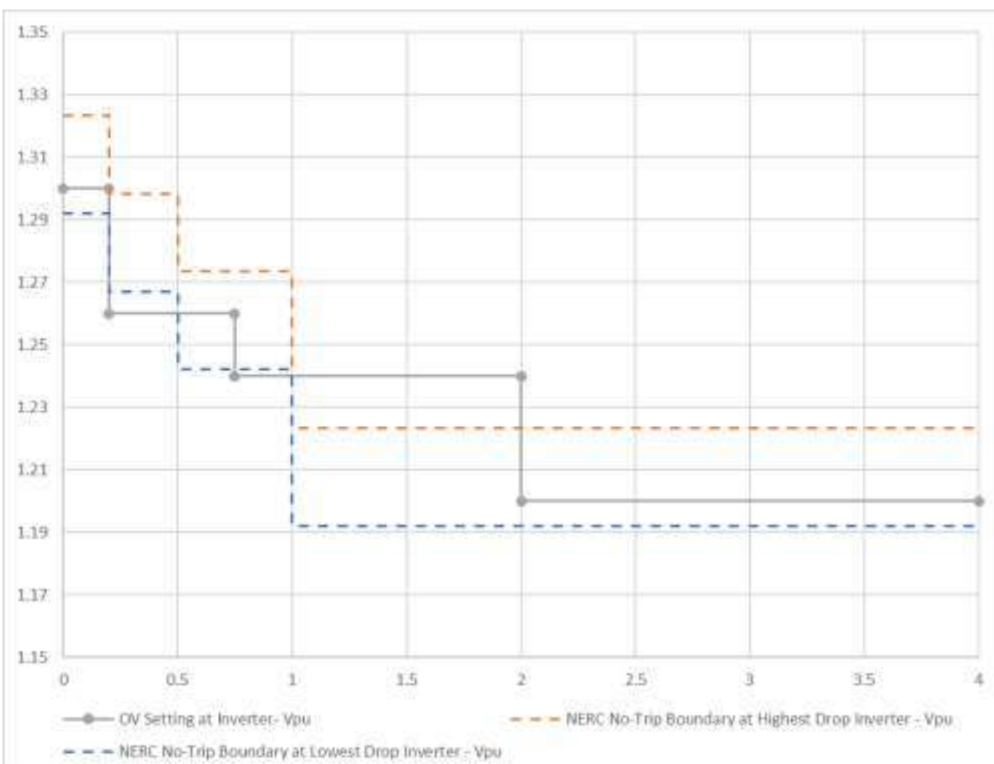


Figure 5: IBR unit Overvoltage Settings Versus PRC-024 No-Trip Boundary Reflected to IBR Unit Terminal

Calculation with Aggregated IBR Unit and Equivalenced Collector System Model

For comparison, the same voltage drop calculations were performed with an aggregated representation of the IBR plant with a single aggregated IBR unit, a single aggregated IBR unit transformer, and a single aggregated collector system below the plant's MPT.[3] Again, this aggregate representation results in an average representation of the voltage drop to IBR units in the plant and does not represent the actual voltage drop for any single actual IBR unit. Calculations with aggregated IBR unit and equivalenced collector system model are not recommended; they are only shown for comparison. As before, the voltage drop was calculated for rated or most probable voltage and 0.95 lagging power factor at the POM while producing as close to rated power as possible while remaining within the P-Q capabilities of the IBR unit. Additionally, the MPT tap was set to nominal and the MPT low-side capacitor bank was connected since this is the normal operating condition for the IBR plant. **Table 5** shows the voltage levels calculated by the simulator for the aggregated IBR unit at different points in the IBR plant.

Table 5: Voltage Levels at Multiple Points within the IBR Plant – Aggregated Plant Mode

IBR unit Setting Level	IBR unit Setting (pu)	MPT Low Side (pu)	MPT High Side (pu)
UV1	0.55	0.4984	0.4423
UV2	0.76	0.7084	0.6523
UV3	0.83	0.7784	0.7223
OV1	1.30	1.2484	1.1923
OV2	1.26	1.2084	1.1523
OV3	1.24	1.1884	1.1323
OV4	1.20	1.1484	1.0923

Figure 6 and **Figure 7** show the undervoltage and overvoltage settings, respectively, at the MPT high side for the aggregated IBR unit compared to the worst-case IBR unit settings from the previous section.

[3] E. Muljadi et al., "Equivalencing the collector system of a large wind power plant," 2006 IEEE Power Engineering Society General Meeting, Montreal, QC, Canada, 2006, pp. 9 pp.-, doi: 10.1109/PES.2006.1708945.

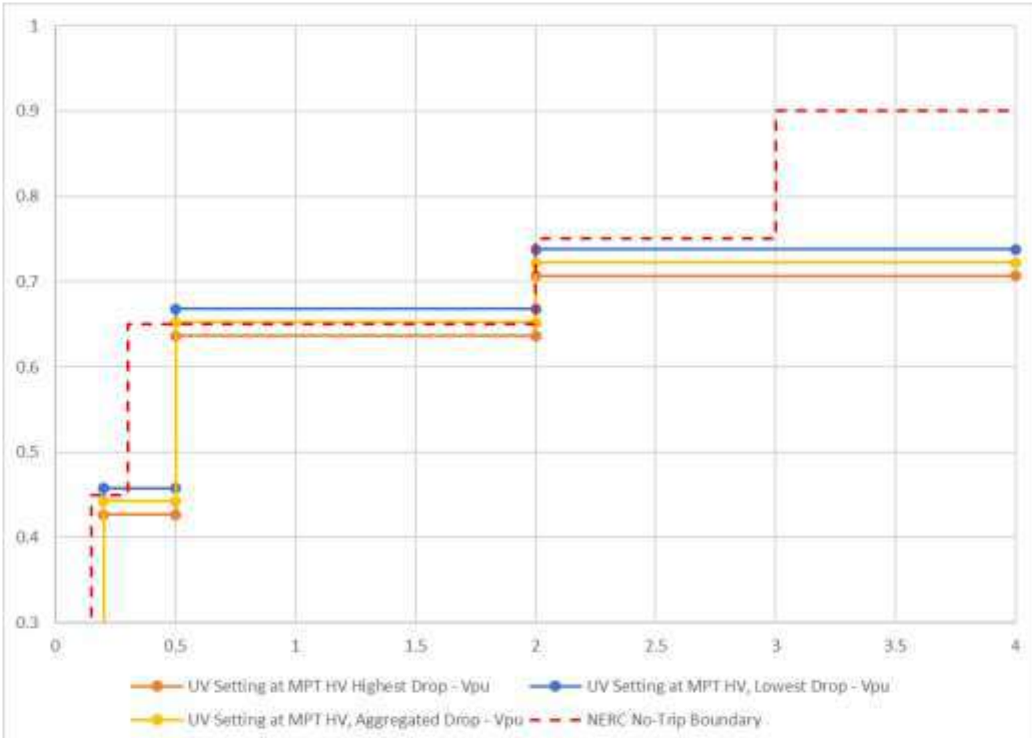


Figure 6: Undervoltage Settings Reflected to High-Side of MPT–Aggregated Versus Detailed IBR Plant

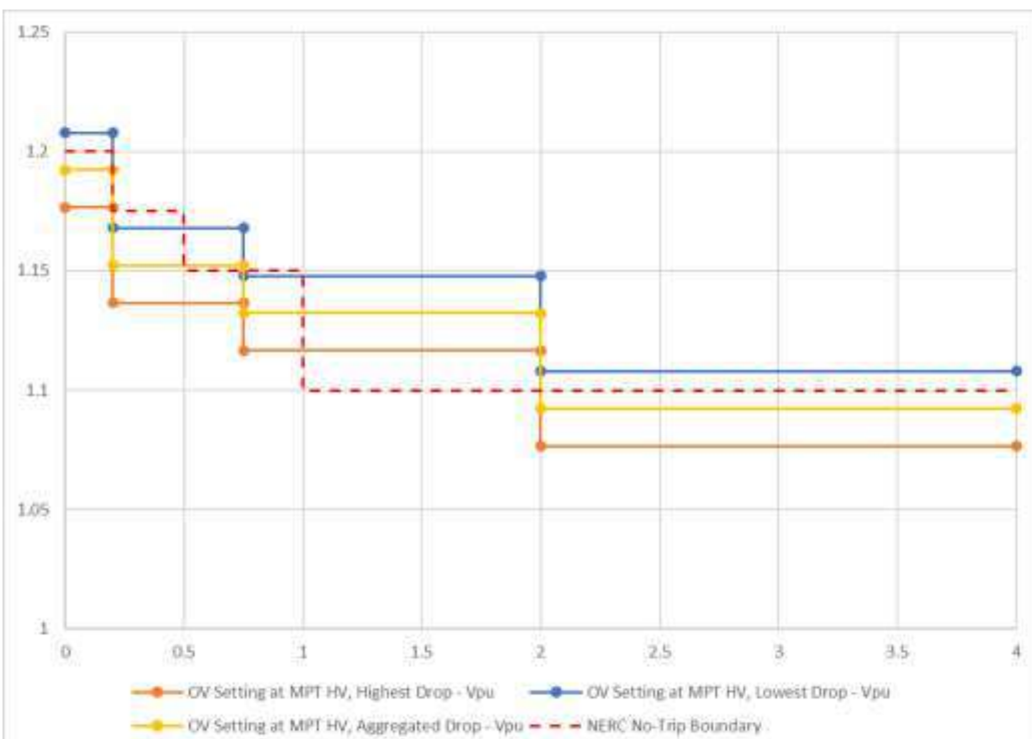


Figure 7: Overvoltage Settings Reflected to High-Side of MPT–Aggregated Versus Detailed IBR Plant

Conclusion

As shown in **Figure 2** and **Figure 3**, there is a significant difference between the voltage setting at the IBR unit terminal and the corresponding voltage at the MPT high side in this example. This case highlights the importance of considering the voltage drop from the protection location to the MPT high side when evaluating compliance with PRC-024. The IBR-plant detailed model produces the most conservative results when used in calculations if the worst-case IBR unit for undervoltage and overvoltage settings are individually identified. Additionally, it can be observed that the difference in voltage drop between the two extreme IBR units can be significant. Only in the simplest collector system configurations, will manual calculations be adequate for showing compliance with PRC-024.

Acknowledgements:

The NERC SPCWG acknowledges valuable contributions from the following non-SPCWG members: Casey Whitt (Shermco Industries), Sid Pant (GE Vernova), and Kevin Dowling (Silicon Ranch).

White Paper	**Steady State Approach for PRC-024-3 Evaluation for Inverter-Based Resources**
Instructions	**Please use this form to submit comments on the draft White Paper. Comments must be submitted within the review period below to Ed Ruck (Ed.Ruck@nerc.net) with the words "White Paper Comments" in the subject line. Only comments submitted in this Microsoft Excel format will be accepted. Both general and specific comments should be provided within this form.** Comments may be submitted by individuals or organizations. Please provide the requested information in Row 6. If comments are submitted on behalf of multiple organizations, list all organizations in Row 6. Please provide the Industry Segment and Region (if applicable) in Rows 7 and 8 and provide the requested contact information in Rows 9 and 10. If you have any questions regarding this process, please contact Sandy Shiflett (sandy.shiflett@nerc.net)
Review Period	**April 24, 2024 - May 23, 2024**

Name of Individual or Organization(s) (list multiple if submitted by a group):	Summary document
Industry Segment (if applicable)	
Region (if applicable)	summary document
Contact Telephone	
Contact Email	

Organization(s)	Page #	Line / Paragraph	Comment	Proposed Change	NERC Response
Manitoba Hydro	1	17	Since a newer version of standard PRC-024-4 is in the work, should this document refer to the latest version of the requirement or wait until the new version of PRC-024-4 is finalized?	no change	While there may need to be a revision once PRC-024-4 is approved or point it to a different standard, this work is still important and contains useful technical information.
FirstEnergy sees no objection to this Document.					Thank you.
Ameren	Whole document	N/A	Ameren support the document	N/A	Thank you
Edison Electric Institute	N/A	N/A	General Comment: EEI supports the approval of this white paper and offers no changes. We further note and appreciate that while this paper is identified as a white paper it also serves as an appropriate guidance document supporting IBR Generator Owners with their compliance relative to PRC-024-3, Requirement R2.	None	Thank you

NERC

NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

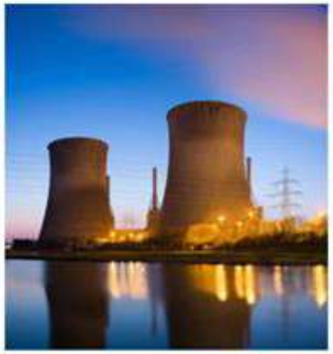
Steady-State Approach for PRC-024-3 Evaluation for Inverter-Based Resources

Manish Patel, SPCWG Vice Chair

RSTC Meeting

September 11, 2024

RELIABILITY | RESILIENCE | SECURITY

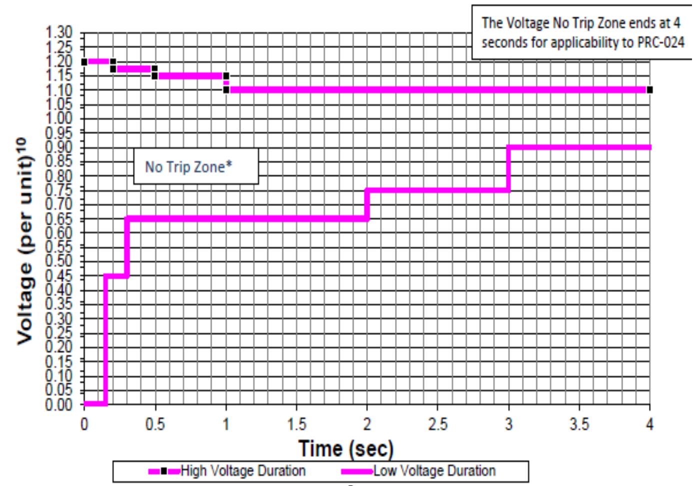
NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

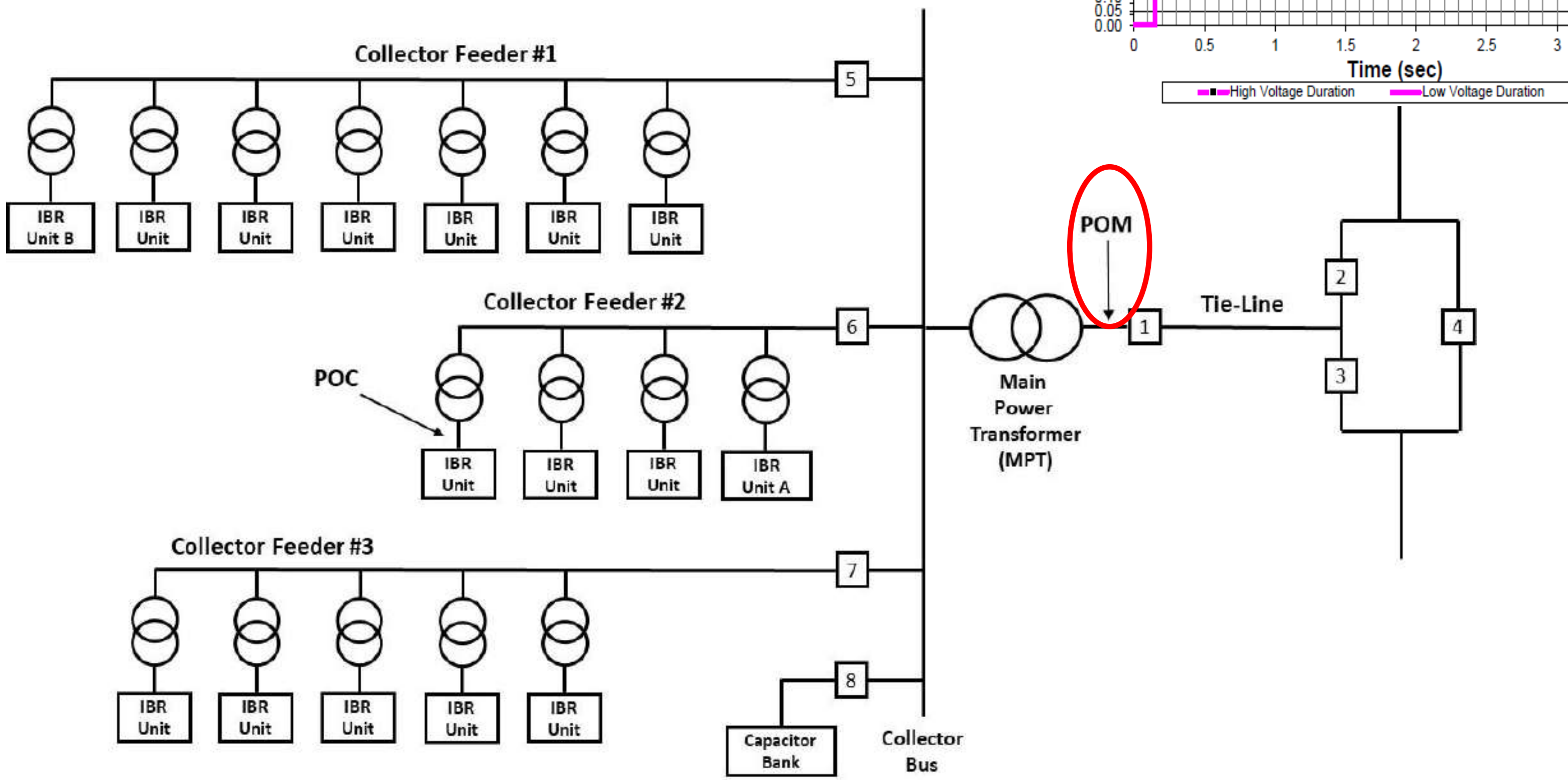
Statement of Purpose

This report illustrates how a Generator Owner (GO) of an inverter-based resource (IBR) may evaluate their compliance with Requirement R2 of the NERC Reliability Standard PRC-024-3. The example provided in this report is not exclusive as there are likely other methods for implementing a standard. This report provides an example of how NERC registered entities can project their IBR unit voltage protection settings to a corresponding main power transformer (MPT) high-side voltage or conversely project the MPT high-side voltages to the corresponding IBR unit voltage protection settings. They can then directly compare the voltage protection settings to the PRC-024-3 voltage boundary curve since both values are on the same basis.

PRC-024 Voltage Boundary Applicability

White Paper provides a steady-state calculation methodology to map POM voltage to POC voltage where typically protection is applied





Steady State Calculations

A steady state assessment consists of the following steps:

- Represent the plant.
- Determine the most probable real and reactive power loading conditions.
- Calculate voltage drops.
- Translate voltages and determine PRC-024 compliance:
  - IBR unit protection settings from the POC to the POM.
  - Compare with the PRC-024-3 voltage no-trip boundaries.

  OR

  - PRC-024-3 voltage no-trip boundaries from the POM to the POC.
  - Compare with IBR unit voltage protection settings

Steady State Calculations

White paper includes example based on following :

- Calculation Using a Detailed Collector System Model
- Calculation with Aggregated IBR Unit and Equivalenced Collector System Model

Calculations with aggregated IBR unit and equivalenced collector system model are not recommended; they are included for comparison only.

Conclusions

- There is typically a significant difference between the voltage setting at the IBR unit terminal (POC) and the corresponding voltage at the MPT high side (POM).
- The paper highlights the importance of considering the voltage drop from the protection location to the MPT high side when evaluating compliance with PRC-024.
- The IBR-plant detailed model produces the most conservative results when used in calculations if the worst-case IBR unit for undervoltage and overvoltage settings are individually identified.
- Only in the simplest collector system configurations, will manual calculations be adequate for showing compliance with PRC-024.

Industry Comments

Organization(s)	Comment
Manitoba Hydro	Since a newer version of standard PRC-024-4 is in the work, should this document refer to the latest version of the requirement or wait until the new version of PRC-024-4 is finalized?
FirstEnergy	FirstEnergy sees no objection to this Document.
Ameren	Ameren support the document
Edison Electric Institute	General Comment: EEI supports the approval of this white paper and offers no changes. We further note and appreciate that while this paper is identified as a white paper it also serves as an appropriate guidance document supporting IBR Generator Owners with their compliance relative to PRC-024-3, Requirement R2.

NERC

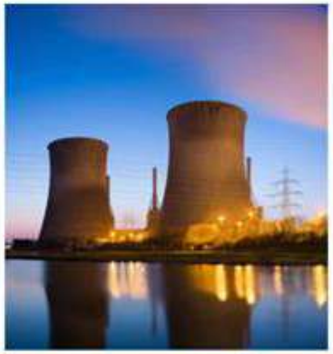
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Transmission System Phase Backup Protection

~~Reliability Guideline~~ Technical Reference Document

~~June 2011~~ September 2024

RELIABILITY | RESILIENCE | SECURITY



Preamble

This document remains unchanged since its original release on June 2011 but has been reformatted and reclassified as a technical reference document and placed into the current NERC report format as it still contains useful information.

Comments received from industry were reviewed and resolved by the SPCWG.

Introduction

A number of significant system disturbance reports since the 2003 Northeast Blackout have recommended evaluating specific applications of adding backup and/or redundant protection to enhance system performance or contain the extent of a disturbance.

The most significant of these is the FRCC report from the February 26, 2008 system disturbance titled "FRCC System Disturbance and Underfrequency Load Shedding Event Report February 26th, 2008 at 1:09 pm".

This report states that "NERC should assign the System Protection and Control Task Force to produce a technical paper describing the issue and application of backup protection for autotransformers".

Details

- Tech Reference discusses
  - Advantages and disadvantages of local and remote back-up protection.
  - System performance requirements and how local and remote backup protection may help.
  - Provides examples for simple and complex scenarios.

Conclusion

- Backup protection can play a significant role in preventing or mitigating the effects of Protection System or equipment failures.
- Local backup inherently addresses single Protection System failures and may address some failures of multiple Protection Systems, but generally will not address these failures to the extent of a remote backup scheme.
- Remote backup can act as a safety net to reduce the extent of a power system disturbance during multiple Protection System failures.
- Careful examination of the overall interaction of Protection Systems may provide insight as to where additional local or remote backup can be applied to help mitigate the spread of an outage.

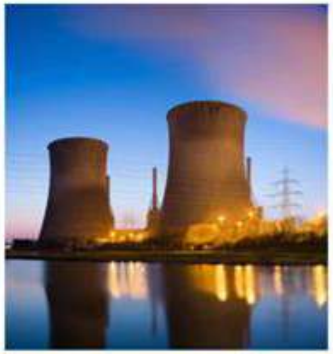
NERC

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

SPCWG's Comment on EMT Reliability Guideline developed by the IRPS

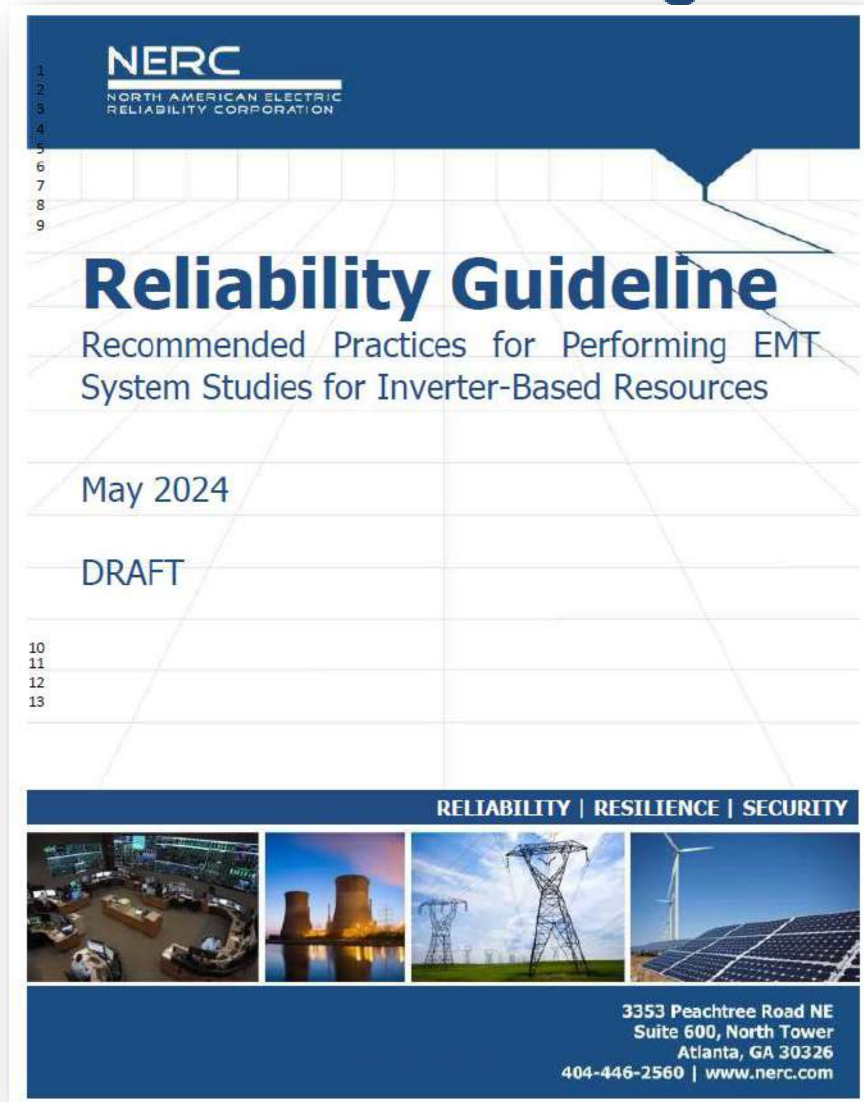
System Protection and Control Working Group

RELIABILITY | RESILIENCE | SECURITY

IRPS EMT TF Developed RG with Recommended Practice

- RSTC asked review by SPCWG, with focus on how it applies to protection.


Reliability Guideline
Recommended Practices for Performing EMT System Studies for Inverter-Based Resources
May 2024
DRAFT
RELIABILITY | RESILIENCE | SECURITY
3353 Peachtree Road NE
Suite 600, North Tower
Atlanta, GA 30326
404-446-2560 | www.nerc.com

SPCWG's Comment

"Transmission System Protection Validation" provides some recommendations, with few references.

SPCWG's comment:

- May be best not to include this section "Transmission Protection Validation". Request RSTC approval to have the SPCWG write their own whitepaper on this subject. Issues and concerns of this section include but are not limited to comments noted above. The SPCWG believes the objective of EMT simulations at this time should be to understand fault response and model validation vs transmission protection validation. The guideline stands on its own without this section.

Questions and Answers

Transmission System Phase Backup Protection

Action

The SPCWG is requesting that the RSTC accept the Transmission System Phase Backup Protection document that reviews the importance of backup protection schemes.

Background:

In 2011, the System Protection and Control Subcommittee published a version of this document as a Reliability Guideline. After the Reliability Guideline review in 2021, this document was recharacterized as a Technical Reference Document. This document has been revised to place it in the new format style and reviewed by the SPCWG and determined that it is still a valid and relevant reference for industry.

This paper was reviewed by industry and only one entity provided suggestions for improvement. The suggestions were analyzed and those that were within scope were implemented for the limited scope of the V1.1 review/update. The remaining suggestions were excellent and have been noted for implementation into any subsequent V2.0 substantial update in the future.

Summary:

The SPCWG requests that the RSTC accept this document

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Transmission System Phase Backup Protection

Technical Reference Document

September 2024

RELIABILITY | RESILIENCE | SECURITY

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

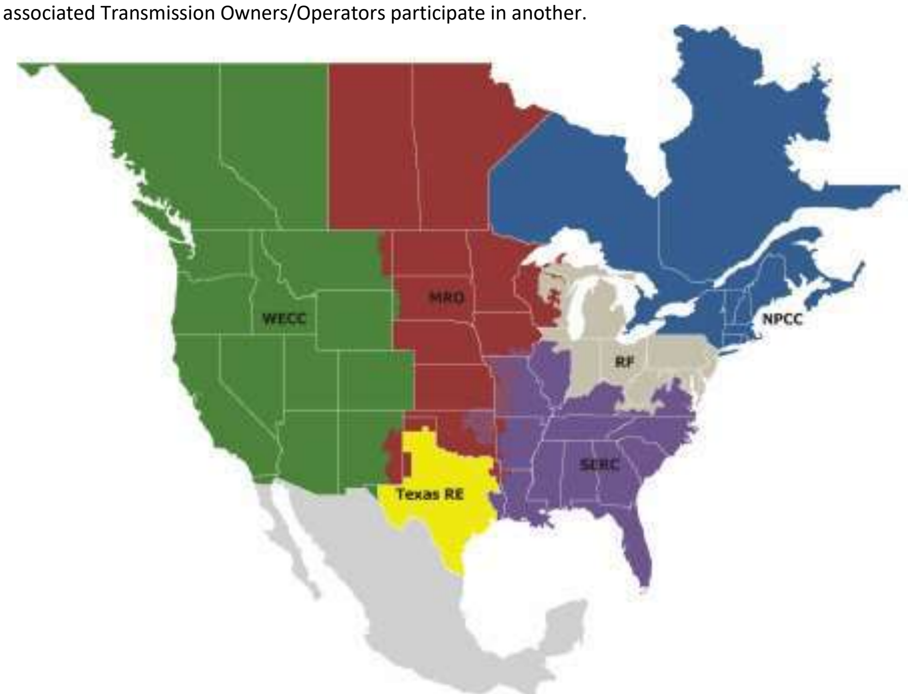
Table of Contents

Preface

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

Preamble

NERC studies information from a variety of sources available to the ERO Enterprise to evaluate potential risks to reliability of the BPS. NERC completes these studies as part of executing its mission to ensure reliability of the BPS and in fulfillment of its responsibilities under section 215 of the Federal Power Act. Such assessments and studies do not seek to plan or propose fully realized solutions for the topic studied; rather, they provide stakeholders with engineering analysis on potential risks to reliability. Such studies provide key findings, guidance, and information on specific issues to promote and maintain a 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. NERC's studies 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 information supplied in this study. Entities should review this study in detail and in conjunction with their evaluation of internal processes and procedures.

Review of this study and such internal processes and procedures could highlight appropriate changes that should be made with consideration of system design, configuration, and business practices.

This document remains unchanged since its original release on June 2011 but has been reformatted and reclassified as a technical reference document and placed into the current NERC report format as it still contains useful information.

Chapter 1: Introduction and Need to Discuss Backup Protection

Backup protection can, and in many cases does, play a significant role in providing adequate system performance or aiding in containing the spread of disturbances due to faults accompanied by Protection System failures or failures of circuit breakers to interrupt current. However, NERC protection standards affect and may limit the use of backup protection to ensure that backup protection does not play a role in increasing the extent of outages during system disturbances. A number of significant system disturbance reports since the 2003 Northeast Blackout have recommended evaluating specific applications of adding backup and/or redundant protection to enhance system performance or contain the extent of a disturbance. The most significant of these is the FRCC report from the February 26, 2008 system disturbance titled "*FRCC System Disturbance and Underfrequency Load Shedding Event Report February 26th, 2008 at 1:09 pm*". This report states that "NERC should assign the System Protection and Control Task Force to produce a technical paper describing the issue and application of backup protection for autotransformers". As a result, the NERC Planning Committee (PC) has assigned the NERC System Protection and Control Subcommittee (SPCS) the task of developing a document on backup protection applications.

The goal of this Technical Reference Document is to ensure the industry has a common understanding of the appropriate uses of Backup Protection in order to ensure an Adequate Level of Reliability. To this end, to the paper will discuss the pros, cons, and limitations of backup protection, and include recommendations, where deemed appropriate, for a balanced approach to the use of backup relaying as a means to ensure adequate system performance and/or to provide a system safety net to limit the spread of a system disturbance for events that exceed design criteria, such as those involving multiple protection system or equipment failures. The document provides a discussion of fundamental concepts related to phase backup protection for the most common equipment on the power system: transmission lines and autotransformers. The document is not intended to provide a comprehensive discussion of all methods used for providing backup protection.

Chapter 2: Background on NERC SPCWG Activities Related to Backup Protection

The use of backup protection and the implications of its use on the power system is a subject that has been discussed many times by the NERC SPCS since its formation as a NERC Task Force[1] after the 2003 Northeast Blackout. Overreaching or backup phase distance relays providing primary and/or backup functions played a role in the cascading portion of the 2003 Northeast Blackout and have played similar roles in other previous and subsequent blackouts.

The SPCS has done much work with respect to backup protection or issues that affect the use of backup protection. One of the first SPCTF reports was on the "Rationale for the Use of Local and Remote (Zone 3) Protective Relaying Backup Systems."[2] This paper discussed the pros and cons of the use of Zone 3 type backup protection in a general sense. The Protection System Reliability Standard developed as a result of the 2003 Northeast Blackout, PRC-023-1 "Transmission Relay Loadability," codified requirements for loadability of phase responsive transmission relays which in some cases significantly limited the ability of some relays to provide backup protection. This led to other SPCTF papers illustrating ways to use legacy and modern protective relays to increase relay loadability while meeting protection requirements.

The SPCTF reference paper "Protection System Reliability"[3] was created to accompany the SAR for a new standard to set the acceptable level of redundancy required in Protection System designs to meet system performance requirements. A new standard is currently being considered under a Standard Authorization Request (SAR) submitted by the SPCS. The Protection System Reliability paper discusses the potential use of local and remote backup Protection Systems to provide redundancy, but purposely does not go into detail regarding all the complexities involved in the use of remote backup protection.

The "Power Plant and Transmission System Protection Coordination"[4] Technical Reference Document describes a number of backup protection elements that may be applied on generators and how to ensure adequate coordination and loadability of these elements. These SPCS efforts, other SPCS efforts, and experiences from other events since the 2003 Northeast Blackout point to a need to address the technical details behind the pros and cons of applying backup protection in greater detail in this technical paper.

[1] The System Protection and Control Task Force (SPCTF), formed in 2004, was the predecessor to the System Protection and Control Subcommittee (SPCS). Since then, the SPCS was recategorized as a working group and renamed the SPCWG

[2] Rationale for the Use of Local and Remote (Zone 3) Protective Relaying Backup Systems – A Report on the Implications and Uses of Zone 3 Relays, February 2, 2005.

[3] Protection System Reliability – Redundancy of Protection System Elements, December 4, 2008.

[4] Power Plant and Transmission System Protection Coordination – Revision 2, July 2015.

Chapter 3: Terminology Used In This Document

Redundancy

In the context of this paper, redundancy is the existence of separate Protection System components, as discussed in the NERC SPCS Technical Reference Document "Protection System Reliability," installed specifically for the purpose of meeting the NERC system performance requirements during a single Protection System failure.

It is not the goal of this paper to specify detailed methods to design redundancy into a Protection System. Other papers, including the NERC document cited above and the IEEE Power System Relaying Committee (PSRC) Working Group I19 document "Redundancy Considerations for Protective Relay Systems,"[5] provide detailed discussion of methods to design redundancy into a Protection System.

Backup Protection

In the context of this paper, backup protection consists of any Protection System elements that clear a fault when the fault is accompanied by a failure of a Protection System component or a failure of a breaker to interrupt current. Backup protection may operate because it is intentionally set to meet specific performance requirements, or it may operate for conditions when multiple contingencies have occurred that bring the event into the backup zone of protection. Backup protection may be provided locally, remotely, or both locally and remotely.

Local Backup

The local backup method provides backup protection by adding redundant Protection Systems locally at a substation such that any Protection System component failure is backed up by another device at the substation. For local backup to provide redundancy, the local backup Protection System must sense every fault and consist of separate Protection System components, as discussed in the NERC SPCS Technical Reference Document "Protection System Reliability." To back up the failure of a circuit breaker to interrupt current, breaker failure circuitry is commonly used to initiate a trip signal to all circuit breakers that are adjacent to the failed breaker. On some bus arrangements, this may require transfer tripping to one or more remote stations.

Remote Backup

The remote backup method provides backup by using the Protection Systems at a remote substation to initiate clearing of faults on equipment terminated at the local substation. Figure 3.1 depicts use of the terms "local" and "remote" in the context of this discussion.

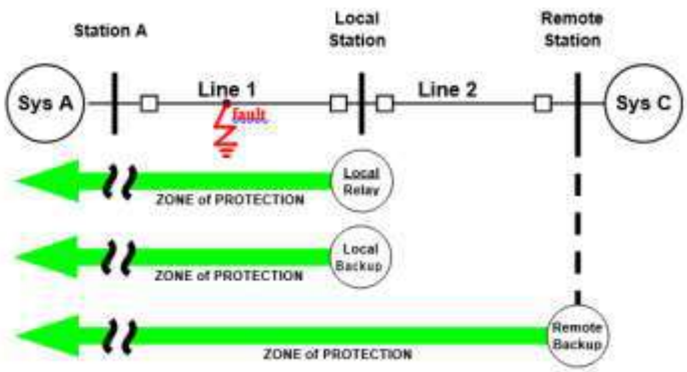


Figure 3.1: Definition of Local and Remote Backup as Applied to Transmission Lines

[5] https://ieeexplore.ieee.org/document/5469478

Remote backup may be used to provide protection for single or multiple Protection System failures or failures of circuit breakers to interrupt current at the local substation. When remote backup is used to provide backup protection for a single Protection System failure or a failure of a circuit breaker to interrupt current, the relays at the remote station are set sensitive enough that they can detect all faults that should be cleared from the adjacent (local) substation for which backup protection is being provided. Remote backup may provide an additional benefit of protecting for multiple Protection System failures, but the relays at the remote station may not be set sensitive enough that they can detect all faults that should be cleared from the local substation.

When remote backup can be set to meet system performance requirements it can provide complete Protection System redundancy since it shares no common components with the local relay system. The remote backup protection is intentionally set with time delay to allow the local relaying enough time to isolate the faulted Elements from the power system prior to the remote terminals operating. The remote backup protection covers the failure of a Protection System and/or the failure of a circuit breaker to interrupt current.

Chapter 4: Advantages and Disadvantages of Local and Remote Backup Protection

Advantages of Local Backup Protection Systems

System disruption - For the failure of the local Protection System or the circuit breaker, local backup protection usually isolates a smaller portion of the transmission grid as compared to remote backup protection.

Relay loadability – Local backup protection generally has no effect on relay loadability because it is set similarly to the primary system. Local backup does not require as sensitive a setting as remote backup and therefore is less susceptible to loadability concerns.

Tripping on Stable System Swings – Local backup protection is less susceptible to operation for stable power swings for the same reasons it is less susceptible to loadability concerns.

Speed of operation – Generally, local backup Protection Systems can be set to operate more quickly than remote backup Protection Systems.

Disadvantage of Local Backup Protection Systems

Multiple Local Protection System Failures – Providing redundant Protection Systems does not eliminate the possibility of all common mode failures. A well designed fully redundant local Protection System can fall short when multiple local Protection System failures occur.

Advantages of Remote Backup Protection Systems

Common Mode Failures – Use of remote backup systems, because of their physical separation, minimizes the probability of delayed clearing or failure to clear a fault due to a common mode failure.

Multiple Protection System Failures – Remote backup can, in some cases, provide a safety net to limit the extent of an outage due to multiple local Protection System failures. This is especially significant for low-probability scenarios that exceed design criteria.

Reduced Reliance on Telecommunication – Remote backup protection generally does not rely on telecommunication between substations.

Disadvantages of Remote Backup Protection Systems

Slow Clearing – Remote backup generally requires longer fault clearing times than local backup to allow the local Protection System to operate first.

Wider-Area Outage for Single Failures – For a single Protection System failure, remote backup generally requires that additional Elements be removed from the power system to clear the fault versus local backup. Depending on the scenario, this can have the added impact of de-energizing the local substation and interrupting all tapped load on the lines that are connected to the substation where the relay or breaker fails to operate.

Relay loadability – The desired setting of remote backup is more likely to conflict with the relay loadability requirements than local backup.

Tripping on Stable System Swings – Remote backup is more susceptible to tripping during stable system swings because this application typically requires relay settings with longer reach or greater sensitivity than local backup.

Difficult to Detect Remote Faults – It is more difficult and more complicated to set remote backup protection to detect all faults in the protected zone for all possible system configurations prior to a fault.

Difficult to Study – It is generally more difficult to study power system and Protection System performance for a remote backup actuation. This is because more power system Elements may trip. Tripping may be sequential, and reclosing may occur at different locations at different times. For example, tapped loads may be automatically reconfigured and prolonged voltage dips that may occur due to the slow clearing may cause tripping due to control system actuations at generating plants or loads. It is very difficult to predict the behavior of all control schemes that may be affected by such a voltage dip; thus it is very difficult to exactly predict the outcome of a remote backup clearing scenario.

Chapter 5: System Performance Requirements

The Bulk Electric System must meet the performance requirements specified in the Transmission Planning (TPL) standards when a single Protection System failure or a failure of a circuit breaker to interrupt current occurs. When a single Protection System failure or failure of a circuit breaker to interrupt current prevents meeting the system performance requirements specified in the TPL standards, either the Protection System or the power system design must be modified.

When time delayed clearing of faults is sufficient to meet reliability performance requirements, owners have the option to deploy either two local systems or one local system and a remote backup system to meet reliability levels. In either case, the Protection Systems must operate and clear faults within the required clearance time to satisfy the system performance requirements in the TPL standards.

Backup protection may also function as a safety net to provide protection for some conditions that are beyond the system performance requirements specified in the TPL standards. When used as a safety net, backup protection may be designed to protect against a specific multiple Protection System failure or failures of circuit breakers to interrupt current. Backup protection may also be designed to limit the extent of disturbances due to unanticipated multiple Protection System failures or failures of circuit breakers to interrupt current. When backup is applied as a safety net it must meet the requirements of current NERC standards related to relay loadability, Protection System coordination, and system performance requirements during a single Protection System failure or failure of a circuit breaker to interrupt current. Future standards related to Protection System performance during stable system swings may also affect the use of backup protection and provide further guidance on assessing relay response during stable swings. When remote backup is applied as a safety net it may be appropriate to place a greater emphasis on security over dependability.

Function of Local Backup

The main function of local backup is to address a single local Protection System failure or failure of a circuit breaker to interrupt current. The redundancy provided by local backup inherently addresses single Protection System failures while minimizing the impact to the system. Local backup may address some failures of multiple Protection Systems, but generally will not address these failures to the extent of a remote backup scheme.

Breaker failure is a form of local backup that must be studied per NERC Planning Standards. The effects of a breaker failure operation must be studied to determine that system performance requirements are met. It is common throughout the industry to apply local breaker failure protection for transmission level circuit breakers.

Function of Remote Backup:

Remote backup can play a role in addressing single or multiple Protection System failures or failures of circuit breakers to interrupt current.

For addressing a single Protection System failure or failure of a circuit breaker to interrupt current, local backup is generally preferred to remote backup for many of the reasons stated above. However, certain configurations lend themselves to the use of remote backup while minimizing the disadvantages of using remote backup. Examples are discussed later in this document.

Multiple Protection System failures may not be anticipated or studied. The degree to which protection designs can detect faults under the condition of multiple Protection System failures varies based on a company's design practices, system topology, and a number of other factors.

Remote backup protection can provide a safety net minimizing the impact of unanticipated conditions caused by multiple Protection System failures to a greater degree than that afforded by local backup protection only.

Multiple failures due to more common combinations of single Protection System failures and/or failures of circuit breakers to interrupt current occurred in a number of the examples of post-2003 events discussed below.

Chapter 6: Post-2003 Events Involving Backup Protection

2008 Florida Event

Description of the 2008 Florida Event

On February 26, 2008, a system disturbance occurred within the FRCC Region that was initiated by delayed clearing of a three-phase fault on a 138 kV switch at a substation in Miami, Florida. According to the report "FRCC System Disturbance and Underfrequency Load Shedding Event Report February 26, 2008 at 1:09 p.m." it resulted in the loss of 22 transmission lines, approximately 4,300 MW of generation and approximately 3650 MW of customer load. The local primary protection and local backup breaker failure protection associated with a 138 kV switch had been manually disabled during troubleshooting. The fault had to be isolated by remote clearing because the local relay protection had been manually disabled.

Backup Protection and the Florida Event:

The report states "The 230 kV/138 kV autotransformers at Flagami do not utilize phase overcurrent or impedance backup protection. Although there are no current industry requirements for this type of protection, the autotransformers offer a position to install additional local relaying that could be used to isolate the 230 kV system from faults on the 138 kV system." Furthermore the investigation recommends "NERC should assign the System Protection and Control Task Force to produce a technical paper describing the issue and application of backup protection of autotransformers." The lack of autotransformer backup protection that contributed to this event was addressed by the installation of new protection equipment after this event.

2004 West Wing Substation Event

Description of the 2004 West Wing Substation Event:

Another significant event where fault clearing times and the extent of outages could have been improved by the use of local backup or planned remote backup protection was the West Wing event on June 14th, 2004. In this event, a 230 kV line faulted to ground. The relay system for the faulted 230 kV line was designed with a single auxiliary tripping relay. This relay was used for tripping of the 230 kV line breakers and breaker failure initiation. The single auxiliary relay failed. Remote backup clearing with clearing times of 20 to 40 seconds was required to clear the fault. The remote clearing required in this case resulted in the loss of ten 500 kV lines, six 230 kV lines, and over 4,500 MW of generation (including three nuclear units) per the initial WECC communication on the event. A couple of weeks after the event, several of the single-phase 500/230 kV autotransformers involved in the event failed catastrophically.

Backup Protection and the West Wing Event:

The first recommendation from the Arizona Public Service (APS) report "June 14, 2004 230 kV Fault Event and Restoration" was to add backup protection to the 500/230 kV autotransformers involved in the event. The report states that had backup protection been installed on the 500/230 kV autotransformers that the fault would have been cleared significantly faster and damage would have been prevented, and this remote backup "would have prevented the disturbance from being cleared within the 500 kV system".

Additionally, if the local protection scheme at West Wing included fully redundant systems with redundant auxiliary tripping relays, this event could have been mitigated.

Both the lack of remote backup protection and the lack of redundant local protection that contributed to this event were addressed by the installation of new protection equipment after this event.

2007 Broad River Event

Description of the 2007 Broad River Event:

Another event where remote backup protection played a key role was the August 25, 2007 Broad River Energy Center Event. In this event, a 230 kV generator step-up transformer bushing failed and faulted to ground. The relay system for the faulted 230 kV transformer was designed with a single auxiliary tripping relay. The single auxiliary relay failed. Remote backup protection cleared the fault in about 0.5 seconds. The remote clearing in this case resulted in the loss of four 230 kV transmission lines and three Broad River Energy Center Units. In addition, one 230 kV transmission line tripped due to a failed relay, two generating units tripped due to incorrectly coordinated backup protection settings, and two generating units tripped due to low station auxiliary bus voltage during the fault.

Backup Protection and the Broad River Event:

Recommendations from the NERC investigation report for this event included installing redundant relaying for the generator step-up transformer that sustained the fault. This recommendation has been implemented.

The overall effects of this event to the power system were minor compared to the Florida or West Wing events. However, this event does illustrate that when remote backup is applied to meet system performance requirements during single Protection System failures, the highest degree of coordination of Protection Systems and knowledge of system reactions to sustained low transmission level voltage is needed.

2006 Upper New York State Event

Description of the 2006 Upper New York State Event:

The last event is a near miss event that occurred in New York State on March, 29, 2006 in the switchyard for a hydro plant. In this event, a ground fault occurred on the 13.8 kV side of a 115/13.8/13.8 kV transformer due to raccoon contact. The fault quickly evolved into a 3-phase to ground fault on the 115 kV side of the transformer. One of the 115 kV circuit breakers required to clear the 13.8 kV and 115 kV faults failed. Breaker failure was initiated to clear the fault via the surrounding circuit breakers; however, one of these breakers failed to clear for about 5 seconds resulting in a double breaker failure for 5 seconds. During this time, all 14 in-service hydro units at the connected plant tripped on backup phase distance relays. The switchyard at this location also included a number of 230/115 kV autotransformers and 230 kV lines. The 230/115 kV autotransformer relay schemes in this area were not designed with phase backup protection that could detect this 115 kV fault. The delayed clearing in this event resulted in the loss of the 14 units at the hydro plant, numerous smaller hydro-generating facilities throughout northern New York, and one unit in Ontario, totaling 1,200 MW, as well as various equipment in the connected switchyard.

Backup Protection and the Upper New York State Event:

Recommendations from the New York Power Authority (NYPA) investigation report for this event included considering whether to apply overcurrent backup protection on autotransformers. A decision whether to add backup overcurrent protection has not been made at this time.

The overall effects of this event to the power system were minor compared to the Florida or West Wing events. However, this event is a good illustration of the type of unanticipated failure event where remote backup protection can provide a safety net that may limit the extent of an outage.

Chapter 7: Examples

The following sections provide a number of examples of backup protection applied to transmission lines and transformers. It is important to note that these examples were selected to illustrate concepts discussed in the paper and are not intended to be prescriptive or to suggest a preferred method of transformer protection, nor are they inclusive of all possible methods for providing backup protection. The protection system design (e.g., CT and PT primary connections) and settings derived in these examples are only for illustrative purposes.

Remote Backup Protection on Transmission Lines

Protection Systems applied to transmission lines commonly include elements which provide remote backup protection. The most common type of remote backup protection for phase faults on transmission lines is phase distance relaying with fixed time delay. The most common methods to provide remote backup for ground faults are by using ground distance relays with fixed time delay, ground time overcurrent relays with inverse time-current curves, or a combination of both. Phase faults generally affect the system to a higher degree than ground faults and phase relays are more susceptible to tripping than ground relays for severe system conditions.

The following series of examples focus on phase faults and illustrate some of the complexities of using remote backup protection as outlined above. Examples 1, 2, and 3 illustrate the complexity of applying remote backup protection to meet NERC system performance requirements during a single Protection System failure. In these examples the line terminals do not have local backup protection. Figure 7.1 is used to illustrate application of remote backup protection for breaker failure protection. In this example the line terminals have local backup protection.

Example 1

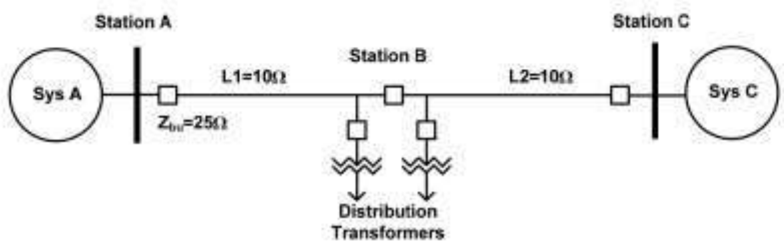


Figure 7.1: Simple Three-Station, Two-Line System Used in Example 1

The simple system of two lines in Figure 7.1 shows the configuration under consideration in this example. In this case, the backup zone at the Station A line terminal can be set to cover phase and ground faults on the transmission line between Stations B and C and provide remote backup for any single transmission line Protection System related component failure. For this configuration, source impedances behind Stations A and C are not important.

For this example, using a 25% margin, the backup relay reach at Station A necessary to detect all faults on line L2 is Z_{bu} = 1.25 (L1 + L2) = 25 Ω

Complexities

If a time delay of 0.7 to 1.0 seconds is assumed, remote backup clearing would be slower than a local breaker failure scheme with transfer trip from Station B to Station A. A transient stability simulation may be necessary to verify that this clearing time results in a system response that meets performance requirements. In many cases similar to this example the remote backup can be set within the loadability requirements of PRC-023, will not reach through the distribution transformers, and will provide adequate backup protection for Protection System failures at Station B.

The simple system of three lines in
Figure 7.2 shows the configuration under consideration in this example.

Example 1A

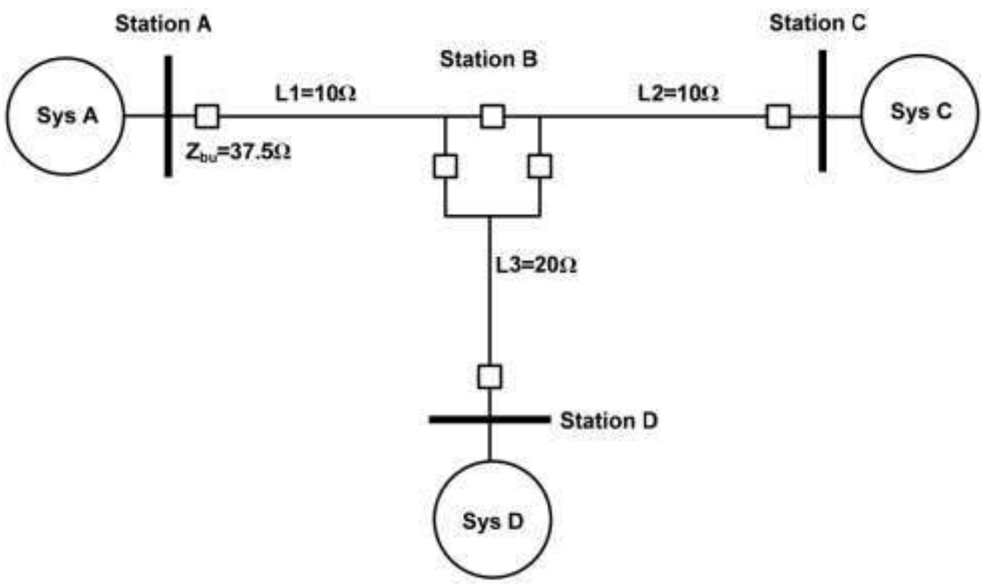


Figure 7.2: Simple Four-Station, Three-Line System Used in Example 1A

In this case, all of the line terminals have local backup protection for line faults as defined in section 3. Thus, a backup zone at the Station A line terminal may be designed to provide protection to address a couple of different situations:

1. The breaker failure protection scheme for the breakers at Station B is designed with local breaker failure but without breaker failure transfer trip communications capability from Station B to Station A. Due to the lack of transfer trip communications, the backup zone at Station A is designed to provide backup protection for faults on lines BC or BD with a breaker failure at Station B. Because the Station B breakers have local breaker failure protection, the Station A relay can be set to cover phase and ground faults on the transmission line between Stations B and C or B and D without considering apparent impedance (i.e., the local breaker failure operation at station B will open the other two breakers and remove the infeed). The owner of this scheme has decided to use backup instead of installing a transfer trip channel. This backup setting will also provide some protection for multiple Protection System failures of line BC or BD relaying. For this configuration and application, source impedances behind Stations A, C and D are not important.
2. The breaker failure protection scheme for the breakers at Station B is designed with local breaker failure and breaker failure transfer trip communications capability from Station B to Station A. The backup zone at Station A is designed to provide backup protection for faults on lines BC or BD with a breaker failure and a loss of transfer trip communications at Station B. Similar to the first situation, because the Station B breakers have local breaker failure protection, the Station A relay can be set to cover phase and ground faults on the transmission line between Stations B and C or B and D without considering apparent impedance for this application. This application protects for a situation that is beyond a single Protection System failure or failure of a circuit breaker to interrupt current and is thus not required to meet system performance requirements.

The owner of this scheme has decided to apply backup as a safety net and may have decided to apply this type of backup based on past experiences or events. This backup setting will also provide some protection for multiple Protection System failures of line BC or BD relaying. For this configuration and application, source impedances behind Stations A, C and D are not important.

For this example, using a 25% margin, the backup relay reach at Station A necessary to detect all faults on line L3 is $Z_{bu} = 1.25\ (L1 + L3) = 37.5\ \Omega$.

Complexities

If a time delay of 0.7 to 1.0 seconds is assumed, remote backup clearing would be slower than a local breaker failure scheme with transfer trip from Station B to Station A. When the system is designed without transfer trip capability, a transient stability simulation may be necessary to verify that this clearing time results in a system response that meets performance requirements. In many cases similar to this example the remote backup can be set within the loadability requirements of PRC-023, will not reach through the distribution transformers, and will provide adequate backup protection for breaker failures at Station B and some line Protection System failures at Station B. Figure 7.3 illustrates the increased backup protection reach in this example compared to Example 1.

Example 2

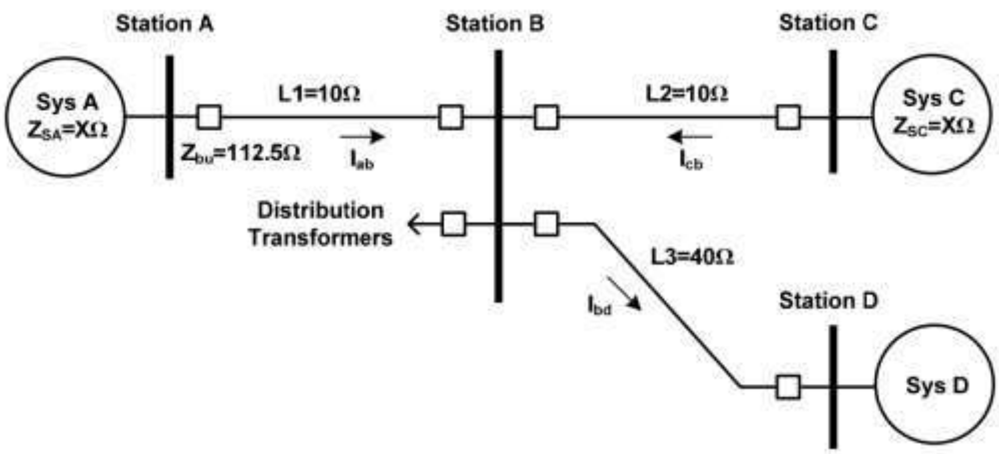


Figure 7.3: Four-Station, Three-Line System Used in Example 2

Example 2 is complicated compared to Example 1A by the presence of a longer line between Stations B and D and the distribution transformers at bus B. For this configuration, source impedances behind Stations A and C are assumed to be equal. The source impedance behind Station D is not important in this simple system. In this case, a fault on L3 near Station D would be difficult to detect from Station A without overreaching for faults beyond Station C or seeing through the distribution transformers.

The apparent impedance seen by the relay at Station A is: $Z_{bu} = V_a/I_{ab} = ((I_{ab} \times L1) + (I_{bd} \times L3))/I_{ab} = L1 + (I_{bd}/I_{ab}) \times L3$
Given the symmetry of the example system, $I_{ab} = I_{cb}$, and thus $I_{bd} = 2Iab$

For this example, using a 25% margin, the backup relay reach at Station A necessary to detect all faults on line L3 is $Z_{bu} = 1.25\ (L1 + 2L3) = 112.5\ \Omega$.

If the source impedance of System A could be higher for certain system conditions, the setting would need to be increased accordingly.

Complexities

In this case, such a large setting at Station A may detect distribution level faults at Station B. A time delay of 0.7 to 1.0 seconds would be required to coordinate with remote relaying at Stations B and C given that the Station A backup zone will likely detect all faults on L2 and may look far past Station C, especially when L3 is out of service. The longer time to clear may also cause power quality issues for the loads at Stations A, B, or C that in the worst case may result in local loss of load. In many cases similar to this example it may not be possible to set the remote backup within the loadability requirements of PRC-023 without the use of some form of load encroachment. The larger setting might also be more susceptible to tripping on stable system swings. A transient stability simulation may be necessary to verify that this clearing time results in a system response that meets performance requirements. **Figure 7.4** illustrates the increased backup protection reach in this example compared to Examples 1 and 1A.

Example 3

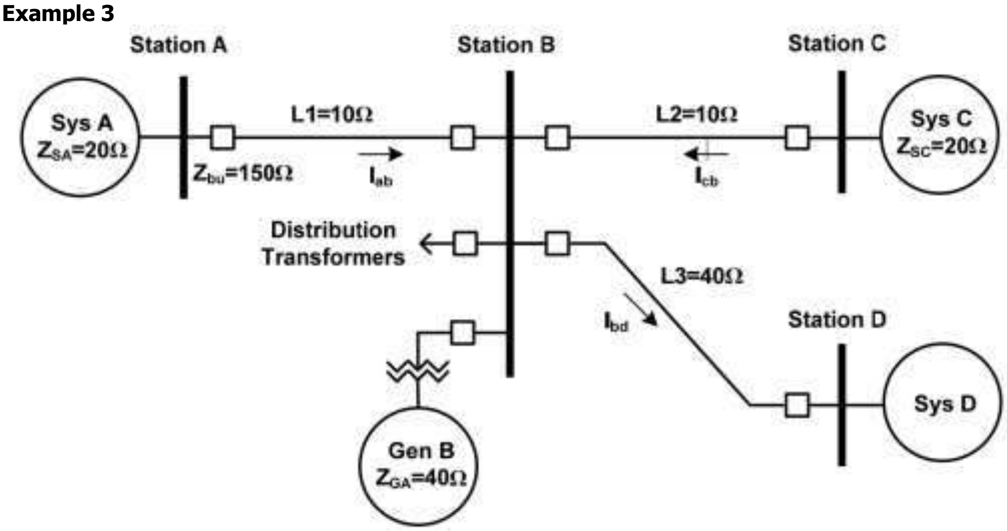


Figure 7.4: Four-Station, Three-Line System Used in Example 3

Example 3 is further complicated compared to Example 2 by the presence of a generator at Station B. For this configuration, source impedances behind Stations A and C are assumed to be equal at 20 Ω with a reasonable system contingency source outage behind Station A. The impedance of the generator at Station B (including the generator step-up transformer) is assumed to be equal to 40 Ω. The source impedance behind Station D is not important for this example and can be ignored. In this case, a fault on L3 near Station D would be more difficult to cover.

The apparent impedance seen by the relay at Station A must be calculated:

For the given fault, System A + L1 is in parallel with System C + L2, and the combination of these two systems is in parallel with Generator B, with all three systems in series with L3,

Or

The equivalent impedance of these systems is 30 Ω is in parallel with 30 Ω, in parallel with 40 Ω, + 40 Ω = 50.9 Ω

For fault near Station D on a 138 kV system, the total fault contribution from System A, System C, and Generator B is 1571 A.

The fault current contribution at Station A is 571 A and the line-to-ground voltage is 68.550 kV.

The apparent impedance at Station A for the L1 line relay is ~120 Ω

For this example, using a 25 percent margin, the backup relay reach at Station A necessary to detect all faults on line L3 is Z_{bu} = 1.25 (120) = 150 Ω
Additionally, the voltage on the Station B 138 kV bus is ~ 0.82 per unit.

Complexities

In this case, such a large setting at Station A may detect distribution level faults at Station B. A time delay of 0.7 to 1.0 seconds may be required to coordinate with remote relaying at Stations B and C given that the Station A backup zone will likely detect all faults on L2 and may look far past Station C, especially when L3 is out of service and/or Generator B is out of service. Thus, remote backup clearing would be much slower than local backup clearing. The longer time to clear may cause power quality issues for the loads at Stations A, B, or C that in the worst case may result in local loss of load. The longer time to clear and resulting lower voltage dip at the Station B bus may also cause an issue for the auxiliary equipment at Generating Station A that could result in a loss of generation. In many cases similar to this example it may not be possible to set the remote backup within the loadability requirements of PRC-023 without the use of some form of load encroachment. The larger setting might also be more susceptible to tripping on stable system swings. A transient stability simulation may be necessary to verify that this clearing time results in a system response that meets performance requirements.

In general, a system such as shown in **Figure 7.4** requires much greater care and study to ensure adequate system performance prior to implementation than a system that uses local backup to cover for faults on L3. Additionally, much greater care is required as the system changes over time to ensure that the remote backup system for Example 3 still provides adequate fault coverage while meeting system performance requirements. **Figure 7.5** illustrates the increased backup protection reach in this example compared to Examples 1, 1A, and 2. It must be noted that the line lengths in the various examples were purposely picked to illustrate the effects that apparent impedance can have on remote backup settings. The extent to which relay reach must be increased for actual configurations may be more or less than shown in these examples.

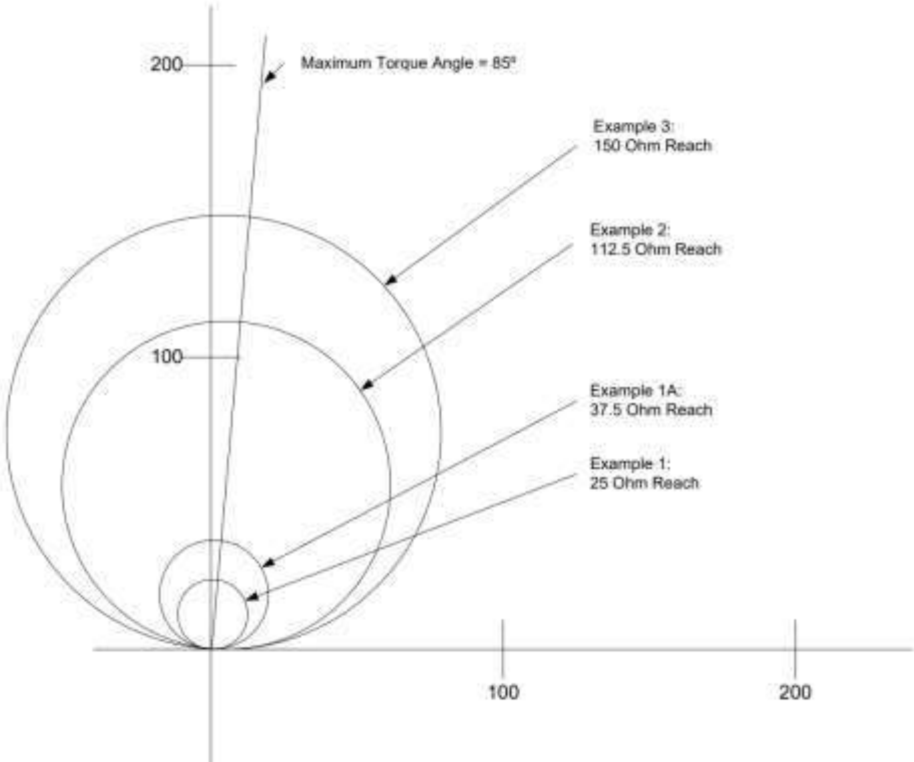


Figure 7.5: Comparison of Backup Protection System Reach for Examples 1, 1A, 2, and 3

Backup Protection on Autotransformers

Applying phase backup protection on autotransformers is not as common as applying remote backup on transmission line terminals. Backup protection on transformers can be applied as backup for faults on both the high side and low side voltage levels and is commonly applied to protect transformers for uncleared faults.

The system events involving multiple voltage levels described in Section 6 were all related to faults on equipment on lower voltage systems (115 kV or 230 kV). These events support the general observation that the level of redundancy of protection on higher voltage level circuits is usually greater than that on the lower voltage circuits connected to autotransformers. Some lower voltage lines may not have local redundancy at all and the use of backup protection on the transformers may provide additional protection for uncleared faults.

Autotransformer backup may be designed to clear faults due to single relay failures or as a safety net. **Figure 7.6** provides examples of the safety net protection coverage that may be achieved for two possible system configurations. In the second configuration, the reach of the backup protection will be reduced by roughly one-half versus the first configuration due solely to the paralleled equivalent contributions of the two transformers. When autotransformer backup protection is counted on to clear faults due to single relay failures, it is subject to meeting system performance requirements and subject to many of the same limitations as remote backup on transmission lines. When lower voltage systems are fully redundant, autotransformer backup can provide a safety net to limit damage to the low voltage system and isolate the low voltage system from the high voltage system for slow clearing faults due to multiple Protection System failures or failures of circuit breakers to interrupt current.

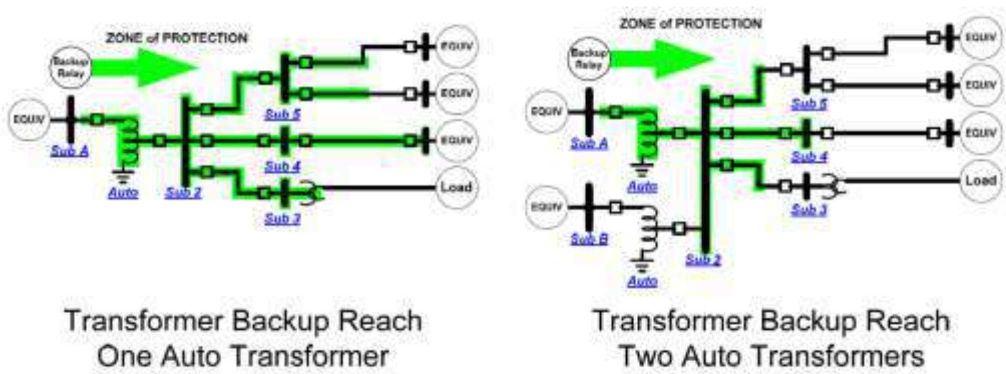


Figure 7.6: Safety Net Backup Protection Reach

Since the cited system events involving multiple voltage levels were related to faults on the lower voltage systems, the discussion on autotransformer backup will focus on backup applied to detect faults on the low voltage side of the autotransformer. The discussion will also be geared toward phase faults since phase faults generally negatively affect the system to a higher degree than ground faults and most transformer Protection Systems include ground backup protection. Additional reasons to focus on phase faults are that slow clearing ground faults can migrate into phase faults, and phase relays are more susceptible to tripping due to loadability issues than ground relays for severe system loading conditions.

Various methods may be utilized to protect and clear an autotransformer for phase faults external to an autotransformer. Three common types of phase backup protection for autotransformers to be discussed in this paper with examples are: phase time overcurrent relays; phase time overcurrent relays torque controlled by phase distance relays and phase instantaneous relays; and phase distance and phase instantaneous relays with fixed time delays. A fourth type of backup that can be applied on a transformer low side to provide backup protection for low side bus or close-in fault protection failure that has little complexity is a limited reach distance function. This application does not have relay loadability issues that may be associated with other methods. Additional discussion on transformer backup protection is provided in the IEEE Guide for Protective Relay Applications to Power Transformers (IEEE C37.91).

A very inverse time overcurrent curve will be used in the examples in this paper. Other types of curves have different advantages and disadvantages which are outside the scope of this paper and require similar considerations.

Example Autotransformer Data:

- 345(wye)/34(delta)/138(wye) kV with no delta connected load
- 300 MVA maximum nameplate for the 345/138 winding
- 1250 A nameplate at 138 kV and 500 A nameplate at 345 kV
- Maximum 138 kV 3-phase fault = 20,000 A ($Z_{TR} \sim 4\ \Omega$ @ 138 kV)
- This transformer has been determined to be critical by the Planning Coordinator and
- is thus subject to PRC-023 limitations

Relay Settings Based on a Simple System

A phase protective relay could be applied on either the high or the low side of the autotransformer. For the examples that follow, the current elements of all of the phase protective relays are connected to current transformers on the high side of the transformer such as in **Figure 7.7**. Thus, these relays also may provide backup protection for faults on the transformer high side and tertiary windings. In many cases, 3-phase potential devices are only available on the low side of the transformer so the phase distance relays are applied on the 138 kV side of the transformer. This also allows for a better reach of the phase distance relay into the 138 kV system as this connection does not result in the Protection System detecting the voltage drop through the transformer for 138 kV faults.

A desirable goal is to create a generic method for setting the phase protection relays that provides adequate backup protection, coordinates with other system relays, provides adequate overload protection for uncleared through-faults, will not trip on transformer inrush, and meets the loadability limitations of PRC-023-1. It may not be possible to meet all of these goals for all configurations of some systems. Two examples (a simple system and a more complex system) illustrate some of these limitations.

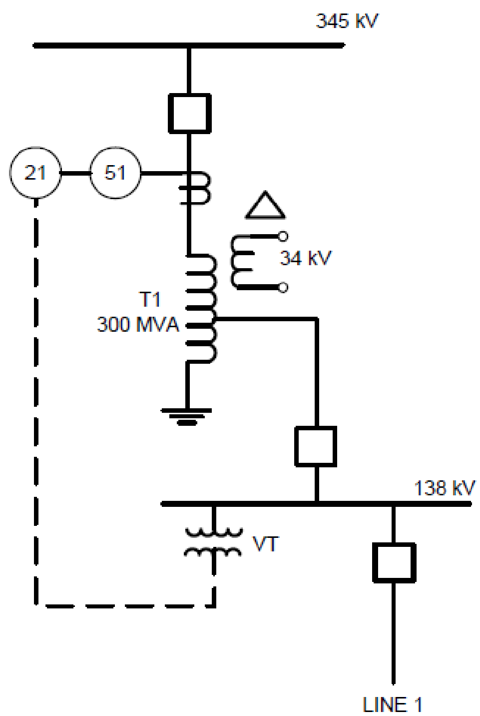


Figure 7.7: Simple System One-Line Used in Transformer Protection Example

Example 4: Phase Time Overcurrent Relay Setting

In this example PRC-023 limitations for phase responsive transformer relays will dictate the minimum pickup setting of the relay. These limitations are:

- 150% of the applicable maximum transformer nameplate rating (expressed in amperes), including the forced cooling ratings corresponding to all installed supplemental cooling equipment.

- 115% of the highest operator established emergency transformer rating.

Assuming there are no operator established emergency transformer ratings for this transformer, the minimum pickup for this relay is limited to 150% of 300 MVA. On the 345 kV side this translates to ~ 750 A. Adding a minimum of additional margin and creating a setting that could likely be used for electromechanical relays with limited tap selections, the minimum pickup will be set to 800 A (about 2000 A at 138 kV).

To coordinate with local 138 kV breaker failure for close-in faults (typical 10 cycle breaker failure relay time is assumed), the minimum time to trip must be at least 0.4 second. This tripping speed also ensures that this relay trips faster than remote backup protection on the high voltage system (1 second is assumed) that may also detect low voltage system faults (especially close-in low voltage system faults). Thus, a time lever of 3 is chosen. Using the very inverse curve, the time for the relay to initiate a trip will then be about 0.4 second for a 20,000 A 138 kV fault, 0.77 second for a 10,000 A 138 kV fault and 1.74 seconds for a 6,000 A 138 kV fault. Coordination must be verified between these fault clearing times and the 138 kV line L1 protection (see **Figure 7.7**). The clearing times in this example were selected because they will coordinate with typical transmission line protection settings, will be secure during transformer inrush conditions, and are faster than required to coordinate with the transformer through-fault damage curve shown in IEEE Standard C37.91- 2000.

Example 5: Torque Controlled Phase Time Overcurrent Settings

For the relay in **Figure 7.8**, a mho phase distance element and a phase instantaneous overcurrent element both torque control a phase time overcurrent. The phase time overcurrent element will not pick up and start timing until the mho phase distance element or the phase instantaneous overcurrent element picks up first. This allows a more sensitive phase time overcurrent setting than a pure phase time overcurrent relay since the phase time overcurrent relay is not subject to the loadability limitation. The phase instantaneous element is needed in addition to the phase distance element to cover for 138 kV bus faults and other close-in faults where the phase distance element may lose memory voltage and drop out prior to fault clearing given that the phase distance element is connected to the 138 kV potential device.

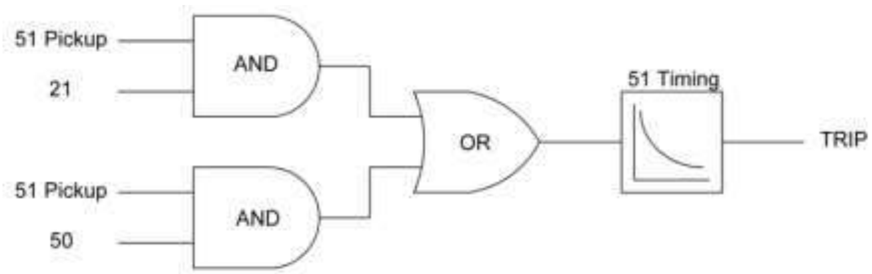


Figure 7.8: Logic Diagram for Application of Phase Time Overcurrent Elements Torque Controlled by Phase Distance and Instantaneous Phase Overcurrent Elements

Phase Distance Element Setting

Assuming there are no operator established emergency transformer ratings for this transformer, the same PRC-023 limitation (150% of maximum nameplate rating) will limit the reach of the phase distance relay. Using the NERC criteria and assuming the relay uses a mho characteristic,

Max Allowable Setting = $_{Zrelay@30}$ = $(0.85*V_{relay})/(1.732*I_{Nameplate}*1.5)$

where V_{relay} = phase-to-phase line voltage at the relay location

and $I_{Nameplate}$ = 1250 A

To make the loadability of this setting equivalent to the time overcurrent for comparison purposes, we will use 800 A at 345 kV (2000 A at 138 kV) instead of $I_{Nameplate}$*1.5 (750 A at 345k V or 1875 A at 138 kV) to determine the loadability limitation. This limits $Z_{relay@30}$ to about 34 Ω at 138 kV. Since this relay is subject to PRC-023, this relay will be set with a 90 degree torque angle to maximize loadability. Thus $Z_{relay@90}$ is set to 68 Ω ($Z_{relay@90} = Z_{relay@30}/\cos(90-30)$). A typical 138 kV line impedance angle is 75 degrees. The reach at the 75 degree line angle is 68*cos(15) = 66 Ω.

Phase Instantaneous Overcurrent Element Setting

If high side potentials are available and used for the phase distance element, this element may not be required. The use of high side potentials to feed a distance relay does, however, limit the reach of the relay into the lower voltage system. The examples in this document are based on use of low side potential devices, so this element is included in this example as a method for assuring reliable operation for close-in low side faults when the phase distance relays do not have sufficient memory polarization for the duration of a zero voltage fault.

The instantaneous phase element setting is required for close-in three-phase faults where the phase distance relay may not operate because of very low voltage. Thus, sensitivity is not a great concern. Set this element to 225% of transformer nameplate to provide ample margin above emergency loading or roughly 1200 A at 345 kV (3000 A at 138 kV).

Phase Time Overcurrent Setting:

The phase time overcurrent minimum pickup is not subject to loadability limitations because the phase distance and instantaneous phase overcurrent relays that provides the torque control meets the loadability requirement; however, it may be desirable to provide additional security. For this example, the relay is set at 500 A at 345 kV (corresponding to the transformer nameplate rating) as a balance between security and sensitivity.

To coordinate with local 138 kV breaker failure for close-in faults, the minimum time to trip must be at least 0.4 second. This tripping speed also ensures that this relay trips faster than remote backup protection on the high voltage system (1 second is assumed) that may also detect low voltage system faults (especially close-in low voltage system faults). Thus, a time lever of 3.5 is chosen. Using the very inverse curve, the time to trip for selected 138 kV faults will then be about 0.39 second for a 20,000 A fault, 0.55 second for a 10,000 A fault, and 0.96 second for a 6,000 A fault. Coordination must be verified between these fault clearing times and the 138 kV line L1 protection (see **Figure 7.7**). The clearing times in this example were selected because they will coordinate with typical transmission line protection settings, will be secure during transformer inrush conditions, and are faster than required to coordinate with the transformer through-fault damage curve shown in IEEE Standard C37.91-2000.

Example 6: Phase Distance and Instantaneous Phase Overcurrent with Fixed Timers Settings

For the relay in **Figure 7.9**, a mho phase distance element tripping through a fixed timer is used. When the potential is provided from the low side of the transformer, the phase distance element is supplemented by an instantaneous phase overcurrent relay that also trips through the fixed timer.

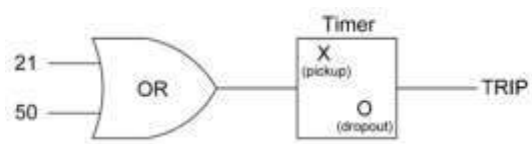


Figure 7.9: Logic Diagram for Application of Phase Distance and Instantaneous Phase Overcurrent Elements with Fixed Timers

Phase Distance Element Setting

Assuming there are no operator established emergency transformer ratings for this transformer, the same PRC-023 limitation (150% of maximum nameplate rating) will limit the reach of the phase distance relay. Using the NERC criteria and assuming the relay uses a mho characteristic,

Max Allowable Setting = $Z_{relay@30}$ = ($0.85*V_{relay}$)/($1.732*I_{Nameplate}*1.5$)

where V_{relay} = Phase-to-phase line voltage at the relay location

and $I_{Nameplate}$ = 1250 A

To make the loadability of this setting equivalent to the unsupervised phase time overcurrent for comparison purposes, we will use 2000 A instead of $I_{Nameplate}*1.5$ (1875 A) to determine the loadability limitation. This limits $Z_{relay@30}$ to about 34 Ω. This relay will be set with a 90 degree torque angle to maximize reach while meeting the loadability limitation. Thus $Z_{relay@90}$ is set to 68 Ω ($Z_{relay@90} = Z_{relay@30}$/cos (90-30)). A typical 138 kV line impedance angle is 75 degrees. This reach at the 75 degree line angle is 68*cos(15) = 66 Ω.

Instantaneous Phase Overcurrent Element Setting

If high side potentials are available, this element may not be required. The use of high side potentials to supply a distance relay does, however, limit the reach of the relay into the lower voltage system. The examples in this document are based on use of low side potential devices, so this element is included in this example.

The instantaneous phase element setting is required only for close-in three-phase faults where the phase distance relay may not operate because of very low voltage. Since for this example the main concern is with using this element to protect for close-in 138 kV faults (approximately 8000 A at 345 kV for a 138 kV bus fault) and the distance element will provide sensitivity for more remote faults sensitivity for this element is not a great concern. Set this element to 800 percent of transformer nameplate to provide security for transformer inrush or roughly 4000 A at 345 kV (10,000 A at 138 kV).

Fixed Timer Settings

Ideally, this timer is set slower than the longest 138 kV line backup protection time and faster than any 345 kV line backup protection that reaches into the 138 kV system.

In practice, 345 kV relaying may not be able to detect 138 kV faults under normal conditions. If so, the timer should be set slightly higher than the longest 138 kV line backup protection time. Assuming a maximum 138 kV line backup time of 1.0 second, this relay may be set at 1.2 seconds.

If 345 kV relays are able to detect 138 kV faults under normal conditions, coordination with 345 backup protection may not be possible. In this case, the Transmission Owner must choose a specific time based on careful consideration of the consequences of the possible tripping sequence that might occur when a 138 kV fault is cleared in backup time or re-coordinate as necessary. Examples of this are shown in **Table 7.1** and **Table 7.2**.

Table 7.1: Simple System Setting and Reach Summary

	345 kV Side Setting	138 kV Side Setting	3-phase fault Reach into simple 138 kV system
Phase Time Overcurrent Only	800	2000	36 Ω
Torque Controlled Phase Time Overcurrent	500	1250	60 Ω
Distance Element	NA	66 Ω @ 75 degrees	66 Ω

Assumptions:

- 345 kV system is an infinite source
- 300 MVA transformer is 4 Ω at 138 kV
- Overcurrent Relay Setting = 80000/(4 + Reach in ohms)

Table 7.2: Simple System Setting and Time to Trip Summary			
	20,000 A 138kV Fault	**10,000 A 138kV Fault**	**6,000 A 138kV Fault**
Phase Time Overcurrent Only	0.4 seconds	0.77 seconds	1.74 seconds
Torque Controlled Phase Time Overcurrent	0.39 seconds	0.55 seconds	0.96 seconds
Distance Element with Fixed Timer	1.2 seconds	1.2 seconds	1.2 seconds

Commented [TC1]: Table needs formatting and referenced.

More Complex Systems

Most systems are not as simple as a single autotransformer feeding a single transmission line. Substations can have numerous transmission lines, multiple transformers in parallel, additional components such as shunt devices, and networked or looped lines. As the substation and its connected transmission system become more complex, so too does the application of backup protection.

A more complex system is shown in **Figure 7.10** consisting of two autotransformers operating in parallel each feeding its own bus. In this example the connected 138 kV transmission lines are networked with significant fault current sources. This substation has two autotransformers operating in parallel feeding four transmission lines. In this configuration, the reach of the backup protection will be reduced by roughly one-half versus the simple system example due solely to the paralleled equivalent contributions of the two 300 MVA transformers. If any of the connected lines are short and provide additional fault current source contributions, the reach will be less than one-half of the reach calculated for the simple system. This reach limitation must be factored into system performance analyses when the Protection System design relies on autotransformer backup to clear faults for single Protection System failures. **Figure 7.10** illustrates the impact on backup protection reach when multiple transformers are in parallel. In some cases it may be difficult, if not impossible, to achieve coordinated backup protection for more than close-in faults. In these cases the Transmission Owner may need to carefully consider the consequences of possible tripping sequences or re- coordinate where possible.

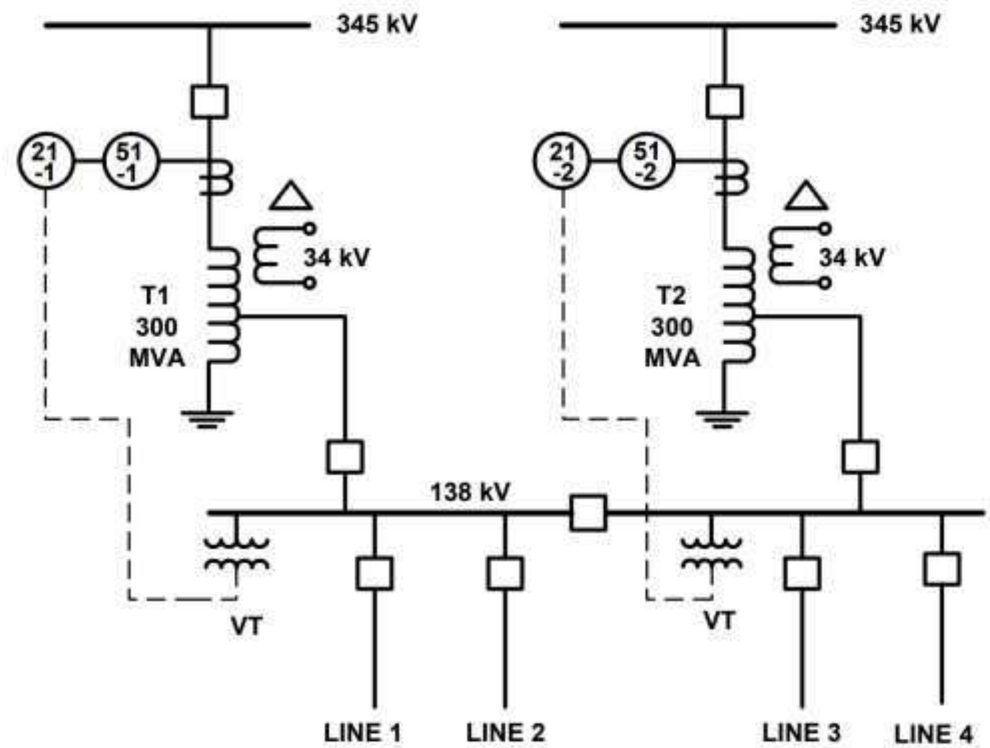


Figure 7.10: More Complex System One-Line Used in Transformer Protection Example

Another problem for autotransformer backup in more complex systems is the inability of the local backup Protection Systems on the two transformers to provide selectivity based on the location of faults. The Protection Systems on both transformers may react similarly and operate simultaneously for faults because they will have similar or identical relay settings. In some cases, it may be worthwhile considering backup protection that will split the bus to limit the number of system Elements interrupted, although for some bus configurations this may be impractical or add an undesired level of Protection System complexity. The relay practitioner will need to consider the application of backup Protection Systems applied on these complex systems and incorporate the appropriate degree of dependability and security to protect the assets and prevent degradation of reliability.

Chapter 8: Conclusions

Transmission system events have shown that backup protection can play a significant role in preventing or mitigating the effects of Protection System or equipment failures.

Local backup inherently addresses single Protection System failures or failures of a circuit breaker to interrupt current while meeting NERC performance requirements and generally reduces the number of Elements that must be removed from the power system to clear the fault. Local backup may address some failures of multiple Protection Systems, but generally will not address these failures to the extent of a remote backup scheme. Remote backup may also adequately perform this function and can also act as a safety net to reduce the extent of a power system disturbance during multiple Protection System failures or failures of circuit breakers to interrupt current. Application of remote backup protection, however, may be limited by the need to meet the requirements of NERC Reliability Standards designed to assure adequate power system response during single failures or severe system events.

The design of the power system and the local protection design practices dictate whether local or remote backup protection can be securely and dependably applied to meet NERC standards for power system and Protection System performance requirements. Careful examination of the overall interaction of Protection Systems may provide insight as to where additional local or remote backup can be applied to help mitigate the spread of an outage.

Chapter 9: Recommendation

Large autotransformers are major capital investments and play a large role in the reliability and flexibility of the Bulk Electric System. Lead times for obtaining replacements are typically a minimum of six to twelve months; therefore, failures of these transformers can result in prolonged reduction in Bulk Electric System reliability and flexibility. Because of this, it is recommended that back up Protection Systems be applied to these assets to reduce the likelihood of damage due to prolonged through-fault currents caused by the failure of local or remote Protection Systems to clear the fault.

Appendix A: Contributors

Jonathan Sykes
Chairman
Manager of System Protection
Pacific Gas and Electric Company

William J. Miller
Vice-Chairman
Principal Engineer
Exelon Corporation

John Mulhausen
RE – FRCC
Manager, Design and Standards
Florida Power & Light Co.

Richard Quest
RE – MRO
Engineer
Xcel Energy, Inc.

Daniel Jesberg
RE – MRO – Alternate
Engineer
Midwest Reliability Organization

Jeff Iler
RE – RFC
Senior Engineer
American Electric Power

Philip B. Winston
RE – SERC
Chief Engineer, Protection and Control
Southern Company

Joe T. Uchiyama
U.S. Federal
Senior Electrical Engineer
U.S. Bureau of Reclamation

Joshua L. Wooten
U.S. Federal
Manager of System Protection and Analysis
Tennessee Valley Authority

Daniel McNeely
U.S. Federal – Alternate
Engineer - System Protection and Analysis
Tennessee Valley Authority

Philip J. Tatro
NERC Staff Coordinator
Senior Performance and Analysis Engineer
NERC

Lynn Schroeder
RE – SPP
Manager – Substation Protection and Control
Westar Energy

Samuel Francis
RE – TRE
System Protection Specialist
Oncor Electric Delivery

Baj Agrawal
RE – WECC
Principal Engineer
Arizona Public Service Company

Miroslav Kostic
Canada Provincial
P&C Planning Manager, Transmission
Hydro One Networks, Inc.

Sungsoo Kim
Canada Provincial
Section Manager – Protections and Technical Compliance
Ontario Power Generation Inc.

Michael J. McDonald
Investor-Owned Utility
Principal Engineer, System Protection
Ameren Services Company

Charles W. Rogers
Transmission Dependent Utility
Principal Engineer
Consumers Energy Co.

Forrest Brock
Observer
Transmission Compliance Specialist
Western Farmers Electric Coop.

Mark Fidrych
Observer
Manager of Performance Reviews and Metrics
North American Transmission Forum

Joe Spencer
Observer
Manager of Planning and Engineering
SERC Reliability Corporation

David Angell
Correspondent
T&D Planning Engineering Leader
Idaho Power Company

Hasnain Ashrafi
Correspondent
Engineer
Sargent & Lundy

Jonathan D. Gardell
Subject Matter Expert – NERC Consultant
Associate Consultant – Quanta Technology
President – Gardell Power Consulting, Inc.

Jim Ingleson
Subject Matter Expert
RLC Engineering

Eric A Udren
Subject Matter Expert
Executive Advisor
Quanta Technology

Tom Wiedman
Subject Matter Expert – NERC Consultant
President
Wiedman Power System Consulting, Ltd.

Murty Yalla
Subject Matter Expert
President
Beckwith Electric Company Inc.

Sara Filling
Correspondent
Director, System Protection & Automation
Baltimore Gas & Electric Company

Jeanne Harshbarger
Correspondent
System Protection Engineer
Puget Sound Energy, Inc.

Fred Ipock
Correspondent
Senior Engineer - Substations & Protection
City Utilities of Springfield, Missouri

Lorissa Jones
Correspondent
Bonneville Power Administration

Mark Lauby
Correspondent
Director, Reliability Assessment and Performance Analysis
NERC

Robert W. Cummings
NERC Staff
Director of System Analysis and Reliability Initiatives
NERC

Deven Bhan
Correspondent
Electrical Engineer
Western Area Power Administration

W. O. (Bill) Kennedy
Subject Matter Expert
Principal
b7kennedy & Associates Inc.

Larry Brusseau
Correspondent
Standards Manager
Midwest Reliability Organization

Dac-Phuoc Bui
Correspondent
Engineer, System Protection
Hydro-Québec TransÉnergie

John L. Ciufo
Correspondent
Principal
Ciufo and Cooperberg Consulting Ltd.

Evan T. Sage
Correspondent
Consulting Engineer
Potomac Electric Power Company

Bob Stuart
Correspondent
Senior Director – Transmission
BrightSource Energy, Inc.

Guy Zito
Correspondent
Assistant Vice President of Standards
NPCC

Lynn Oelker
Correspondent
EON-US

Dean Sikes
Correspondent
Manager, Transmission Protection, Apparatus, and Metering
Cleco Power, LLC

Saurabh Sauksena
Correspondent
National Grid

James Roberts
Correspondent
Transmission Planning
Tennessee Valley Authority

Mahmood Safi
Correspondent
Omaha Public Power District

Revision 1.1
2022-2024 SPCWG members and observers

Appendix B: Revision History

Revision History		
Version	**Comments**	**Approval Date**
V1.0	Original Approved document	June 2011
V1.1	SPCWG review and minor revision of approved document – transition to Technical Reference Document	Pending

Technical Reference Document	**Transmission System Phase Backup Protection**
Instructions	**Please use this form to submit comments on the draft Technical Reference Document Comments must be submitted within the review period below to Ed Ruck**
Review Period	**April 24, 2024 - May 23, 2024**

Name of Individual or Organization(s) (list multiple if submitted by a group)**:**	composite document
Industry Segment (if applicable)	
Region (if applicable)	
Contact Telephone	
Contact Email	

Organization(s)	Page #	Line / Paragr	Comment	Proposed Change	NERC Response
Manitoba Hydro	6	124	I understand that this guide is aimed for BES transmission transformers (autotransformers), but can this guide be applicable to other transformers especially those identified as crtitical elements?	none	The guidance provided in this document can be applied to any transformer as appropriate.
Manitoba Hydro	16	426	Is there any point to mention the use (or not to use) of phase overcurrent relay on transmission lines as backup protection IF anyone is using it?	none	Phase overcurrent may be used as backup protection.
Manitoba Hydro	24	673	Figure 7.2.2 is missing?	changed to figure 7.7	This was figure 7.7
Manitoba Hydro	25	729	Figure 7.2.2 is missing?	changed to figure 7.7	This was figure 7.7
FirstEnergy			FirstEnergy sees no objection to this Document.		Thank you
Ameren	Whole document	N/A	Ameren supports the document.	N/A	Thank you
Edison Electric Institute	N/A	N/A	General Comment: In general, EEI is supportive of this document. However, it appears the document was not revised but simply converted to the current NERC template. Chapter 1 reads more like historical background rather than relevant and compelling justification for changes that would drive the need to republish this Technical Reference Document. It would be valuable to industry for the document to be brought up to date with more relevant data and more recent, relevant examples that support the document's continued use as a reference document. Otherwise, it should be clear to stakeholders that the document didn't change but was converted to the current NERC template.	EEI suggests this document would benefit from a full refresh bring it up to date with more relevant data but if there is no desire to conduct a full refresh, we alternatively suggest changing the last paragraph in the Statement of Purpose section to read as follows "This document remains unchanged since its original release on June 2011 but has been reformatted and reclassified as a technical reference document and placed into the current NERC report format as it still contains useful information." With the addition of this statement, we could support the minimal changes made to this document.	A new version is a good idea for the next revision. We have implemented your suggested rewording of the Statement of Purpose section.

Organization(s)	Page #	Line / Paragr	Comment	Proposed Change	NERC Response
Edison Electric Institute	1	119 - 120	This paper is not a Reliability Guideline. It is a Technical Reference Document, as stated in the title.	EEI suggests the following edits in boldface to correct this non-substantive error. The goal of this ~~reliability guideline~~ **Technical Reference Document is to ensure the industry has a common understanding of the appropriate uses of Backup Protection in order to ensure an Adequate Level of Reliability. To this end,** the paper will discuss the pros, cons, ...	accepted, thank you
Edison Electric Institute	1, 2	103 - 158	EEI suggests that the historically relevant parts of Chapter 1 & 2 be moved to a new section or chapter titled "Background". Most of this information only has relevance from a background standpoint and would be better place in a separate section title as such. Footnote 2 can be incorporated into the background section.	Suggest adding a background section to this document in order to capture meaningful information from the past.	since this was just a format change, we will keep the current wording. This is an excellent example for a full revision.
Edison Electric Institute	2	140	Footnote 3 appears to be a dead link.	The footnoted document link should be fixed.	fixed
Edison Electric Institute	2	147	Footnote 4 appears to be a dead link.	The footnoted document link should be fixed.	fixed
Edison Electric Institute	2	154	Footnote 5 appears to be a dead link.	The footnoted document link should be fixed.	fixed
Edison Electric Institute	3	166	The SPCWG document titled Protection System Reliability should be referenced and footnoted.	The Technical Reference Document title "Protection System Reliability" should be referenced and footnoted.	this is footnote 4
Edison Electric Institute	3	169 - 170	IEEE paper title "Redundancy Considerations for Protective Relay Systems" has a footnote number (i.e., 6) but there is no associated footnote in the document.	Add ~~the~~ **a** footnote **to** the referenced IEEE document.	footnote added with a link to the abstract
Edison Electric Institute	3	174	EEI suggests that the term "Backup Protection" should be aligned with the IEEE Standards Dictionary.	EEI suggests "Protection that operates independently of specified components in the primary protective system and that is intended to operate if the primary protection fails or is temporarily out of service." Additionally, the above was from an older reference and should be checked against a more modern version of the IEEE Standards Dictionary. Additionally, we are not suggesting that the sentences contained between 177 and 179 should be deleted or modified.	since this was just a format change, we will keep the current wording. This is an excellent example for a full revision.
Edison Electric Institute	3	181	EEI suggests aligning "Local Backup" with the latest version of the IEEE Standards Dictionary.	EEI suggests aligning "Local Backup" with the latest version of the IEEE Standards Dictionary.	since this was just a format change, we will keep the current wording. This is an excellent example for a full revision.
Edison Electric Institute	3	190	EEI suggests aligning "Remote Backup" with the latest version of the IEEE Standards Dictionary.	EEI suggests aligning "Remote Backup" with the latest version of the IEEE Standards Dictionary.	since this was just a format change, we will keep the current wording. This is an excellent example for a full revision.

Organization(s)	Page #	Line / Paragr	Comment	Proposed Change	NERC Response
Edison Electric Institute	3	330	Chapter 6: One event that ultimately drove changes to TPL-001-5.1 was the PacifiCorp East Disturbance of Feb. 14, 2008. EEI suggests that this disturbance be added to the list of other events that drove increased requirements associated with backup relay protection.	Suggest adding the PacifiCorp (Feb. 14, 2008) event involving backup protection. It might also be useful to add a reference to the joint SPCS and SAMs report title Order 754 "Assessment of Protection System Single Points of Failure Based on the Section 1600 Data Request".	since this was just a format change, we will keep the current wording. This is an excellent example for a full revision.
Edison Electric Institute	25	836	The recommendations in chapter 9 feel very dated and should be reconsidered and embellished appropriately. At a minimum, it is widely know that the lead time to obtain large power transformers is significantly longer than 6 to 12 months.	Update the recommendations section to align with current supply chain concerns.	since this was just a format change, we will keep the current wording. This is an excellent example for a full revision.
Edison Electric Institute	26	845	The contributors list remains unchanged from the previous 2011 version. At a minimum, those from the current SPCWG who worked to review and update this document should be added along with those who helped develop this document originally. Additionally, those who are still working in the industry should have their titles and company updated.	Update the contributors list.	added the SPCWG members and observers

Presentation of Comments on "Reliability Guideline: Electromagnetic Transient Studies for Interconnection of Inverter-Based Resources"

Action
The SPCWG is requesting that the RSTC accept and implement the recommendations of the SPCWG that the RSTC requested on the proposed Reliability Guideline: Electromagnetic Transient Studies for Interconnection of Inverter-Based Resources

Background
In the June RSTC meeting, the RSTC assigned the SPCWG to review and provide feedback on the proposed Reliability Guideline: Electromagnetic Transient Studies for Interconnection of Inverter-Based Resources document.

Based on the SPCWG's review, the following suggestion is made:

- Remove the section "Transmission Protection Validation".
- In addition, the SPCWG requests that the RSTC have the SPCWG write their own whitepaper on this subject. The SPCWG believes the objective of EMT simulations at this time should be to understand fault response and model validation instead of transmission protection validation. The proposed EMT guideline stands on its own without this section.

The full list of comments has been provided for the agenda.

Summary
The SPCWG reviewed the document as assigned and is providing the requested feedback and recommendations.

Technical Reference Document	**Electromagnetic Transient Studies for Interconnection of Inverter-Based Resources**
Instructions	**Please use this form to submit comments on the draft Technical Reference Document Comments must be submitted within the review period below to Ed Ruck (Ed.Ruck@nerc.net) with the words "EMT document review comments" in the subject line. Only comments submitted in this Microsoft Excel format will be accepted. Both general and specific comments should be provided within this form.**
Review Period	**June 12, 2024 - July 10, 2024**

Name of Individual or Organization(s) (list multiple if submitted by a group)**:**	
Industry Segment (if applicable)	
Region (if applicable)	
Contact Telephone	
Contact Email	

Organization(s)	**Page #**	**Line / Paragraph**	**Comment**	**Proposed Change**	**NERC Response**
NERC System Protection and Control Subcommittee (SPCS)	ix	164	"The accuracy and fidelity of a given EMT model depends on the model development process, the modeling requirements they were developed for and assumptions." This sentence needs some grammatical work	Consider modifying to "The accuracy and fidelity of a given EMT model depends on the model development process and assumptions."	
NERC System Protection and Control Subcommittee (SPCS)	ix	168	"Comprehensive model requirements and model quality verification practices recommended in the previous guideline should be followed." What are these previous guidelines??	Add reference to these guidelines you are referring to here	
NERC System Protection and Control Subcommittee (SPCS)	ix	170	I do not think the third paragraph on this page provides any value. There is already a table of contents in the report	Consider deleting the entire third paragraph	

NERC System Protection and Control Subcommittee (SPCS)	1	190	"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." Interactions between IBRs is a subset of control system stability correct?? Also, "controller stability" is "control system stability" correct?? What are these other dynamic devices you are referring to here?? EMT studies can be used to evaluate all protection schemes within the system not just tranmission protection schemes correct??	Consider modifying to "What is of interest to be evaluated in those studies are aspects related to IBR control system stability and system protection schemes (e.g. remedial action schemes, etc.)." If you want to keep the dynamic devices portion then consider providing more details in a seperate sentence.	
	1	199	I do not understand, why are we using steady state metrics to evaluate system strength?? Based on the fundamentals of power system analysis it would appear that a dynamic metric should be used to determine system strength. Intuitively, a grid following IBR is reliant on the synchronous generation throughout the BES to ensure that the systems voltage magnitude and angle stay within a continous operating window. During a system disturbance, the synchronous generator control system design and parameters will determine (for the most part) how fast the system will re-establish equilibrium. So shouldn't we find a better way to evaluate this??	Consider finding a better way to define system strength. I know metric like SIR have been shown to have some flaws	
	1	202	"These metrics are, however, based on the steady state network topology and power flow across the network." The CIGRE TB 885 Guide for the Assessment, Specification and Design of Synchronous Condenser for Power system with Predominance of Low or Zero Intertia Generators defines the electromagnetic strength metric. This metric helps determine how strong the system is for dynamic voltage events. Should we consider using this metric to define system strength??	Consider using the electromagnetic strength metric in reference to IBRs	

	1	208	"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." I do not think it is fair to the industry to expect them to be able to develop system strength metrics and criteria to determine weak areas. As an industry, we are not that familiar with this. If this document is guidance for EMT studies then why would this document not provide more guidance on how an entity can come up with this??	Consider adding more guidance here for the industry	
	1	216	"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." This goes back to my previous point. I am not sure if most TPs know how to determine violation of stability criteria for IBR systems because the industry has been conditioned to define stability from a synchronous generation perspective.	Provide more guidance to the industry on stability criteria	
	2	229	"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]" What are these analystical methods?? What are these known limits?? Also the reference is missing at the end of the sentence	Provide more clairy on the analytical methods and known limits mentioned in the sentence. Also, fix reference link	

	38	1262	"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." I think this is missing the point a tad bit. It is not so much that these schemes were developed when just the fault currents were predominated by synchronous schemes. These schemes were MOLDED AND OPTIMIZED around the entire behavior of synchronous generation. For example, the distance protection schemes were optimized based on the intertial response of the rotor during a fault and the negative sequence voltage to current angle. Also, when it says particularly synchronous generators, what other generators would there be?? The only think I can think of is a synchronous condenser but I do not believe these schemes were considering synchronous condensers to that degree.	Consider modifying to "Traditional protection schems were optimized based on the behavior of synchronous generation to abnormal system conditions and faults."	
	38	1264	"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." I think it may be good to add some clarity to this	Consider modifying to "The response of a synchronous generator during a fault event is dictated by the law of physics. The current magnitude will decay based on the machines subtransient, transient, and sychronous impedances; as well as their associated time constants."	
	38	1268	I think we should add a sentence in the beginning of this paragraph explicitly stating that IBRs do not have subtransient and transient impedances. I have seen technical specifications from transmission planners where they ask inverter manufacturers for this data because they are conditioned to ask for this	Consider adding "IBRs do not have internal subtransient or transient synchronous impedances."	

	38	1268	"In contrast, the fault response of an IBR depends on how its inverter control system is programmed to react to terminal conditions." I do not understand what the term "terminal conditions" means in the context of this sentence. To me, terminal means at the terminals of the machine but I know inverters do not all respond to faults that way. I believe some inverters fault response is also dictated by the power plant controller	Consider modifying to "In contrast, the fault response of an IBR depends on how its inverter control system is programmed to react to abnormal system conditions."	
	38	1268	"While the behavior of synchronous generators is predictable based on established physics, IBR responses vary based on the specific programming of their control systems." We have already stated this in the previous sentence and paragraph.	Consider removing since this is redundant	
	38	1270	"This aspect, particularly the rapid adjustments made by the inverter controls to changing terminal conditions, remains less understood by protection engineers." See my previous comment on the usage of "terminal conditions"	Consider modifying to "This aspect, particularly the rapid adjustments made by the inverter control system based on the systems dynamic abnormal conditions, remains less understood by protection engineers."	
	38	1274	"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." Make this two sentences for clarity. Also make some adjustments and additions to provide further information	Consider modifying to "In essence, the current protection practices were not designed for IBR based systems. Currently, industry practices rely on synchronous generation to provide the operating quantities for systems with IBRs. This may prove insufficient as synchronous generation is retied and IBR penetration grows. This highlights the need for reassessment and potential adjustments in system protection strategies."	
	38	1281	"or implement new schemes that works well with high level of IBRs." As an industry, I do not believe we know of new schemes that work well with predominately based IBR systems	Consider removing this part since this is not guidance and we as an industry do not know how to do this. Alternatively, you can write language in this document to identify some of these schemes. This will provide guidance to the industry.	

	38	1283	"Identification of IBR-based power plant interconnection scenarios" Why would is only be interconnection scenarios?? As IBRs are integrated onto the system I would think there is going to be an aggregate effect that would impact the system not just a singular interconnection	Consider modifying languge to fully encompass potential problems and not just focus on an interconnection study	
	38	1286	"could manifest themselves as failure of the IBR to ride through grid voltage disturbances." Historically, this has not been an issue with the protection schemes on the transmission system. This has historically been an issue with the protections schemes within the IBR generating facility	Consider removing this since I do not believe this relates to transmission system protections schemes	
			"The list of disturbances (as discussed in Chapter 5) to be applied will be decided based on the protection relays under study." If this document is supposed to be guidance on this topic then some level of guidance should be provided here. There is not guidance here	Add guidance for the industry	
	39	1297	"can be used for Protection Systems Validation study as well." I am not sure if "Protection Systems Validation" is capitalized because of some BES definition reason. Regardless, this is guidance so I do not think we need to restrict this to BES defined terms	Make "Protection Systems Validation" lower case	

	39	1301	"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." Is this suggesting that we model the CTs and VTs in a special manner or in detail?? We typically do not model instrument transformers in detail within short circuit studies. We typically just focus on CT ratio full winding ratio and the tap ratio this is going to be used in the design. If this is what is being recommended then some guidance should be provided to us so we understand how much detail we need to implement for instrument transformers. Instrument transformers typically saturate for some high magnitude of fault current. Existing CTs are likley going to be rated for a synchronous generation based system. If this system becomes a predominately IBR based system then the fault current would be severely reduced. So how would the CTs saturate in this situation?? Where is the resultant high voltage condition	Consider removing this sentence or provide a lot more guidance to the industry	

	39	1304	"Ideally, the real code EMT models of transmission system protective devices are also to be included in the EMT model." I take exception to most of this paragraph within the note. I do not think this language should be in this guidance. I do not believe the real code for microprocess relays are availabel within EMT software. A few sentences late this is essentially stated by the authors. The point about relay internal algorithms is very valid and important but it is impractical on a large scale. I think the only way to do this now is through CHIL testing. CHIL testing requires A LOT more hardware then a standard EMT study. When in the project cycle are protection engineers supposed to send relays to perform CHIL testing? For existing relays how are we supposed to test them using real time simulation software? Wouldn't it be better for NERC to advocate for a more standard approach for inverter fault response instead of asking the industry to do CHIL testing on all of their relays?	The part about OEM algorithms is very important so I think we should keep that. However, the rest of this should be removed, rewritten, or additional guidance provided. When I read the current language I do not see how you can apply this in a practical manner	
	39	1310	"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." Wouldn't you need to include the actual inverter control system model within the simulation to have a high degree of confidence in the results? Should this be control hardware in the loop testing?	I think this should be control hardware in the loop for accurate relay results. Even if you run a PSCAD model and generate COMTRADE files, the PSCAD model should have the inverter control system model, and correct settings, to obtain a high degree of confidence in performance	
	39	1312	I know RSCAD, and I believe PSCAD, has virtual relay models. However, they do not function that well when evaluating actual relay performance. This is implied in this paragraph but I think it should be very explicitly stated and explained that their use is not an adequate measure of performance.	Add a few sentences discussing virtual relays and their deficienies in terms of performance. Also consider writing a statement that these relay models are not recommended for EMT studies	

	39	1321	"Active power, reactive power and frequency." Why would you need to monitor active and reactive power for a transmission protection scheme?	Consider providing additional guidance here or removing the "real and reactive power" portion	
	39	1322	"alarm signals," Why would you need to monitor alarm signals when evaluating a transmission protection scheme?	Consider providing additional guidance here or removing the "alarm signal" portion	
	39	1325	"i.e. if the measured impedance is available as an internal output," What is an internal output?	Provide more guidance here	
	39	1329	"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 entire section basically just says "review the results". As an industry, we already know that. Protection engineers are conditioned to review relay performance during traditional short circuit studies. What we do not know is HOW to review the results because they are so different then traditional short circuit studies. Even the text identified above just says "use a screening process" but it does not provide any recommendations for quantitive thresholds or pretty much any guidance. What is most likely to happen is that transmission planners (or people who do modeling) are going to go to protection engineers and ask us what our criteria is for passing. Protection engineers are most likely not going to be able to answer that	Provide a lot more guidance here so the industry can use this. Right now I do not believe protection engineers will be able to use this guidance.	
	40	1335	"In case of relay mal/mis operation occur," Needs some tweaks for grammar	Modify to "In the case that a relay mal/mis operation occurs,"	

	40	1338	"Make changes to relay protection algorithm" If this is in reference to OEM internal algorithm, I think this is highly impractical. A manufacturer could issue a firmware update but what requires a lot of time. Also, given the frequency of inverter control system firmware updates, you cannot expect the relay manufacturers to constantly issue firmware updates to try and keep up with the inverter performance. I think this is only practical in reference to user defined logic within the microprocessor relay since that can be changed by the protection engineer faily quickly	Modify "protection algorith" to "user defined logic"	
	40		General comment: While we are on this topic, what are we supposed to do about firmware updates? Are we supposed to perform protection validation studies everytime an inverter manufacturer issues a firmware update?	Provide guidance on firmware updates in referfence to protection validation studies	
	40	1360	"Protection relay mis operations during ERCOT Odessa Disturbance31" Doing a quick review of the Odessa report, it does not appear that there are transmission system protection schemes identified in the report. Most, if not all, of the protection schemes are within the IBR generating facility. I think the Odessa information is valuable I just don't think it belongs in the transmission protection section	Consider moving this to "Modeling and Testing of Protection System Elements of an IBR Plant" subclause	
	40	1366	"Currently, the industry lacks clear guidance on necessary modifications to existing protection systems without further investigation." What is this further investigation exactly? Because I do not see any meaningful progress throughout the industry on this front. To me, this is just NERC kicking the can down the road on this issue. This entire subclause basically says you need to do these studies and make modifications to relays so they perform reliably. And then at the very end the statement identified above is made. How are we as an industry supposed to make modifications if we do not even have guidance on what to change?	Consider removing this statement	

	40	1367	"Additionally, inverter manufacturers are seeking direction on how to appropriately respond to grid disturbances to better support the power system during such events." The approach that the inverter manufacturers are taking on this seems backwards (if not just a cop out). As an industry, we have never had to tell synchronous generators or the power system how to "approrpiately respond" to disturbances. As an industry, we do not know how to answer this question. Protection schemes were developed based on how the power system performed, not the other way around. If the inverters could produce a more standardized and reliable response, then we could begin to try and develop protection schemes for them. But instead of doing this they are using this excuse to skirt their way around the crux of the issue	Consider removing this statement	
	46	1597	"Power System Protection" See my previous comment about BES defined terms and guidelines	Make this lower case	
	47	1598	"steady-state fundamental frequency loads" Are these loads within the auxiliary load system of the IBR generaitng facility or loads on the tranmsission system? How can these create issues for protection schemes? Most protection schemes operate in a dynamic environment, so how can these steady state loads cause issues for protection schemes within an IBR generating facility?	Provide further clarity or remove this language	
	47	1599	"In addition, the RMS power flow and short-circuit simulation tools assume the system is balanced." This statement applies to traditional softwares like PSSE or ASPEN	Add the term "traditional" "In addition, the traditional RMS power flow and short-circuit simulation tools assume the system is balanced."	

	47	1602	"This information is valuable for harmonic rejections in the relays." What are harmonic rejections? Also, the evaluation of protection functions within the inverter control systems are just as important, if not more important, than relays. However, this is not discussed at all in this paragraph	re-write this to be more clear on exactly what is being referred to here within microprocessor relays. Add language about protection functions embedded within the inverter control system	
	47	1604	"Furthermore, EMT tools are very powerful for transient applications." This does not accurately explain the value EMT brings. Powerful is very subjective and there are many tools we use that can be considered powerful	Consider replacing "powerful" with "insightful"	
	47	1604	"The protective relays must operate in transient conditions and therefore EMT tools can be utilized over conventional short-circuit simulation software." See previous comment about protection functions within inverter control systems	Add language about protection functions embedded within the inverter control system	
	47	1606	"The IBRs are subject to the NERC Reliability Standards, such as PRC-024-3, PRC-025-2, and PRC-027-1." I do not believe this sentence adds much value the way it is written. IBRs are subject to more than just these specific NERC standards. This is missing PRC-019 (the sentence right after the above statement is pretty much the requirements of PRC-019). NERC is currently trying to remove IBRs from PRC-024. For these standards it is not the entire IBR that is subject to these requirements, it is the protection functions embedded within the inverter control system that are under the purview of most (if not all) of these standards.	Consider modifying to "Protection functions within the inverter control system are subject to meet the minimum requirements of various NERC PRC standards.	
	47	1607	"The IBRs have several protection elements in their protection system." This is not a protection system, these are embedded within the inverter control system	replace "protection systen" with "control system"	
	47	1607	"Few of these elements are listed below:" Grammar correction	Modify to "A few of these elements are listed below:"	

	47	1609	"Inverter protection functions:" Need to be more specific that these are within the control system	Modify to "Protection functions embedded within the inverter control system:"	
	47	1612	"Under/Over frequency protection." Why would a PV or BESS inverter have these protection schemes? I am pretty sure that these inverters have been implementing these protection schemes s a carry over from IEEE 1547. I do not believe they are need in transmission applications for these inverter types	Consider adding qualifying statement that this applies to wind turbines	
	47	1615	You have DC undervoltage protection identified twice in this list	Consolidate and only have one bullet for DC undervoltage	
	47	1615	What about the phase lock loop function? I think that should be included in this list	Add phase lock loop function to this list	
	47	1615	Are all of the functions within the inverter models in PSCAD/RSCAD? Are they available in the OEM inverter models? Most of the time when I review the inverter settings (text file) it is hard to locate the protection functions if they are even in there at all. If they are not, what should the utility do?	Add more clarification for guidance on this topic	
	47	1616	"Inverter transformer protection." What ANSI protection elements are being used here? Are these provided within the inverter control system? Or are there separate external realys for GSU transformer protection?	Add more clarification for guidance	
	47	1617	"Collector system protection." What ANSI protection elements are being used here? I think a lot of folks are misapplying protection schemes here due to a carry over from IEEE 1547 or a misinterpretation of PRC-024	Add more clarification for guidance	
	47	1618	"Substation and Main Power Transformer Protection." What is the difference between these two? There is typically only one transformer that connects the collector bus to the transmission system	Add more clarification for guidance	

	47	1619	"Main line and breaker protection" What is a main line? What is breaker protection? This has traditionally been referred to as the generator lead line or interconnecting line. What ANSI protection elements are being used here?	Consider changing to "Generator lead line or interconnecting line" Add more clarification for guidance	
	47	1621	"The protection functions for these resources can often use phase-based quantities instead of positive sequence values." What does this mean exactly? Also, does this statement only refer to the inverters or does it also apply to the other pieces of equipment (e.g. transformers, transmission lines, etc.) in this list?	Add more clarification for guidance	
	47	1623	"In addition, in some cases the simulated fault clearing time may be passed the ride-through capability of the inverters." This is hard to read. Also, I strongly believe that the term "ride through" has provided little benefit, if any at all, to the industry understanding how generation works during a disturbance. I think we should move away from that term and focus more in the engineering and operation of generation. Typically, ride through is just a term folks like to use when they do not understand how generation works or understand power system stability. I do not know of another term that has wrecked more havoc on the inverter industry and power system than ride through has.	Modify to "In addition, in some cases the simulated fault clearing time may exceed the capabilities of the inverters."	
	47	1624	"Therefore, EMT simulation tools might be needed to fully capture the dynamic behavior of the inverters." This sentence is not really about protection, it is more about the inverter	Consider modifying to "Therefore, EMT simulation tools might be needed to fully capture the dynamic behavior of the protection schemes relative to inverter capabilites."	

	47	1627	I think this entire paragraph should be removed for multiple reasons. NERC is currently advocating for the removal of inverters from PRC-024. In this specific case, EMT should not be used to just evaluate the IBR, it should be used to evaluate the performance of the entire IBR generating facility. If you are using EMT and have created an accurate model, then the software simulation should be able to evaluate the voltage drop throughout the IBR generating facility. A calculation is needed if the utility is performing a static analysis.	Remove this paragraph	
	48	1635	"The inverter model and associated protection elements should come from Original Equipment Manufacturer (OEM)." What happens if the utility can not obtain this from the manufacturer? What happens if the manufacturer gives the utility a flawed model? What happens if the OEM issues a firmware update? How do protection engineers review the models to determine that the protection settings are correct?	Add more clarification for guidance. Also add language in the nature of "OEMs should provide a list and description of all of the control functions and protection functions within their control system. The description should also explain how this function affects the performance of the IBR. The set point ranges should also be provided. Utilities should add this requirement in their technical specification. If inverter manufacturers are unwilling to provide this information, the the utility should consider alternative inverter manufacturs or liquidated damage contractual language."	
	48	1636	"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." See previous comment about PRC-024. As an industry, we should focus more on the engineering and operation of generation	Modify to "After the site-specific model is built in the EMT tool, then various grid conditions can be simulated to determine the performance of the IBR generating facility."	

	48	1646	"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." How do you have mechanical constraints in PV and BESS inverters? I believe t onlyhis statement is in reference to wind turbines.	Add a qualiying statement that the mechanical constraints are only for wind turbines	
	48	1648	I think this paragraph does a really good job of pointing out the flaws of modeling. In my experience, you can spend a ton of time modeling and have a "perfect model" of the electrical power grid but if the inverter OEM model is inaccurate then the entire model simulations are most likley going to be inaccurate. The one example given here is just what we know of but there are other gaps in the modeling that we are just now aware of and we do not know how they will impact performance (unknown unknowns). Utilities can optimize the grid portion of the model because we have the data from our system. However, we have not control over the quality of the model from the inverter OEM. When we get the model, most of the time we have to blindly implement it because we do not understand the parameters in the model and the inverter manufacturers do not do a good enough job explaining the parameters to us	Add more and stronger language about the importance of accurate inverter models. Put more pressure on the inverter manufacturers to give us the tools we need to be successful and provide reliability	
	48	1655	"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." When you say "per se" it implies that PPL is similiar in nature to ROCOF. I do not believe that is the case. ROCOF is looking at a rate of change while PLL is monitoring the angle of the system voltage and determinign whether it is above or below a certain set point. These functions do not operate the same. It also does not provide any value to refer to PLL in the context of this paragraph	Remove the reference to PLL	

	48	1657	"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." What are the critical vulnerabilities with the auxiliary loads? If it is just that they are not being modeled than that is not a vulnerability with the auxiliary loads, that is a gap in modeling. If folks are not modeling the IBR generating facility auxiliary loads, then how are they evaluating the performance of the entire IBR generating facility. It is my understanding that IEEE 2800 requires a full IBR generating facility "ride through" performance	Add more clarification for guidance	
	48	1674	"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." This statement is only valid if the OEM model is correct and accurate	Add qualifying language for the quality of the OEM model	
	49	1679	"IBR plant performance with SMIB tests" Define SMIB, I do not believe this term is defined throughout the document. Also, what is an SMIB test?	Define SMIB. Add more clarification for guidance	

	49	1679	"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." I just do not see how this is practical in utility applications. This may work in a lab where there are no production requirements. I do not believe most, if not all, OEMs are providing this now. Obtaining an accurate model should be done at the beginning of the project phase. How are we supposed to do CHIL test and field tests, provide the results back to the OEM, wait for the OEM to correct issues, and then continue on with the project? More importantly, if you get all the way to commissioning where you performa field tests and the model is proven to be not accurate, do you have to start the entire engineering process over again? NERC has to give us actionable guidance when it comes to something like this. Right now this is not actionable guidance because all the OEM has to do is say "we not not normally provide that" or	Provide more guidance on this and explain SMIB tests. Add language for something along the lines of "Utilities should add this as a requirement in their technical specification documents to inverter manufacturers. If inverter manufaturers are unwilling to provide this, then utilities should consider alternative inverter manufacturers or liquidated damages contractual language." This will give us the power we need to try to hold the inverter manufacturers accountable.	
	49	1682	"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" I struggle to see how this is practical. The manufacturer does not know the parameters of the power system they are interconnecting to. How are they supposed to my model the IBR genertaing facility and transmission system and run these simulations?	Add more clarification for guidance	
	49	1682	There are two reference links broken in this paragraph	fix the reference links	

	50	1746	"TPs and PCs should require OEMs to deliver models with detailed documentation as much as possible." I agree that this is what we want. However, I struggle to see how we can achieve this in a practical manner based on the existing interactions with the OEM. We have no authority over them providing this. If you look at their response to the ODESSA event, most of the OEMs are just flat out ignoring this. Also, how do we even know if the model they have provided is accurate? It is a black box model and they share very little information for us. It is very difficult if not impossible to perform a Q&A and identify if the model is accurate when we receive the model.	Provide guidance for how we can evaluate the accuracy of the model to hold the OEMs accountable	
	50	1747	"In the pre-compiled, black-box code, comprehensive error messages should be configured to provide information to the users whenever any exceptions are encountered." I strongly agree with this. However, we have no power or authoritie over the OEM to enforce this. Even the PSCAD/RSCAD software has error messages that are not intuitive	Provide guidance on how we can practically implement and enforce this	
SPCWG	38-40	1259-1371	May be best not to include this section "Transmission Protection Validation". Request RSTC approval to have the SPCWG write their own whitepaper on this subject. Issues and concerns of this section include but are not limited to comments noted above. The SPCWG believes the objective of EMT simulations at this time should be to understand fault response and model validation vs transmission protection validation. The guideline stands on its own without this section.	Remove "Transmission Protection Validation".	

SAR: Revisions to FAC-001 and FAC-002

Action

Approve the Standard Authorization Request (SAR): Revisions to FAC-001 and FAC-002.

Background

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

This draft SAR has undergone multiple IRPS comment periods, a joint RSTC and public comment period, and a final review by the IRPS before attempting to achieve consensus to send the document to the RSTC for approval.

Conclusion

All comments throughout all comment periods were considered with significant changes made to the SAR document. On August 8, 2024, the IRPS reached unanimous consensus to send the SAR to the RSTC for approval with one abstention. With approximately 40 members on the call, there were 11 “Yes” votes and 0 “No” votes and one member abstained. With this consensus, IRPS requests the RSTC approve this SAR.

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Standard Authorization Request (SAR)

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

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

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

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

Requested information

• Opportunities for improvement to ensure consistent practices in implementation of Federal Energy Regulatory Commission ("FERC") Generator Interconnection requirements under the Large and Small Generator Interconnection Agreements and Procedures (LGIA/LGIP/SGIA/SGIP also referred to herein as the GIA and GIP for convenience).Failures in the voluntary adoption of NERC recommendations and guidance to enhance generator interconnection requirements and ensure reliable connection IBRs.
• Opportunities to enhance current practices for assessing IBR plant capability and performance against applicable generator interconnection requirements as created according to FAC-001. (i.e., conformance testing)
• Opportunities to enhance generator interconnection study processes as created according to FAC-002 to help ensure the reliable commissioning of IBR facilities during the generator interconnection process, due to gaps in current IBR commissioning practices.
  ○ Lack of adequate or sufficient performance tests during commissioning.
  ○ Lack of verification of the as-built models as part of feedback loop.
  ○ Lack of adequate benchmarking of models(e.g. positive sequence phasor domain (PSPD) and electromagnetic transient (EMT) models) against each other and real product performance.
 	
Without taking advantage of the opportunities for improvement summarized above to enhance NERC reliability standards in complement with the FERC GIA/GIP, large disturbances involving non-consequential tripping of many IBRs or other abnormal power changes from IBRs will continue with increased frequency and likelihood, subsequently increasing risks to BPS reliability. NERC continues to highlight the increased risk profile of IBRs due to the rapidly changing resource mix.

Purpose or Goal (What are the reliability gap(s) or risk(s) to the Bulk Electric System being addressed, and how does this proposed project provide the reliability-related benefit described above?):
A series of NERC disturbance reports highlight systemic performance issues that have led to unexpected IBR plant reductions during normal grid faults. For instance, phase jump or phase lock loop (PLL) synchronization issues were described as one cause of IBR plant tripping in three reports.[3,4,5] Similarly,

[3] *Odessa Disturbance,* NERC. September 2021.https://www.nerc.com/pa/rrm/ea/Documents/Odessa_Disturbance_Report.pdf
[4] *2022 Odessa Disturbance,* NERC. Atlanta, GA: December 2022. https://www.nerc.com/comm/RSTC_Reliability_Guidelines/NERC_2022_Odessa_Disturbance_Report%20%281%29.pdf
[5] *900 MW Fault Induced Solar Photovoltaic Resource Interruption Disturbance Report*, NERC. Atlanta, GA: February 2018. https://www.nerc.com/pa/rrm/ea/October%209%202017%20Canyon%202%20Fire%20Disturbance%20Report/900%20MW%20Solar%20Photovoltaic%20Resource%20Interruption%20Disturbance%20Report.pdf

Requested information
other reports describe tripping causes that include overvoltage,[6] undervoltage,[7] frequency protection,[8] momentary cessation,[9] and slow active power recovery,[10] among other causes. The purpose of this Standards project is to address the reliability risks presented to the BPS due to the observed systemic deficiencies in IBR performance and modeling. These performance deficiencies could be mitigated by taking advantage of the above-mentioned opportunities for improvement to enhance generator interconnection requirements and study processes through enhancements to FAC-001 and FAC-002. Deficiencies observed by NERC in numerous disturbance reports and other NERC publications show that Transmission Owners (TOs) have a need to enhance their publicly available generator interconnection requirements, as required in FAC-001, with uniform and comprehensive requirements. Additionally, enhancements to generator interconnection study processes, including conformity assessment processes for IBRs connecting to the BPS (i.e., all registered IBRs), are paramount to ensure reliable IBR operation and to prevent large disturbance events during normally cleared BPS events. Conformity assessments are intended to leverage existing skillsets within a more structured process with well-defined success criteria. Opportunities to improve generator interconnection requirements and conformity assessments[11], in the aforementioned technical areas and others, must be capitalized upon to prevent future unexpected IBR plant tripping risks that could compromise system reliability. Furthermore, insufficient commissioning practices have led to many facilities having protection, control settings, or control modes installed that were not studied as part of the generator interconnection process and going unnoticed until a major grid disturbance occurs. This proposed project intends to address the reliability issues identified in the NERC disturbance reports by accomplishing the following: 1. Enhancing the latest FAC-001 Standard, in complement with FERC Order No. 2023 and FERC GIA/GIP to require that TOs in coordination with their associated Transmission Planners (TP) and Planning Coordinators (PC) establish IBR performance requirements covering specific topics of paramount importance for BPS reliability while leveraging technical aspects of work already completed within the industry. 2. Enhancing the latest FAC-002 Standard, in complement with FERC Order No. 2023 and FERC GIA/GIP to require TPs and PCs to enhance their generation interconnection study processes to assess in more detail IBR plant capability and performance conformity for example through a

[6] *April and May 2018 Fault Induced Solar Photovoltaic Resource Interruption Disturbances Report*, NERC. Atlanta, GA: January 2019. https://www.nerc.com/pa/rrm/ea/April_May_2018_Fault_Induced_Solar_PV_Resource_Int/April_May_2018_Solar_PV_Disturbance_Report.pdf
[7] *Panhandle Wind Disturbance*, NERC. Atlanta, GA: August 2022. https://www.nerc.com/pa/rrm/ea/Documents/Panhandle_Wind_Disturbance_Report.pdf
[8] *Multiple Solar PV Disturbances in CAISO*, NERC. April 2022. https://www.nerc.com/pa/rrm/ea/Documents/NERC_2021_California_Solar_PV_Disturbances_Report.pdf
[9] *1,200 MW Fault Induced Solar Photovoltaic Resource Interruption Disturbance Report*, NERC. June 2017. https://www.nerc.com/pa/rrm/ea/1200_MW_Fault_Induced_Solar_Photovoltaic_Resource_/1200_MW_Fault_Induced_Solar_Photovoltaic_Resource_Interruption_Final.pdf
[10] *San Fernando Disturbance*, NERC. November 2020. https://www.nerc.com/pa/rrm/ea/Documents/San_Fernando_Disturbance_Report.pdf
[11] https://www.iec.ch/conformity-assessment/what-conformity-assessment

Requested information
combination of review of documentation, simulation studies, and physical tests that a newly interconnecting IBR complies with applicable IBR performance requirements. 3. Modifying either FAC-001 or FAC-002 , in complement with FERC Order No. 2023 and FERC GIA/GIP, to include requirements for applicable entities (TOs, TOPs, Balancing Authority (BA), etc.) to enhance existing generator interconnection requirements and study practices, to include requirements for Generator Owners (GO) to appropriately and reliably commission IBR facilities and provide adequate proof that commissioning checks (i.e., as-built evaluation, commissioning testing, etc.) were conducted and that the as-built IBR plant is parameterized to represent the latest revision of the as-modeled IBR facility used in generator interconnection studies. Reliability-related benefits of each of the above proposals are further clarified below. Language in the latest FAC-001 Standard requires a TO to document Facility Interconnection Requirements, update them as needed, and make them available upon request; however, there is no specificity regarding what the requirements should entail. Some entities rely heavily or entirely on high-level requirements established in the *pro forma* LGIA and have not expanded upon these requirements. NERC Reliability Standards should operate in complement with FERC Order No. 2023 and FERC GIA/GIP and modernize and enhance requirements and study processes associated with IBRs. NERC disturbance reports highlight repeated causes of tripping that are not captured by existing requirements in the FERC GIA/GIP , nor should industry rely solely on the these procedures for the establishment of performance-based requirements. This SAR proposes the enhancement of existing interconnection requirements and study processes through the inclusion of specific categories of requirements (i.e., voltage ride-through, fault ride-through performance, validation between models and installed equipment, etc) in FAC-001. These requirements must be coordinated with current and future NERC Standards, FERC Order No. 2023 and FERC GIA/GIP, and existing generator interconnection requirements. Having a uniform minimum set of generator interconnection requirement categories across North America outlined throughout NERC Reliability Standard requirements will help ensure clarity and consistency among equipment manufacturers, IBR developers, GOs, and TOs, and lead to new BPS-connected IBR plants designed with the capabilities necessary for reliable operation of the BPS. Currently, the latest version of FAC-002 requires TPs and PCs to study the reliability impact of interconnecting generation and existing generation seeking to make a qualified change, as defined by the PC under requirement R6. There is currently no requirement to ensure that these generators, as-designed and as-installed or to-be-installed in the field, are assessed for compliance with applicable interconnection requirements (as created per FAC-001) during the interconnection process. Having a specific conformity assessment process (as enhancements to currently performed interconnection studies) will help ensure that the TP and PC verify generating resource conformity with applicable interconnection requirements, preferably prior to IBR plant commissioning. The standard drafting team should leverage FERC GIA/GIP requirements to determine sufficient timelines for resolving discrepancies in plant conformity. Enhancing current generator interconnection processes with clear conformity assessment processes will ensure that new BPS-connected IBR facilities are designed with the capabilities necessary for reliable operation.

Requested information
Lastly, IBR facility commissioning deficiencies have been documented numerous times by NERC in disturbance reports, alert findings, and other publications. Entities must adhere to both FERC Orders and FERC GIA/GIP throughout the generator interconnection processes, and NERC Standards that become subject to mandatory enforcement only upon commercial operation. Therefore, there is a handoff that occurs between the developer and GO, as well as between the FERC GIA/GIP and the NERC Standards. Because of these technically sensitive issues and the urgency to connect renewable energy resources to the BPS due to policies, tax credits, economics, etc., IBR interconnection is under intense pressure to be completed as quickly as possible. Therefore, there is a need to focus on the quality of commissioning and assurance that the as-built or to-be-built facility is consistent with the latest revision of the models used in generator interconnection studies conducted during the generator interconnection process and to reduce the risk of expected performance during real-time operations. To help ensure reliable operation of the BPS, as-built evaluation and commissioning requirements should be created to help ensure that the IBR will operate as expected and studied and that sufficiently documented proof of compliance has been provided to applicable TOs and TPs.
Project Scope (Define the parameters of the proposed project):
This project will modify the latest versions of NERC FAC-001 and FAC-002, while ensuring alignment and complement with FERC Order No. 2023 and FERC GIA/GIP. The scope of the project is to modify NERC Standards to: 1) Include specific IBR interconnection topics in FAC-001-4 for which generator interconnection requirements shall be defined by TOs/TPs 2) Include specific steps for a conformity assessment intended to assess FAC-001-4 conformity in FAC-002-4 3) Include requirements for TOs to include pre-commissioning requirements for GOs to provide evidence that the facility: a. Successfully passes an evaluation with performance that meets commissioning requirements. Discrepancies between plant performance and commissioning requirements should be shared with associated TP and PC to ensure visibility into the discrepancies and mitigation actions. b. Ensure that the parameters and control modes intended to be placed in-service produce performance that matches the performance of the as-designed plant model that was used in generator interconnection studies. 4) IBR control parameter updates that affect the performance of the facility, made during the comissioning process, are updated in the facility model and studied to ensure reliability

Requested information
Detailed Description (Describe the proposed deliverable(s) with sufficient detail for a drafting team to execute the project. If you propose a new or substantially revised Reliability Standard or definition, provide: (1) a technical justification[12] of developing a new or revised Reliability Standard or definition, which includes a discussion of the risk and impact to reliability-of the BES, and (2) a technical foundation document (*e.g.,* research paper) to guide development of the Standard or definition):

The proposed project will produce the following deliverables: modifications to the latest FAC-001 and modifications to the latest FAC-002 while ensuring alignment and complement with FERC Order No. 2023 and GIP.
 	
NERC FAC-001-4 Enhancements to the requirement R1:
• Each TO shall document enhanced Facility Interconnection Requirements for IBR, in coordination with their TP, PC, and affected TOs, update them as needed and make them available upon request. IBR facilities generator interconnection requirements shall, at a minimum, include some or all of the following scope leveraged from existing industry standards, NERC Standards and other NERC Publications, and other industry works. The Standard Drafting Team shall ensure coordination with FERC Order 901 and FERC GIA/GIP, already-approved NERC Standards, Standards currently under development, and consider region-specific reliability concerns and processes to allow variances to certain requirements if necessary to ensure BPS reliability.
  • General generation interconnection technical specifications and performance requirements
    o Reference points of applicability (e.g., specifying[13] where the interconnection requirements apply, e.g., point of interconnection)
    o Applicable voltages and frequencies (e.g., specifying the meaning of voltage and frequency for each of the following interconnection requirements (e.g., phase or instantaneous values, etc.))
    o Measurement accuracy (e.g., specifying the accuracy of steady state and transient measurement, accuracy requirements for an IBR Facility’s performance monitoring and validation)
    o Operational measurement and communication capability (e.g. specifying communication capabilities required from an IBR Facility for providing real-time operational information)
    o Control capability requirements (e.g., specifying the capability of an IBR Facility to respond to external control inputs, e.g., capability to limit active power as specified by a TO)
    o Prioritization of IBR responses (e.g., specifying the priority of IBR Facility responses to TO’s interconnection requirements)
    o Isolation device (e.g., specifying the requirement for break isolation device between the TO’s network and the IBR Facility)

[12] The NERC Rules of Procedure require a technical justification for new or substantially revised Reliability standards. Please attach pertinent information to this form before submittal to NERC.
[13] For the purpose of this document, specifying means developing or referring to a requirement within a certain category.

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

Requested information
○ Model Validation report showing benchmarking between all submitted model types (Standard Library Model, Positive Sequence User-defined model, and Electromagnetic Transient (EMT)) model and the real equipment as per FERC Order 2023[14] • Measurement data for performance monitoring and validation (e.g., specifying measurements, data recording, and retention requirements at an IBR Facility for the purpose of performance monitoring and validation during an IBR Facility operation) • Test and verification requirements (e.g., specifying requirements for testing and verifying an IBR Facility's conformity with applicable interconnection requirements during the interconnection process, at the commissioning stage, and during IBR Facility operation) **NERC FAC-002-4 Enhancements:** • Additional requirement: TPs and PCs shall develop the process for assessment and assess conformity with applicable interconnection requirements (as per FAC-001-4) for interconnecting IBR facilities and existing IBR facilities seeking to make a qualified change as defined by the Planning Coordinator under requirement R6. The SDT should reference the FERC GIA/GIP to ensure alignment when determining appropriate timelines for generator interconnection processes milestones along with the submission of qualified changes, updated models, model documentation, and test reports. The assessment may include physical testing such as factory testing or simulation-based assessment using detailed, representative models of the IBR facility that will be built in the field. Entities that implement physical testing requirements should also create requirements under FAC-001 that specify the data and measurements needed to be recorded during physical tests. These assessment processes should again leverage the work being done in the IEEE P2800.2 working groups. • The Standard Drafting Team shall ensure coordination with FERC Order 901 and NERC Standards under development or currently subject to mandatory enforcement. **IBR Facility Commissioning Enhancements:** • New requirements created by applicable entities that require the GO of a registered IBR facility provide adequate proof that the facility was commissioned reliably. • Documentation to the TO, Transmission Operator (TOP), TP, PC, Reliability Coordinator (RC), and BA regarding commissioning checks related to protection and control systems as well as plant capability. • Documentation that the commissioned in-service facility matches the model used during the interconnection process. Any discrepancies should be identified and reported to the ERO Enterprise and the aforementioned transmission entities for corrective action as needed. (NOTE: As-built settings, controls, or protections that do not match what was studied during the interconnection process present serious adverse BPS reliability impacts, leaving the TOP, RC, and BA operating the system in an "unknown operating state" since grid performance cannot be predicted.)

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

Requested information
Cost Impact Assessment, if known (Provide a paragraph describing the potential cost impacts associated with the proposed project):
The exact costs for this project are unknown. Near-term and long term costs are likely to increase as industry develops practices around IBR interconnection requirements and conformity assessment. GOs will need to familiarize themselves with newly developed and implemented interconnection requirements, procure equipment, and design IBR facilities in conformity with these. They will also need to do their own IBR Facility design evaluation to verify the IBR Facility's conformity with applicable interconnection requirements. TOs will need to develop IBR interconnection requirements, leveraging existing Standards insofar possible. TPs and PCs will need to develop conformity assessment and testing practices. Additionally, more testing and study work will be added during the interconnection process in order to conduct the conformity assessment, which will demand engineering staff's time and result in increased costs of interconnection studies overall. These initial costs may lead to reduced transmission expansion costs, as increased IBR performance and modeling should lead to a more efficient use of the transmission system. These costs are recognized; however, the team has made a focused and concerted effort to minimize costs while achieving the necessary reliability outcomes for this project. Additionally, added time costs due to added study work may necessitate adjustments to IBR interconnection timelines. Outcomes from this project will help ensure an adequate level of reliability for the BPS significantly outweighs the incremental costs of implementation from this proposed project.
Please describe any unique characteristics of the BES facilities that may be impacted by this proposed Standard development project (*e.g.*, Dispersed Generation Resources):
New BPS-connected IBR facilities and existing BPS-connected IBR facilities seeking to make a qualified change as defined by PC under requirement R6 of FAC-002-4 will be directly impacted as the Facility will need to be designed in conformity with the newly-implemented interconnection requirements.
To assist the NERC Standards Committee in appointing a drafting team with the appropriate members, please indicate to which Functional Entities the proposed Standard(s) should apply (*e.g.*, Transmission Operator, Reliability Coordinator, etc. See the NERC Rules of Procedure Appendix 5A:
This section presents two questions, and therefore the IRPS will address each separately. 1) Appropriate drafting team members could involve individuals from the following entities: TOs, TPs, PCs, GOs, OEMs, IBR commissioning contractors or consultants, TOPs, RCs, BAs 2) The proposed Standards changes should apply to the following: TOs, TPs, PCs, GOs
Do you know of any consensus building activities[15] in connection with this SAR? If so, please provide any recommendations or findings resulting from the consensus building activity.
This SAR was developed by the NERC IRPS, which is a consensus building stakeholder group under the NERC RSTC. Upon endorsement by the NERC Reliability and Security Technical Committee (RSTC) through its stakeholder process and associated industry comment periods, the IRPS submits this SAR with that consensus building as well.

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

Requested information
Are there any related Standards or SARs that should be assessed for impact as a result of this proposed project? If so, which Standard(s) or project number(s)?
Project 2023-05 is currently working on modifications to both FAC-001-4 and FAC-002-4 but modifications focus on distributed resources and not IBR. This SAR helps meet the goals of FERC Order 901 and thus should be coordinated with ongoing NERC Order No. 901 activities.
Are there alternatives (e.g., guidelines, white paper, alerts, etc.) that have been considered or could meet the objectives? If so, please list the alternatives with the benefits of using them.

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

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

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

For Use by NERC Only

SAR Status Tracking (Check off as appropriate).	
☐ Draft SAR reviewed by NERC Staff ☐ Draft SAR presented to SC for acceptance ☐ DRAFT SAR approved for posting by the SC	☐ Final SAR endorsed by the SC ☐ SAR assigned a Standards Project by NERC ☐ SAR denied or proposed as Guidance document
Risk Tracking.	
☐ Grid Transformation ☐ Resilience/Extreme Events	☐ Energy Policy ☐ Critical Infrastructure Interdependencies
☐ Security Risks	

Version History

Version	Date	Owner	Change Tracking
1	June 3, 2013		Revised
1	August 29, 2014	Standards Information Staff	Updated template
2	January 18, 2017	Standards Information Staff	Revised
2	June 28, 2017	Standards Information Staff	Updated template
3	February 22, 2019	Standards Information Staff	Added instructions to submit via Help Desk
4	February 25, 2020	Standards Information Staff	Updated template footer
5	August 14, 2023	Standards Development Staff	Updated template as part of Standards Process Stakeholder Engagement Group

NERC

NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

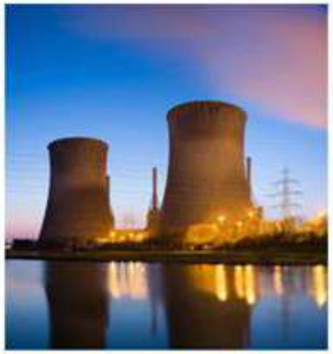
Development of SAR - Enhancements to FAC-001 and FAC-002

Alex Shattuck, NERC

RSTC Meeting

September 11, 2024

RELIABILITY | RESILIENCE | SECURITY



Draft SAR Background

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

Intent of the SAR

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

IRPS Drafting and Review Process

- The SAR was initially created by a group of expert members of the IRPS
- The draft SAR underwent a 2 week IRPS comment period, RSTC and public joint comment period, and a final IRPS comment and review period
- All comments were considered with most resulting in clarifying and technical revisions
- This SAR received 11 “Yes” votes and 0 “No” votes during the consensus building process

Action

- IRPS is seeking RSTC approval of this SAR: Enhancements to FAC-001 and FAC-002

Questions and Answers

Assessing the Effectiveness of Facility Ratings Methodologies "Incorporating Quality Assurance Controls (e.g., sampling) into Facility Ratings Assurance"

Action

Approve

Background

Facility Ratings are among the most data-intensive regulations in NERC's Reliability Standards and the stated purpose of FAC-008-5 is 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. Registered entities required to develop Facility Ratings methodologies (FRMs) can strengthen their FRMs by incorporating quality controls such as sampling. The goal of this white paper is to provide a reference resource for registered entities seeking to improve their FRMs by adding sampling or enhancing existing sampling. To facilitate this goal, the paper discusses the assessment of risks inherent to an FRM, the benefits of sampling as part of an FRM, and methods for and examples of sampling in an FRM.

Summary

The Facility Ratings Task Force is requesting that the RSTC approve the whitepaper "Assessing the Effectiveness of Facility Ratings Methodologies - Incorporating Quality Assurance Controls (e.g., sampling) into Facility Ratings Assurance."

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Assessing the Effectiveness of Facility Ratings Methodologies

Incorporating Quality Assurance Controls (e.g., sampling) into Facility Ratings Assurance / September 2024

Executive Summary

Facility Ratings are among the most data-intensive regulations in NERC's Reliability Standards and are essential for oversight and validation. Using internal controls for process validation can provide solutions that strengthen an entity's methodology and increase success rates. The quality assurance controls, such as sampling, discussed in this white paper are the following:

- **Accuracy and reliability:** Sampling may ensure the accuracy and reliability of the process being validated by establishing checks and balances throughout the process. This helps identify any errors or deviations and can ensure that the data collected is accurate and trustworthy.
- **Compliance:** Sampling can help organizations validate their methodologies and comply with regulatory requirements, industry standards, and best practices. Implementing internal controls allows companies to 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. Appropriate controls allow companies to mitigate these risks—including both operational risks (such as errors) and compliance risks (such as violations of laws or regulations)—and prevent potential issues or failures.
- **Continual improvement:** Sampling allows continuous monitoring of the validated process, thereby helping increase the likelihood of success. In addition, it will help identify areas for improvement and ensure that the process remains effective and efficient over time. Internal controls allow companies to 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. The use of strong internal controls demonstrates a company's commitment to accuracy, reliability, and compliance. This transparency helps build trust and credibility among stakeholders.

In summary, sampling as a quality assurance control for the Facility Ratings methodology (FRM) can be a helpful tool and may be essential for process validation as it can help ensure accuracy, compliance, risk mitigation, continual improvement, and transparency. Companies can use sampling as a control to enhance the validation process and minimize the likelihood of issues or failures.

Introduction

The stated purpose of Standard FAC-008-5 is **"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, refers to a set of equipment that operates as a single BES Element (e.g., a generator, transformer, or transmission line). The individual components that comprise a BES Element may be referenced as facilities.

Though determining a Facility Rating for a BES Element seems reasonably simple, many factors can lead to individual Facility Ratings being mis-determined, rendering a company's Facility Ratings inaccurate. An FRM should accurately represent the capabilities for each BES Element such that a Facility can be effectively and fully utilized without jeopardizing any of the underlying facilities. The following actions should be taken when measuring the effectiveness of a registered entity's FRM:

- Consider the completeness of the methodology,
- Measure the consistency of the FRM's application, and
- Evaluate the accuracy of the results or outputs.

Any discrepancy detected in the process or in the accuracy of the results may indicate that the methodology requires focused improvements, depending on the nature and timing of the issue.

Audit principles and practices, such as sampling, can be especially useful for registered entities and the Regional Entities in measuring the effectiveness of the FRM. In 2015, the Electric Reliability Organization (ERO) published a Sampling Handbook to define sampling for audit practitioners. This handbook can also be used by industry, but a deeper exploration of the types of tools that may be more useful in an FRM, and the tools' potential uses is warranted. While the Public Company Accounting Oversight Board and the Institute of Internal Auditors both define (audit) sampling and the methods for using it to support an opinion, this paper discusses data sampling as an internal control or quality inspection metric within an FRM.

Sampling evaluates a subset of a population by reviewing only a portion of that population to reach conclusions with a predefined level of certainty. This approach is useful when performing quality checks to validate the accuracy of ratings, the completeness of ratings implementation in the FRM, and the consistency of the methodology's application. Sampling is fundamentally broken into statistical and non-statistical sampling despite multiple potential methods. Statistical sampling would be considered a sample pulled from a population that is representative or contains the characteristics of the entire population of Facility Ratings under the umbrella of the Facility Ratings methodology. Non-statistical is random selection sampling or based on experience or judgment of the person performing the sampling.

Sampling is a detective control that may identify defects or inconsistencies in the FRM based on a predefined level of desired accuracy. These findings are useful in identifying process gaps, inconsistent execution of the organization's FRM, human errors, control failures, or control design failures, thereby allowing correction of these issues and improving the processes and FRM. 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 FRM execution. Furthermore, sampling when used over time can identify trends and areas of focus to strengthen a registered entity's FRM and drive continuous improvements.

The goal of this white paper is to provide a reference resource for registered entities seeking to improve their FRMs by adding sampling or enhancing existing sampling. To facilitate this goal, the paper discusses the assessment of risks inherent to an FRM, the benefits of sampling as part of an FRM, and methods for and examples of sampling in an FRM.

Sample size is another consideration that is complex to codify where the size would be applicable for all companies. Sample size (in broad terms) should be representative in nature and percent of total population to provide the company a view of the effectiveness and accuracy of the implementation of the Facility Ratings Methodology. Based on the sampling results and confidence in the outcome, the company may elect to do further sampling to extrapolate error rates and assess the need for methodology or process reviews if prudent. Remember that sampling is designed to be a quality control for the Facility Ratings Methodology implementation success and can assist the entity to identify process opportunities or methodology errors to strengthen reliability overall.

From an effectiveness and practical application perspective, it is difficult to prescribe for an entity how to design sampling and when to incorporate what type. The sampling should be a product of the assessed risk and where additional quality control checks are desired or necessary to encourage improved performance or process consistency. Sampling is an entire function within the discipline of process improvement and auditing. Comprehensive curricula exist with degreed programs on statistics and sampling. This paper is not intended to replace those or provide the fulsome information represented in a college course. Alternatively, this white paper provides additional considerations for ensuring the most effective implementation of the entity's methodology with the opportunity to use sampling as a tool to increase the likelihood of success.

Parameters That 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) FRM

Regulations and Industry Guidelines

NERC Standards, Federal Energy Regulatory Commission (FERC) regulations, National Electrical Safety Code (NESC) requirements, state administrative codes and other regulations can impact Facility Ratings. Some requirements are clear, but others are up for interpretation or to define for themselves. Note that changing regulations sometimes require systemwide Facility Ratings updates, while some only need to be applied going forward. FAC-008 requires underlying assumptions used in establishing the equipment ratings that comprise a Facility Rating to 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. Some TOs, however, do not explicitly have bus sections; rather, the bus ratings are accounted for in their line Facility Ratings.

Equipment Types

TOs use many common equipment types in electric power transmission systems, but not all TOs own and operate the same types of equipment. FAC-008 lists several types of equipment in scope but not the entire scope of equipment that falls under its purview.

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 flexible alternating current transmission systems (FACTS)). Some of this equipment falls into 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 to equipment ratings and Facility Ratings because current carrying capacity typically depends on the heating and cooling of metal equipment. Examples include the following:

- 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 can therefore 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 variables 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., an 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 due to their unique properties.
- Unique properties of submarine (underwater) cables. These installations do not lend themselves to field verification due to their unique properties.
- Assumptions related to current transformers.
- Assumptions related to connectors and fittings.
- Other characteristics not related to equipment material include the following:
  - 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 refers to 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. 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 equipment owned by different TOs or equipment co-owned by 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 the following:

- Reference to detailed equipment ratings methodology documents (e.g., separate criteria documents that 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 that the rating was established and updating the respective equipment rating accordingly if new or improved equipment records become available.
- A statement about limiting the number of emergency events to stop loss of equipment life from accelerating.
- 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

Many processes and practices that could impact Facility Ratings are not part of a TO's FRM, including the following:

- 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 Power Line Systems – Computer Aided Design and Drafting (PLS-CADD) models for line ratings.
  - Guidance on how to evaluate different rating scenarios (e.g., feature codes of LiDAR point types, code clearances for ground and buildings)
  - As-built modeling practices
    - PLS-CADD models are typically not updated with 100% of as-built information.
    - Note: These models are based on surveys (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 (SOL), 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), registered entities must have strong and sustainable FRMs. Facility Ratings are essential to planning and operating the BPS, and errors can put the BPS at significant risk. SOLs—essential for real-time grid operations—are based on Facility Ratings and are vital to supporting and maintaining situational awareness. Incorrect Facility Ratings can result in issues including operating in an unknown state, uncontrolled widespread service outages, and fires. Furthermore, Facility Ratings and SOLs play a key role in modeling the grid as future BPS projects are contemplated to manage load growth and mitigate system constraints. If Facility Ratings are not determined correctly and applied consistently for all applicable Facilities, equipment can be forced to operate beyond its capability. This can cause equipment damage or line sagging beyond the equipment's design and result in unplanned outages and safety issues. For this reason, Facility Ratings issues were noted as contributing to the August 2003 blackout.

A foundational step in producing a strong and sustainable FRM 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 help ensure that the methodology has been implemented as intended. These include the following:

- **Voltage level:** Higher-voltage Facilities indicate power transfer capability, which implies larger risk.
- **Interface limits:** Facilities included in Interconnection Reliability Operating Limits (IROL), transfer paths, Flow Gates, and generic transmission constraints are in place to mitigate significant risks.
- **Remedial Action Schemes:** Facilities involving Remedial Action Schemes and the alternate-flow Facilities that support Remedial Action Schemes provide for reliable operations.
- **Generation interconnects:** Facilities supporting current and near-future generation interconnections are emerging as a risk due to the grid transformation seen across the BPS.
- **Facilities impacted by long-duration planned outages:** Facilities supporting flows during construction, rebuilds, and extended maintenance periods are needed for reliable operations while reliability improvements are underway.
- **Facilities normally involved in congestion:** Facilities that cause congestion or are continually supporting flow because of congestion may be worth periodically validating.
- **High-profile Facilities:** Facilities that support locations considered high profile (e.g., state capitols, major infrastructure like gas refineries) may warrant a review.
- **Facilities maintained after an event:** Facilities that had equipment changes (e.g., storm restoration, fire, flood, sabotage) warrant a review soon after the change is completed.
- **Residual Facilities:** Facilities that did not necessarily meet any other risk evaluation warrant a periodic review specific to the risk posed.

The following four attributes are foundational to the successful implementation of a sustainable Facility Ratings Methodology:

- Leadership commitment for consistent messaging and training,
- Effective inventory and change management,
- Quality assurance reviews (e.g., methodology, equipment changes), and
- Periodic validation through risk-based sampling.

These attributes of an FRM provide the basis to help ensure that entities have strong and sustainable methodologies and programs. Depending on the organization, each of the items represents significant effort. There may not be a single, absolute solution across all organizations, each of which should consider its own risk. The nature of the organization will determine if leadership is a senior-level executive or a department head. Tools for inventory and change management should be selected to fit the needs of the organization and with processes to minimize errors. Due to the complexity of the FRM, employing quality assurance reviews to validate precision and effectiveness of the implementation must be based on risk.

The key factors below summarize how to institute a sound methodology for FAC-008. 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. In response, the organization should do the following:

- Document Control
  - Define the approval authority over and the review cycle of the FRM.
- Define the Scope of Equipment
  - List all equipment that applies,
  - Define clearly reasoning on how ratings for each equipment type are determined,
  - Determine Normal and Emergency Ratings for each equipment type,
  - Consider ambient adjusted temperature for each equipment type, and
  - Consider operating limitations (abnormal configurations, protection setting limitations, clearances).
- Determine the most limiting element.
- Define how jointly owned Facilities will be addressed.
- Utilize internal controls to identify gaps in methodology execution and mitigate drift to failure.

Facility Ratings, while representing table stakes of reliability, require effective coordination and communication across organization with numerous stakeholders. Ensuring that stakeholder actions support implementation of the methodology with the understanding of how Facility Ratings impact different process areas or organizational areas across the company is paramount to success.

Leadership Commitment

A sustainable FRM begins with the "tone at the top;" an entity needs high-level support and understanding regarding the criticality of Facility Ratings and the business need to maintain them. A sustainable methodology requires time and resource investments balanced against the risks associated with Facility Ratings. A lack of executive-level or leadership advocacy may limit success. The "tone at the top" also supports consistent messaging and expectations of accountability across the organization. Each group, department, or employee should be aware of the importance of a Facility Ratings methodology based on the leadership commitment to reinforce its importance to reliability.

The FRM must address all equipment types that impact Facility Ratings while focusing on the reliable performance of and protection of assets. An organization should maintain an accurate inventory of equipment that comprises a Facility or impacts a Facility Rating. In the most recent Standard Authorization Request (SAR) focused on FAC-008, the Project 2021-08 Standard Drafting Team discussed a possibility for a non-electrical component of a Facility may be the most limiting element that defines a Facility Rating. An example of this, in which Facility Ratings are limited by protection system settings, has been seen in the field and highlights the need to understand equipment that could affect Facility Ratings that exceed the historical understanding of a Facility. Remaining cognizant of the reliability impact of Facility Ratings and how they are used within a given methodology should facilitate reliable operations and awareness.

Effective Inventory and Change Management

The idea of a Facilities baseline, presented at the May 2023 ERO Enterprise webinar on Facility Ratings Themes, supports this discussion, as understanding the baseline is key to understanding risk. This white paper covers several aspects of a Facility baseline, but knowing what the baseline consists of is essential for success. The *ERO Enterprise Themes and Best Practices for Sustaining Accurate Facility Ratings* report states that, as a best practice, trained personnel should use inventory management tools to maintain a change management process. The inventory must be documented and managed such that the attributes necessary to implement the organization's FRM are supported consistently across all departments.

Simply knowing the equipment may be insufficient for maintaining reliable operations. Understanding what equipment is more susceptible to overloads (e.g., thermal, voltage) because of the type, loading, or system configuration is important, and being aware of the Facility Ratings for electrically connected Facilities is important to understand from a reliability perspective. A change by one company could impact what may be the most and next most limiting element in an electrically connected Facility. This scenario requires consideration in the FRM 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 (as discussed later). Project 2021-08 Modifications to FAC-008 is considering defining responsibilities for owners of electrically connected Facilities to help ensure that 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.

Internal Controls

As with any methodology, a certain level of internal controls is needed to maintain sustainability. At a minimum, organizations should consider the robustness of their methodology in terms of managing, reporting, and validating Facility Ratings information. Detective, preventive, and corrective controls should be integrated into the workflows to help ensure that the most accurate information is being utilized. These controls can identify errors and mitigate issues or identify process design flaws for review.

Understanding the nature of the error is as important as identifying the error itself. An organization should be able to differentiate between the impact of 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. To ensure that all affected parties are made aware, communications associated with finding the error should be part of the internal control environment.

Some cases may require checklists to be built into processes to help prevent errors; these may also be useful in detecting errors when validating information through sampling. Of course, if issues are identified, the organization should consider the most effective way to incorporate lessons learned into its methodology to avoid repeat occurrences. The cause of the issue should be reviewed to help 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 details a significant need for enhanced internal controls at every level of an FRM. The robustness of the controls may be dependent upon the risk associated with the process or methodology broadly, such as the number of assets in scope, number of changes to elements, and number of ratings changes. 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 approach internal controls differently from 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, an accurate starting point or baseline should be established. The first of several steps for doing so is field verification of the assets. Typically, this is followed by a review of the drawings and a recalculation of the Facility Ratings while keeping in mind that the Facility Ratings are an aggregate of system elements as defined in the NERC *Glossary of Terms*. Entities should consider periodically evaluating the effectiveness of their change and asset management process to potentially reveal areas that may benefit from additional attention. Appropriate internal team stakeholders, such as key departments and contractors, must be accounted for and involved in the periodic review/assessment process. Once the change and asset management processes undergo review, the documentation associated with the processes and procedures should 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 established by the "tone from the top." Specifically, company executives help ensure that involved personnel and departments are aware that they are critical in assuring overall reliability, as their work is crucial, and accuracy is important. Successful companies usually have an executive sponsor to support their efforts. The best practices used by companies that have positioned their FRMs for long-term sustainability are the following:

- Robust documented change management process
- Inventory management tools with required training
- Checklists for new inventory additions
- Effective data capture processes
- Single database for master recordkeeping
- Access controls established for Facility management tools
- Built-in quality assurance reviews in concert with internal controls
- Periodic in-field validation/field walk-downs
- FRM organizational owner
- Management oversight

Lastly, the impact of mergers and acquisitions should be taken into consideration, as, when two or more entities merge, each brings their own set of FRMs, supporting policies, and procedures. Company executives should reinforce efforts to create and maintain a single comprehensive FRM and program. A "pre-merger" effort for Facility Ratings and other Reliability Standards would serve to help ensure the consistent establishment and management of these ratings and standards across the new organization.

Periodic Validation

There is currently no one single solution that considers how Facility Ratings are validated. Facility Ratings are good for the day on which they are created, but "drift" may occur after that. "Drift," either slower paced (like exposure to the elements over time) or faster paced (like restoration after a storm), can be approached through a risk-based sampling validation effort. Facility Ratings, based on reliability risk posed, is the defining parameter for how organizations consider sampling for validation. Again, a blank prescriptive "X% per year" approach should not be placed upon the industry due to the approach's impacts on the many 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 (i.e., likelihood times consequence). In several cases, a risk matrix tool (as visualized 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 them accordingly. Considering the recent *ERO Enterprise Themes and Best Practices for Sustaining Accurate Facility Ratings* report, it should be asked if the organization has considered the risk of having some of the themes noted being present and the potential impact on reliable operations. Understanding what Facilities are being rated and how those Facility Ratings impact the BPS is critical to recognizing risk.

When preparing to sample, ask, "If I lost this Facility, what would be the reliability impact to the BPS?" Prioritizing based on this impact question will allow sampling decisions to be started/continued on the most critical assets first. In some cases, where appropriate, assessing the risk of Facility loss or impact to the BPS may require additional information be provided by another Registered Entity (i.e., Transmission Operator, Transmission Planner, Reliability Coordinator, Planning Coordinator, etc.).

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 validation results are finalized, an organization should review the results for improvements. Error rates should be factored into future sampling efforts, and the trends of the error rates (e.g., human error typo, contractor management, emergency restoration) should be defined. The reliability risks associated with the errors may impact the sampling, the timing of the sampling, or other internal triggers (such as an in-depth root-cause analysis). The sampling strategy should adapt to the results that are being received. 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 the 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 given sample period contain errors, at what point should the third-party organization be reconsidered as a resource? This may require a secondary risk evaluation depending upon the nature of the error.

Timing must be considered when using sampling as periodic validation. The organization's risk appetite is key when designing how to use sampling as a quality control or assurance check. Previous sampling results (failure rates) should factor in the determination of sample size and frequency of sampling.

- Should all sampling occur annually?
- Should sampling occur annually for some items and every three years for others?
- Should sampling results change the periodicity of sampling?

As companies perform risk assessments of their inventories, an understanding of how sampling timing was determined will be needed. 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 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 FAC-008 outreach, as some companies felt that they were effectively managing Facility Ratings until an external party initiated a review or convinced the organizations to thoroughly review all aspects of their methodologies.

Methods for Verifying Facility Ratings

When formulating a plan for ratings verification, the unique differences between existing vs. new or modified facilities and substation vs. transmission line facilities should be considered.

Existing Facilities

Existing equipment ratings and Facility Ratings are typically verified by confirming that field conditions match the ratings system of record (SOR). This verification is typically viewed as a "detective" control because it is undertaken 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 that 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.
- 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 method involves a site visit after a substation Facility construction is completed and the Facility placed in service, but before the project is closed out, to confirm that all records and the ratings SOR match field conditions. The method is used for substations because a site visit cannot verify transmission line rating attributes. This is a detective method for recently installed existing facilities and therefore can identify gaps in current business practices and preventive controls.

  Note: Depending on timing, this method could function as a preventive control for new and modified facilities if executed prior to energization or in-service.

Commented [NS1]: Flagging bullet formatting in this section.

Transmission Line Methods

- LiDAR survey, PLS-CADD 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 (e.g., change in survey technology/accuracy, third-party activities near lines, reflecting current methodology and practices vs. legacy)
- 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 business practices requiring third parties to contact the TO before constructing facilities near transmission lines, business practices to detect unapproved third-party encroachments and evaluate their impacts, and 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 is undertaken during the construction or maintenance project process.

- Note: Business practices that route maintenance replacements through the construction process for ratings updates help ensure that ratings data is updated accurately and timely.

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 the potential for error but should include quality checks/validations before acceptance 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 the potential for error but should include quality checks/validations before acceptance 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 by using metrics to track the characteristics of identified Facility Rating issues. This can help focus future efforts on helping 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 PLS-CADD 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.
Third 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
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

Registered entities must employ strong and sustainable FRMs to help ensure a reliable and secure BPS. Accurate Facility Ratings are needed for operating, planning, and maintaining the BES; determining SOLs and IROLs; and for making decisions associated with BPS operations.

Nonetheless, companies studying FRMs still must determine which types of verification and validation activities should be part of the methodology that provides assurance of accuracy. Considering risk and risk tolerance, the entity needs to balance verification and process controls by building on the risk assessment discussion earlier in this document. A good FRM takes the methods described in the earlier **Methods for Verifying Facility Ratings** section and incorporates validation activities into each step of the Facility Ratings process to provide additional assurance that processes are working as designed and controls are operating effectively.

Verification at Various Process Stages

It may be discovered during many stages of a process, procedure, or project (including project initiation, emergency work, or changes or upgrades to the ratings database or drawing updates) that further verification is necessary or desired for additional assurance. In addition, 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)
  - EMS and Facility Ratings database auto-comparison tools should be considered if available to help 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 accuracy of Facility Ratings and corresponding EMS ratings should be completed.
- Planning Database
  - Planning database and Facility Ratings database auto-comparison tools should be developed/considered if available to help ensure consistency between programs. A similar approach should be considered for an entity's planning database (TO) and Transmission Planner 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 accuracy of the Facility Rating and corresponding entries in the planning database to help ensure all post-project and emergent work changes were captured.

Ranges of Reasonableness (Robustness, Frequency, Risk Criteria, Sampling Size)

- Establishing an accurate starting point or baseline for both equipment and Facility Ratings is essential to sustaining a methodology. To develop a robust periodic verification program, an appropriate baseline must be established. Furthermore, as Facility Ratings are affected by many changes as previously discussed, change management programs should be implemented with the support of tools to document the ratings in place.
- For example, if a ratings database is utilized where all equipment and its characteristics are captured, an entity could leverage the database as a "checklist" or means during field verification to confirm that the equipment exists.
- For frequency, an entity should leverage existing processes and procedures where possible. Field verification frequency could be associated with capital project work, preventive maintenance work, or an appropriate period that provides the entity reasonable assurance.
  - For example, certain entities that perform full-system walkdowns may try to leverage a 5–6-year period that covers approximately 20% of their facilities.
- For 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 identified as potentially driving risk higher and suggest additional testing or controls. Risk considerations of this type may look at mergers and acquisitions, personnel changes, process changes, unclear or undefined ownership of equipment, shared responsibilities, contractor work, or undocumented processes.

Metrics as Validation

Metrics can effectively serve as a checkpoint or dashboard that indicates controls are working as designed. Balancing metrics with the benefit received from tracking is also important. For instance, during field verifications of information captured in as-builts or one-line diagrams to equipment in a Facility, the number of variances or percentage variance to the total could be captured as a metric. Most importantly, the metrics should be designed to support control validation, process effectiveness validation, and tracking efficiency to benefit from the data produced. When striving for efficiency in industry resource usage, it can be easy to over architect processes, metrics, and controls in search of ratings accuracy. Each organization will identify its own appropriate specific use of processes, controls, and metrics but should efficiently deploy the appropriate resources to achieve Facility Ratings accuracy and nimble processes for dynamic changes.

Value Proposition

Essential to the methodology is evaluating the processes and steps executed by measuring the resources expended against the benefit recognized. Cost-benefit analysis, a systematic process that businesses use to optimize decision-making, applies to the evaluation of controls to enact to assure that objectives (e.g., accurate Facility Ratings or the implementation of successful FRMs) are met. The sum of the potential rewards expected from a control or process step minus the associated total costs represents the cost benefit.

All cost-benefit analysis should be framed according to the level of risk. As previously discussed, to guide the level of validation or verification necessary to help ensure successful implementation of ratings, the organization should assess the risk by considering its execution of its FRM, the risk of inaccurate ratings or failure to adhere to its methodology, and the risk threshold or tolerance. These risk analytics should be key considerations in the cost benefit equation and decision-making process.

Implementation Guidance for FAC-008-5

Action
Endorse

Background
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.

Summary
Sub-team 1 of the Facility Ratings Task Force requests that the RSTC endorse this proposed Implementation Guidance such that it can be submitted to the ERO Enterprise Compliance staff for further vetting and eventual endorsement.

RSTC
Facility Ratings Task Force
2023

Implementation Guidance for FAC-008-5

August 2024

Table of Contents

Introduction

The FAC-008-5 standard is applicable to Transmission Owners (TOs) and Generator Owners (GOs) that are required to determine Facility Ratings for their respective Facility(ies).

The purpose of FAC-008-5 is "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."

Facility Ratings are one of the basic building blocks of a transmission network or generation Facility. Facility Ratings help determine System Operating Limits. Facility Ratings are also used in power flow analysis to analyze and plan the system.

Note from the drafting team: We attempted to use simple and generic examples that could be considered to meet compliance requirements and it was never the intent to cover all specific configurations or methodologies that asset owners may use. Please read the document considering that, while requirements are unique, methodologies applied to meet compliance could go beyond the purview of this Implementation Guidance.

Goal/Problem Statement

This document, including possible examples, is being provided as an implementation guidance, to assist registered entities when considering methods and practices for meeting compliance. Registered entities are reminded that Facility Ratings are used in the reliable planning and operation of the BES and should be determined based on technically sound principles. This document is also intended to provide guidance on attaining and sustaining accurate Facility Ratings as outlined in Standard FAC-008-5. To exemplify options that a registered entity may apply, Appendix A and D offer some practices to consider, Appendix B frequently asked questions, Appendix C list of acronyms, Appendix E defined terms and Appendix F, additional example diagrams that are an attempt to provide clarity for different configurations used in the industry. These diagrams are not exhaustive and other configurations could also be used.

The goals of this Implementation Guidance are to:

- Provide guidance for developing Facility Ratings that are consistent with industry standards and/or regulations developed through an open process such as Institute of Electrical and Electronics Engineers (IEEE) or CIGRE (Council on Large Electric Systems)[1], manufacturer ratings (e.g., original equipment manufacturing ratings (OEM)) or testing;

- Provide guidance and clarity for identifying the most limiting applicable Equipment Rating for equipment comprising the Facility(ies);

[1] Translation of the French acronym Conseil International des Grands Réseaux Electriques.

- Describe the processes and outcomes that may be used for the appropriate application of the Standard to support the reliability of the BES.

Reliability Standard FAC-008-5

Requirement 1

R1. Each Generator Owner shall have documentation for determining the Facility Ratings of its solely and jointly owned generator Facility(ies) up to the low side terminals of the main step up transformer if the Generator Owner does not own the main step uptransformer and the high side terminals of the main step up transformer if the Generator Owner owns the main step up transformer. *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

1.1. The documentation shall contain assumptions used to rate the generator and at least one of the following:

- Design or construction information such as design criteria, ratings provided by equipment manufacturers, equipment drawings and/or specifications, engineering analyses, method(s) consistent with industry standards (e.g. ANSI and IEEE), or an established engineering practice that has been verifiedby testing or engineering analysis.
- Operational information such as commissioning test results, performance testing or historical performance records, any of which may be supplemented by engineering analyses.

1.2. The documentation shall be consistent with the principle that the Facility Ratings do not exceed the most limiting applicable Equipment Rating of the individual equipment that comprises that Facility.

Example 1 - Documentation

As an application example, although Requirement R1 does not require a methodology, it is recommended that some type of technically sound, repeatable process using engineering principles be applied – see Appendix F. As such, R1 does require GOs to have documentation supporting the Rating of each piece of equipment in the Facility from the generator up to the GSU low side bushings if the GO does not own the generator step-up (GSU); or to the high side bushings if the GO owns the GSU. Figure 1 shows these two different ownership examples.
It is important to note that in Figure 1, the Point of Interconnection (POI) only determines the change in ownership and does not indicate the endpoint of the Facility. Irrespective of the POI configuration, Facility Ratings should be available for R1, R2 and R3 in this example.

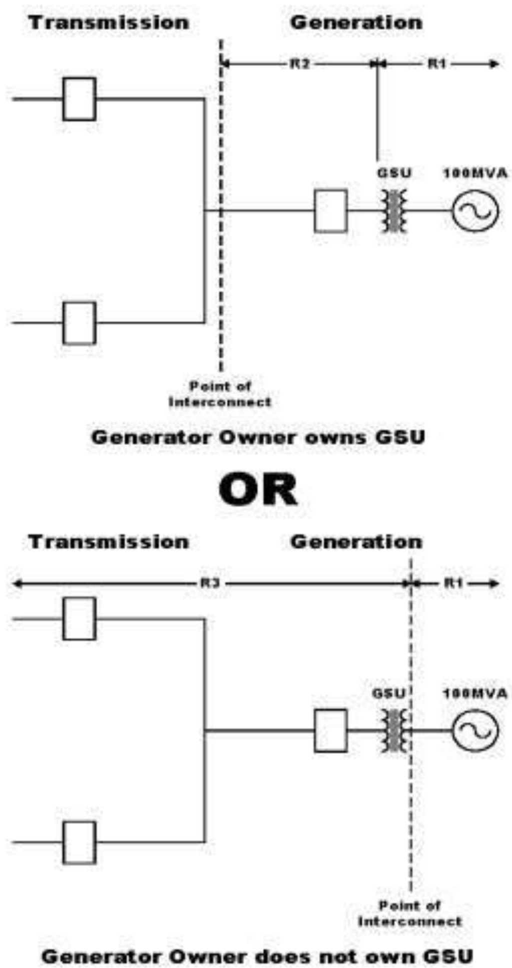


Figure 1. Requirement applicability based upon ownership.

This approach ensures that Facility Ratings are consistent with the Requirement R1 documentation by developing a list with each piece of equipment within the generator Facility. The list identifies applicable Ratings for each piece of equipment comprising the Facility and identify the document supporting the identified Rating. In addition, the documentation identifies the assumption(s) used to rate the generator using at least one of the following sources:

- Nameplate ratings
- Design drawings
- Engineering Analysis
- Test results

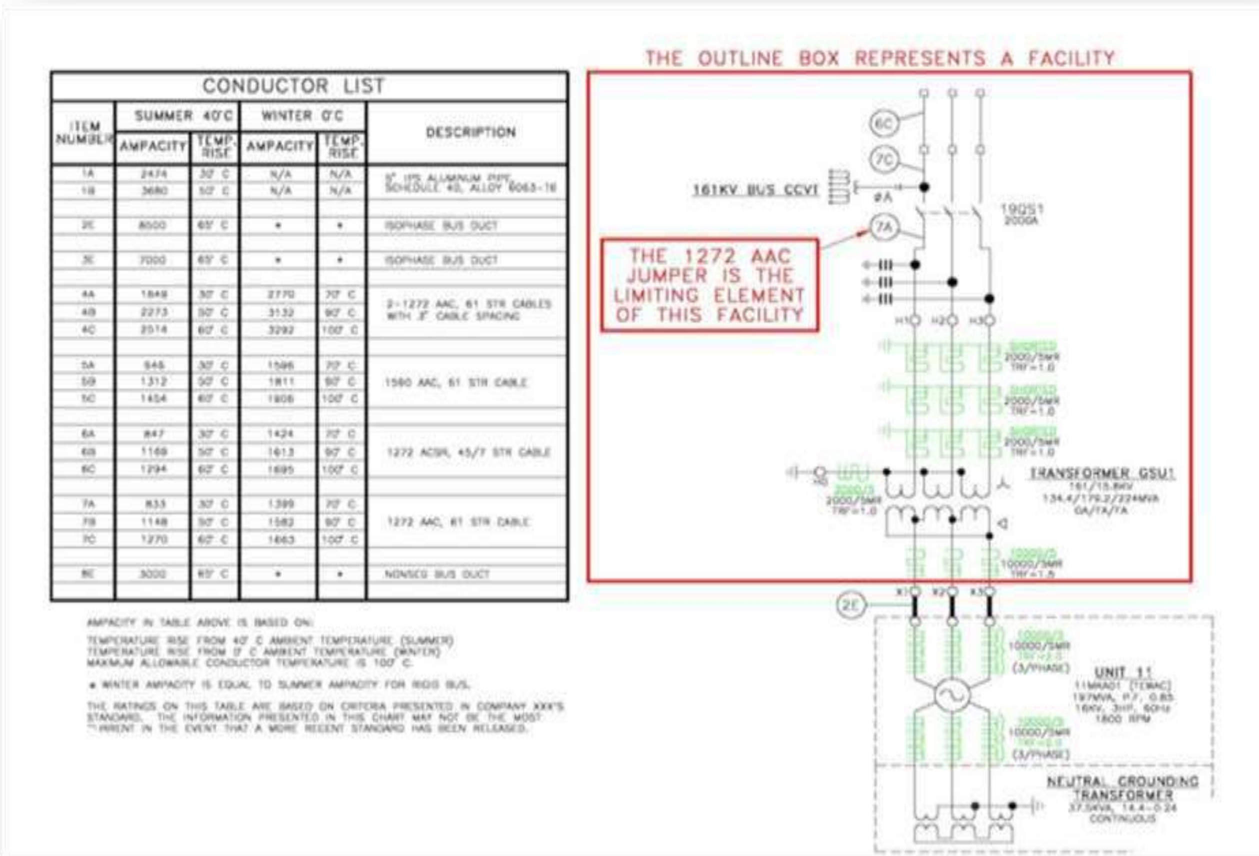


Figure 2. Sample Ampacity Diagram

Example 2 – Operational Data

In certain instances, operational data may be selected to use as a justification for rating a piece of equipment. When operational data is used, documentation should be retained to capture the assumption(s) used to rate the equipment. Examples of operational data includes:

- Average monthly temperature data may be collected for each station to be used for ambient condition unit Rating determinations.
- Annual Real Power verification testing may be performed, and manufacturer published performance capability data used to determine monthly temperature corrected unit Ratings.

- Ratings may be derived from Real Power verification testing and published performance capability data and documented using sound engineering principles.

From the list of equipment and their associated Ratings, the GO would be able to clearly identify the most limiting applicable Equipment Rating of the Facility to determine its Facility Rating.

Example 3 – Emergency Ratings

FAC-008-5 Requirement R1 does not require Emergency Ratings to be developed for equipment that comprise the generator Facility(ies). However, if Emergency Ratings are available, they can be documented to help ensure reliable operations.

Requirement 2 and 3

R2. Each Generator Owner shall have a documented methodology for determining Facility Ratings (Facility Ratings methodology) of its solely and jointly owned equipment connected between the location specified in R1 and the point of interconnection with the Transmission Owner that contains all of the following. [Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]

2.1. The methodology used to establish the Ratings of the equipment that comprises the Facility(ies) shall be consistent with at least one of the following:

- Ratings provided by equipment manufacturers or obtained from equipment manufacturer specifications such as nameplate rating.
- One or more industry standards developed through an open process such as Institute of Electrical and Electronic Engineers (IEEE) or International Council on Large Electric Systems (CIGRE).
- A practice that has been verified by testing, performance history or engineering analysis. Provide a detailed description of the issues\concerns with the Requirement that the proposed IG will address.

2.2. The underlying assumptions, design criteria, and methods used to determine the Equipment Ratings identified in Requirement R2, Part 2.1 including identification of how each of the following were considered:

2.2.1. Equipment Rating standard(s) used in development of this methodology.

2.2.2. Ratings provided by equipment manufacturers or obtained fromequipment manufacturer specifications.

2.2.3. Ambient conditions (for particular or average conditions or as they varyin real-time).

2.2.4. Operating limitations.[2]

[2] Such as temporary de-ratings of impaired equipment in accordance with good utility practice.

2.3. A statement that a Facility Rating shall respect the most limiting applicable Equipment Rating of the individual equipment that comprises that Facility.

2.4. The process by which the Rating of equipment that comprises a Facility isdetermined.

2.4.1. The scope of equipment addressed shall include, but not be limited to, conductors, transformers, relay protective devices, terminal equipment,and series and shunt compensation devices.

2.4.2. The scope of Ratings addressed shall include, as a minimum, both Normal and Emergency Ratings.

R3. Each Transmission Owner shall have a documented methodology for determining Facility Ratings (Facility Ratings methodology) of its solely and jointly owned Facilities (except for those generating unit Facilities addressed in R1 and R2) that contains all of the following: [Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]

3.1. The methodology used to establish the Ratings of the equipment that comprises the Facility shall be consistent with at least one of the following:

- Ratings provided by equipment manufacturers or obtained from equipment manufacturer specifications such as nameplate rating.
- One or more industry standards developed through an open process such as Institute of Electrical and Electronics Engineers (IEEE) or International Council on Large Electric Systems (CIGRE).
- A practice that has been verified by testing, performance history or engineering analysis.

3.2. The underlying assumptions, design criteria, and methods used to determine the Equipment Ratings identified in Requirement R3, Part 3.1 including identification of how each of the following were considered:

3.2.1. Equipment Rating standard(s) used in development of this methodology.

3.2.2. Ratings provided by equipment manufacturers or obtained fromequipment manufacturer specifications.

3.2.3. Ambient conditions (for particular or average conditions or as they vary in real-time).

3.2.4. Operating limitations.[3]

3.3. A statement that a Facility Rating shall respect the most limiting applicable Equipment Rating of the individual equipment that comprises that Facility.

3.4. The process by which the Rating of equipment that comprises a Facility is determined.

[3] Such as temporary de-ratings of impaired equipment in accordance with good utility practice.

3.4.1. The scope of equipment addressed shall include, but not be limited to, transmission conductors, transformers, relay protective devices, terminalequipment, and series and shunt compensation devices.

3.4.2. The scope of Ratings addressed shall include, as a minimum, both Normal and Emergency Ratings.

Example 1 – Facility Ratings methodology

As an example, this Facility Ratings methodology (FRM) should consider including both Normal and Emergency Ratings. The Normal Rating for ampacity is usually expressed in mega volt-ampere (MVA) or amperes or other appropriate units representing current carrying capability that a Facility or Element can support or withstand through the daily demand cycles (i.e., continuous operation) without loss of equipment life to the Facility or Element. The Emergency Rating for ampacity is usually expressed in MVA or amperes or other appropriate units that a Facility or Element can withstand for a finite period (e.g., 30 minutes). Facility Ratings also include voltage ratings expressing in volts, and for frequency-sensitive equipment, the frequency ratings expressed in hertz (Hz).

The Emergency Rating assumes acceptable loss of equipment life or other physical or safety limitation for the equipment involved. The GO, as per 2.4.2, and the TO, as per 3.4.2, should determine an acceptable loss of life or other physical or safety limitation before determination of its Emergency Ratings. This can vary depending upon the configuration of the system or characteristics of the Facility or Element. If the owner has determined the acceptable loss of equipment life based on sound engineering principles is equal to zero, the Emergency Rating can be set to the Normal Rating. Each entity may consider different asset management principles for determining equipment life and as a result, it is important that the engineering documentation and FRM are applied with consistency.

A FRM should be developed for each series-connected piece of equipment that comprises the overall Facility. The FRM needs to be based on a solid technical foundation such as industry standards, local state or provincial requirements, information from manufacturers, or test data. See additional examples in Appendix A and D.

The FRM should document how ambient conditions were considered, according to R2.2.3 for the GO and R3.2.3 for the TO. These ambient conditions should be consistent with the ambient conditions in the region in which the Facilities will operate. If the ambient conditions vary throughout the year, consideration should be given to having more than one Rating set (e.g., a winter set and a summer set, or a set for each of the four seasons). Consideration may be given to including separate daytime and nighttime ratings or a single rating based on the lower of the two ratings. A Normal and Emergency Rating shall be developed for each rating set. The Emergency Ratings shall be uniquely determined and reflect the specific finite duration of the Emergency Rating.

If the TO or GO is adopting either ambient adjusted ratings[4] or dynamic line ratings[5], then the FRM should describe how these are determined and applied.

The FRM should also document the assumption that the equipment is operating as designed. The FRM should reference provisions for modifying the rating, should temporary operating conditions occur (e.g., a hot spot on a disconnect switch or loss of cooling fans on a transformer), including temporary changes that are applied towards the ratings themselves and situations that do not require a change in the methodology. The sources for equipment ratings and assumptions utilized in the FRM may be identified using matrices (Figures 3 and 4) or through a narrative specific to each type of equipment, that includes a description of each input and how they are applied.

[4] According to FERC Order 881, an Ambient-Adjusted Rating (AAR) means a transmission line Rating that:

a) Applies to a time period of not greater than one hour.

b) Reflects an up-to-date forecast of ambient air temperature across the time period to which the rating applies.

c) Reflects the absence of solar heating during nighttime periods where the local sunrise/sunset times used to determine daytime and nighttime periods are updated at least monthly, if not more frequently.

d) Is calculated at least each hour, if not more frequently.

[5] Dynamic Line Rating (DLR) is also known as real-time thermal Rating (RTTR). Consult the FERC June 27, 2024, Fact Sheet – ANOPR Implementation of Dynamic Line Rating. DLR relies on sensors or weather stations to monitor local environmental conditions for calculating a more accurate real-time thermal rating of a transmission line.

	Example Methodology R2.1/R3.1 One of the following				
Electrical Element or components	Manufacturer	Industry Standard	Verified practice. One of the following		
			Testing	Performance History	Engineering Analysis
Generator Step Up Transformer		X			
ISO Phase Bus		X			X
Overhead Conductor		X			
Line switch		X			
Cable Conductor		X			
Circuit breakers		X			
Current Transformers		X			
Jumper Conductors		X			
Disconnect switch		X			
Power transformer	X	X			
Rigid bus conductor		X			
Circuit breakers – GIS	X				
Series Compensation	X				
Other electrical Components as			X		

Figure 3 Example for R2.1 (GO) and R3.1 (TO).

	R2.2/R3.2 Identification of the Underlying Assumptions/Design Criteria/Methods Employed			
Element	Equipment Rating Standards Used (example standards only-is not inclusive of all possible standards) R2.2.1/R3.2.1	Ratings Provided by Manufacturer- or Equipment Specifications R2.2.2/R3.2.2	Ambient Conditions R2.2.3/R3.2.3	Operating Limitations R2.2.4/R3.2.4
Transmission Conductor	Calculations per IEEE 738	Input to Calculations	Input to Calculations	Input to Calculations
Transmission Line Switch	Calculations per ANSI C37.37	Input to Calculations	Input to Calculations	Input to Calculations
Underground Transmission Cable	Calculations per IEEE 835	Input to Calculations	Input to Calculations	Input to Calculations
Circuit Breakers	Calculations per ANSI C37.010	Input to Calculations	Input to Calculations	Input to Calculations
Current Transformers	Calculations per C57.13	Input to Calculations	Input to Calculations	Input to Calculations
Jumper Conductors	Calculations per IEEE 738	Input to Calculations	Input to Calculations	Input to Calculations
Substation Disconnect Switch	Calculations per ANSI C37.37	Input to Calculations	Input to Calculations	Input to Calculations
Power Transformer	Calculations per ANSI C57.12.00	Input to Calculations	Input to Calculations	Input to Calculations
Series Compensation	Not Applicable	Nameplate	Input to Calculations	Input to Calculations
Rigid Bus Conductor	Calculations per IEEE 605	Input to Calculations	Input to Calculations	Input to Calculations
Circuit breake	[illegible]	Namepl	[illegible]	Input to

Figure 4 Example for R2.2 (GO) and R3.2 (TO).

In some cases, a manufacturer's nameplate or recommended Rating may not be used and the asset owner may propose a different value. In those cases, here are a few examples of potential documentation that could be used when developing Ratings:

Transformers:

Document the software program used to determine operating limits, such as the IEEE C57.91 Transformer Loading Guide used to calculate emergency ratings for transformers (R2.2.1). However, if the transformer is known to have design issues – (gassing or stray flux), it may be limited to the manufacturer's nameplate capability (2.2.2 and 2.2.4). Documentation that supports the revised rating caused by the design issue should be referenced in the FRM. The IEEE / ANSI standard C57 considered ambient conditions (2.2.3). The emergency overload rating is based off an operating limitation of X degrees rise over ambient (R2.2.4).

When the operating limitation of equipment or a component is identified during inspections to be operating outside expected parameters, it is best to make a case specific evaluation, take appropriate action, and document the Rating.

During any replacement of ancillary equipment associated with the Transformer, if the equipment is not considered like for like, analysis should be completed to determine the new Rating of the Facility prior to placing the equipment in service. As an example, the Facility Rating can be determined via nameplate or manufacturer's Rating, test reports or appropriate engineering judgement and should be documented.

Circuit Breakers:

Equipment Rating Standards Used – IEEE ANSI C37.010 (R2.2.1E)

Ratings provided by manufacturer are based off industry standards and the owner's defined ambient conditions and operating conditions (per specification of the circuit breaker (R2.2.2)

Documented evidence in certified drawings and/or nameplate

- Ambient conditions are defined in Entities Specification (R2.2.3)
- Operating limitations are defined by the applicable design considerations or operational requirements used or developed by the owner

Line Conductors:

Equipment Rating Standards Used – IEEE Standard 738 (R3.2.1). The conductor characteristics, such as maximum operating temperature, were considered to avoid annealing (R3.2.2, and R3.2.4).

Ambient assumptions (R3.2.3): The Normal and Emergency bare overhead conductor Rating shall be calculated under the following assumed atmospheric conditions:

- Ambient air temperature of 100 degrees F for summer season Ratings and 32 degrees F for winter season Ratings,
- A wind velocity of 7 ft/sec,
- An incident wind angle of 20 degrees,
- The following solar factors: Latitude of 41 degrees north and longitude of 95 degrees west.

Transmission lines may be limited to less than thermal capability for relay loading limits or clearances where applicable. Considering the safety aspect of conductor clearances, the applicable standards should be consulted. There are IEEE or National Electrical Safety Codes that can be used, or consideration given to local relevant standards developed by the Authority Having Jurisdiction (AHJ).

Remember to include in your documentation the components that may need additional consideration when rating the overall Facility or Element. For example:

- Bushings / Load Tap Changers / No-Load Tap Changers sometimes limit the emergency capability of a power transformer and should be included.
- Current transformers in a circuit breaker or transformer could either be included in the Rating of the circuit breaker or transformer or rated separately.
- Limitations set by relay protective devices are the limitation based upon the thermal limitation of the relay, the relay settings, or both.
- System meters or telemetry equipment may contribute to exceeding a series circuit electrical Rating and resulting in equipment damage.

As an example, it is assumed that the meter small tolerance error is not a risk, however installation error may lead to damage and therefore coordinating primary and secondary electrical Equipment Rating is important.

Once the rating of each individual equipment or component has been developed, the “Facility or Facilities” need to be defined. A Facility is (per NERC Glossary of Terms) a “set of electrical equipment that operates as a single Bulk Electric System Element.” Facilities may vary slightly by owner but should generally include anything from the generator to the point of transmission interconnection for a generator and transformers, lines, and busses for a Transmission Facility. During the process to develop the list of Facilities, it should be noted which of the electrically-connected Facilities are jointly owned to coordinate the Ratings of those Facilities with the other owner(s).

The Facility Rating should reflect the most limiting applicable Equipment Rating or component that is included in the Facility. The document could include a statement that meets R3.3:

- Facility Rating shall respect the most limiting applicable Equipment Rating of the individual equipment that comprises that Facility.
- Facility Ratings documentation should include the scope of equipment to be included and details on how the Facility Rating is determined.

As an example, for a Generator Owner the generator Facility may include but not be limited to the following equipment:

- Generator, and generator leads,
- relay protection, metering and/or telemetry devices, current transformers,
- bus work, rigid and/or stranded conductor,
- generator circuit breakers,
- generator step-up transformer (if applicable),
- jumpers,
- disconnect switches,
- reactors,
- capacitors.

As an example, for a Transmission Owner the Facility may include but not be limited to the following equipment:

- bus work, rigid bus and/or stranded conductor,
- disconnect switch,
- current transformers,
- relay protective, metering and/or telemetry devices, including consideration of relay loadability,
- circuit breaker or circuit switchers,
- power transformers,
- jumpers,
- wave trap,
- Devices such as: reactors, capacitors, synchronous condensers power electronic flow-limiters,
- line sectionalizing switch,
- line conductor.

Example 2 – How to define Facility boundaries

A key concept in defining Facility boundaries is that adequate granularity to support planning and operating functions should be provided regardless of the method chosen to define Facilities to support reliable operations. Figure 5a is just one possible method of meeting the standard using very high granularity. Note that some equipment, such as main and auxiliary buses in Figure 5a, are not highlighted as a Facility only to simplify the drawing.

Entities can use a variety of ways to ensure that all relevant components and equipment are considered in a Facility Rating. As shown in Figure 5b, entities can use a component block coverage method, node-to-node coverage or breaker-to-breaker coverage. Consistency in applying the adopted FRM and including all equipment, remains a very critical step throughout the process.

It is equally important that the model is shared and consistently applied in the BA/RC control area to ensure that all entities relying on the model manage to the same most limiting applicable Equipment Rating. This implies that entities relying on the model, review the FRM and coordinate the implementation with consistency.

For complex transmission configurations, such as breaker and a half (e.g., see Figure 5a) or ring bus, analyze and define the Facility to ensure all equipment is captured in an appropriate manner depending on normal or abnormal configurations.
For example, consider the potential configurations during normal operations and outage conditions and include all necessary series connected equipment.

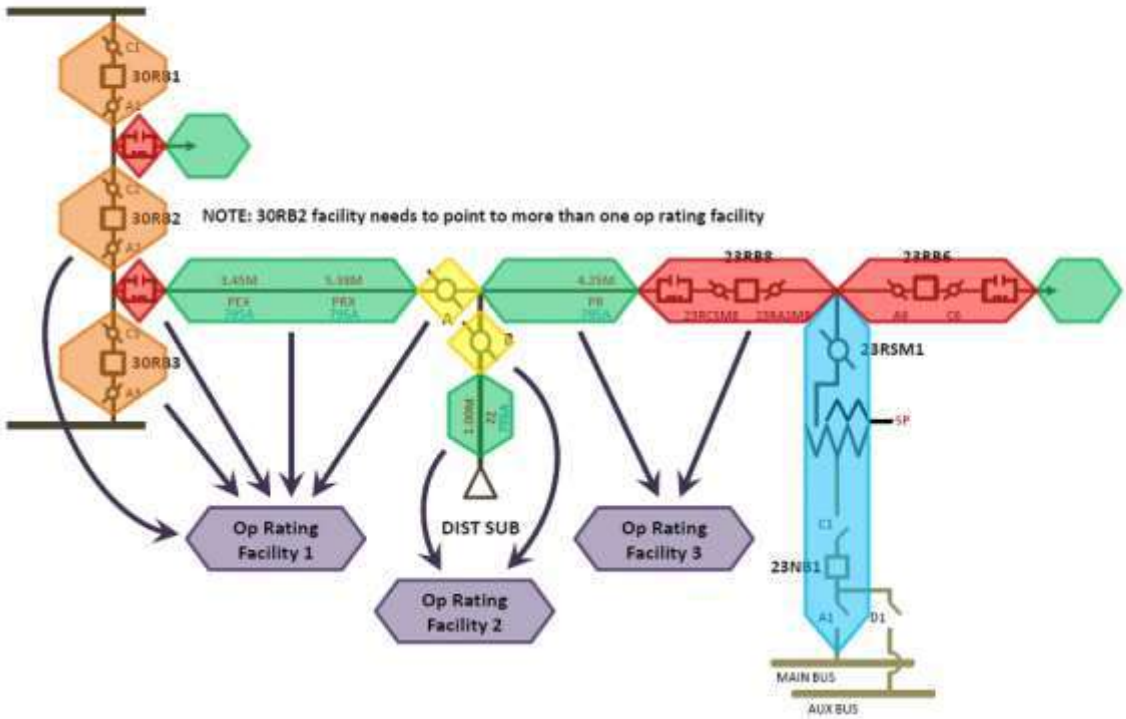


Figure 5a General Example of Complex Transmission Facility boundaries (other configurations may be used)

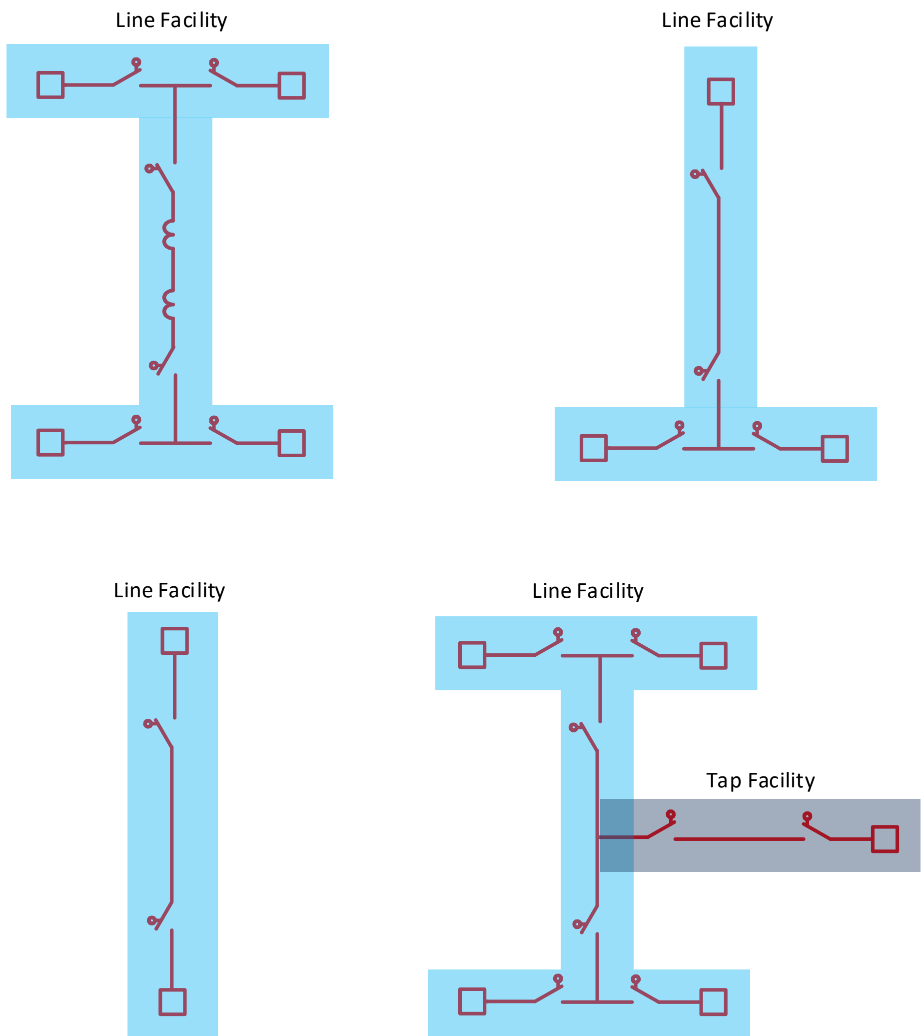


Figure 5b Simplified examples of transmission Facility boundaries (other configurations may be used)

Example 3 – Data Management or Tracking Tool

As each equipment is identified, it should be recorded with some type of data tracking tool by Facility. This may be as simple as a spreadsheet, simplified "Facility Ratings Diagram", or a complex data management tool (Figure 6).

Facility Rating Sample FAC008 R6	From Substation: MRO1 To Substation: MRO2	Summer Normal (SN)	Summer Emergency (SE)	Winter Normal (WN)	Winter Emergency (WE)
Facility Limits: MRO1 to MRO2		1030	1043	1221	1231
Facility Limits: MRO2 to MRO1		1030	1043	1221	1231
Substation: MRO1	Owner: Utility A				
Equipment	**Description**	**SN**	**SE**	**WN**	**WE**
Conductor	1 - 795.0 kcmil ACSR 26/7 Drake, JUMPER, 200°F Norm, 300°F Emer	1030	1402	1221	1524
Trap	2000A, B-Phase	2040	2240	2100	2400
Conductor	2 - 1590.0 kcmil AAC 61 Coreopsis, JUMPER, 200°F Norm, 275°F Emer	3096	4000	3668	4404
Switch	1600A, Switch #78661-L, AO6	1795	2126	2264	2482
Conductor	2 - 1272.0 kcmil AAC 259 Rope-Lay, JUMPER, 200°F Norm, 275°F Emer, 5% derate proximity effect	2637	3401	3124	3743
CT	1200:5 Full Ratio, 1200:5 Conn Tap, RF = 2.00, Bushing (Bkr)-Type	2400	2400	2400	2400
Circuit Breaker	1600 A, OIL, Device #78661	1704	1894	2101	2264
Relay	Forward Setting	5631	5631	5631	5631
Relay	Non-Directional Thermal	3600	3600	3600	3600
RTU	RTU	13708	13708	13708	13708
CT	1200:5 Full Ratio, 1200:5 Conn Tap, RF = 2.00, Bushing (Bkr)-Type	2400	2400	2400	2400
Conductor	2 - 1272.0 kcmil AAC 259 Rope-Lay, JUMPER, 200°F Norm, 275°F Emer, 5% derate proximity effect	2637	3401	3124	3743
Switch	1600A, Switch #78661-B, AO6	1795	2126	2264	2482
Conductor	1 - 5.0" Al Tube, Sch 40, 6063-T6, BUS	4608	5075	5590	5998
From- To Nodes	**Line Segments - Description**	**SN**	**SE**	**WN**	**WE**
MRO1 to STR 125	1 - 795.0 kcmil ACSR 26/7 Drake, 200°F Norm, 245°F Emer	1030	1214	1221	1367
STR 125 to MRO2	1 - 795.0 kcmil ACSR 26/7 Drake, 200°F Norm, 203°F Emer	1030	1043	1221	1231
Substation: MRO2	Owner: Utility B				
Equipment	**Description**	**SN**	**SE**	**WN**	**WE**
Conductor	1 - 795.0 kcmil ACSR 26/7 Drake, JUMPER, 200°F Norm, 300°F Emer	1030	1402	1221	1524
Trap	1200A, B-Phase	1224	1344	1260	1440
	[illegible] JUMPER, 200°F Norm [illegible]	1030	1402	[illegible]	1524

Figure 6 Example of output from a data management tool.

Example 4 – Jointly Owned Facilities

The FRM should address how the Facility Rating could be addressed for jointly owned Facilities. The owners may share all of their equipment Ratings with each other in order to identify the most limiting applicable equipment or share only their respective most limiting applicable Equipment Ratings to determine the overall most limiting applicable Equipment Rating for the Facility. In the example of a tie-line Facility[6], in certain regions, the Regional Transmission Operator (RTO) could determine the most limiting applicable Equipment Rating in a jointly owned Facility. A process should be developed by the TO or GO, as applicable, to demonstrate how Facility Ratings of jointly owned Facilities are determined. The process should be documented in the FRM.

See some common examples of jointly owned Facilities below:

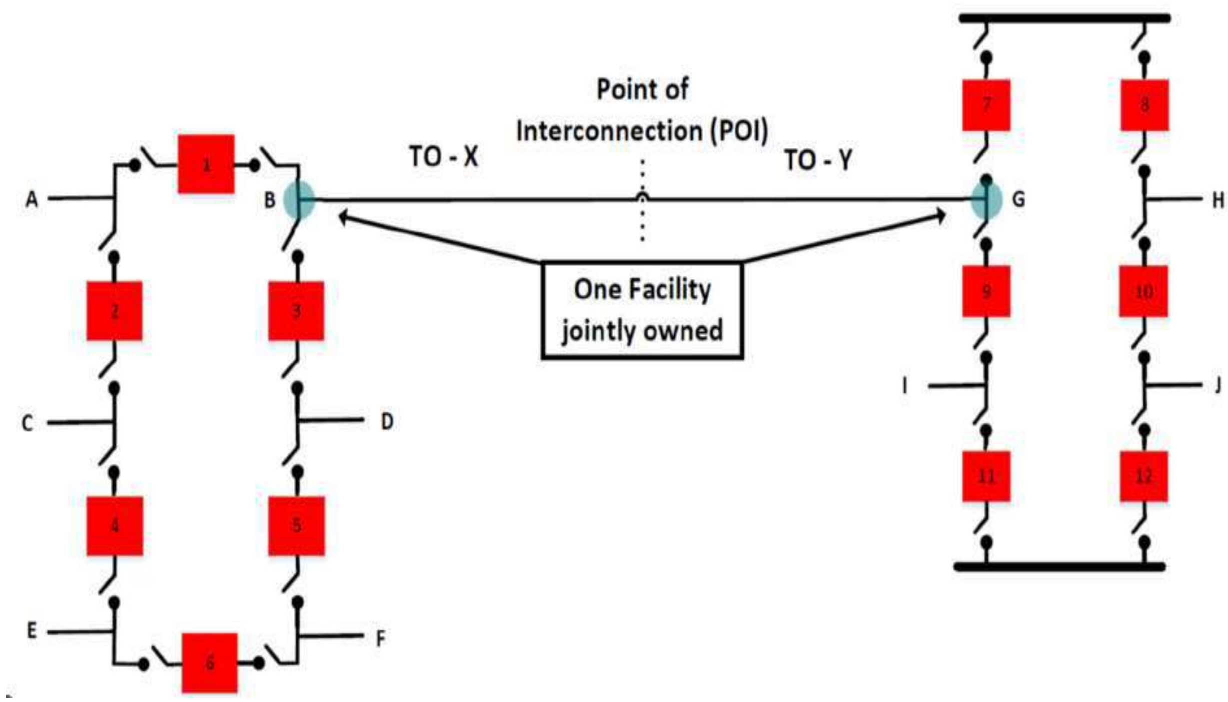


Figure 7 Example of Jointly Owned Line Facility

[6] A tie-line Facility is a facility that typically connects the Facilities of two Transmission Owners together or a TO and a GO together.

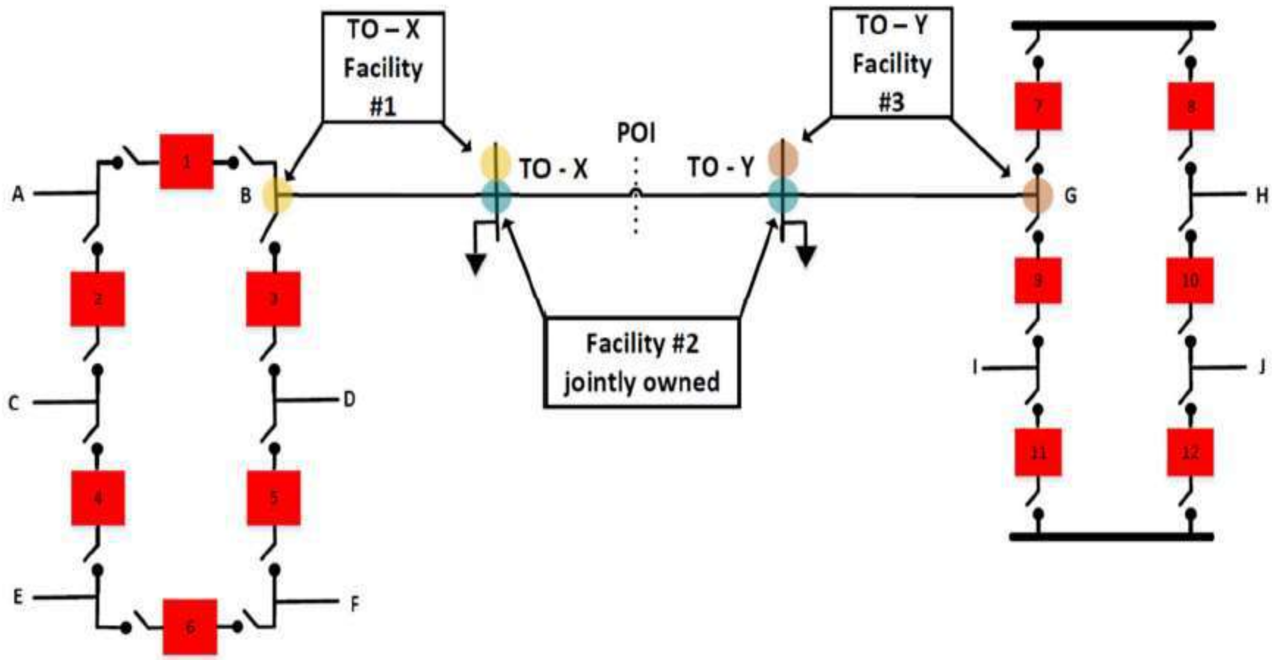
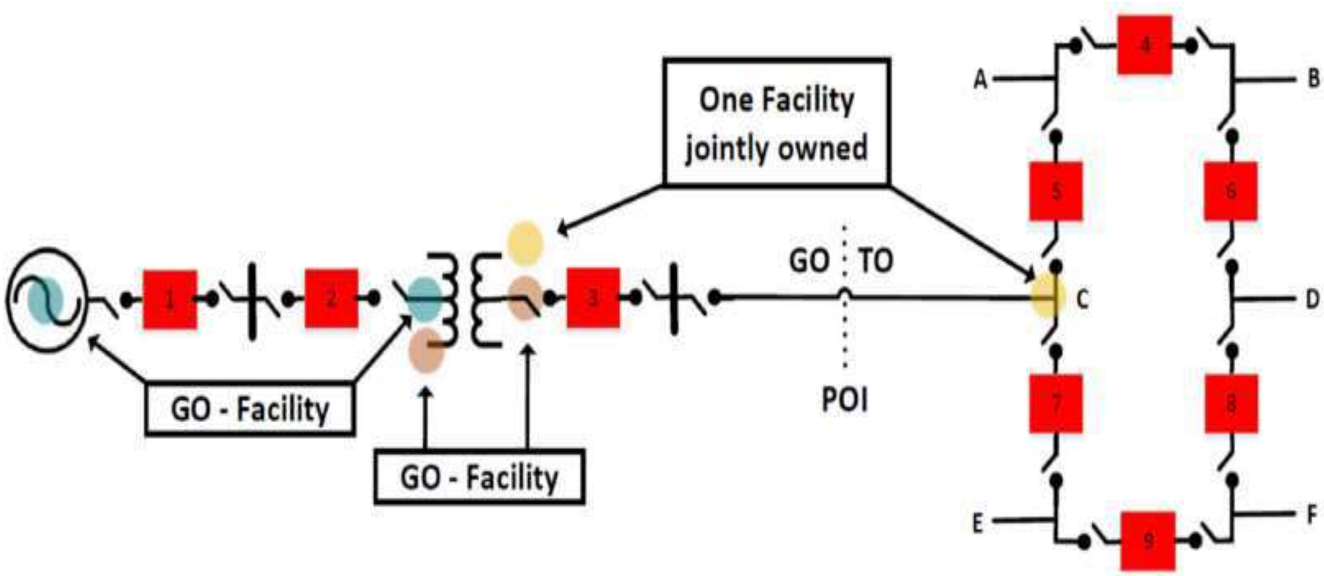


Figure 8: Example of Jointly Owned Tie-Line Facility



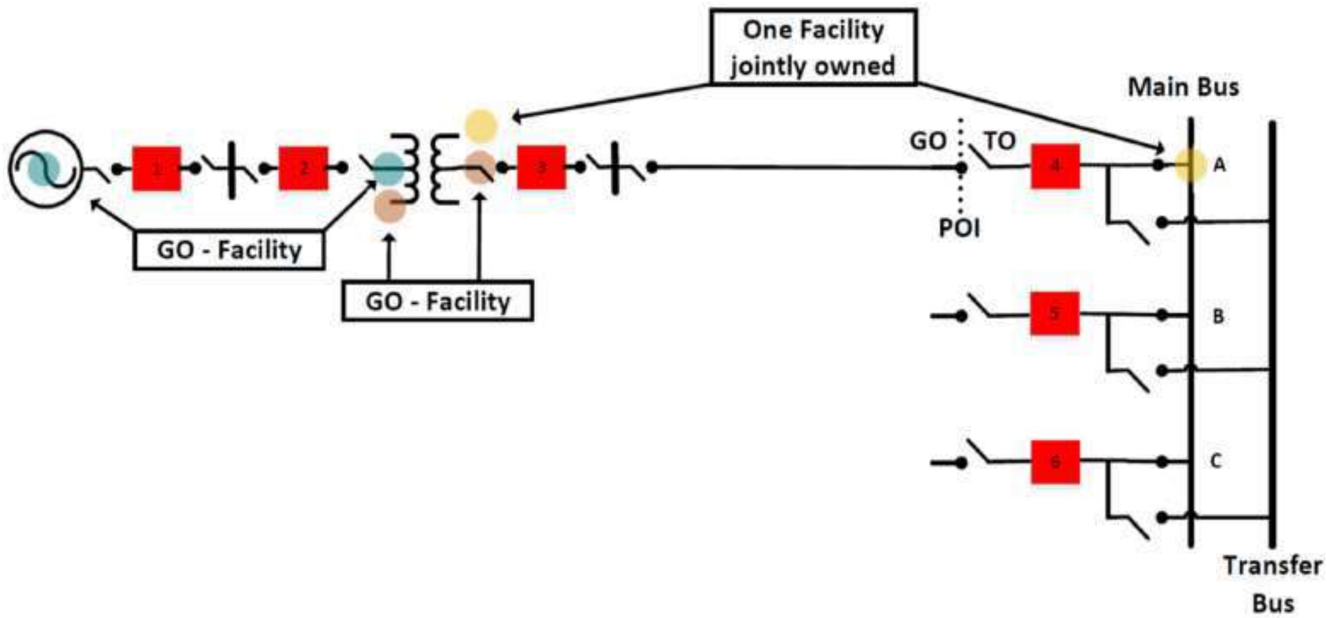


Figure 9: Examples of a Jointly Owned Generator Facility

Example 5 – Next most limiting equipment

Provisions to address requests for identification of the next most limiting equipment and its Thermal Rating for the specific operation condition (i.e., via R8) could be addressed in the Facility Rating methodology for Facilities that are associated with one of the following:

- An Interconnection Reliability Operating Limit,
- A limitation of Total Transfer Capability,
- An impediment to generator deliverability, or
- An impediment to service to a major load center.

The next most limiting Thermal Rating is considered to include both the Normal and Emergency Rating of the next most limiting equipment and should be established as per the FRM and available in advance of any of the conditions noted above materializing.

This situation, while rare, could potentially arise within the same Facility, in situations where an equipment upgrade would change the most limiting equipment or in a separate Facility where a change in the operating configuration introduces a different most limiting equipment. While there are practical ways to manage these situations, through planning processes and operations instructions, it is important that the identification of the next most limiting equipment's Thermal Rating, is considered for planning or operating scenarios, where equipment or configuration changes are considered.

One potential benefit for identifying the next most limiting equipment Thermal Ratings is to assist in the development of procedures or instructions for the identified Facilities and to operate these Facilities in real time while respecting the Emergency Ratings.

Example 6 – Change management

Ratings and procedures to revise ratings should be documented, and then included in the construction and maintenance processes. Change controls and data quality controls for the data management tools are essential for ensuring accurate Facility Ratings for the safe and reliable operation of the BES. These controls may consist of field audits or automated data checks to make sure accidental changes are not made. Ratings and rating changes need to be communicated to ensure reliable operations.

Requirement 6

R6. Each Transmission Owner and Generator Owner shall have Facility Ratings for its solely and jointly owned Facilities that are consistent with the associated Facility Ratings methodology or documentation for determining its Facility Ratings. [Violation Risk Factor: Medium] [Time Horizon: Operations Planning]

Example 1 – Facility Rating Methodology

As an example, to help address this requirement, Generator Owners and Transmission Owners are required to develop Facility Ratings methodologies for its BES facilities. Documentation or documented methodology are required for determining the Normal and Emergency Facility Ratings of its (solely and jointly owned) equipment.

Application of the FRM yields Facility Ratings resulting from identification and documentation of each piece of equipment in a Facility. Additional consideration is given to other factors such as operational limitations and protective relay settings during the analysis and application of the methodology.

Generator Owners and Transmission Owners are required to have Facility Ratings for their solely and jointly owned Facilities that are consistent with their associated Facility Ratings methodology or documentation for determining its Facility Ratings. In Figure 9, there are several diagrams that illustrate how registered entities could separate ownership that designate Facilities that they own and require a Facility Rating. Equipment ownership should assign and define what equipment each owner is accountable for determining the rating. Then an agreed upon process should be in place to assess and determine the overall Facility Rating. This process should be documented in the FRM.

Generator Owners and Transmission Owners should maintain a list of all solely and jointly owned Transmission and Generation Facilities.

System schematics may be used to identify and document each individual equipment that makes up each Facility. Through the application of their methodology (R2 and R3) or application of the documentation (R1), the entity should determine ratings of each piece of equipment in the Facility. Once all individual equipment making up each Facility is determined, the applicable entity should have the necessary information to determine the overall Facility Rating. Both the Normal and Emergency Ratings should be identified for equipment that have been identified in R2 and R3. Responsible entities may develop a database similar to the example in Figure 3 which identifies all of the equipment in a Facility as well as the Facility Ratings.

In addition, responsible entities should develop a process that identifies all jointly owned Facilities. Consideration should include but not be limited to:

- Interconnection points with adjacent owners,
- Generator interconnections.

Owners of jointly owned Facilities should coordinate and document their Facility Ratings with the other owners of the Facility or rely on the RTO as noted earlier to determine the overall Facility Rating.

Owners should have documentation of each Facility Rating and should have source documentation applied in the determination of the Ratings of all equipment comprising a Facility to demonstrate it is *consistent with the associated Facility Ratings methodology.* Source documentation may include but not be limited to:

- Manufacture Rating of each equipment,
- Photos of nameplate Rating of each equipment,
- Copies of calculations used in determination of Equipment Ratings,
- Copies of ratings used for each equipment,
- Engineering drawings.

The Normal and Emergency Ratings of each Facility should be maintained in a process that allows the entity to:

- Identify each Facility,
- Identify the rating of each piece of equipment that comprises the Facility,

- Identify the most limiting and the next most limiting applicable Equipment identified by the owner,
- Identify the most limiting and the next most limiting applicable Equipment Rating identified by joint owner,
- Identify the overall most limiting and the next most limiting applicable Equipment Rating for the Facility.

Example 2 – Facility Rating Change Management Process

As one potential process step, through methodology and data, owners should verify the following:

To maintain compliance and avoid discrepancies between Facility Ratings and Model Data, the Generator and Transmission Owners should have a Facility Rating validation process, documented in the FRM.

For example, an Energy Management System (EMS) value used to trigger alarms or support other real-time applications may or may not align with a Facility Rating determined through FAC-008-5. The FRM used by the asset owner should document the steps to capture the rationale and supporting evidence for the discrepancy. To illustrate the potential steps, during system maintenance and or restoration work, system reconfiguration may be needed. When that occurs, Facility Ratings may need to be adjusted. These adjusted Facility Ratings may be different than the typical Facility Ratings used in planning or operating models. These adjustments are required in Real-time operations to operate the system reliably. The modified Facility Ratings should be determined and documented based on the FRM, when determining the overall Facility Ratings for Real-Time operations.

Given the complexity of managing methodology and data in planning and operation, the Facility Rating validation process, or a similar verification step, should be performed regularly to minimize discrepancies.

Example 3 – Field Verification of Equipment

Field verification of FAC-008-5 is an acceptable approach to use in reviewing the completeness and accuracy of Facility Rating data. Comparison of actual equipment lists or Facility Ratings database information with one-line diagrams and through a physical walk-down of equipment is just one manner to validate Facility Ratings are consistent with documentation and the FRM. Inaccurate or missing Equipment Ratings identified during a review need to be addressed succinctly with emphasis on impacts to the Facility Rating. Emphasis should be placed on field verification of Facility Rating(s) that could impact on operations, considering the urgency and the ability to obtain required outages, without compromising reliability. (i.e., most limiting and next most limiting equipment).

Requirement 8

R8. Each Transmission Owner (and each Generator Owner subject to Requirement R2) shall provide requested information as specified below (for its solely and jointly owned Facilities that are existing Facilities, new Facilities, modifications to existing Facilities and re-ratings of existing Facilities) to its associated Reliability Coordinator(s), Planning Coordinator(s), Transmission Planner(s), Transmission Owner(s) and Transmission Operator(s): [Violation Risk Factor: Medium] [Time Horizon: Operations Planning]

8.1. As scheduled by the requesting entities:

8.1.1. Facility Ratings

8.1.2. Identify of the most limiting equipment of the Facilities

8.2. Within 30 calendar days (or a later date if specified by the requester), for any requested Facility with a Thermal Rating that limits the use of Facilities under the requester's authority by causing any of the following: 1) An Interconnection Reliability Operating Limit, 2) A limitation of Total Transfer Capability, 3) An impediment to generator deliverability, or 4) An impediment to service to a major load center:

8.2.1. Identity of the existing next most limiting equipment of the Facility

8.2.2. The Thermal Rating for the next most limiting equipment identified in Requirement R8, Part 8.2.1.

Example 1 Documentation

In addition to submittal of Facility Ratings and identification of the most limiting equipment of the Facility, TOs (and those GOs subject to R2) may also be required to provide the next most limiting equipment in the Facility and its Thermal Rating that affects:

- Interconnection Reliability Operating Limit (IROL)
- A limitation of Total Transfer Capability
- An impediment to generator deliverability, or
- An impediment to service to a major load center

As an example, responsible entities may elect to develop a matrix with Normal and Emergency Ratings across one axis and criteria for identifying the most limiting equipment and the Rating on another axis. Below is one example of a four-position matrix that has both Normal and Emergency Ratings such as a large power transformer. Owners may have different Normal and Emergency Ratings along with different seasonal Ratings.

	Normal Rating	Emergency Rating
Most Limiting Rating	500 MVA Summer 500 MVA Winter **Power Transformer**	750 MVA Summer 750 MVA Winter **Power Transformer**
Next Most Limiting Thermal Rating	717 MVA for more than 1 hour Summer 717 MVA for more than 1-hour Winter **Breaker**	956 MVA Summer 956 MVA Winter **Switch**

Figure 10: Example of Seasonal Normal and Emergency Ratings

The owner should be prepared to provide appropriate schedules, and response transmittals or emails to and from appropriate entities and refers to those entities who jointly own facilities, owners of adjacent Facilities, and those entities that have been identified as the Reliability Coordinator, Transmission Planner and Planning Coordinator of those Facilities.

As good practice, documentation showing that Transmission Owner and each Generator Owner shared Facility Ratings should be retained. A process to show how that sharing is to occur should be maintained. If a specific request was made (pursuant to R8), all documentation should be preserved to demonstrate compliance.

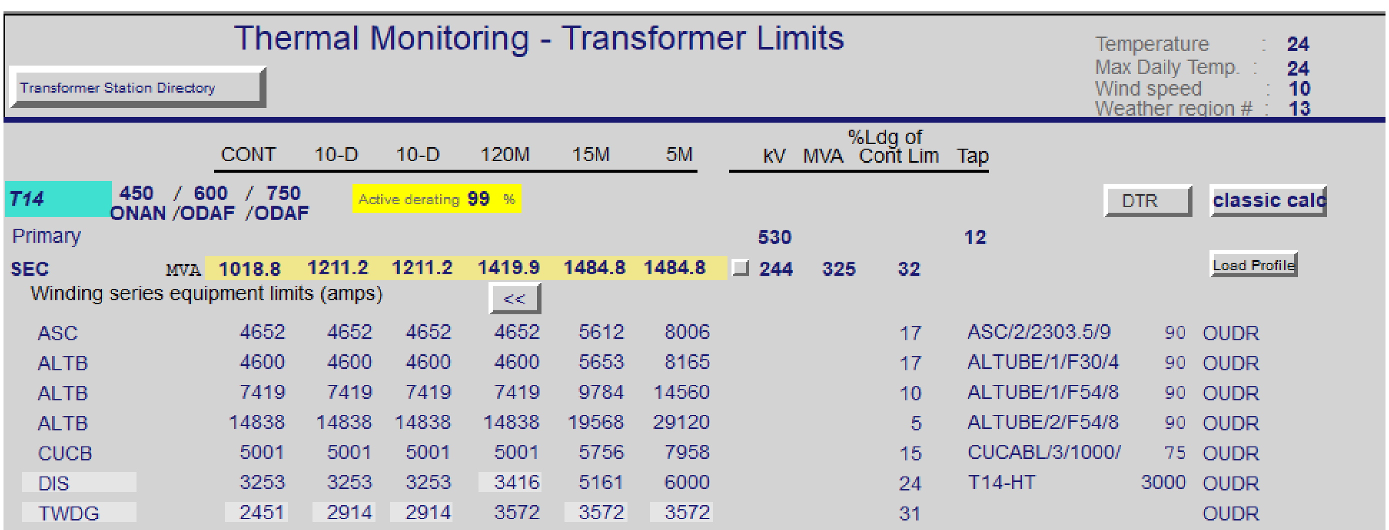


Figure 11: Example of Thermal Monitoring Tool and Specific Owner Considerations

Periodic Review

This document will be reviewed by the RSTC periodically (TBD and will be updated for Final version) or updated upon initiation of a standards development project to modify the FAC-008 Standard. The updates will be undertaken by an assigned Task Force or the SDT.

Reviewed By	Title	Comments / Notes	Review Date	Next Scheduled Review Date

Appendices

APPENDIX A: Recommended Practices

Disclaimer: Recommendations made in this implementation guidance are intended to demonstrate potential ways of approaching internal controls and are not all-inclusive.

Summary: Accurate Facility Ratings are essential in the development of System Operating Limits (SOL). Management practices are developed to ensure Facility Ratings are utilizing the correct equipment Ratings, match field conditions, ensure the most limiting equipment has been identified and a second independent review of the Ratings has been conducted in order to validate derived Facility Rating.

Generic Examples of Practices:

Requirement 1: Identify documentation of equipment Ratings used to develop the generator Facility Rating.

Measure: The entity should be able to verify that Ratings documentation exists for each piece of equipment at a generator facility:

- Use a table similar to Figure 1 to ensure all equipment of the generator Facility are being considered.
- Review ownership documentation for establishing whether high side or low side bushings are the demarcation point for the generator Facility Rating.
- Develop a report to provide internal feedback.

Requirements 2 and 3: Develop a Facility Ratings Methodology.

Measure: The entity should be able to verify it has a documented Facility Ratings methodology that covers all equipment owned by the entity:

- Use a table similar to Figure 2 to make sure all equipment of the Facility are being considered in the methodology.
- Develop a report to provide internal feedback.

Requirement 6: Develop a Facility Rating for each solely and jointly-owned Facility.

Measures: The entity should be able to provide:

- Equipment Ratings that make up each Facility Rating,

- The most limiting applicable equipment Thermal Rating,
- The next most limiting applicable Thermal Rating, in situations where and equipment upgrade or operating configuration changes would change the most limiting equipment
- Periodic validation of Facility Ratings to ensure that they are consistent with its rating methodology or documentation.

Examples of Internal Controls

(1) Develop processes and procedures to accomplish these measures which:

- Identify all Facilities,
- Identify all equipment that comprise each Facility,
- Be able to identify the source documentation for each Equipment's Rating,
- Implement a system, spreadsheet, or one-line diagram able to reproduce the equipment data for a given Facility demonstrating that the most limiting equipment was chosen,
- Identify the second most limiting applicable equipment Thermal Rating,
- Provides for notification of new facilities,
- Provides for replacement of existing equipment,
- Provides for review of system changes on a periodic basis (such as sampling) to ensure all modifications to Facilities have been reviewed,
- Provide a change control mechanism to make corrections to Facility Ratings when it is found that they are not consistent with the methodology.

(2) Provide for a second independent review (-peer review) to ensure the accuracy of the developed Facility Ratings

APPENDIX B: Frequently Asked Questions

Disclaimer: Recommendations made in this appendix are intended to demonstrate potential way(s) of approaching certain situations and are not all-inclusive.

1. **What is acceptable for multiple components with the same Ratings? Are you to group like rated items together and treat them as one rated thing?**

   Example:
   Switch 1 = 600 amps
   CT1 = 600 amps
   CT2 = 600 amps
   Breaker = 1200 amps.

   A. Is the most limiting Rating 600 amps and the next most limiting Rating also 600 amps?

   B. Is the most limiting Rating 600 amps and the next most limiting Rating 1200 amps?

   <u>FAC-008-5 Recommendation:</u> Answer A. equipment comprising a Facility are individual and should not be grouped. Therefore, if two pieces of equipment within a Facility have the same Rating, the most limiting and next most limiting Rating are the same.

2. **Look closely at the word "or" in R6. Does "or" mean I need to provide a methodology and documentation, or does it mean I can supply a methodology or documentation.**

   R6. *Each Transmission Owner and Generator Owner shall have Facility Ratings for its solely and jointly owned Facilities that are consistent with the associated Facility Ratings methodology or documentation for determining its Facility Ratings.*

   <u>FAC-008-5 Recommendation:</u> The use of the term "or" is in reference to R2 and R3 that requires the use of a Facility Ratings methodology while R1 requires the use of "documentation" in support of the Facility Rating.

3. **What should I do about joint owned Facilities?**

   <u>FAC-008-5 Recommendation:</u> Entities must consider all equipment in determining a Facility Rating. This requires coordination between owners to determine the most limiting applicable Equipment Rating.

Case 1 – Clearly divided facilities: Company 1 owns terminal A and line section up to structure X somewhere in the middle of the line. Company 2 owns terminal B and the remainder of the line section. Each entity should calculate its most limiting Equipment Rating considering the equipment within its portion of the Facility (e.g., conductor, terminal equipment, etc.). All equipment and their Ratings should be accounted for by both parties to determine the most limiting applicable Equipment Rating (e.g., Normal, Emergency, and Thermal as applicable) to determine an overall Facility Rating – See **Appendix E** for examples of connected facilities.

Case 2 – Undivided facilities: Company 1 owns an undivided 30% of a Facility from terminal A (and breaker A) to terminal B (and breaker B). Company 2 owns an undivided 70% of a Facility from terminal A (and breaker A) to terminal B (and breaker B). Each entity should calculate its most limiting Equipment Rating. All equipment should be accounted for by both parties when coordinating Ratings. An alternative would be for one entity may take complete responsibility for the Facility with appropriate documentation retained – See **Appendix E** for examples of connected facilities.

In both cases, entities should consider adding all owners' most limiting and next most limiting information in their Ratings databases and / or calculations. This could facilitate notifications when changes occur that may affect the most limiting Rating for the Facility.

APPENDIX C: Acronym List

CIGRE – International Council on Large Electric Systems

IEEE – Institute of Electrical and Electronic Engineers

APPENDIX D: ERO Enterprise Themes and Best Practices for Sustaining Accurate Facility Ratings

Disclaimer: Recommendations made in this appendix are intended to demonstrate potential way(s) of improving a Facility Rating program and are not all-inclusive.

Fundamentally, developing and maintaining an accurate rating program with established change management steps, is key to achieving the overall coordination across the entire asset base and key overlaps with other connecting entities, like generators or load customers. A complete and coordinated, end to end process with visibility from planning to execution to implementation and verification of assets as well as alignment with the day-to-day operations, via real time ratings is generally viewed as a good coordination loop. This process is usually based on mature change management principles with internal controls and records management that ensure prompt and accurate changes, and updates, if and when assets are modified, replaced, or retired.

1. Improving Accuracy of Facility Ratings

   Senior management should perform the following:
   - Clearly define the control environment/culture of maintaining a reliable electric system and regularly reinforce these expectations at all levels. This includes explaining to staff the foundational nature and importance of accurate facility ratings.
   - Establish clarity on the facility ratings program foundational components.
   - Identify a facility ratings program sponsor and owner who is responsible for and provides adequate supervisory controls for overall facility ratings monitoring and management.
   - Ensure that there are documented facility ratings processes and procedures (i.e., internal controls) with clear roles, clear responsibilities, and appropriate communication expectations.
   - Manage the facility ratings process(es) to ensure all departments and contractors have the appropriate level of expertise and are trained —at least annually or on an effective periodic basis — on the facility ratings program requirements and associated procedures and controls.
   - Support development of internal control testing processes and ensure assessments are performed on a consistent and periodic basis to assess facility ratings program controls efficiency and effectiveness.
   - Provide adequate resources in support of a robust facility ratings program and associated internal controls.

a) <u>In-Field Verification of Facility Ratings</u>

The in-field verification process should be risk-informed (e.g., consider Facility Ratings age, recent equipment upgrades/changes, Facility criticality). Completing the in-field verification process on 20% of an entity's applicable Facilities annually, for example, would result in all applicable Facilities being completed in five years. This assumes either no additions or modifications after the in-field verification.

The individual completing the in-field verifications should perform the following:

- Identify all equipment and take photos of nameplates where possible,
- Document/record equipment details in a spreadsheet or other tracking tool,
- Have drawings, equipment Ratings information, and one-line diagrams in hand to make note of field equipment that does not appear in the drawings/diagrams,
- Be aware of the internally and externally documented Facility Ratings,
- Identify ownership of the equipment comprising the Facility.

Once in-field verifications are complete, personnel should compare the equipment inventory, equipment ratings, and other information obtained during the in-field verification to all relevant source documents (e.g., one-line diagrams, design drawings, ratings database/drawings) to ensure what is in the field matches the source documents. Any discrepancies between the field and documentation should be reconciled regardless of the immediate potential impact on the Facility Fating.
Once an entity establishes its baseline, any equipment rating and Facility Fating changes thereafter should follow a robust change management process, which can include periodic in-field verifications where a percentage of facilities are completed annually. This process should be risk informed.

The in-field verification should be followed by a quality assurance review by experienced personnel to ensure the correct equipment ratings have been captured.

b) <u>Corrective Action Program</u>

An entity should have a corrective action program that establishes responsibility and describes the process to document, track, and trend things like the following:

- Adverse conditions, including industrial safety incidents and compliance issues,
- Restoration efforts involving equipment changes in the field,
- Minor problems that may be precursors to more significant problems,
- Areas for improvement identified during assessments,
- Other internally identified issues,
- Corrective actions pertaining to identified underlying causes.

2. Facility Ratings Data Management

   Transmission Owners and Generator Owners should create an accurate Facility Ratings database considering the following:

   - Establish a single official Facility Ratings database or declare an official Facility Ratings repository or a master spreadsheet at minimum.
   - Ensure downstream processes that require Facility Ratings (such as model building for real-time operations or planning) leverage the facility ratings database as the official record.
   - Communicate the location of the official facility ratings database (or repository or master spreadsheet) to all relevant personnel.
   - Document the process to obtain information from the field and enter the data into the official database, repository, or master spreadsheet.
   - Reinforce the documented process with work-flow diagrams and provide training on the process on at least an annual basis or an effective periodic basis.
   - Ensure that a peer review is performed to verify that the data has been entered into the database, repository, or master spreadsheet correctly.
   - Implement strict access controls to the official facility ratings database, repository, or master spreadsheet to limit write access so that only a small group of necessary personnel can make changes in the database and source documents (Individuals with write access should be properly trained before receiving write access and on a continuous basis thereafter.)

3. Change Management Process

   A strong change management process should include the following:

   - A requirement for data entry verification by qualified personnel.
   - A clearly outlined approval process prior to a change being implemented.
   - Notification to update equipment inventory after a change is implemented.
   - Confirmation that the change is implemented as planned.
   - Automated notification of the change to all appropriate departments and external stakeholders.
   - Checklist to verify all appropriate follow-up actions are taken after a change (e.g., an equipment change should prompt a review of other facility equipment ratings to ensure the most limiting equipment has not changed).
   - Validation through periodic reviews.
   - A change process flowchart to help personnel and project teams identify the different steps in the change process and understand the relationships among the various steps.
   - capturing changes because of emergency repairs or changes following post-storm or extreme weather restoration.

- Comprehensive training program including clarification of roles and responsibilities.

4. Development and Application of a Consistent Facility Rating Methodology

Best practices show that entities most successful in this area do the following:

- Develop and maintain a detailed and comprehensive FRM.
- Provide the specific rating method for each class and type of equipment comprising a BES Facility.
- Train appropriate personnel on how to apply the methodology.

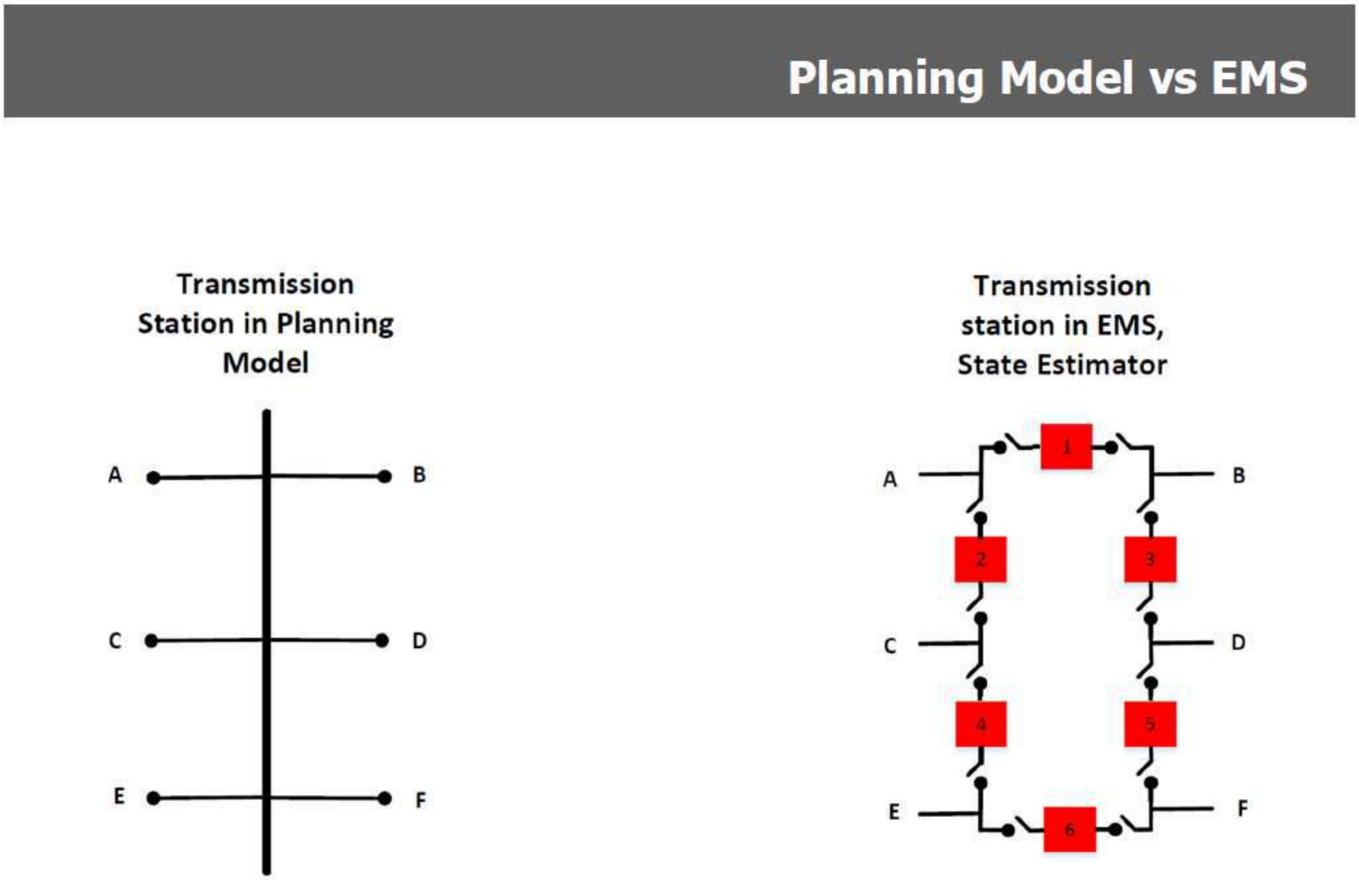
APPENDIX E: Terms and Definitions

Definitions from NERC Glossary of Terms

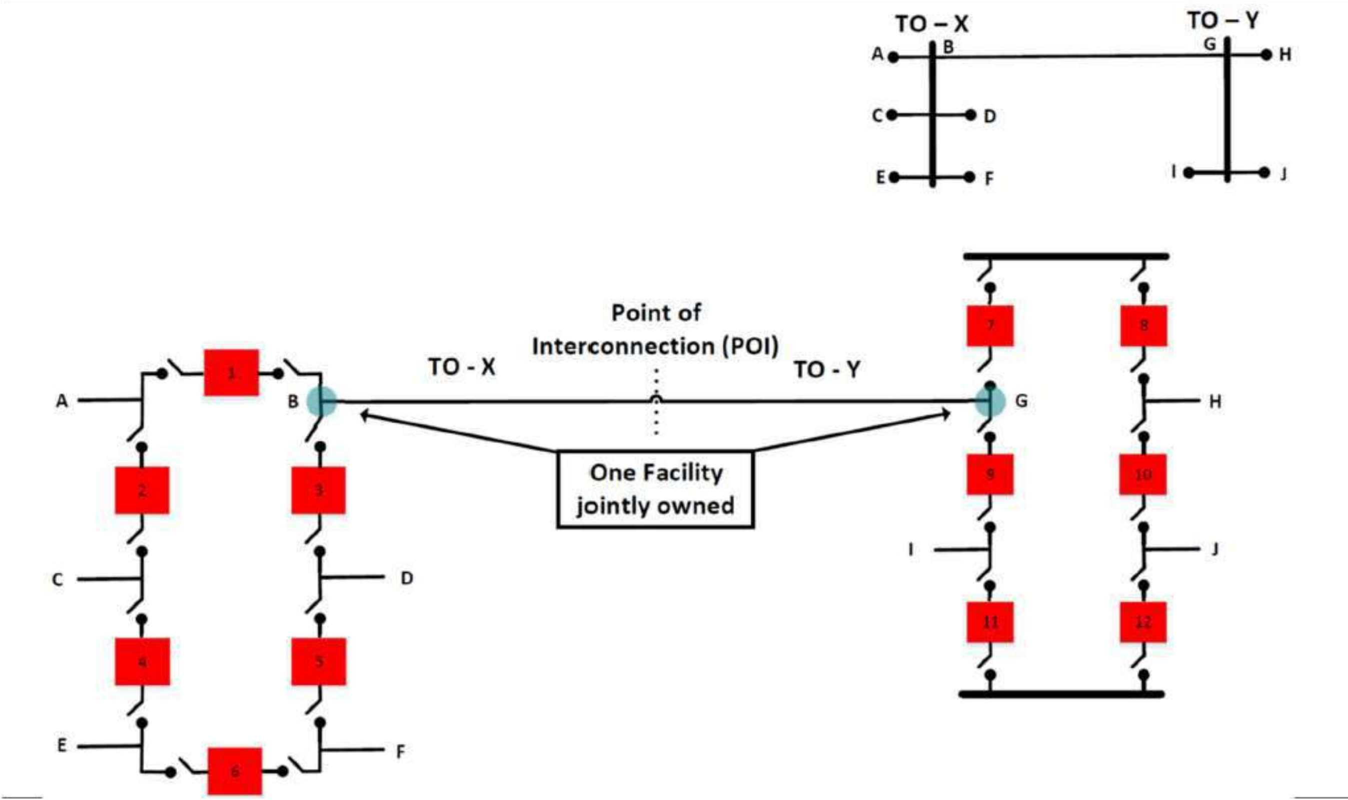
Element	Any electrical device with terminals that may be connected to other electrical devices such as a generator, transformer, circuit breaker, bus section, or transmission line. An Element may be comprised of one or more components.
Emergency Rating	The rating as defined by the equipment owner that specifies the level of electrical loading or output, usually expressed in megawatts (MW) or Mvar or other appropriate units, that a system, facility, or element can support, produce, or withstand for a finite period. The rating assumes acceptable loss of equipment life or other physical or safety limitations for the equipment involved.
Equipment Rating	The maximum and minimum voltage, current, frequency, real and reactive power flows on individual equipment under steady state, short-circuit and transient conditions, as permitted or assigned by the equipment owner.
Facility	A set of electrical equipment that operates as a single Bulk Electric System Element (e.g., a line, a generator, a shunt compensator, transformer, etc.)
Facility Rating	The maximum or minimum voltage, current, frequency, or real or reactive power flow through a facility that does not violate the applicable equipment rating of any equipment comprising the facility.
Limiting Element	The element that is 1. Either operating at its appropriate rating, or 2. Would be following the limiting contingency. Thus, the Limiting Element establishes a system limit.
Normal Rating	The rating as defined by the equipment owner that specifies the level of electrical loading, usually expressed in megawatts (MW) or other appropriate units that a system, facility, or element can support or withstand through the daily demand cycles without loss of equipment life.
Rating	The operational limits of a transmission system element under a set of specified conditions.
System Operating Limit	The value (such as MW, Mvar, amperes, frequency, or volts) that satisfies the most limiting of the prescribed operating criteria for a specified system configuration to ensure operation within acceptable reliability criteria. System Operating Limits are based upon certain operating criteria. These include, but are not limited to: • Facility Ratings (applicable pre- and post-Contingency Equipment Ratings or Facility Ratings) • transient stability ratings (applicable pre- and post-Contingency stability limits) • voltage stability ratings (applicable pre- and post-Contingency voltage stability)

	• system voltage limits (applicable pre- and post-Contingency voltage limits)
Thermal Rating	The maximum amount of electrical current that a transmission line or electrical facility can conduct over a specified time period before it sustains permanent damage by overheating or before it sags to the point that it violates public safety requirements.

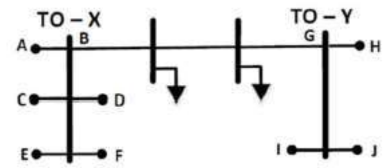
APPENDIX F: OTHER MODEL EXAMPLES

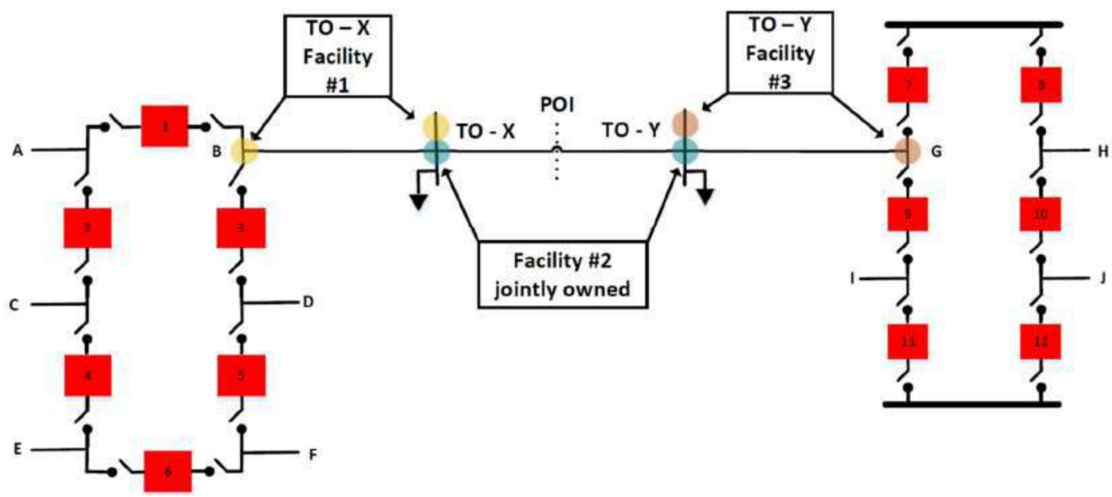


TO Connected to TO (Jointly Owned)

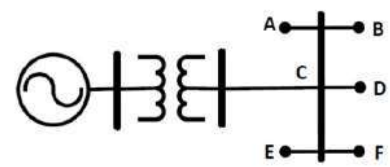


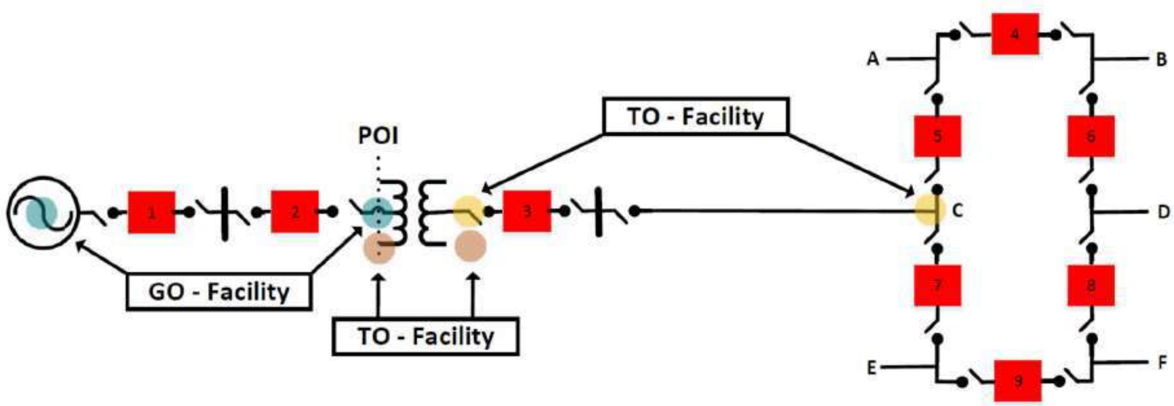
TO Connected to TO (Jointly Owned)



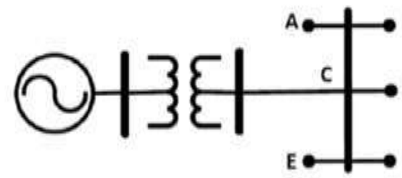


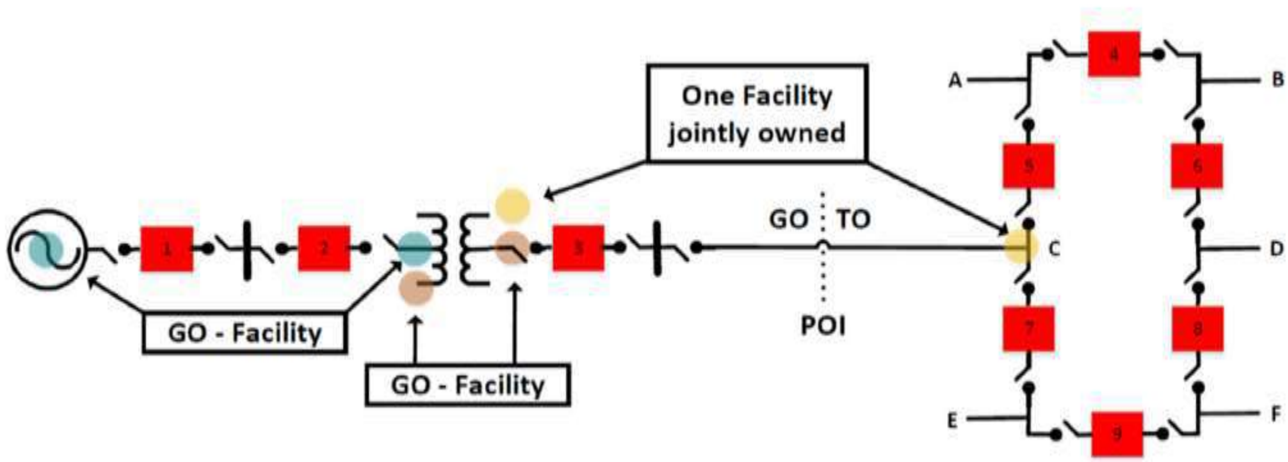
GO Connected to TO (Solely Owned)



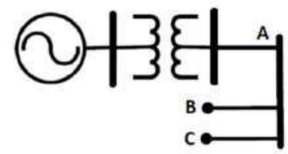


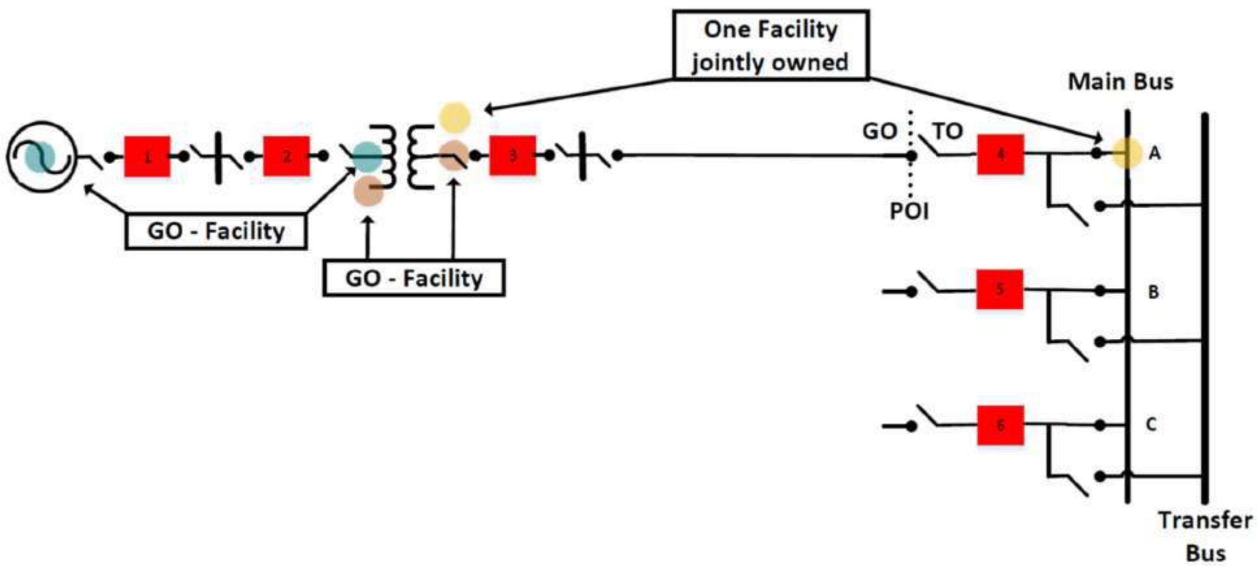
GO Connected to TO (Jointly Owned)



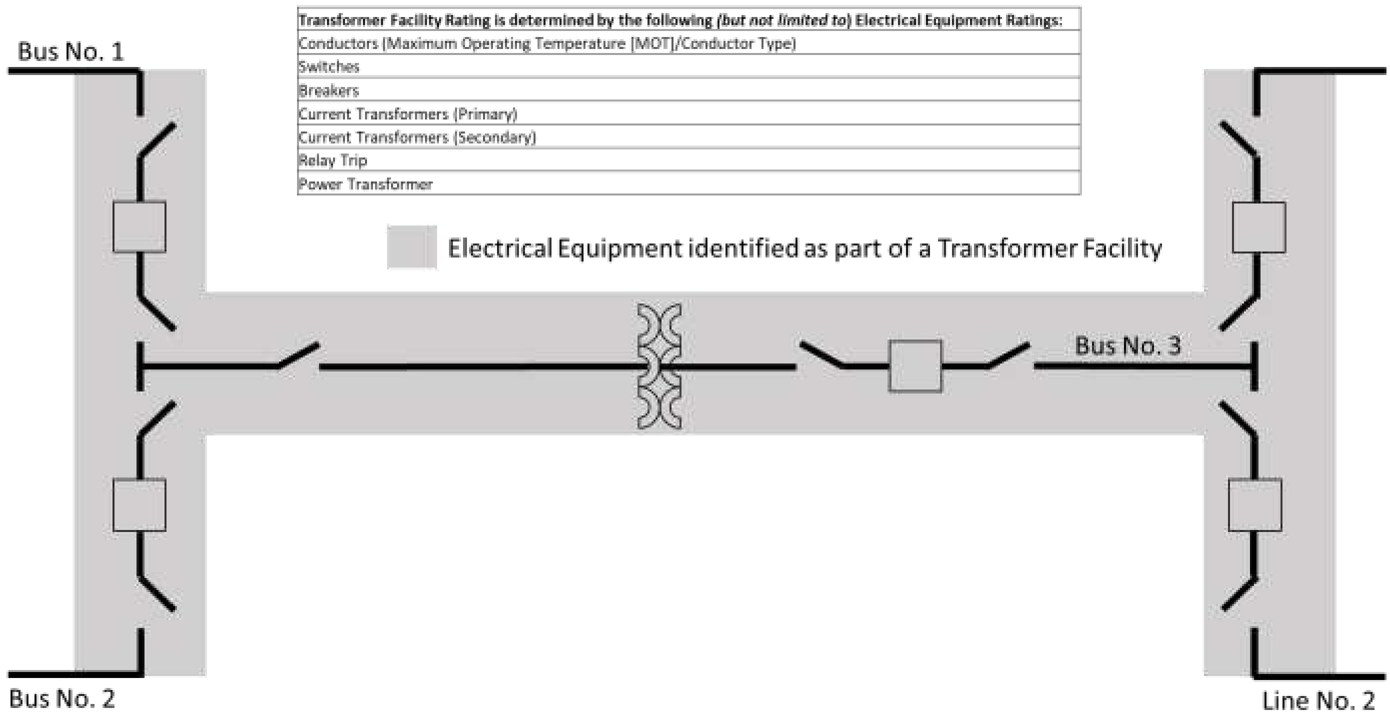


GO Connected to TO (Jointly Owned)

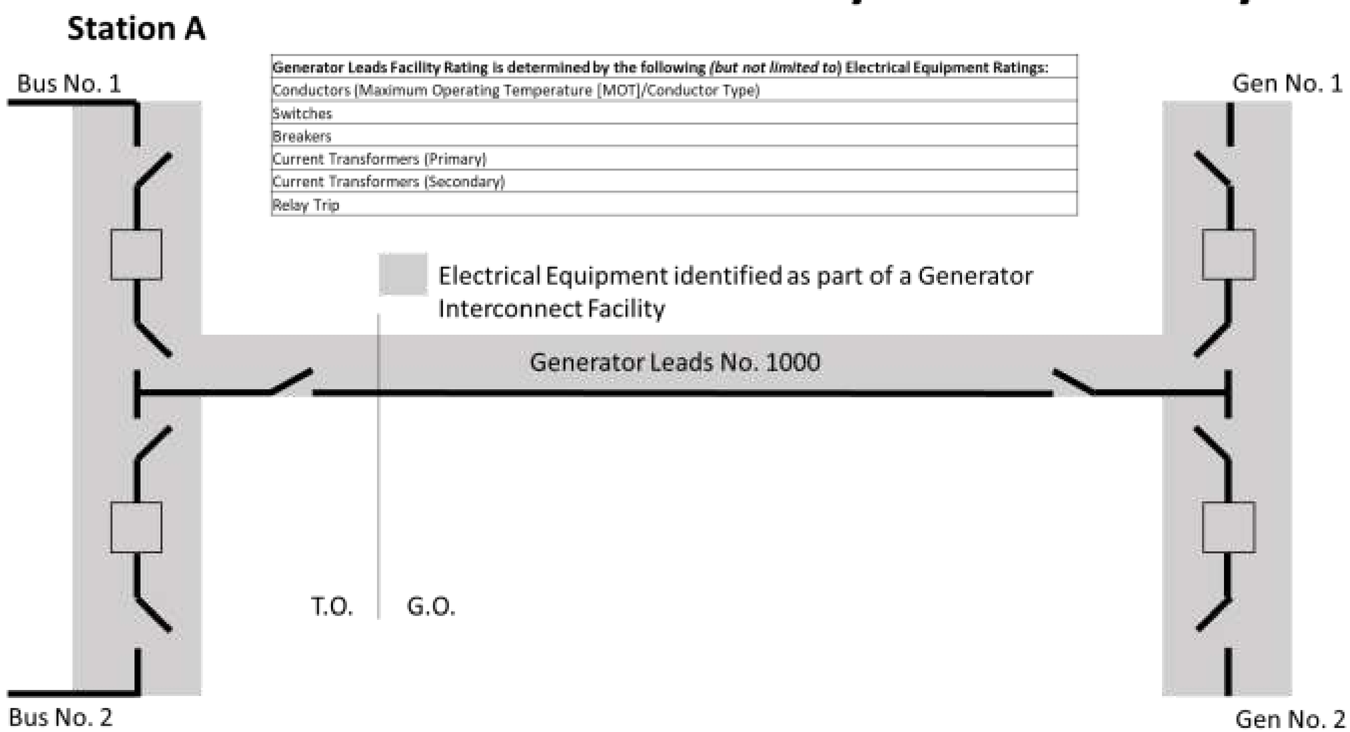




Transformer Facility

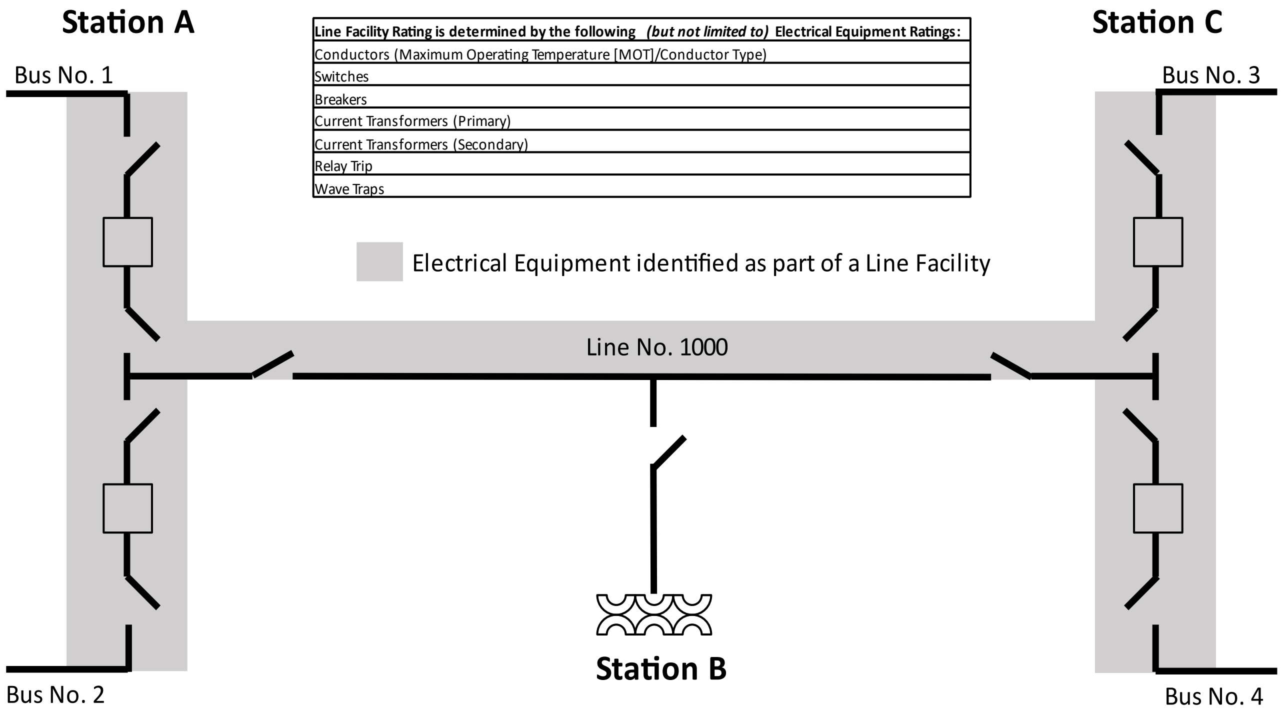


Generator Interconnect Jointly Owned Facility



Line Facility

Line Facility Rating is determined by the following *(but not limited to)* Electrical Equipment Ratings:
Conductors (Maximum Operating Temperature [MOT]/Conductor Type)
Switches
Breakers
Current Transformers (Primary)
Current Transformers (Secondary)
Relay Trip
Wave Traps



FAC-008-5 Implementation Guidance

Facility Ratings Task Force
Request for Endorsement

Robert Reinmuller
Reliability and Security Technical Committee Meeting
September 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 draft IG was shared with the FRTF membership in March 2024 for review and comment.
- The revised document was subsequently presented to the RSTC in June 2024 for further review and comment.
- The team has addressed the comments received from the RSTC and has submitted the revised IG document to NERC Publications for final preparation.
- The draft IG is included in the agenda package.

The Ask

- The team is requesting the RSTC endorse this proposed Implementation Guidance such that it can be submitted to the ERO Enterprise Compliance staff for further vetting and eventual endorsement.

Questions and Answers

Agenda Item 14
RSTC Meeting
September 11, 2024

Status Update on the Winter Storm Elliott Report Cold Weather Event Recommendations

Action

RSTC Information and Discussion

Background

In October 2023, FERC, NERC and the Regional Entities published the *Inquiry into Bulk-Power System Operations During December 2022 Winter Storm Elliott* and this report had 11 recommendations.

Winter Storm Elliott is the fifth event in the past 11 years which jeopardized bulk-power system reliability due to unplanned generating unit outages which escalated due to cold weather. The extreme cold weather conditions of Winter Storm Elliott resulted in a total of 1,702 individual bulk-power system generating units experiencing either an outage, a derate, or a failure to start from December 21 through December 26, 2022, a six-day period.

Three causes accounted for 96 percent of the generating unit outages, derates or failures to start, based on number of megawatts: mechanical/electrical failures, freezing, and fuel issues. Freezing issues and fuel issues combined caused 55 percent of all unplanned generating unit outages, derates and failures to start during the event, as measured by MW.

The report made 11 recommendations in 4 categories: cold weather reliability of generators, natural gas infrastructure, natural gas and electric industry coordination, and electric grid operations.

Summary

NERC staff will give a status update on the progress made on the 11 Winter Storm Elliott recommendations.

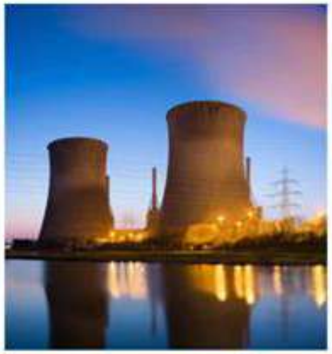
NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Winter Storm Elliott Recommendations

Status Update

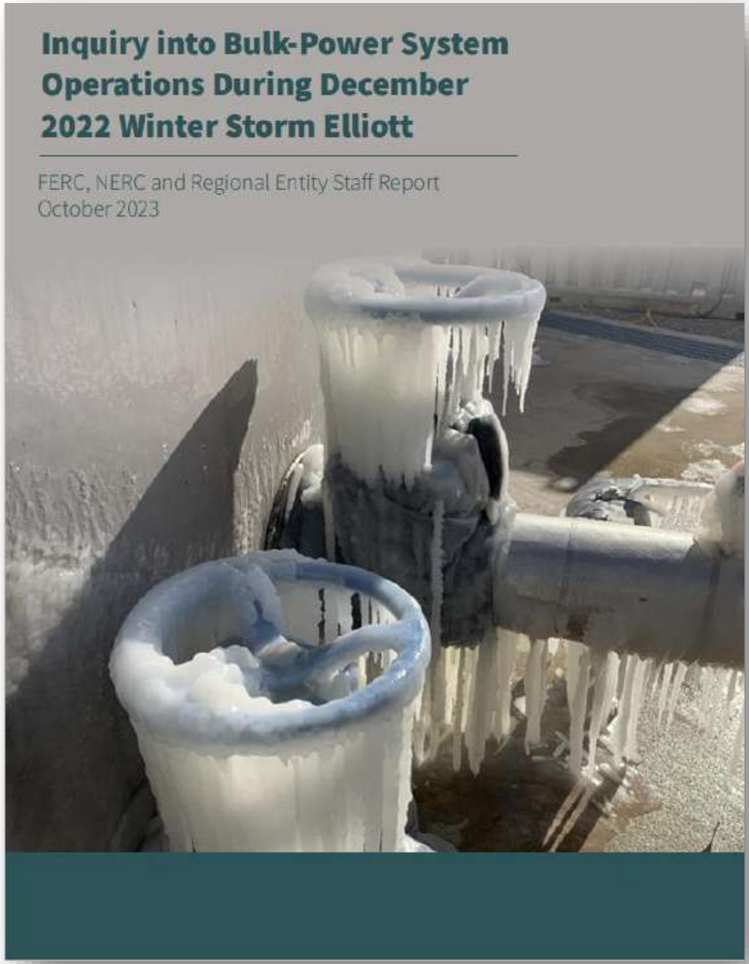
Elsa Prince, Principal Technical Advisor, PRISM
Reliability and Security Technical Committee Meeting
September 11, 2024

RELIABILITY | RESILIENCE | SECURITY

Background

- Report: Inquiry into Bulk-Power System Operations During December 2022 Winter Storm Elliott
  - FERC, NERC and Regional Entity Staff Report, October 2023
  - 60+ contributors from FERC, NERC and it's Regional Entities and NOAA



Overview

- 11 Recommendations
  - Cold Weather Reliability of Generators
  - Natural Gas Infrastructure Cold Weather Reliability
  - Natural Gas-Electric Coordination for Cold Weather Reliability
  - Electric Grid Operations Cold Weather Reliability
- Where appropriate, recommendations have timeframes for initiation or implementation
  - Recommendations associated with the legislation process or the Commission do not have dates provided
- Owners – NERC, Regional Entities, GOs/GOPs, FERC, Independent SMEs
- The recommendations are in progress

Status Update

Rec #	Owner	Recommendation Topics Summary	
1	NERC/RE/GOs/GOPs	Cold Weather Reliability of Generators	
2	NERC	Cold Weather Reliability of Generators	
3	NERC/RE	Cold Weather Reliability of Generators	
4	FERC	Natural Gas Infrastructure	
5	NERC/ISO-RTO	Natural Gas – Electric Coordination	
6	FERC	Natural Gas – Electric Coordination	
7	FERC	Natural Gas – Electric Coordination	
8	NERC/RSTC	Electric Grid Operations	
9	NERC/RSTC	Electric Grid Operations	
10	NERC/RSTC	Electric Grid Operations	
11	EIPC	Electric Grid Operations	

Legend	Completed	Progressing as Expected	More Progress Needed	FERC

Status Update

#	Owner	Recommendation Topics Summary	
1	NERC/RE/ GOs/GOPs	Generator cold weather reliability guidance and monitor efforts	
2	NERC	Technical review of generator mechanical/electrical-caused outages	
3	NERC/RE	Blackstart cold weather reliability	
4	FERC	Establish rules and practices for natural gas facilities' cold weather preparedness	
5	NERC/IRC	NAESB gas-electric coordination business practice standards development	
6	FERC	Consider report outlining vulnerabilities nat gas ind cold weather grid support	
7	FERC	Technical review on natural gas reliability for grid support	
8	NERC/RSTC	Balancing Authorities assess processes to reduce uncertainty	
9	NERC/RSTC	Balancing Authorities should improve short term load forecasts	
10	NERC/RSTC	Resource Planners sponsor assessments to reduce risk of firm load shed	
11	EIPC	Examine dynamic stability of EI during the WS Elliott event	

Legend	Completed	Progressing as Expected	More Progress Needed	FERC

Questions and Answers

Load Forecasting Panel Session

Action
Information

Background
In October 2023, NERC and the Regional Entities participated in a joint inquiry with FERC on Winter Storm Elliott and there were several load forecasting type recommendations. We were unable to successfully assign tracking/resolution of those recommendations to groups under the RSTC. The issue that we noticed is that none of those groups have load forecasting within their scoping documentation. To help address the load forecasting recommendations, we decided to host a panel session on load forecasting changes/improvements that companies have made to address the Winter Storm Elliott recommendations.

The companies that are participating in the panel session include California ISO, Duke Energy, ERCOT, IESO, PJM, SPP, Southern Company.

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

Action

Requesting RSTC Reviewers

Summary

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

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

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

Technical Reference Document

September 2024

RELIABILITY | RESILIENCE | SECURITY




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

Table of Contents

Preface

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

Reliability | Resilience | Security

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

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

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

Statement of Purpose

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

Chapter 1: Review of SPIDERWG SAR and Comments Received

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

Review of SPIDERWG Identified Reliability Concern

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

> "**Operational Planning Analysis (OPA)**: An evaluation of projected system conditions to assess anticipated (pre-Contingency) and potential (post-Contingency) conditions for next-day operations. The evaluation shall reflect applicable inputs including, but not limited to, load forecasts; generation output levels; Interchange; known Protection System and Special Protection System status or degradation; Transmission outages; generator outages; Facility Ratings; and identified phase angle and equipment limitations. (Operational Planning Analysis may be provided through internal systems or through third-party services.)"

> "**Real-time Assessment (RTA):** An evaluation of system conditions using Real-time data to assess existing (pre-Contingency) and potential (post-Contingency) operating conditions. The assessment shall reflect applicable inputs including, but not limited to: load, generation output levels, known Protection System and Special Protection System status or degradation, Transmission outages, generator outages, Interchange, Facility Ratings, and identified phase angle and equipment limitations. (Real-time Assessment may be provided through internal systems or through third-party services.)"

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

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

Review Method

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

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

Review Outcomes:

- What is the outcome of this review?

Review Details:

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

Qualifiers of SPIDERWG Review in Relation to Current Surveys

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

SPIDERWG Development of the SAR

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

SPIDERWG's draft SAR had the following scope items:

1. Revise the OPA definition in the NERC Glossary of Terms so that it is clearly addressing aggregate DERs. This includes referring to "gross load", "net load", "Load", or other clarity enhancement to ensure the proper quantity (i.e., DER + gross load, or net load) is represented in the listed example inputs. These edits should replace the unclear terms such as "load", "load forecast", and "generation output levels" to be clear on including aggregate DER.
2. Revise the RTA definition in the NERC Glossary of Terms so that it is clearly addressing aggregate DERs. This includes referring to "gross load", "net load", "Load", or other clarity enhancements to ensure the proper quantity (i.e., DER + gross load, or net load) is represented in the listed example inputs. These edits should replace the unclear terms such as "load" and "generation output levels" to be clear on including aggregate DER.
3. Revise TOP-002-4 Requirement R4 to clearly address aggregate DERs. Specifically, to address the accounting for next-day condition impacts DER have on expected generation resource commitment and dispatch as well as the Demand patterns. The SDT should ensure language edits are such that DERs are not double counted when committing generation to serve net demand (i.e., reduction of load in addition to adding to the generation commitment.)
4. Ensure that changes to the OPA and RTA definition are clear when read in-text in TOP-001, TOP-002, TOP-003, and TOP-010 where the Reliability Standard refers to OPA or RTA.

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

> "Further, FERC Order 901 directed NERC to submit 'one or more new or modified Reliability Standards that require …. distribution providers to provide Bulk-Power system planners and *operators* modeling data and parameters for IBR-DERs in the aggregate in their distribution provider areas where the IBR-DERs in the aggregate materially affect the reliable operation of the Bulk-Power System.' [Emphasis added]"

Additionally, the SPIDERWG added that the ongoing work with Project 2022-02 and the operational needs for FERC 901 in the statement above would require review of the standards project work in those areas to align with the work in the SAR. SPIDERWG also added that "the SAR is scoped not to address procedure but to require clarity edits to identified terms such that aggregate DER is clearly addressed in the OPAs and RTAs in the NERC Glossary of Terms."

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

Comments Received

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

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

Chapter 2: SPIDERWG Technical Opinion on Comments Received

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

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

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

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

Theme 2 – Undefined Relationship to IBR Registration

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

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

Theme 3 – No Modeling Information Exists for DERs

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

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

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

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

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

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

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

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

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

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

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

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

Theme 7 – Bad Information is Worse than No Information

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

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

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

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

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

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

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

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

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

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

Interconnection Regulation

Action
Information

Background
Traditional metrics of monitoring interconnection frequency performance did **NOT** indicate any significant changes in year over year regulation control issues. The NERC Resources Subcommittee explored a methodology to determine if time of day frequency control was becoming more difficult with the increased amount of solar generation on the interconnections.

1. Evidence indicated that entities that normally had little to no problems meeting compliance with BAL-001-2 were becoming more difficult.
2. The NERC RS wanted to utilize publicly available data for analysis.
   a. Utilization of individual BA Reporting ACE data could have been used and anonymized, but the data set would have been extremely large and cumbersome.
   b. A "library" of 4-second interconnection frequency data was available for at least the preceding ten years.
   c. Nearly anyone with electric service in the United States or Canada could collect the same data.
3. The NERC RS selected the metric "Control Performance Standard 1" (CPS1) as the metric to evaluate performance on an hourly basis as the metric is well understood in the entities operating a Balancing Authority Area.

Summary
This presentation will detail the methodologies used to determine trends in interconnection frequency control and impacts based upon the time of the day and the season of the year.

Interconnection CPS1 Performance
July 2024

Table of Contents

Background

Daniel Baker demonstrates below how to derive CPS1 for the interconnection.

From Attachment 1 BAL-001-2:

$$CPS1 = 100 * (2 - CF)$$

$$CF_{1\ minute} = \frac{ACE * \Delta F}{-10\beta}$$

$$CF = \frac{CF_{1\ minute}}{\varepsilon_1^2}$$

Combine (2) and (3):

$$CF = \frac{ACE * \Delta F}{-10\beta * \varepsilon_1^2}$$

Expand ACE:

$$CF = \frac{(NAI - NSI) - 10\beta(\Delta F) * \Delta F}{-10\beta * \varepsilon_1^2}$$

Assume NAI-NSI = 0 for interconnection level:

$$CF = \frac{(0) - 10\beta(\Delta F) * \Delta F}{-10\beta * \varepsilon_1^2}$$

Cancel and simplify:

$$CF = \frac{\Delta F^2}{\varepsilon_1^2}$$

$$CPS1_{Interconnection} = 100 * \left(2 - \frac{\Delta F^2}{\varepsilon_1^2}\right)$$

Daniel Baker can provide more information on this derivation if interested.

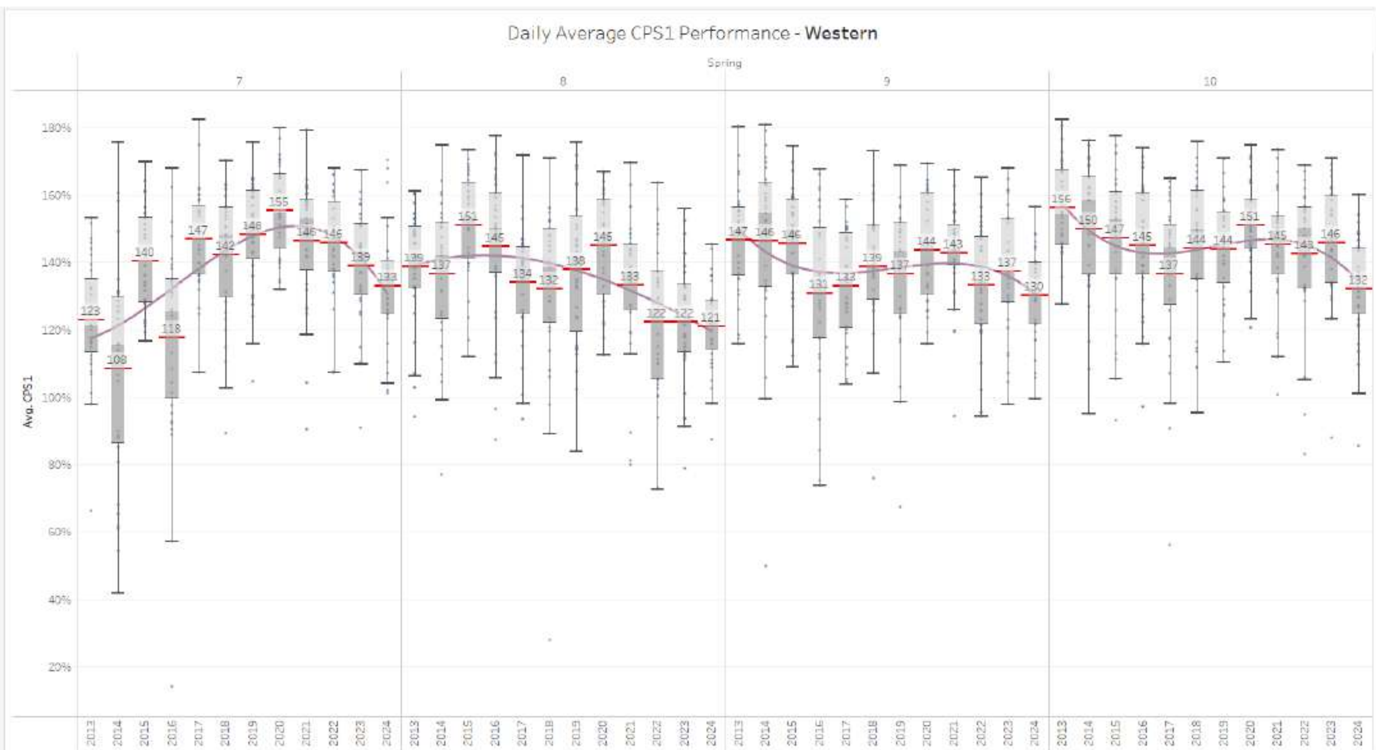
The goal of this report is to plot CPS1 performance year-over-year to determine which hours are experiencing more degradation than others, specifically solar AM/PM hours.

Solar AM Charts

These box and whisker charts provide a year-over-year look at CPS1 performance for each interconnection during solar AM hours (HE 7, HE 8, HE 9, and HE 10). The season and hours are shown across the top of the chart, and the years are shown across the bottom of the chart. Each dot represents a day in the season. The seasons are represented as Spring (March-May), Summer (June-August), Fall (September-November), and Winter (December-February). The box and whisker chart provides the distribution for each year and allows you to see the changing patterns year-over-year. Since the previous season is always the objective, we're looking to see if we improved frequency performance throughout that season.

Western Interconnect

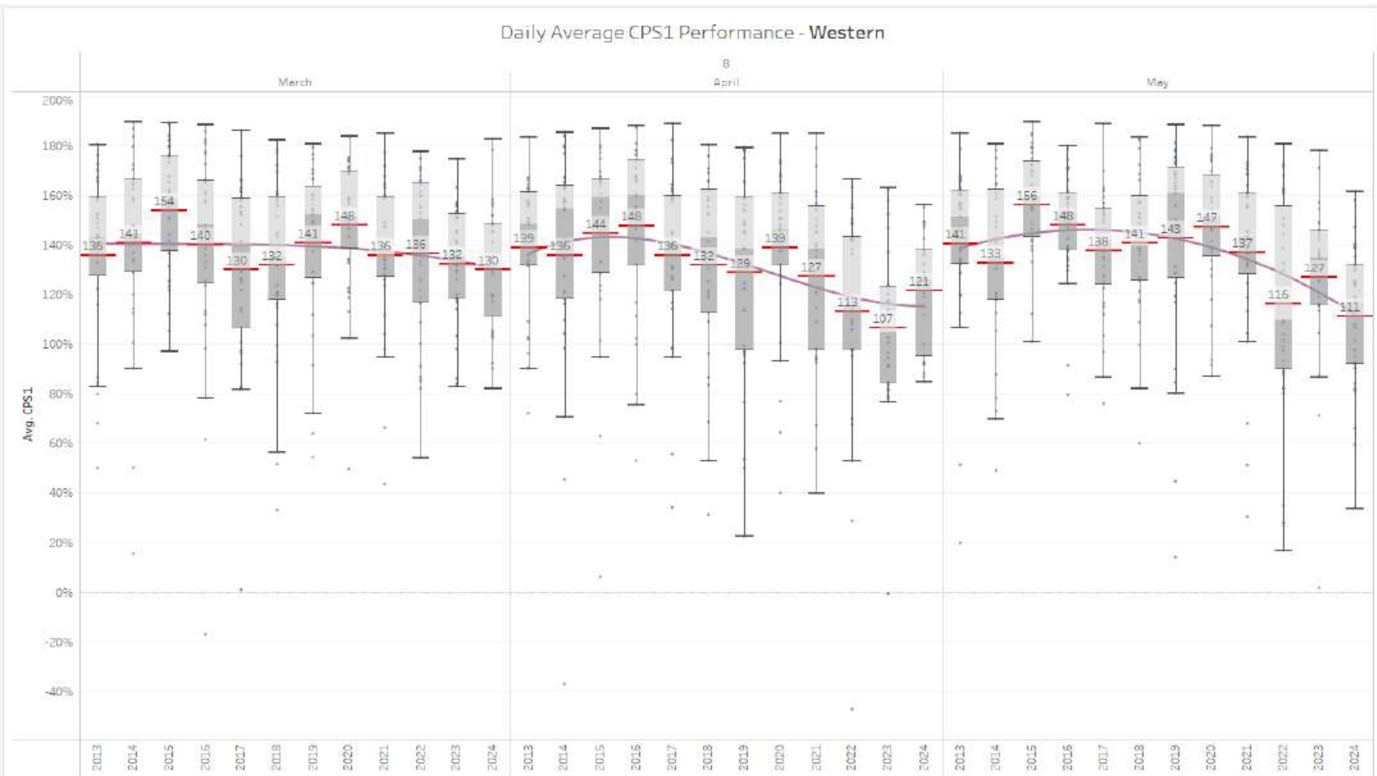
These charts represent Spring data from 2013-2024. If we focus on the purple polynomial trendline, the average CPS1 performance shows a downward trend in all HE hours year-over-year, with **HE 8** showing the greatest drop in average performance.



HE 8

Takeaways:

1. Variability has decreased significantly in April in recent years.
2. Average performance changes from 2022-2023:
    a. March decreased **2%**
    b. April increased **14%**
    c. May decreased **16%**



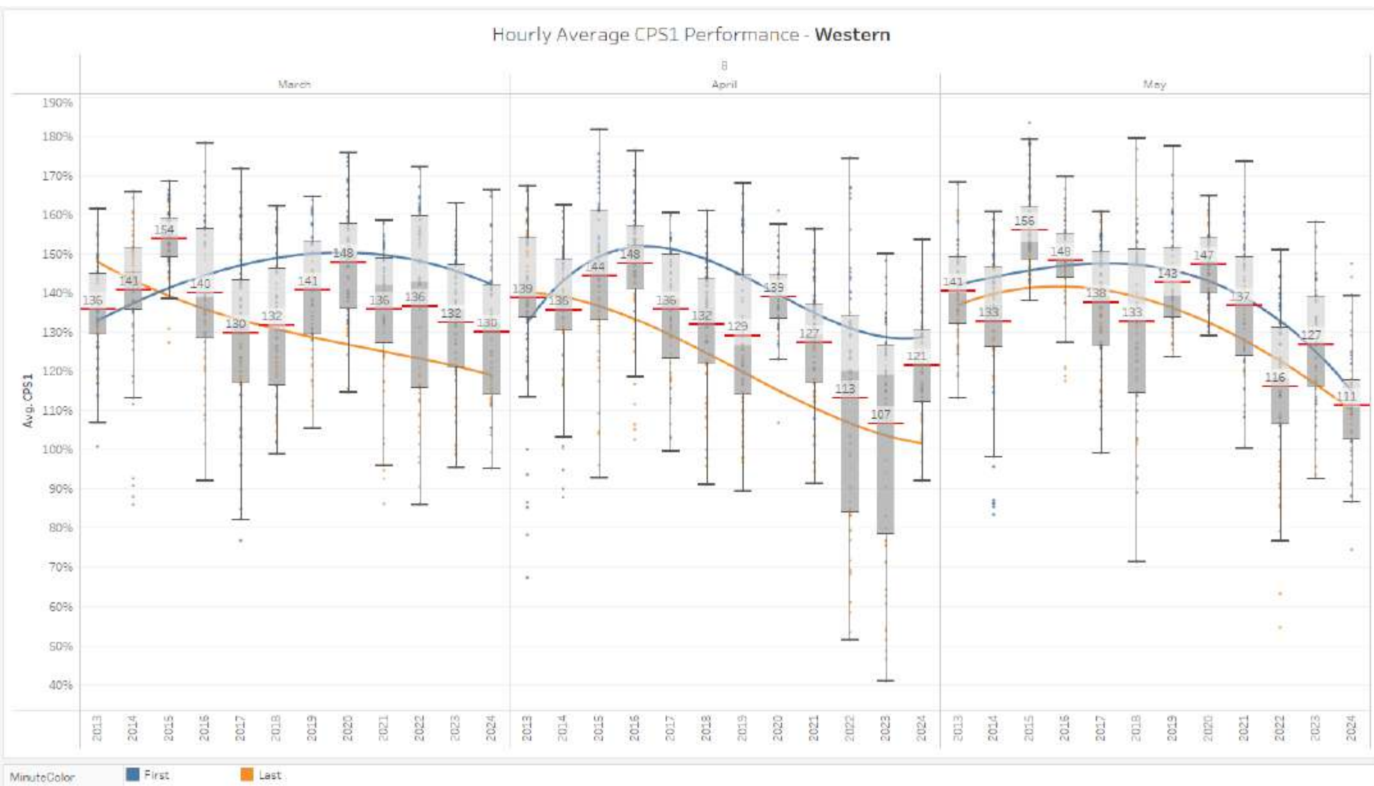
Hourly Performance

Based on the previous analysis, March and May look to be contributing to the downward trend in Spring performance during HE 8. What is the data telling me at the hourly and minute level? This chart is a look at solar AM hours during each of these months (year-over-year), for all days in the month, with HE across the top. This time, the dots represent minutes.

There are two separate polynomial trends comparing the **first half** of the hour to the **last half** of the hour. I color-coded the dots (minutes) to differentiate the minutes in the first half of the hour (blue) from the minutes in the last half of the hour (orange).

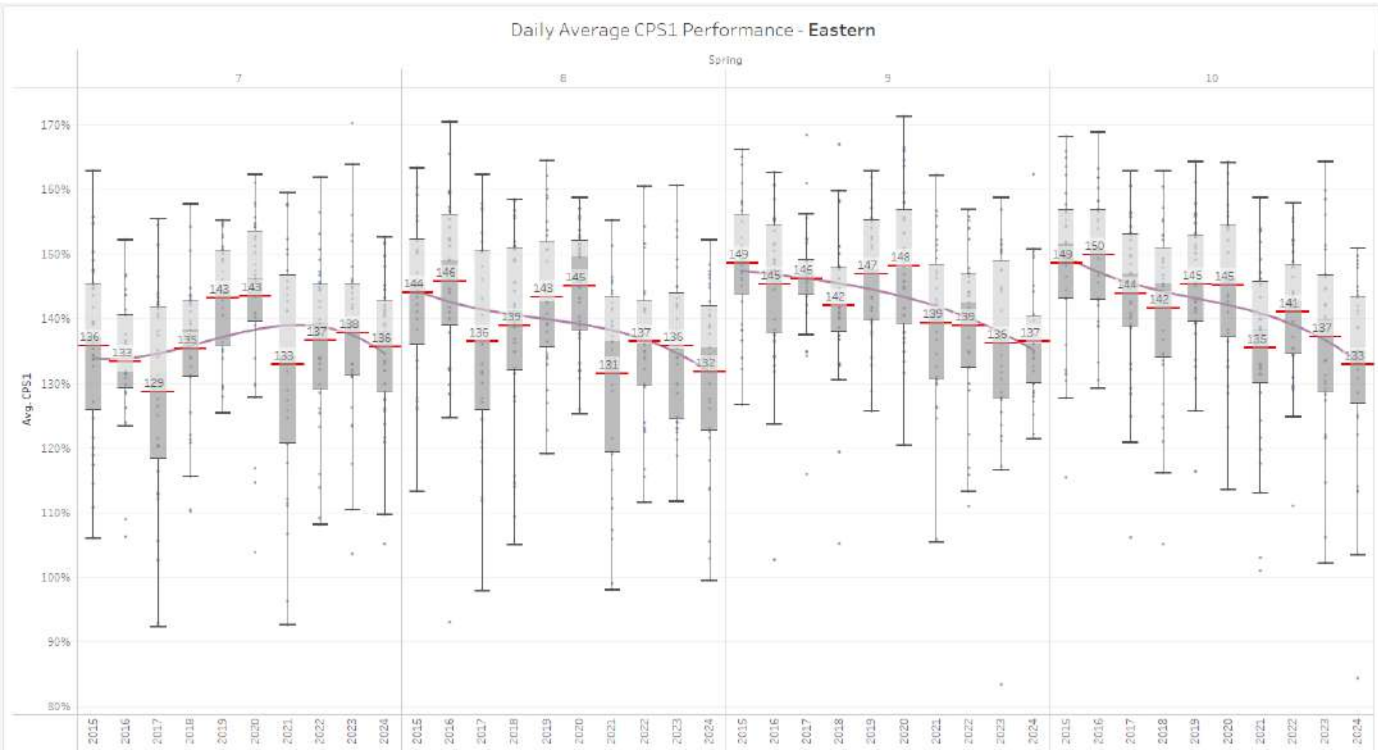
Takeaways:

1. May shows downward trends in recent years **throughout** the hour.
2. March and April show a greater struggle during the **second half** of the hour.



Eastern Interconnect

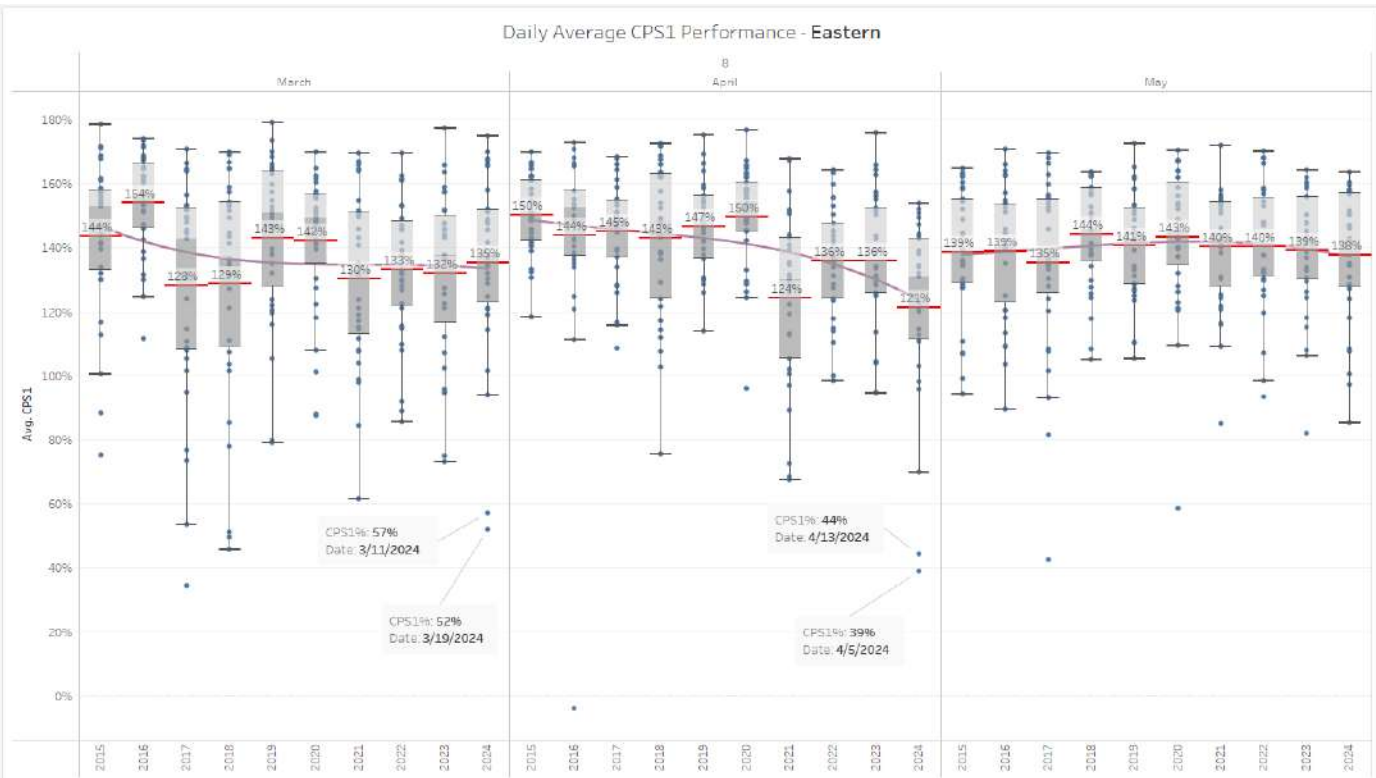
These charts represent Spring data from 2015-2024. The average performance from 2015-2020 was ~145%. Since 2021, average performance is ~135% in all HE hours year-over-year. Is this the new normal?



HE 8

Takeaways:

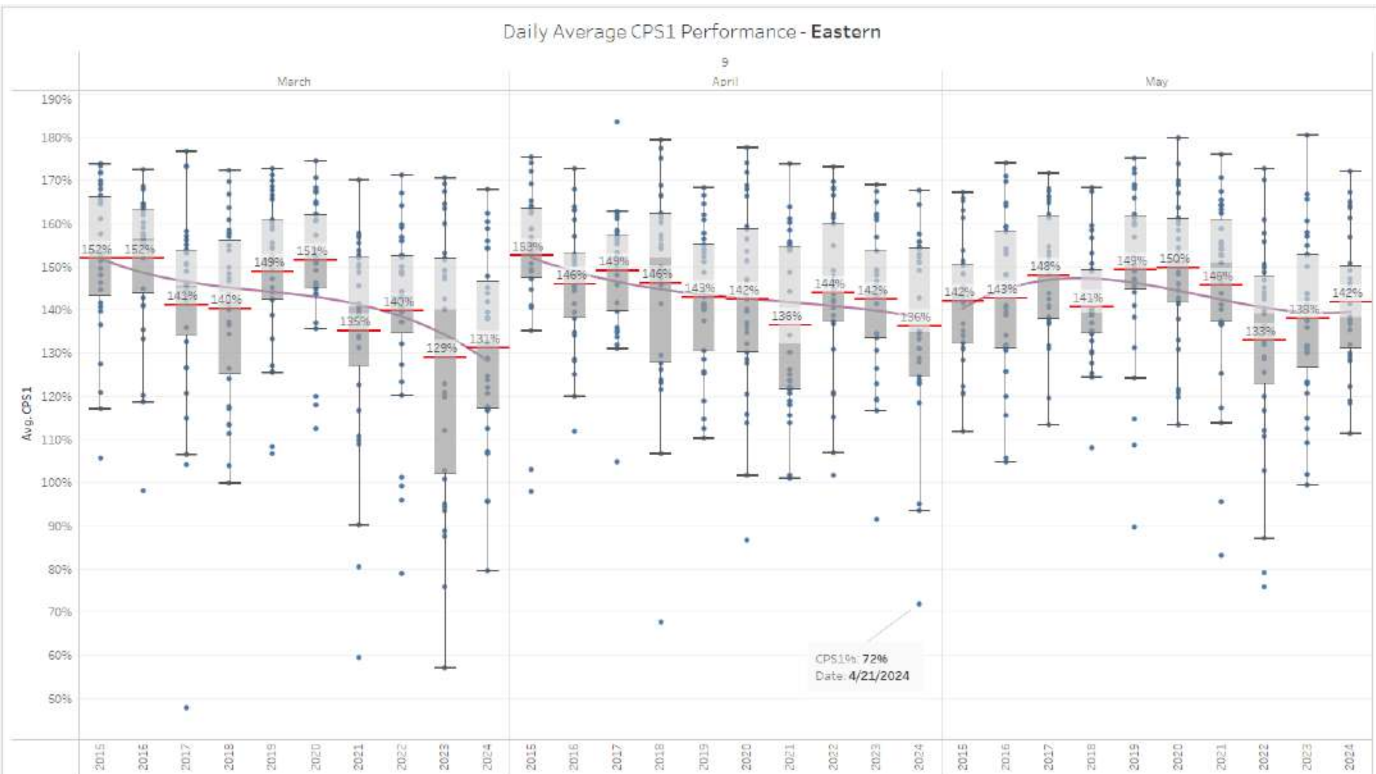
1. April experienced the most change in average performance since 2020.
2. Average performance changes from 2023-2024:
    a. March increased **3%**
    b. April decreased **15%**
    c. May decreased **1%**



HE 9

Takeaways:

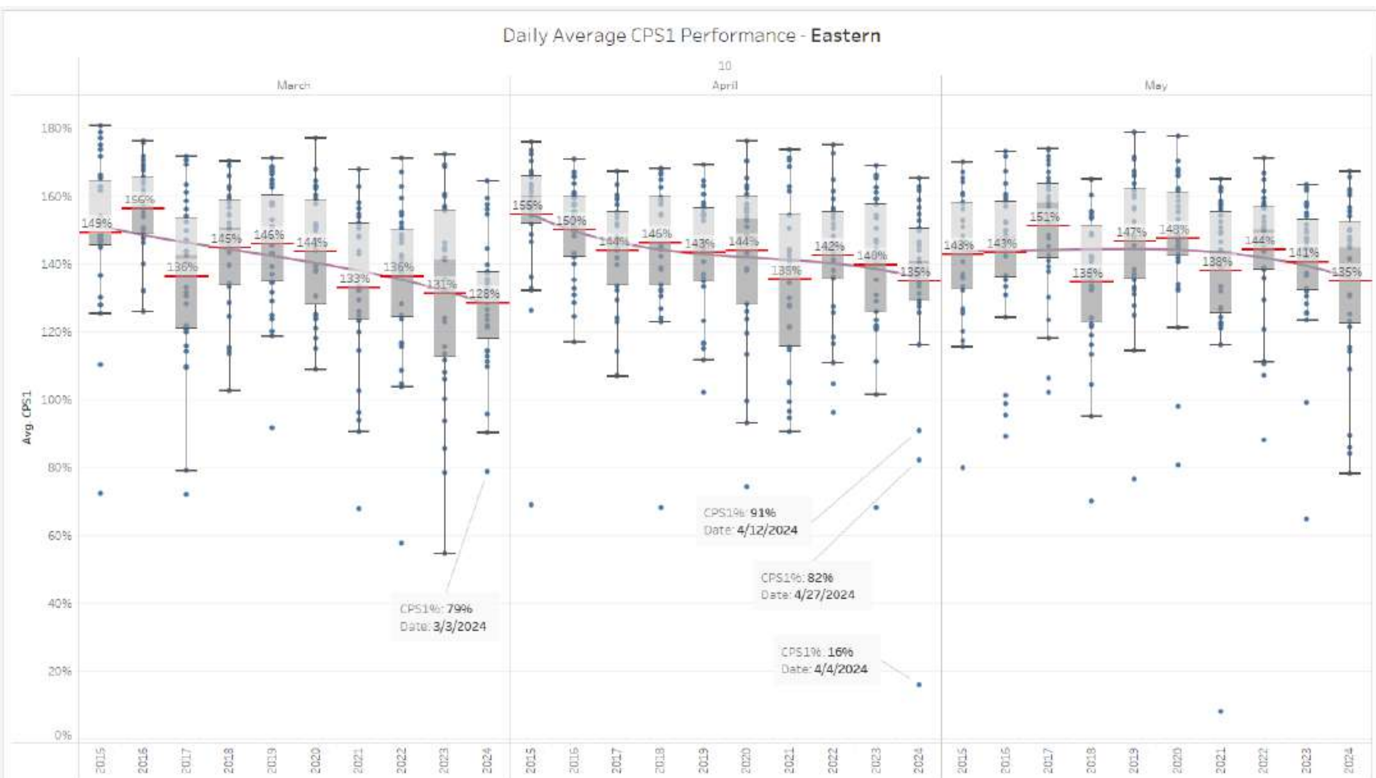
1. March has experienced considerable changes in variability in recent years.
    a. Tall boxes = wide IQR
    b. Long whiskers = wide range of performance outside IQR
2. Average performance changes from 2023-2024:
    a. March increased **2%**
    b. April decreased **6%**
    c. May increased **4%**



HE 10

Takeaways:

1. All months have experienced a steady decline in average performance in recent years.
2. **March** and **May** have experienced changes in variability in recent years.
3. Average performance changes from 2023-2024:
    a. March decreased **3%**
    b. April decreased **5%**
    c. May decreased **6%**



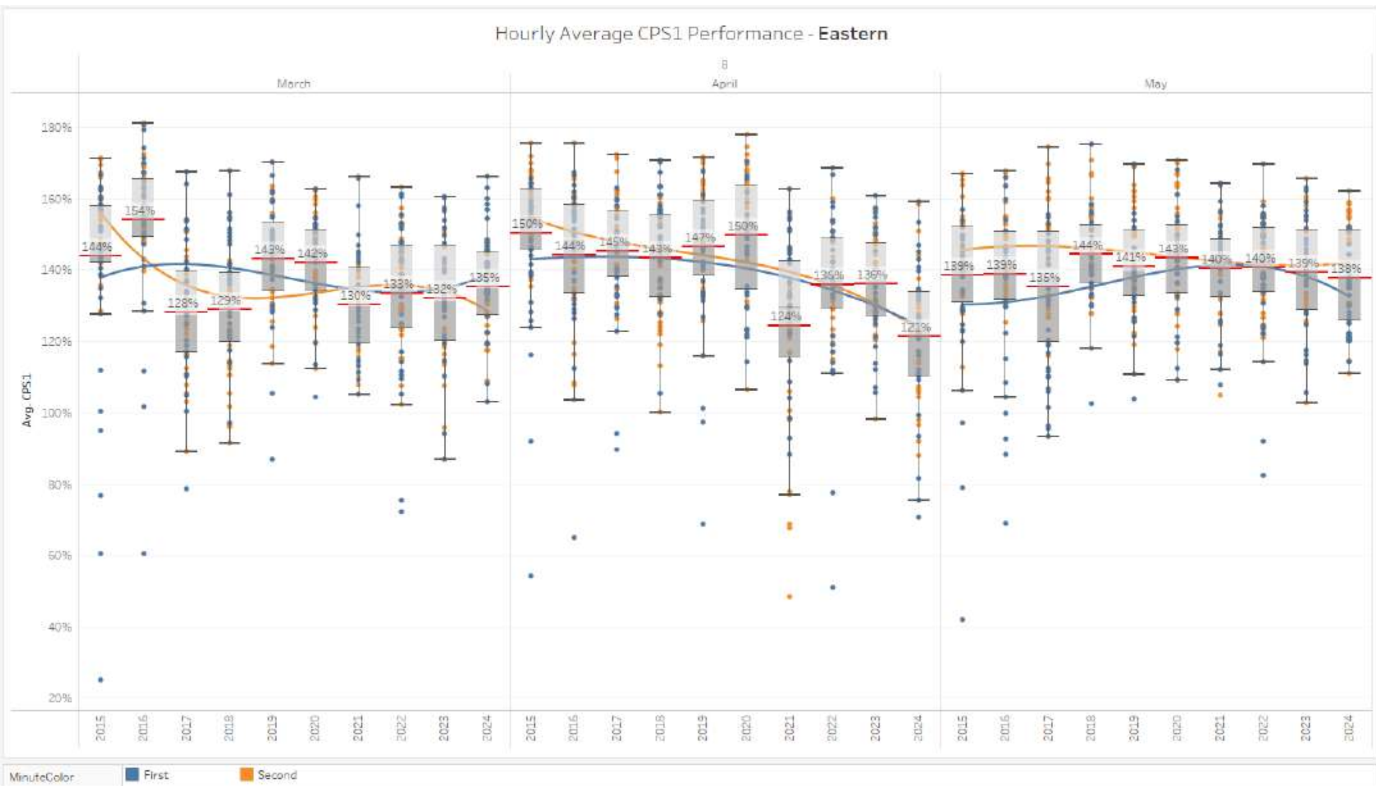
Hourly Performance

Based on the previous analysis, both **March** and **April** look to be contributing to the downward trend in Spring performance during **HE 8-10**. What is the data telling me at the hourly and minute level? These charts provide a look at solar AM hours during each of these months (year-over-year), for all days in the month, with HE across the top. This time, the dots represent minutes.

There are two separate polynomial trends comparing the **first half** of the hour to the **last half** of the hour. I color-coded the dots (minutes) to differentiate the minutes in the first half of the hour (blue) from the minutes in the last half of the hour (orange).

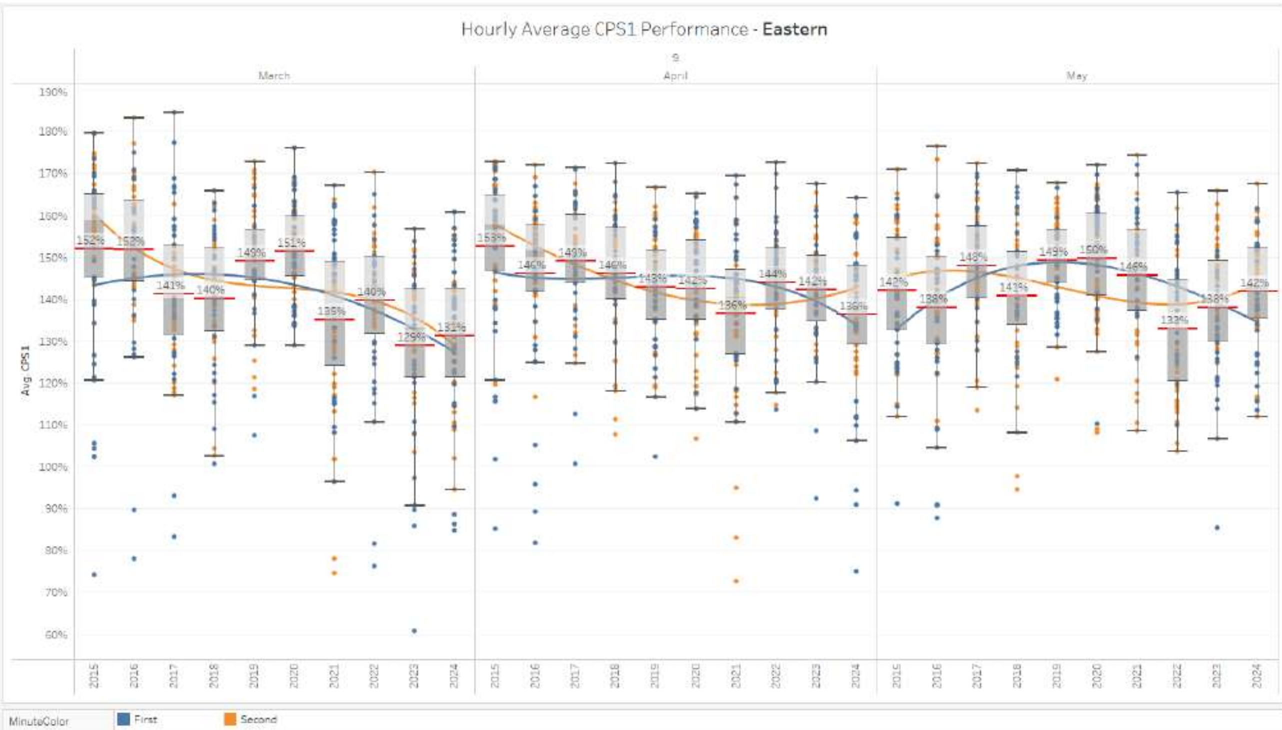
Takeaways (**HE 8**):

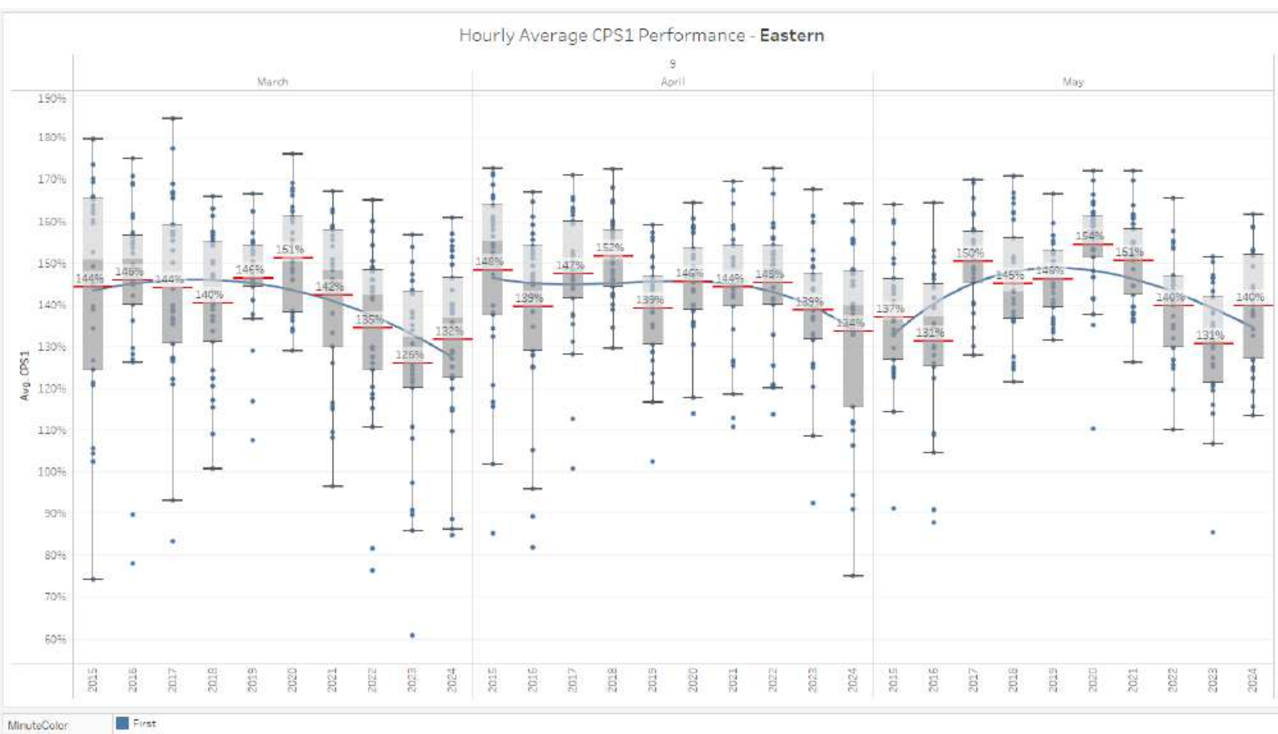
1. **April** has experienced more struggles during the second half of the hour in recent years.



Takeaways (**HE 9**):

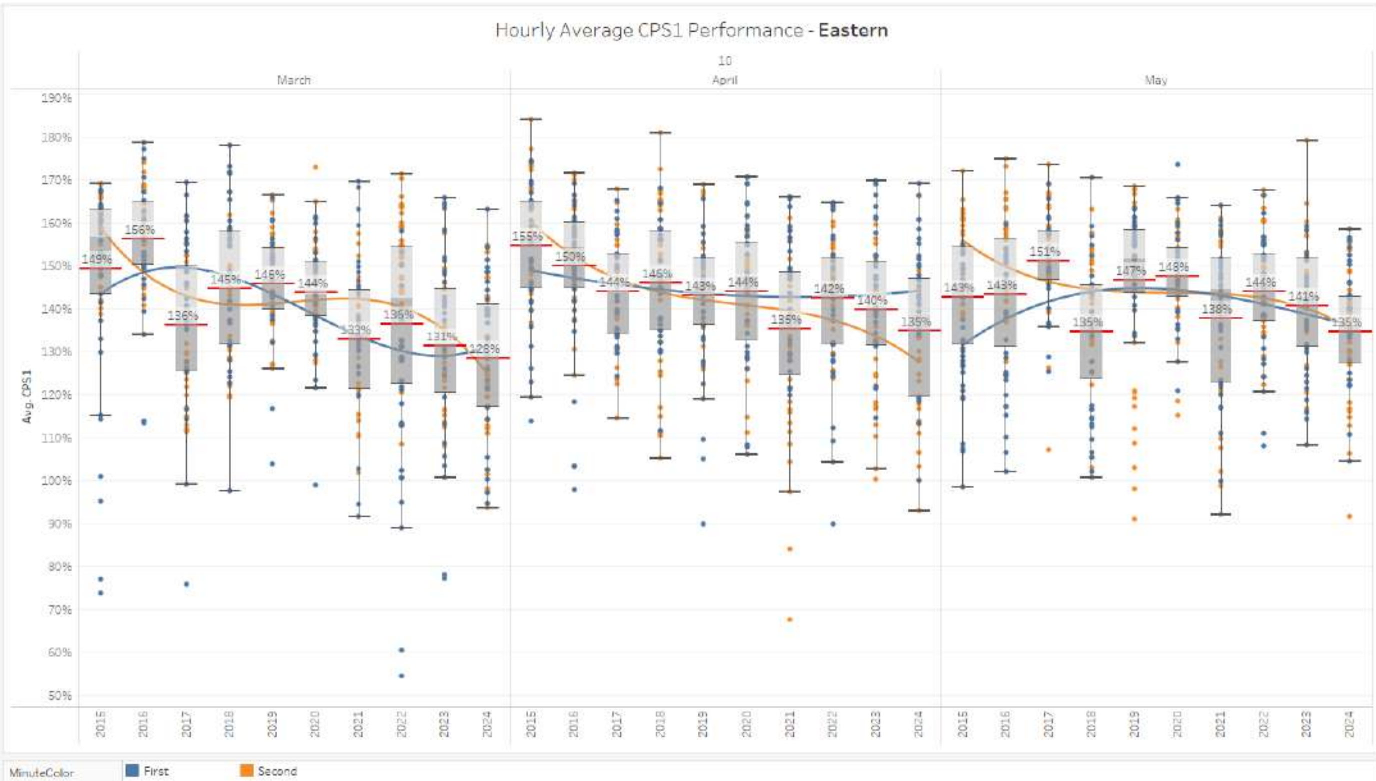
1. **March** shows downward trends **throughout** the hour since 2021.
2. **March** and **April** have experienced increased variability during the **first half** of the hour in recent years.

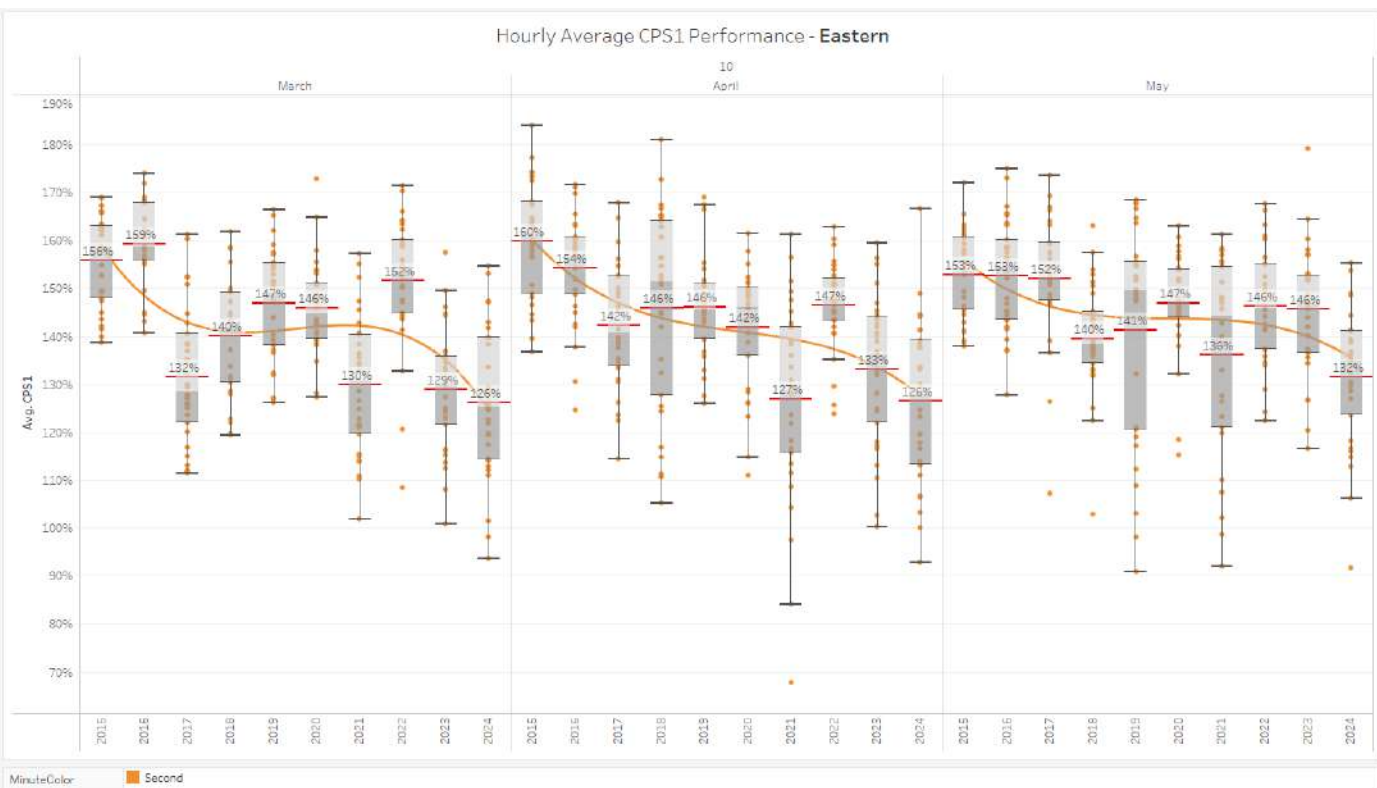




Takeaways (**HE 10**):

1. All months show a greater struggle during the **second half** of the hour in recent years.



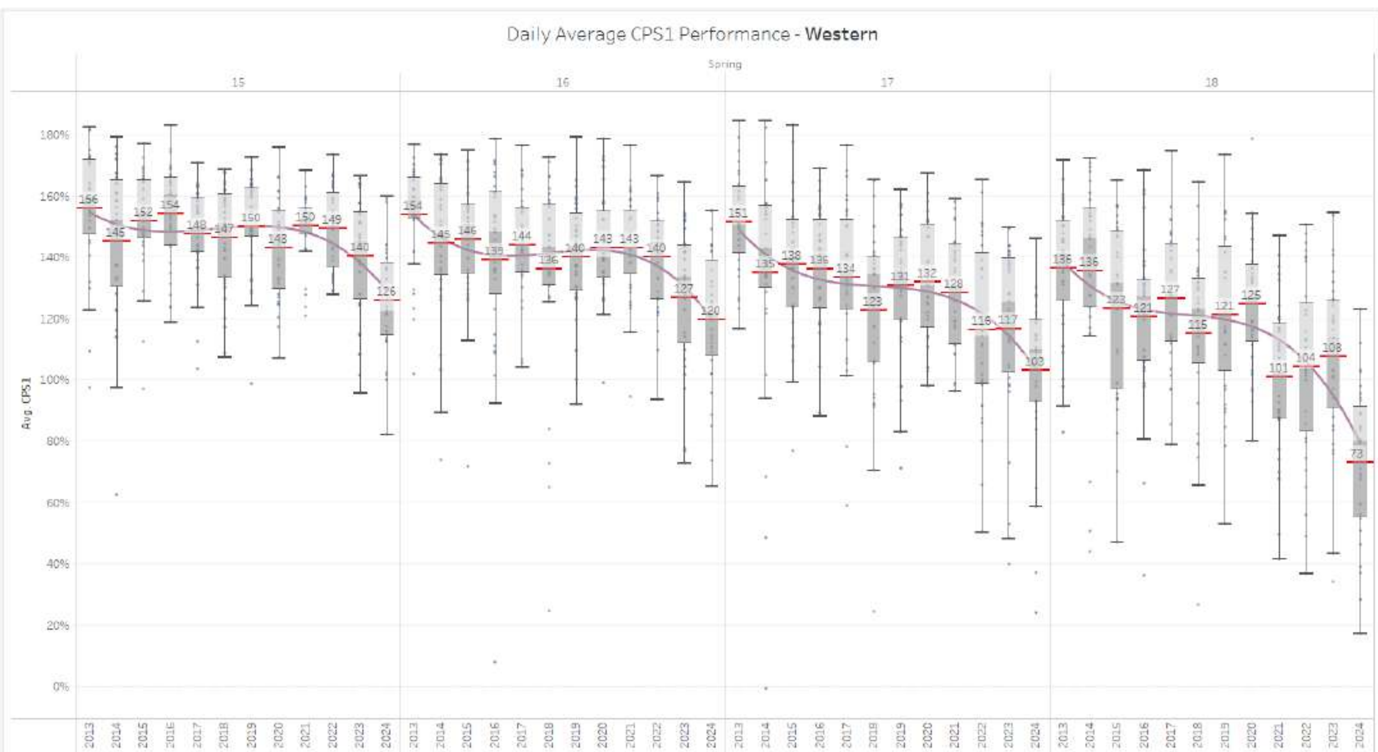


Solar PM Charts

These box and whisker charts provide a year-over-year look at CPS1 performance for each interconnection during solar PM hours (HE 15, HE 16, HE 17, and HE 18). The season and hours are shown across the top of the chart, and the years are shown across the bottom of the chart. Each dot represents a day in the season. The seasons are represented as Spring (March-May), Summer (June-August), Fall (September-November), and Winter (December-February). The box and whisker chart provides the distribution for each year and allows you to see the changing patterns year-over-year. Since the previous season is always the objective, we're looking to see if we improved frequency performance throughout that season.

Western Interconnect

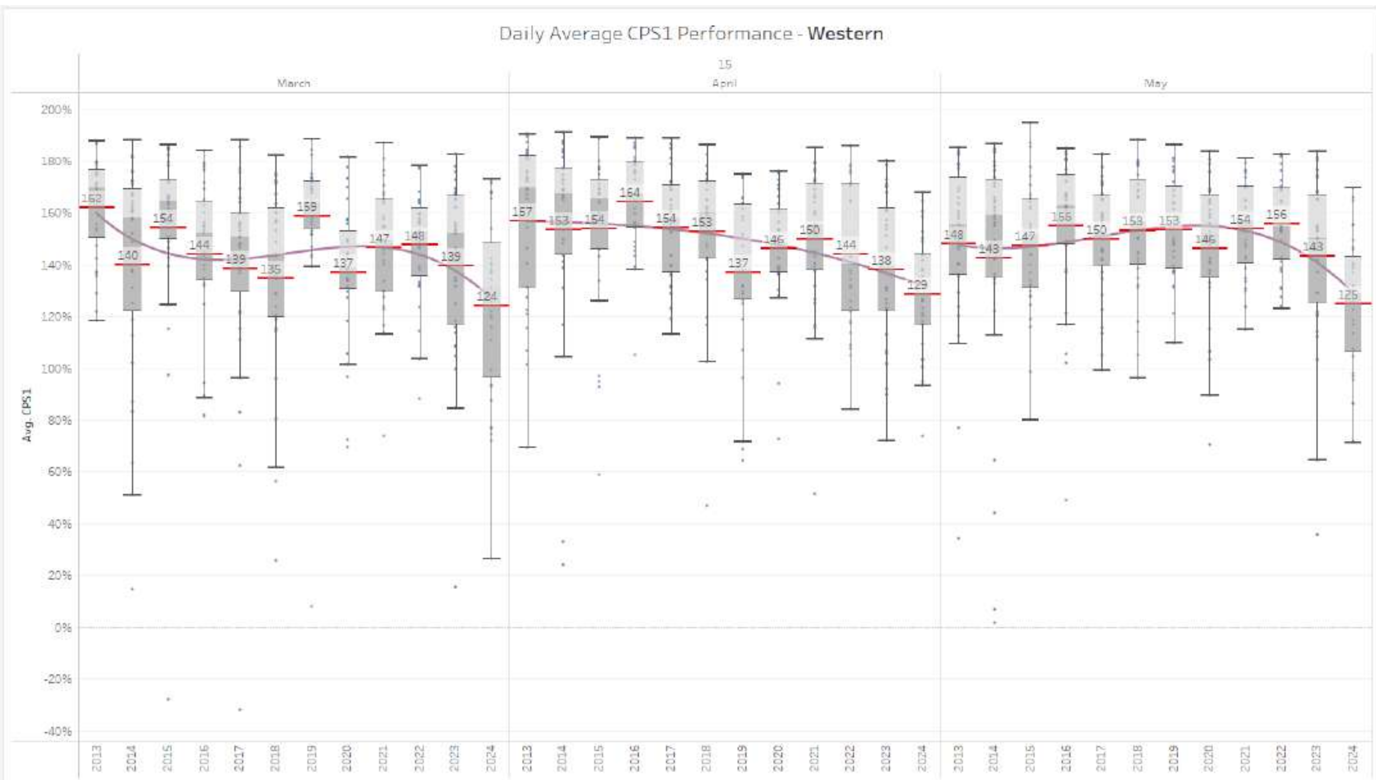
These charts represent **Spring** data from 2013-2024. If we focus on the purple polynomial trendline, the average CPS1 performance shows a downward trend in all HE hours year-over-year, with **HE 18** showing the greatest drop in performance in 2024.



HE 15

Takeaways:

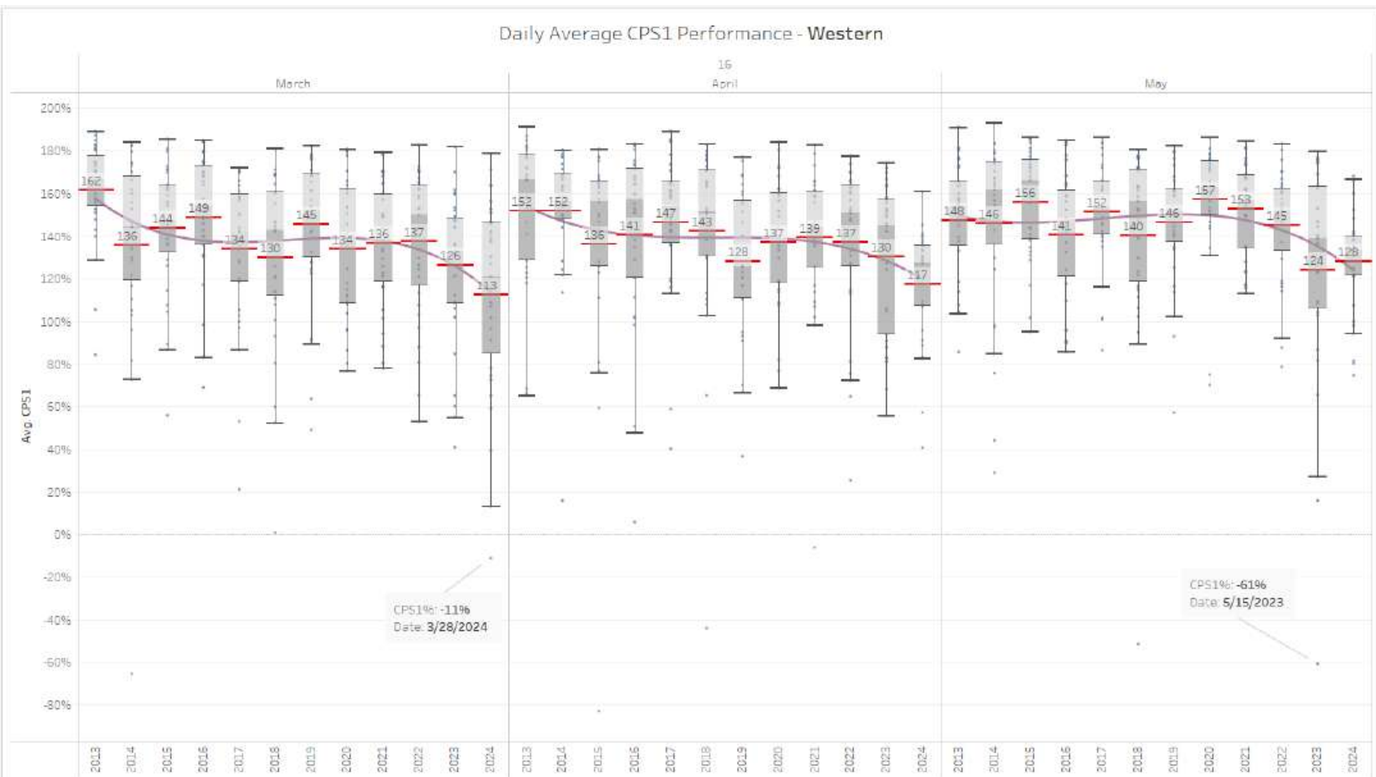
1. All months have experienced a significant decline in average performance in recent years.
2. **March** experienced an increase in variability in recent years.
3. Average performance changes from 2023-2024:
    a. March decreased **15%**
    b. April decreased **9%**
    c. May decreased **18%**



HE 16

Takeaways:

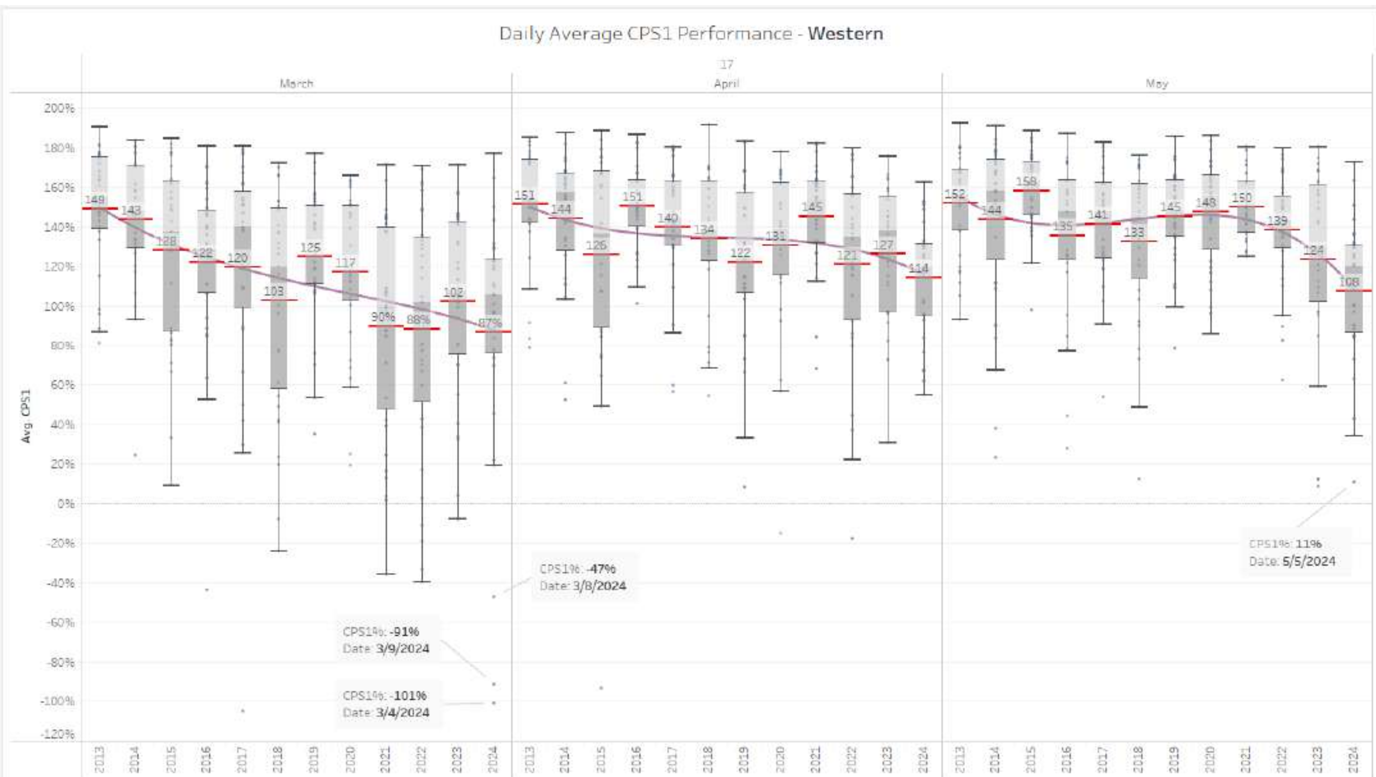
1. **March** and **April** have experienced a significant decline in average performance in recent years.
2. March experienced an increase in variability in 2024 in both the IQR and the whiskers.
3. Average performance changes from 2023-2024:
    a. March decreased **13%**
    b. April decreased **13%**
    c. May increased **4%**



HE 17

Takeaways:

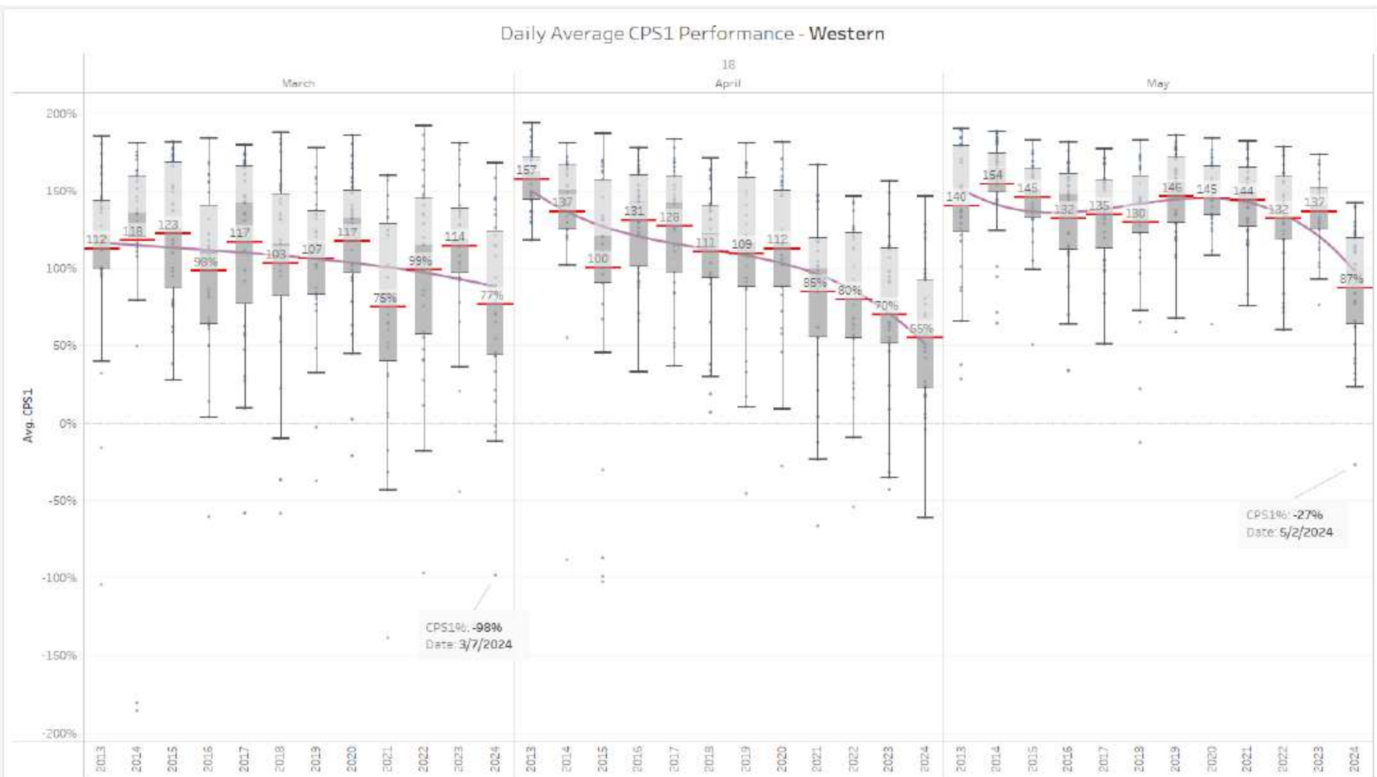
1. **March** continues to experience high variability year-over-year with significant outliers in 2024.
2. Is ~90% the new normal for **March**?
3. Average performance changes from 2023-2024:
    a. March decreased **15%**
    b. April decreased **13%**
    c. May decreased **16%**



HE 18

Takeaways:

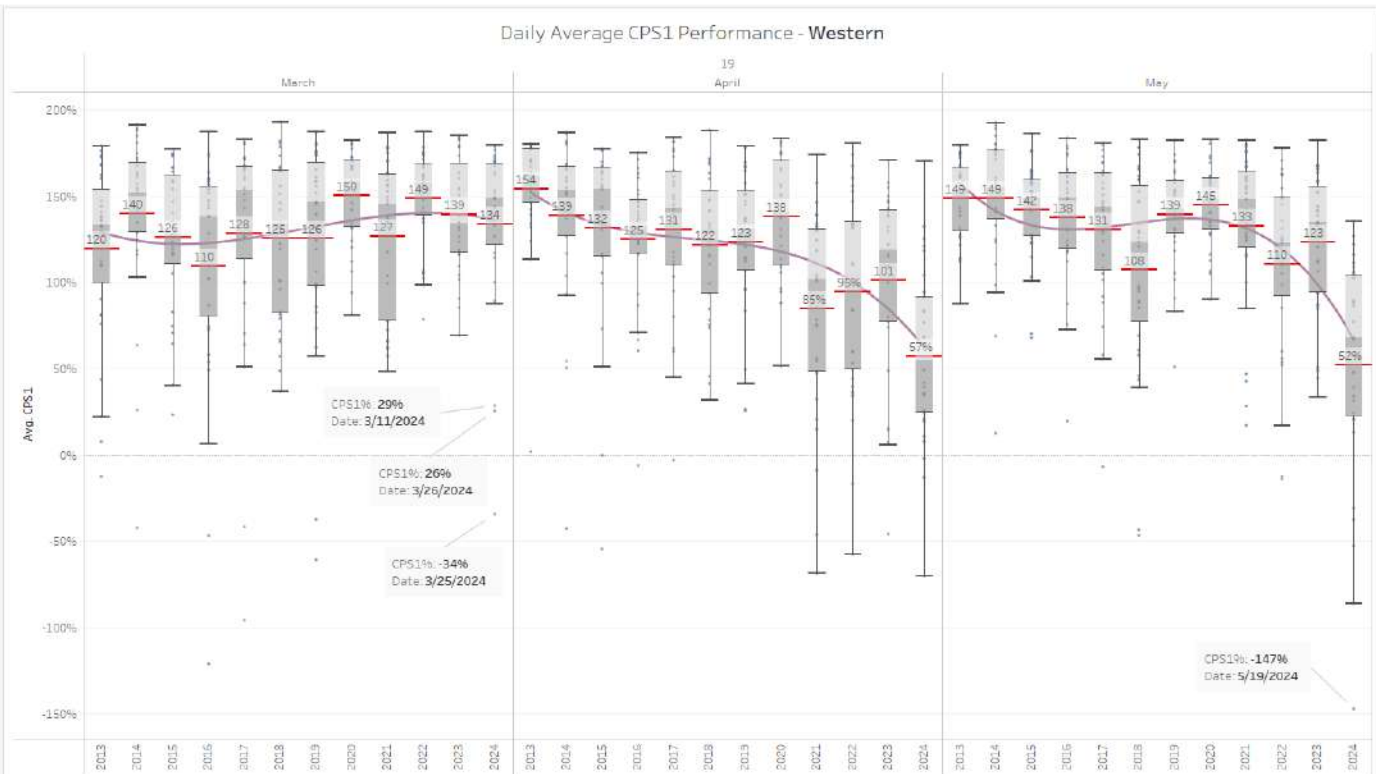
1. May took a huge hit in 2024 in average performance.
2. April has experienced a significant decline in average performance in recent years.
3. Average performance changes from 2023-2024:
    a. March decreased **37%**
    b. April decreased **15%**
    c. May decreased **50%**



HE 19

Takeaways:

1. **April** has experienced a significant decline in average performance and an increase in variability in recent years.
2. **May** took a huge hit in 2024 in average performance.
3. Average performance changes from 2023-2024:
    a. March decreased **5%**
    b. April decreased **44%**
    c. May decreased **71%**



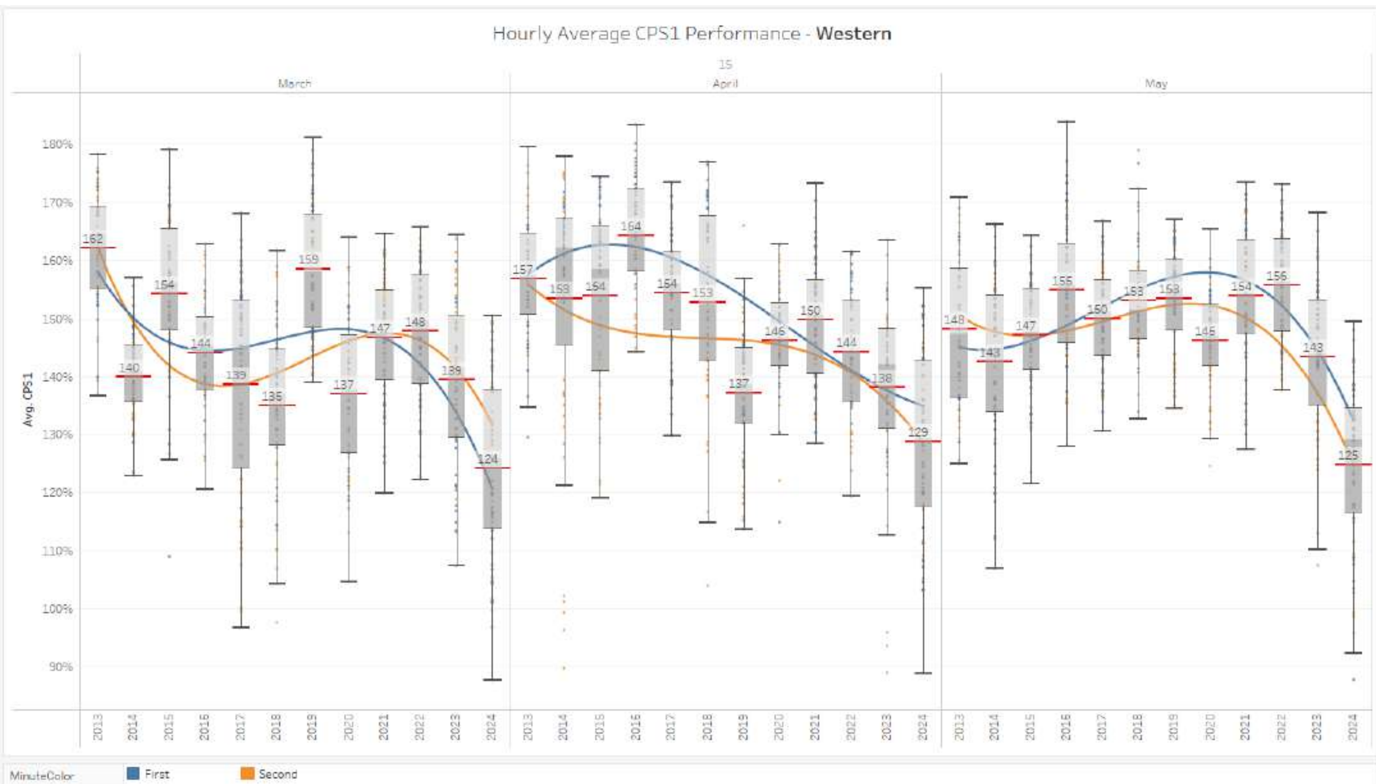
Hourly Performance

Based on the previous analysis, all months look to be contributing to the downward trend in Spring performance during **HE 15-17**. What is the data telling me at the hourly and minute level? These charts provide a look at solar PM hours during each of these months (year-over-year), for all days in the month, with HE across the top. This time, the dots represent minutes.

There are two separate polynomial trends comparing the **first half** of the hour to the **last half** of the hour. I color-coded the dots (minutes) to differentiate the minutes in the first half of the hour (blue) from the minutes in the last half of the hour (orange).

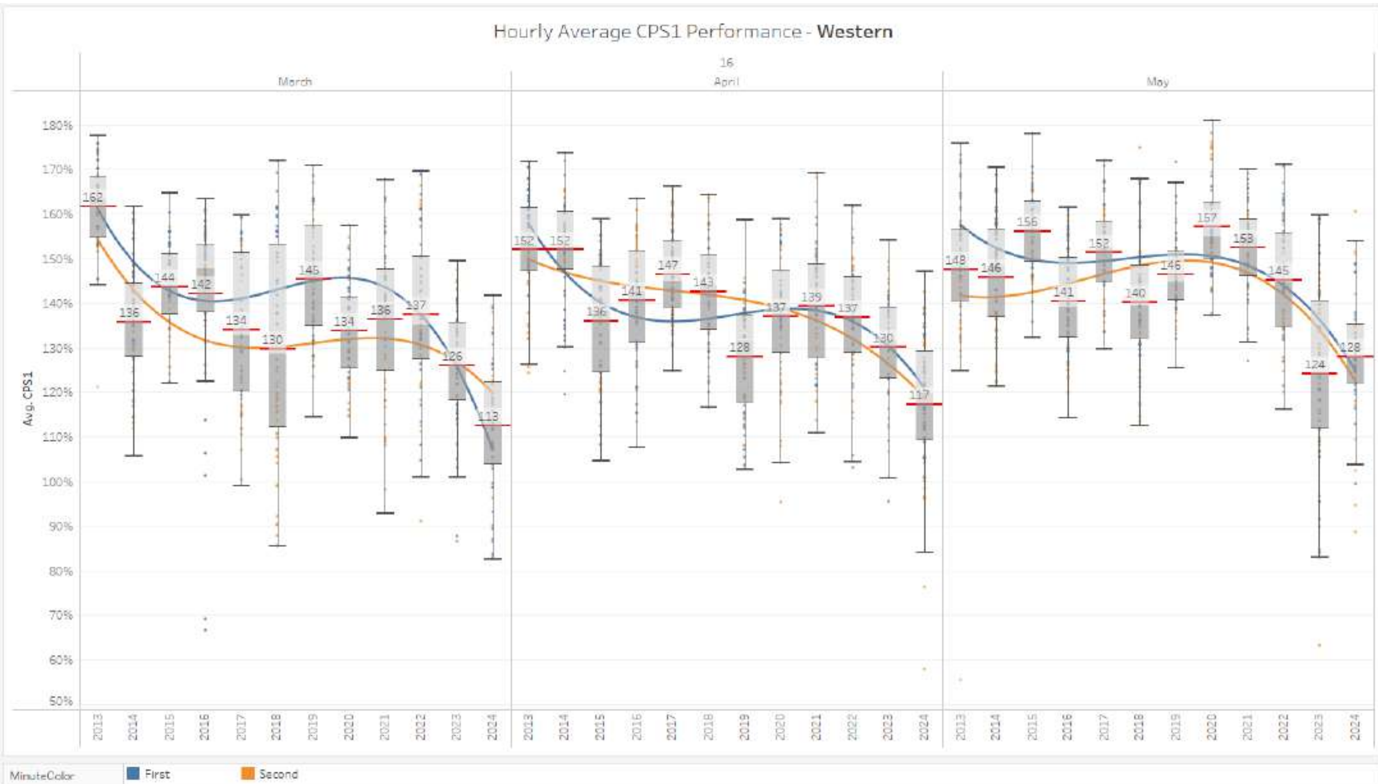
Takeaways (**HE 15**):

1. All months show downward trends in recent years **throughout** the hour.



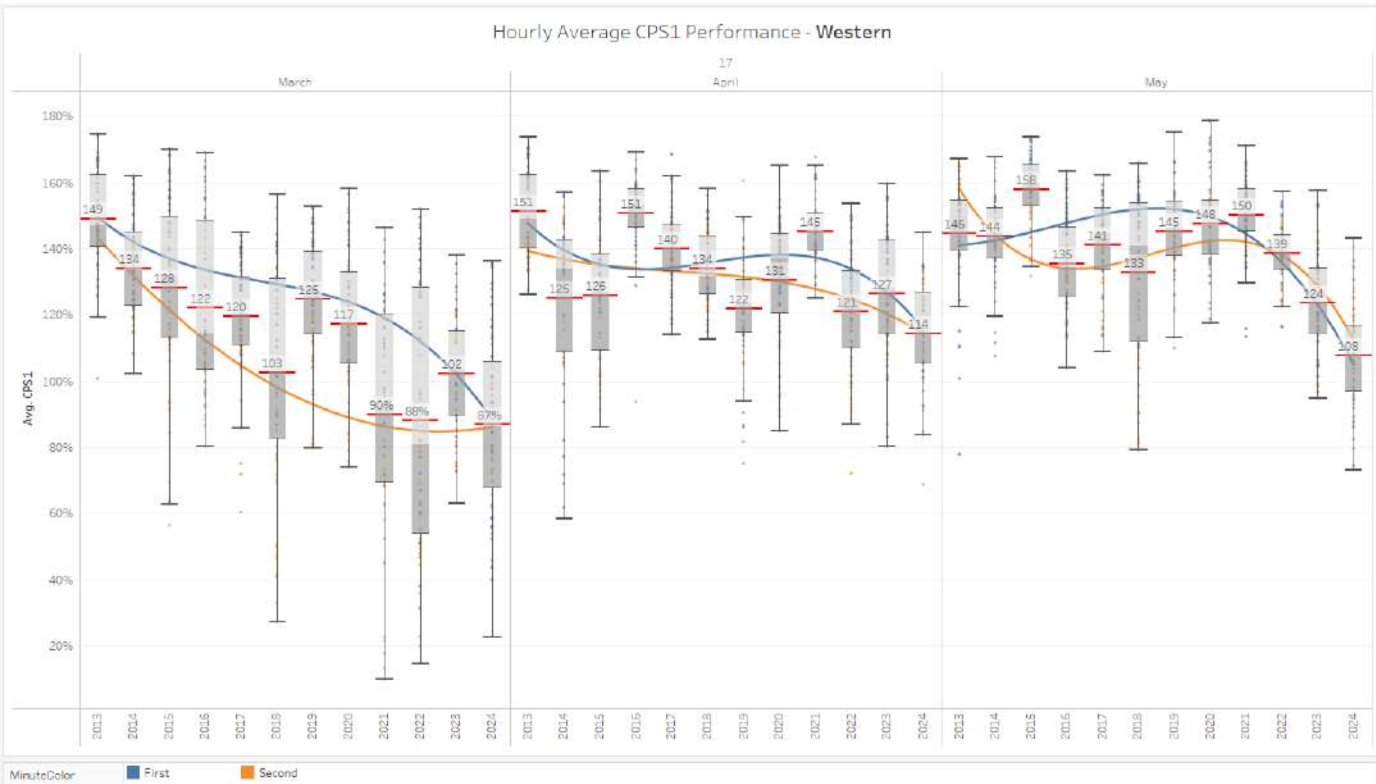
Takeaways (**HE 16**):

1. All months show downward trends in recent years **throughout** the hour.
2. **March** shows a greater struggle during the **first half** of the hour in recent years.
3. **April** shows a greater struggle during the **second half** of the hour in recent years.



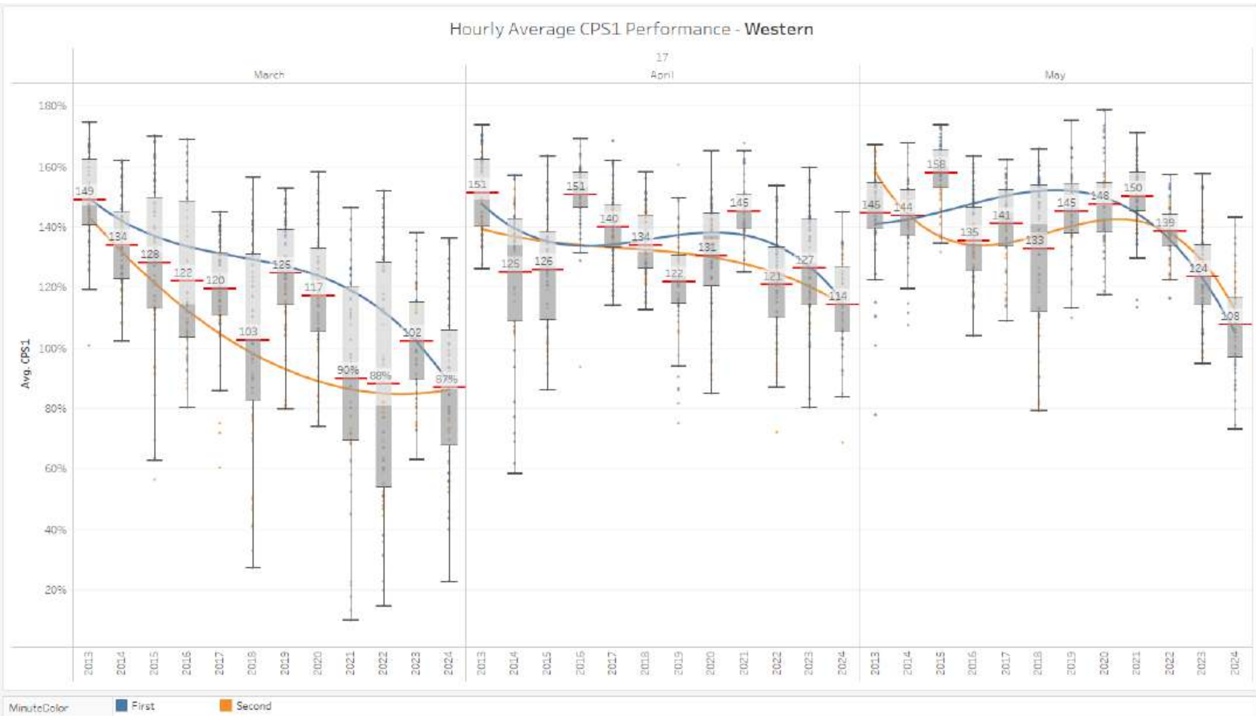
Takeaways (**HE 17**):

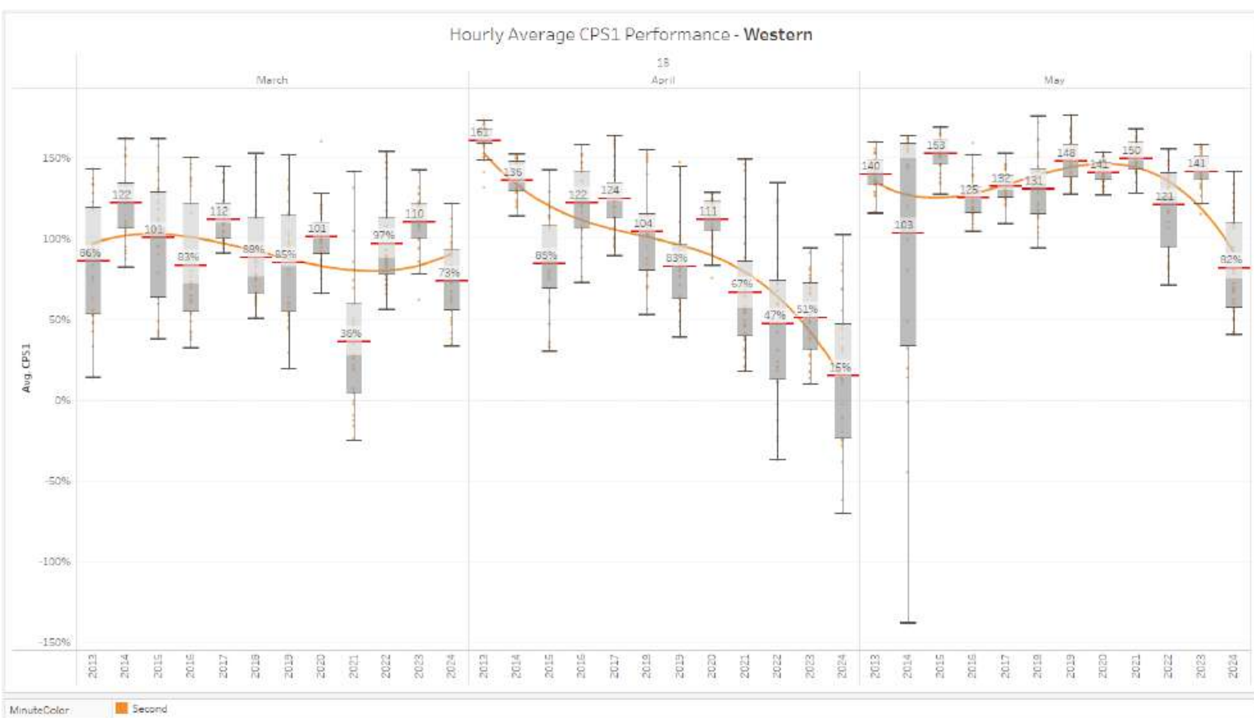
1. All months show downward trends in recent years **throughout** the hour.
2. **March** and **May** show a greater struggle during the **first half** of the hour in recent years.
3. **March** looks to have improved average performance during the **second half** of the hour in recent years.



Takeaways (**HE 18**):

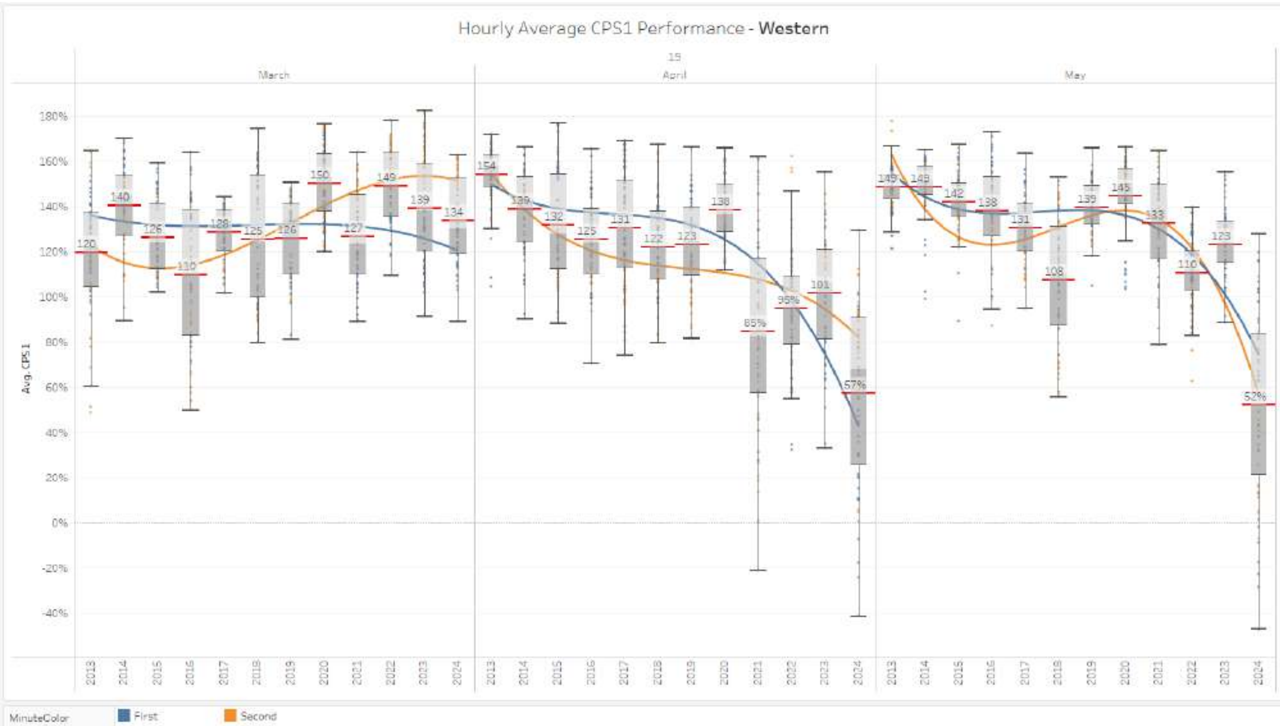
1. April shows a downward trend during the **second half** of the hour in recent years.
2. **March** and **May** show a greater struggle during the **first half** of the hour in recent years.
3. **March** and **April** have experienced increased variability **throughout** the hour in recent years.

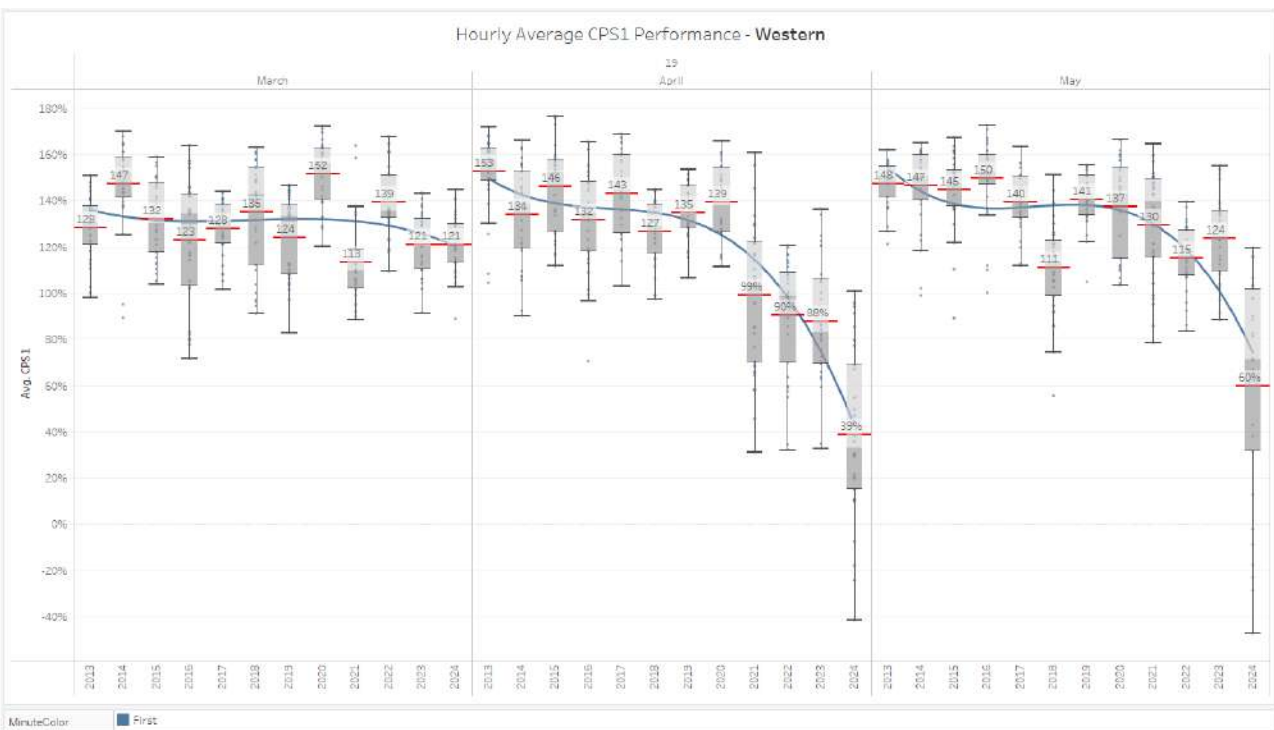




Takeaways (**HE 19**):

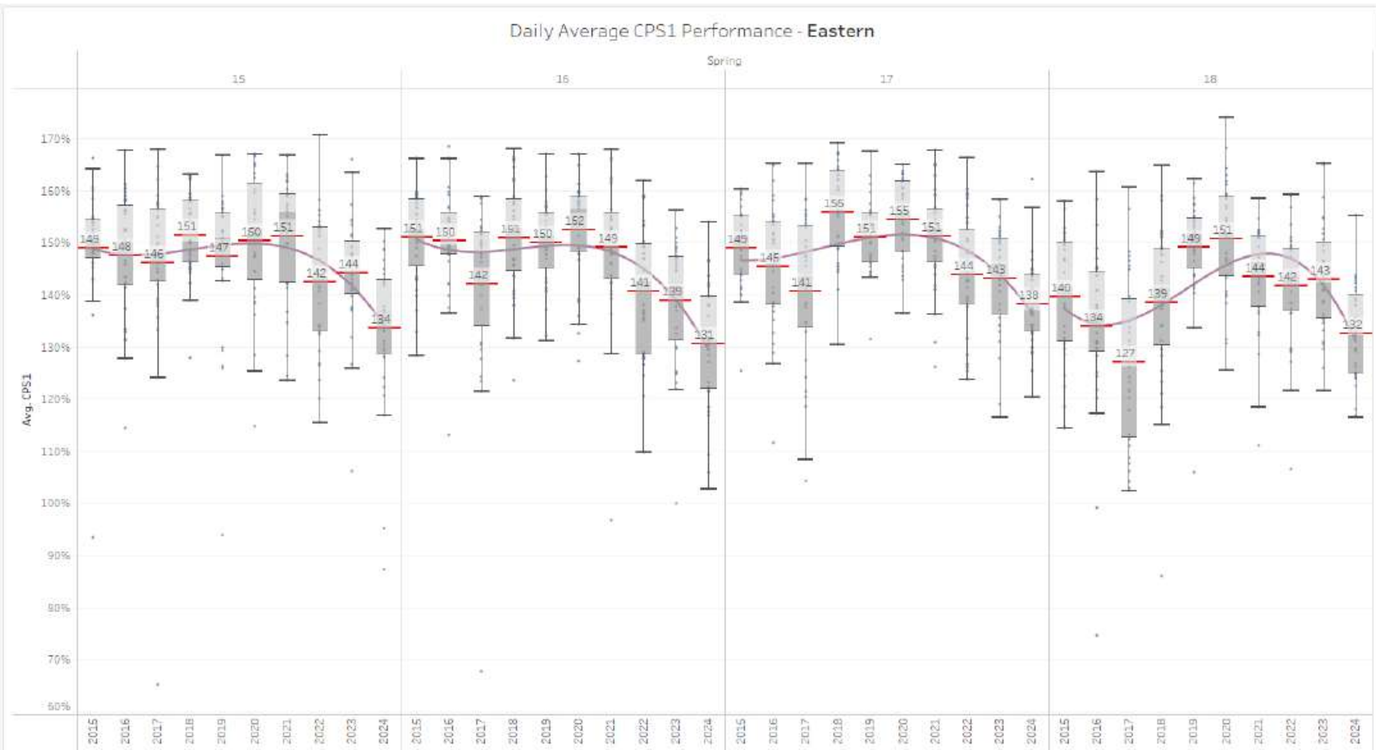
1. **April** and **May** show downward trends **throughout** the hour in recent years.
2. **March** shows increased average performance during the **second half** of the hour in recent years.
3. **April** has experienced increased variability **throughout** the hour in recent years.





Eastern Interconnect

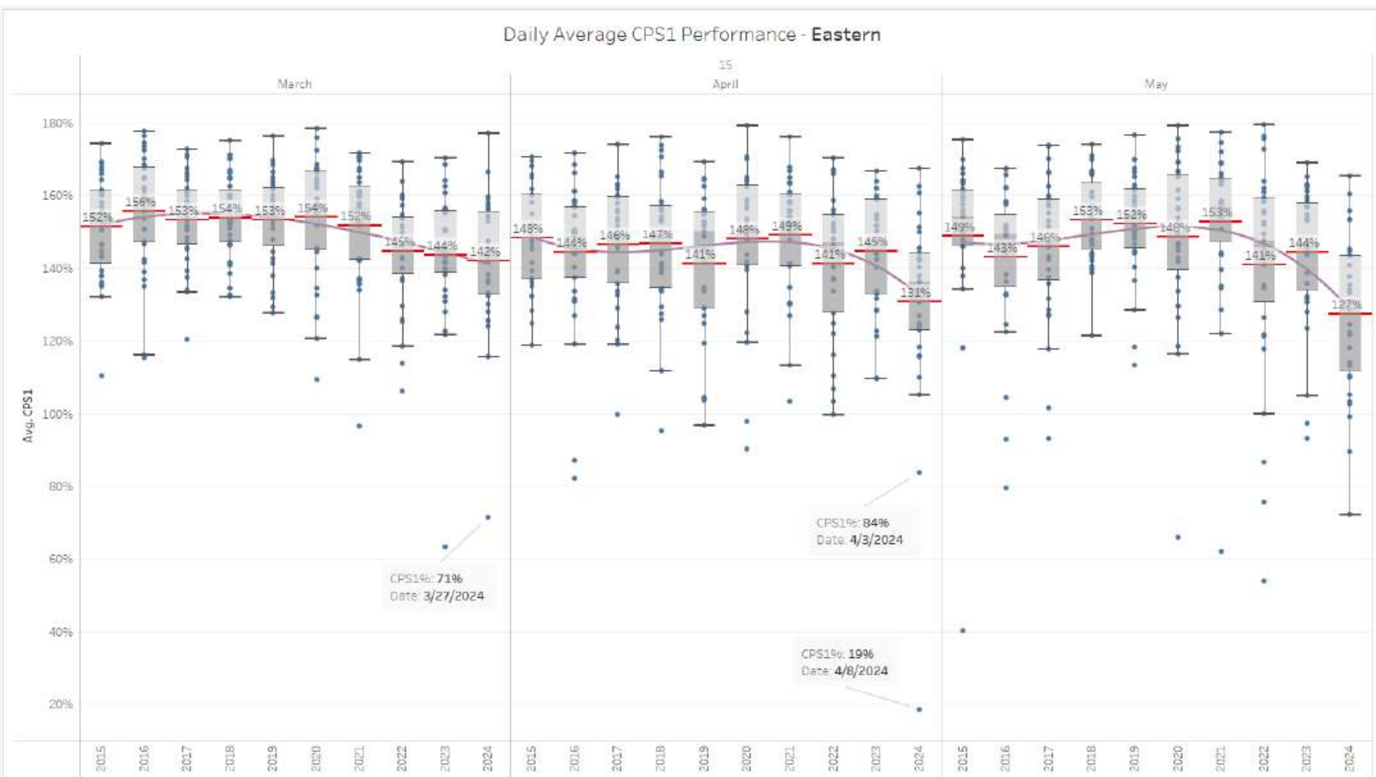
These charts represent **Spring** data from 2015-2024. If we focus on the purple polynomial trendline, the average CPS1 performance shows a downward trend in all HE hours year-over-year.



HE 15

Takeaways:

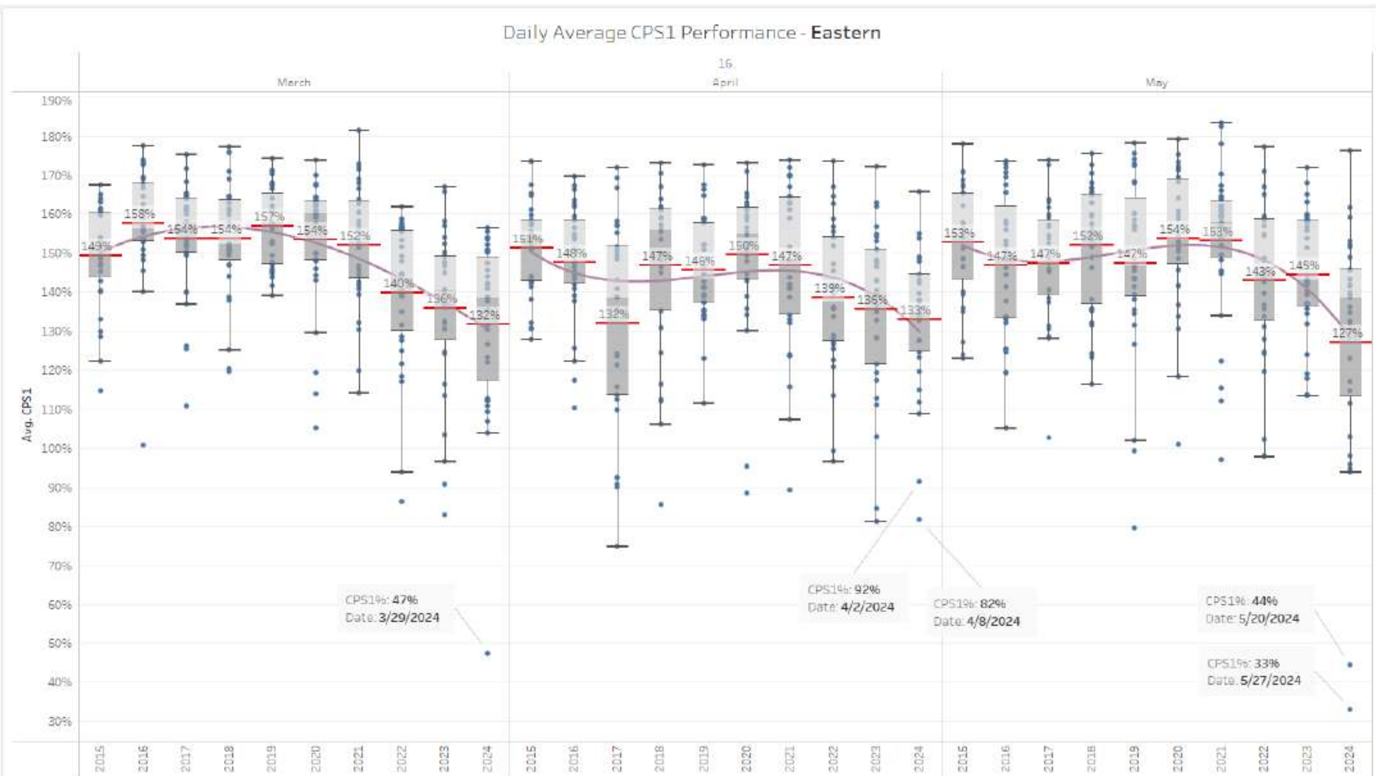
1. **April** and **May** have experienced a decline in average performance in recent years.
2. May has experienced increased variability in recent years.
3. Average performance changes from 2023-2024:
    a. March decreased **2%**
    b. April decreased **14%**
    c. May decreased **17%**



HE 16

Takeaways:

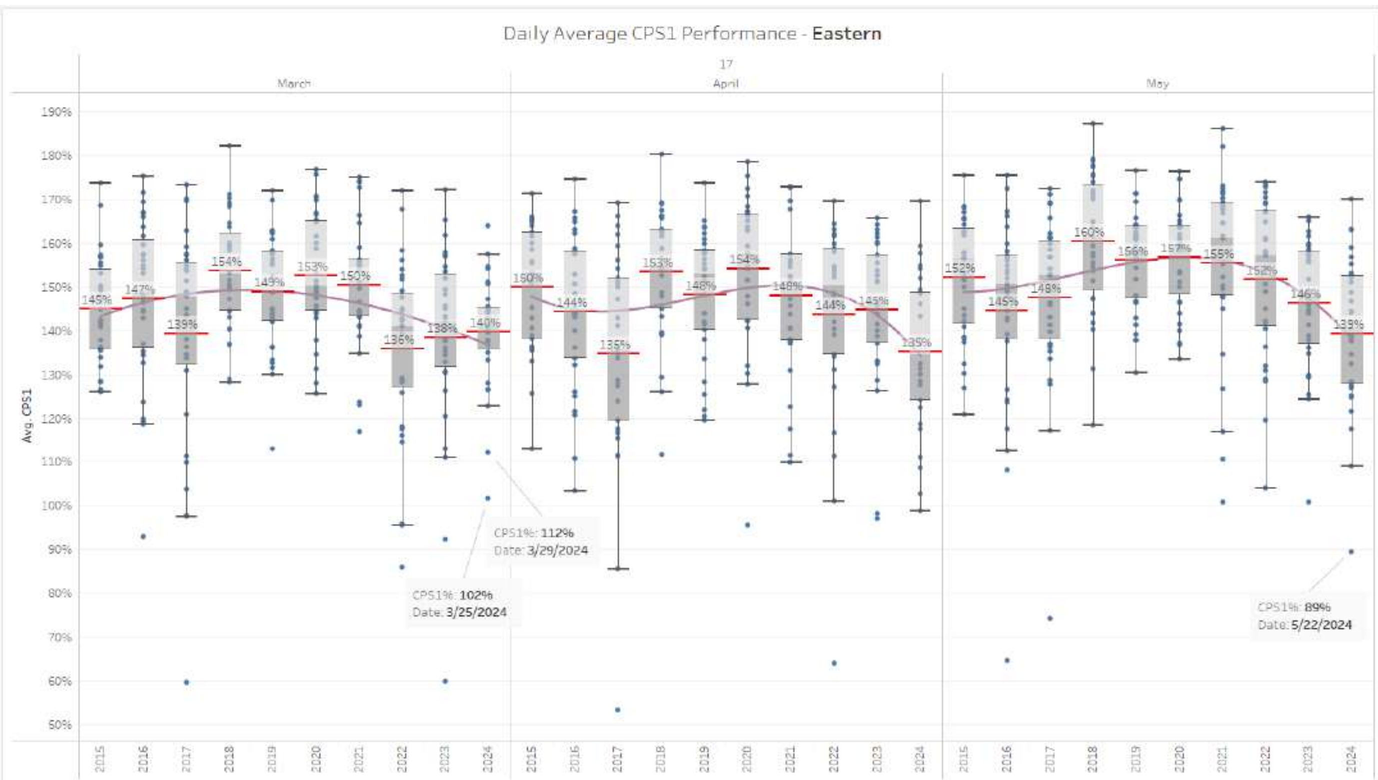
1. **March** and **May** have experienced a decline in average performance in recent years.
2. Average performance changes from 2023-2024:
    a. March decreased **4%**
    b. April decreased **3%**
    c. May decreased **18%**



HE 17

Takeaways:

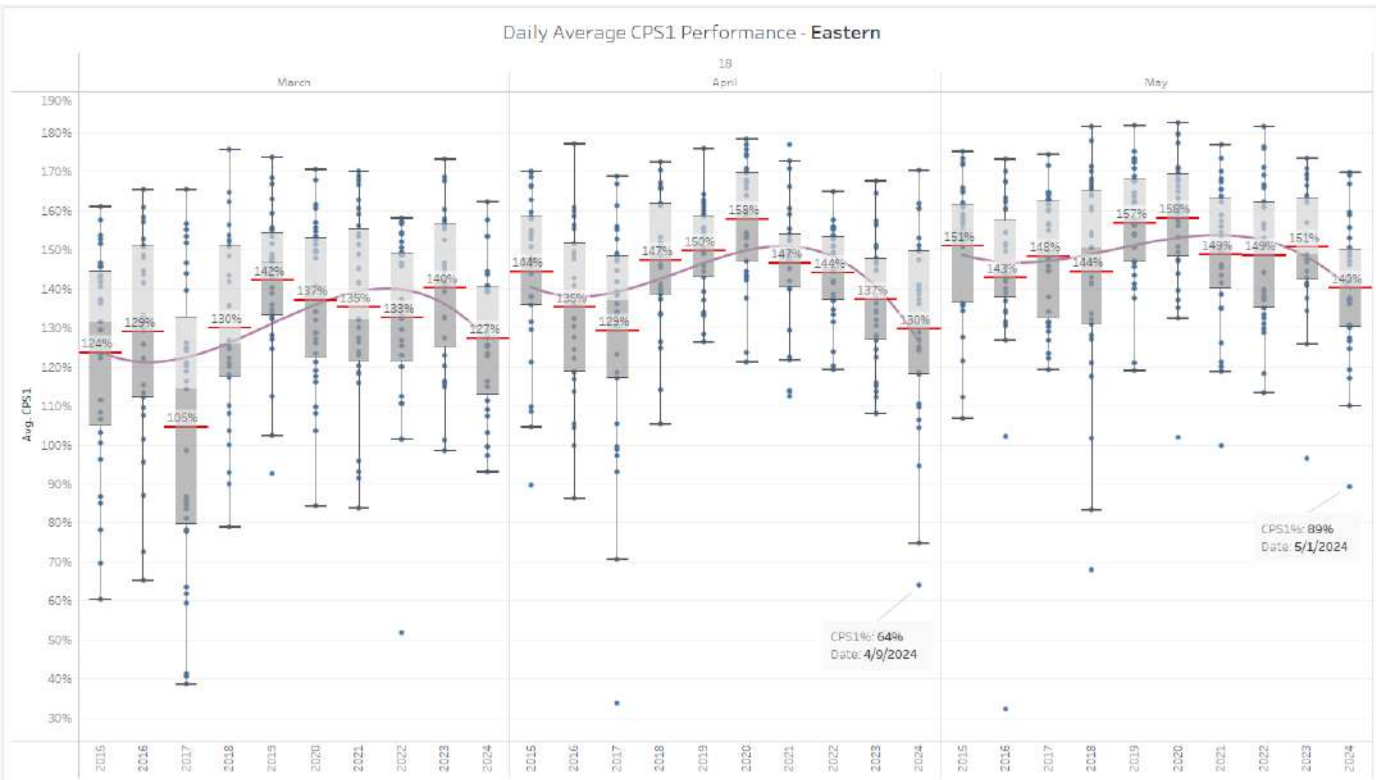
1. **April** and **May** have experienced a decline in average performance in recent years.
2. March has seen an improvement in variability in recent years.
3. Average performance changes from 2023-2024:
    a. March increased **2%**
    b. April decreased **10%**
    c. May decreased **7%**



HE 18

Takeaways:

1. **April** has experienced a decline in average performance in recent years.
2. Average performance changes from 2023-2024:
    a. March decreased **13%**
    b. April decreased **7%**
    c. May decreased **9%**



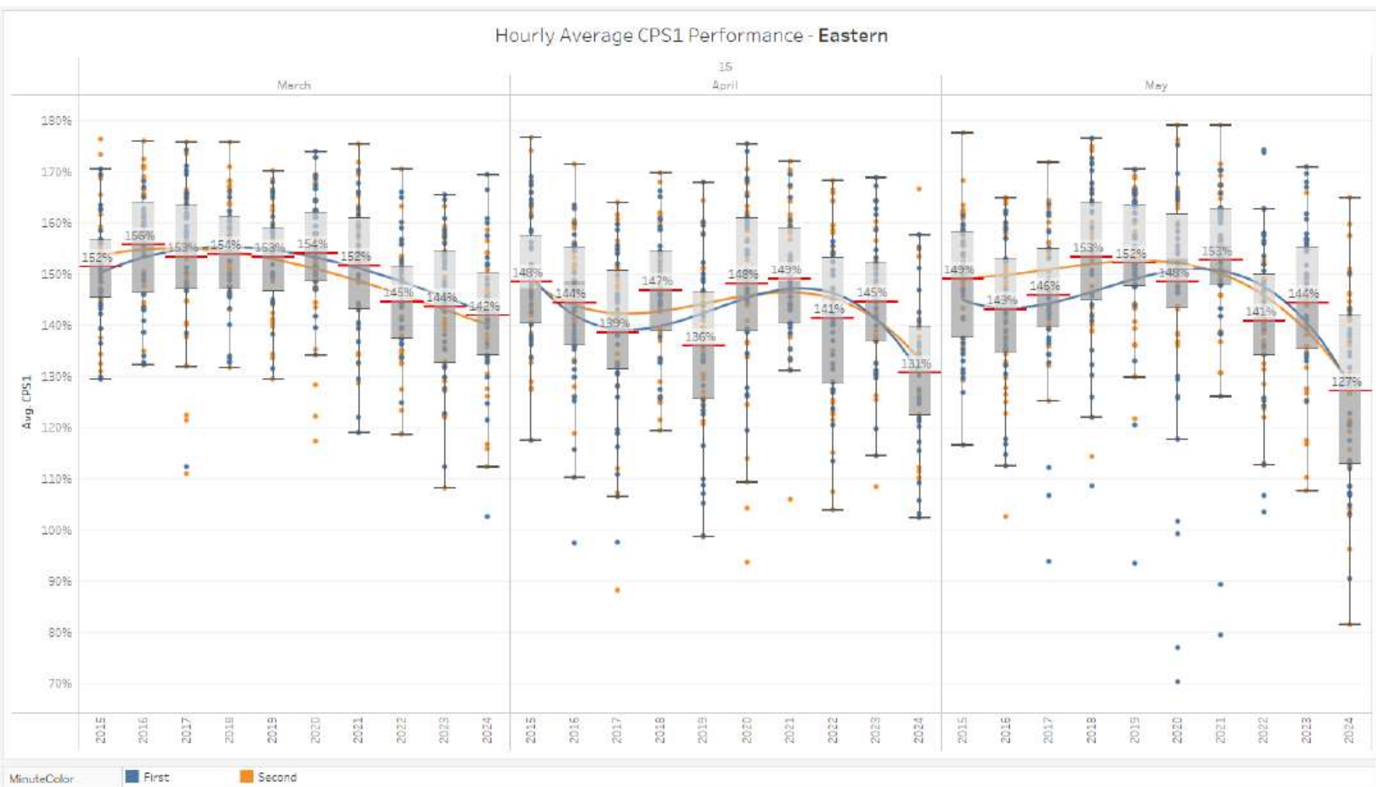
Hourly Performance

Based on the previous analysis, all months look to be contributing to the downward trend in Spring performance during **HE 15-18**. What is the data telling me at the hourly and minute level? These charts provide a look at solar PM hours during each of these months (year-over-year), for all days in the month, with HE across the top. This time, the dots represent minutes.

There are two separate polynomial trends comparing the **first half** of the hour to the **last half** of the hour. I color-coded the dots (minutes) to differentiate the minutes in the first half of the hour (blue) from the minutes in the last half of the hour (orange).

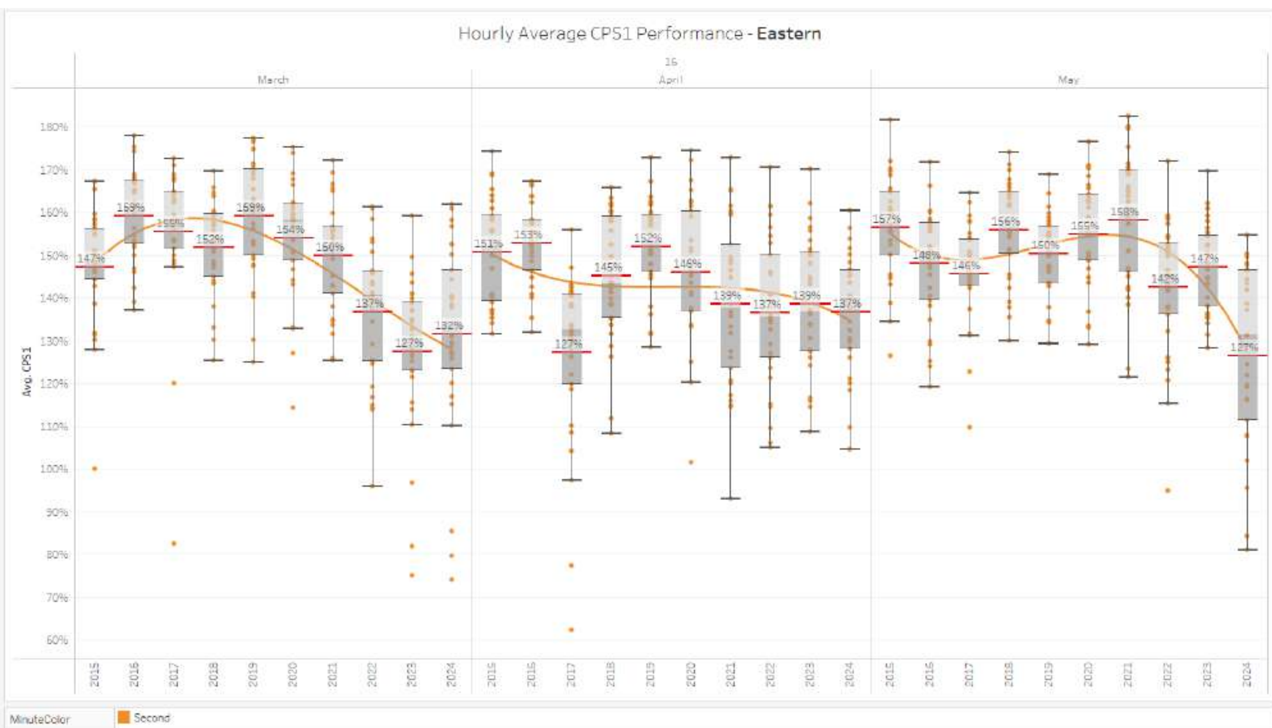
Takeaways (**HE 15**):

1. All months show downward trends **throughout** the hour in recent years.
2. **May** has experienced increased variability during the **second half** of the hour in recent years.



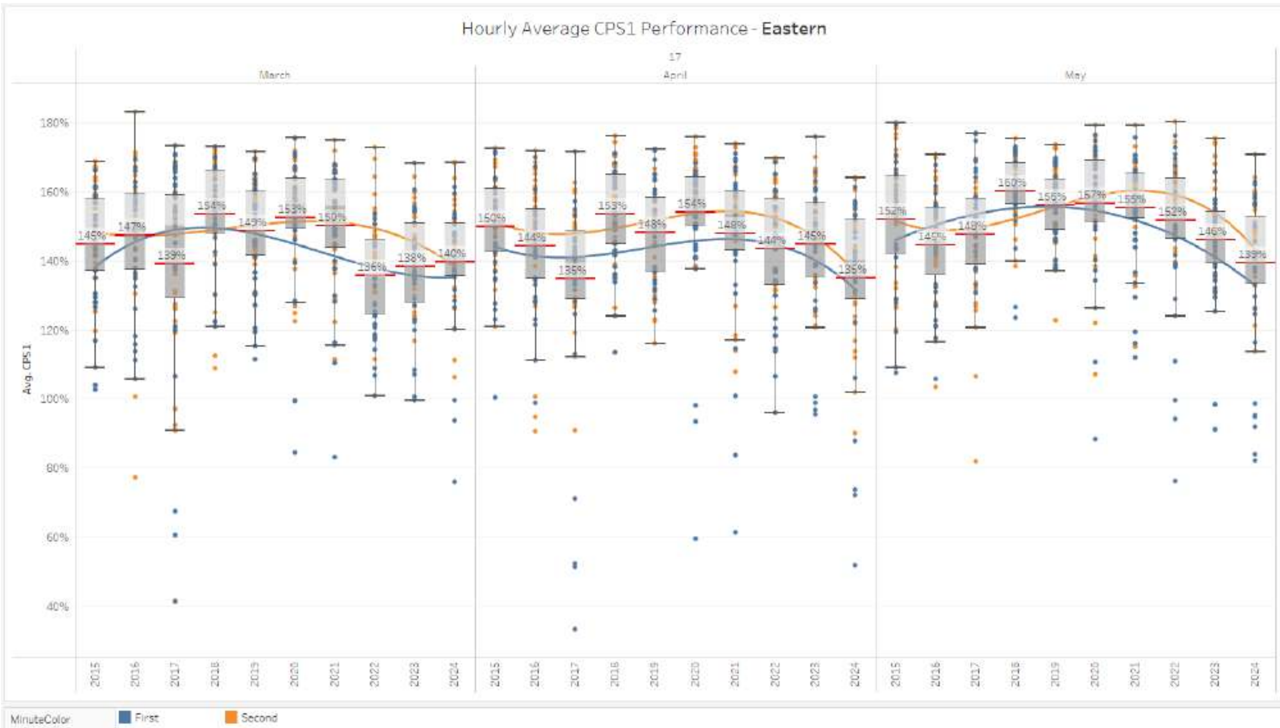
Takeaways (**HE 16**):

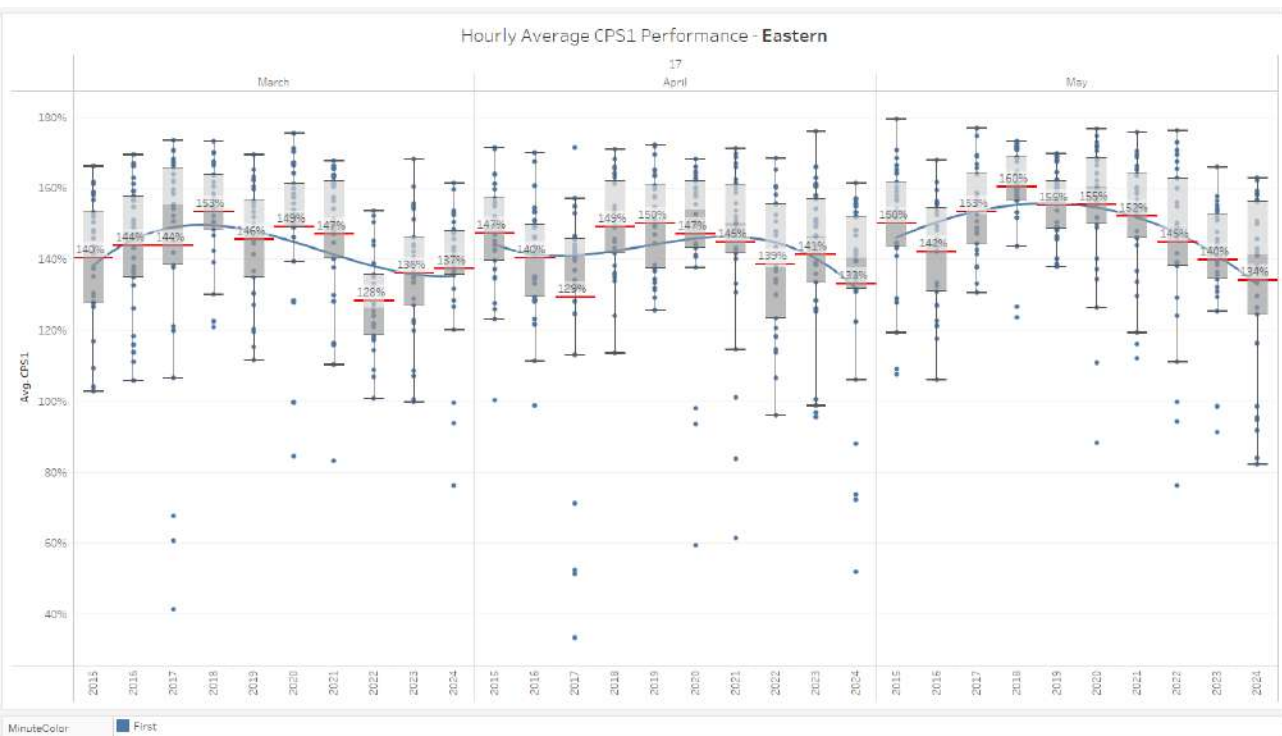
1. All months have experienced downward trends during the **first half** of the hour in recent years.
2. **March** and **May** have experienced inconsistent average performance during the **second half** of the hour in recent years.



Takeaways (**HE 17**):

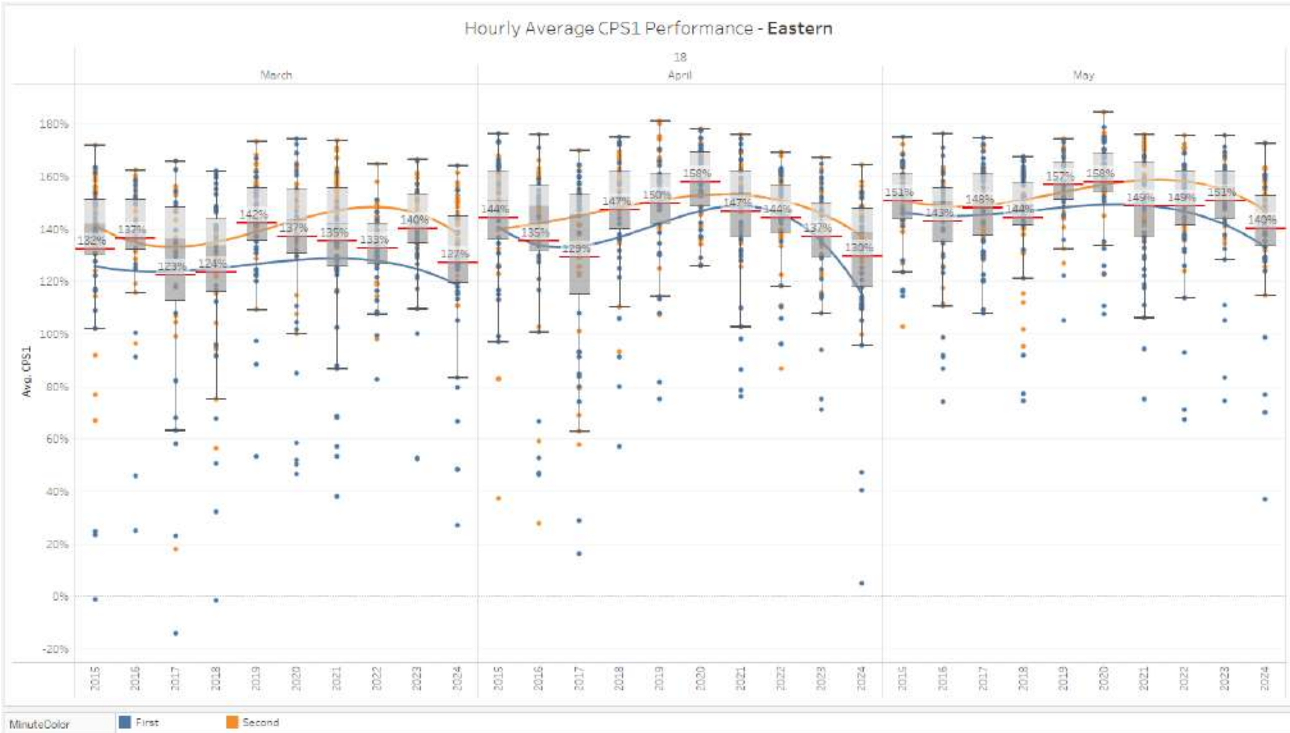
1. **May** shows downward trends **throughout** the hour in recent years.
2. **May** has experienced increased variability during the **first half** of the hour in recent years.

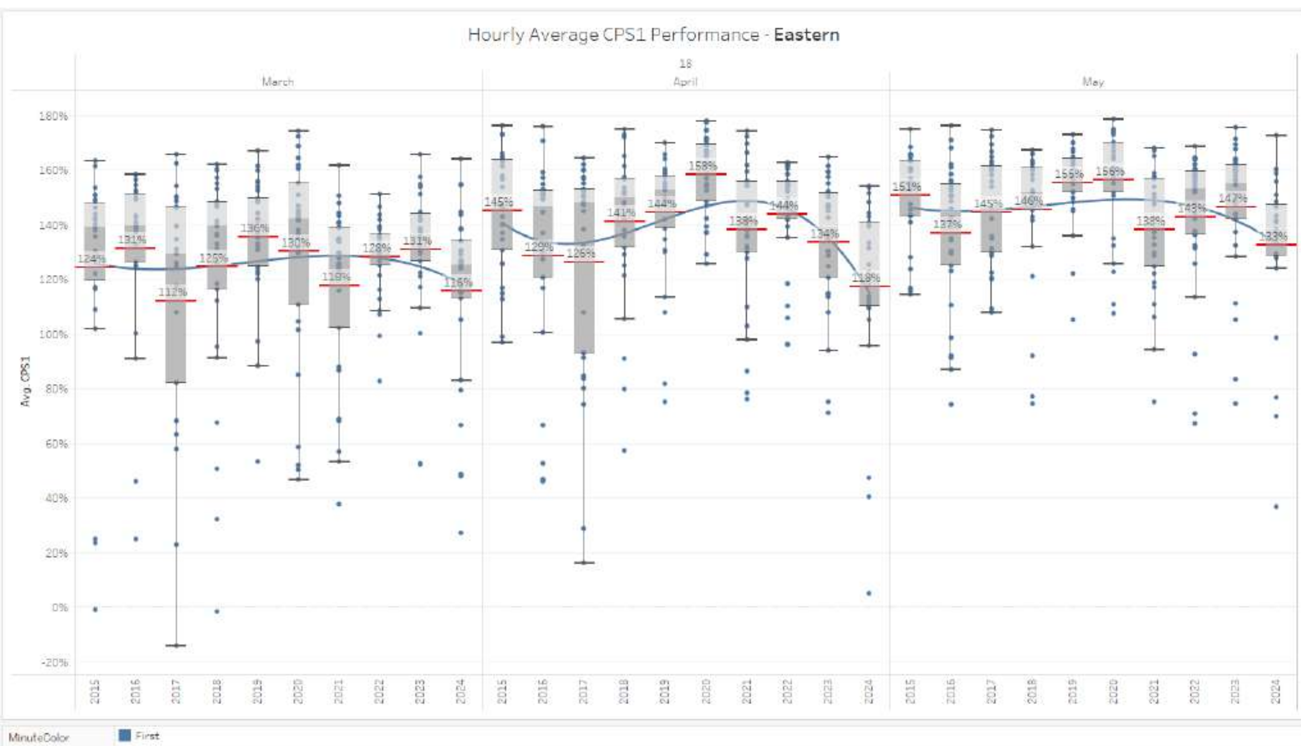




Takeaways (**HE 18**):

1. **March** took a hit in average performance during the first half of the hour in 2024.
2. April shows a downward trend during the **first half** of the hour in recent years.





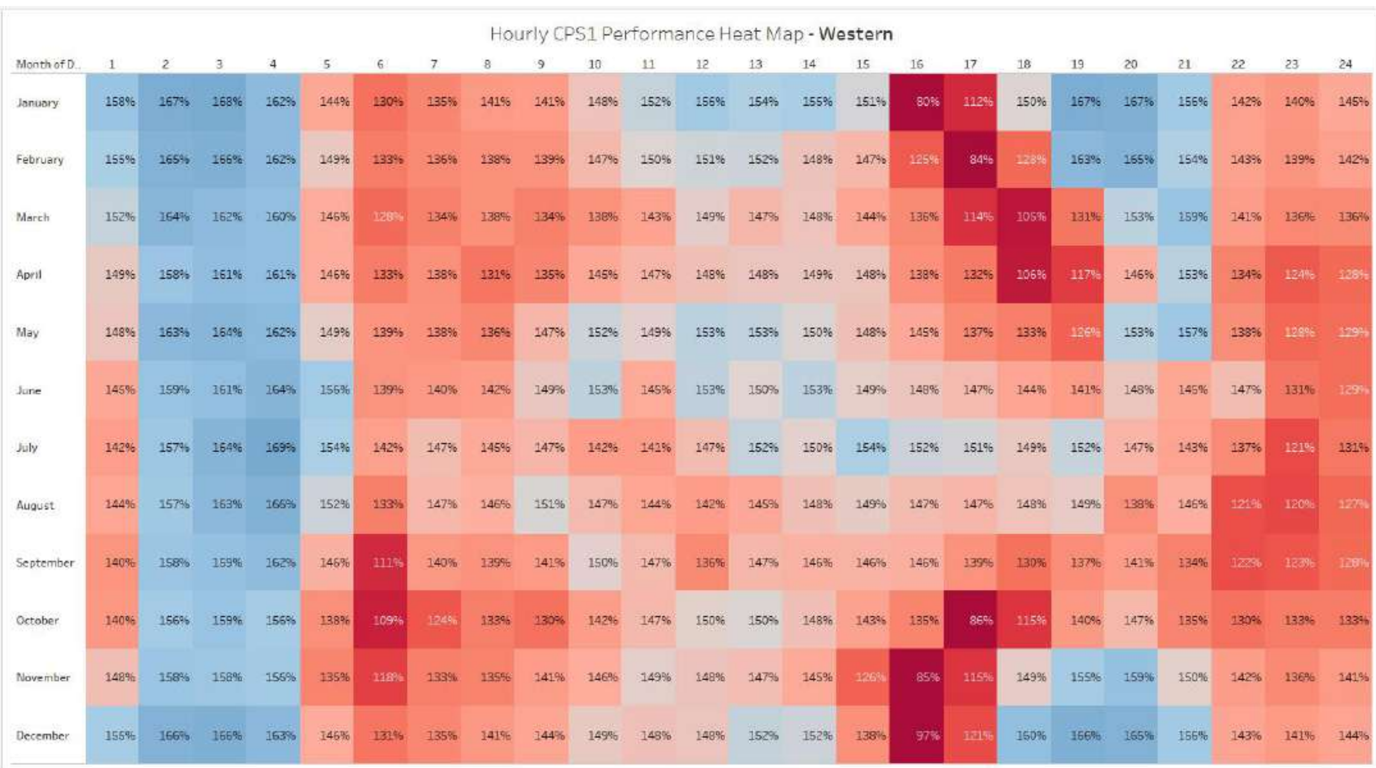
Heat Map Charts

These charts show hourly patterns throughout the year and help us identify the hours we should be focused on. If we don't show data at the hourly level, it averages out and we can't see these indicators.

Western Interconnect

Takeaways:

1. This chart represents data from 2013–2024.
2. The Winter and shoulder months have more of an impact to average performance during solar PM hours than the Summer months.
3. There seems to be a predictable pattern of off nominal frequency twice per day.
4. The succeeding page will show YTD performance for comparison.



Takeaways (**2024**):

1. Average performance is lower across the board in all hours than in the overall plot.
2. Lower average performance is beginning to bleed over into **HE 19**.

2024

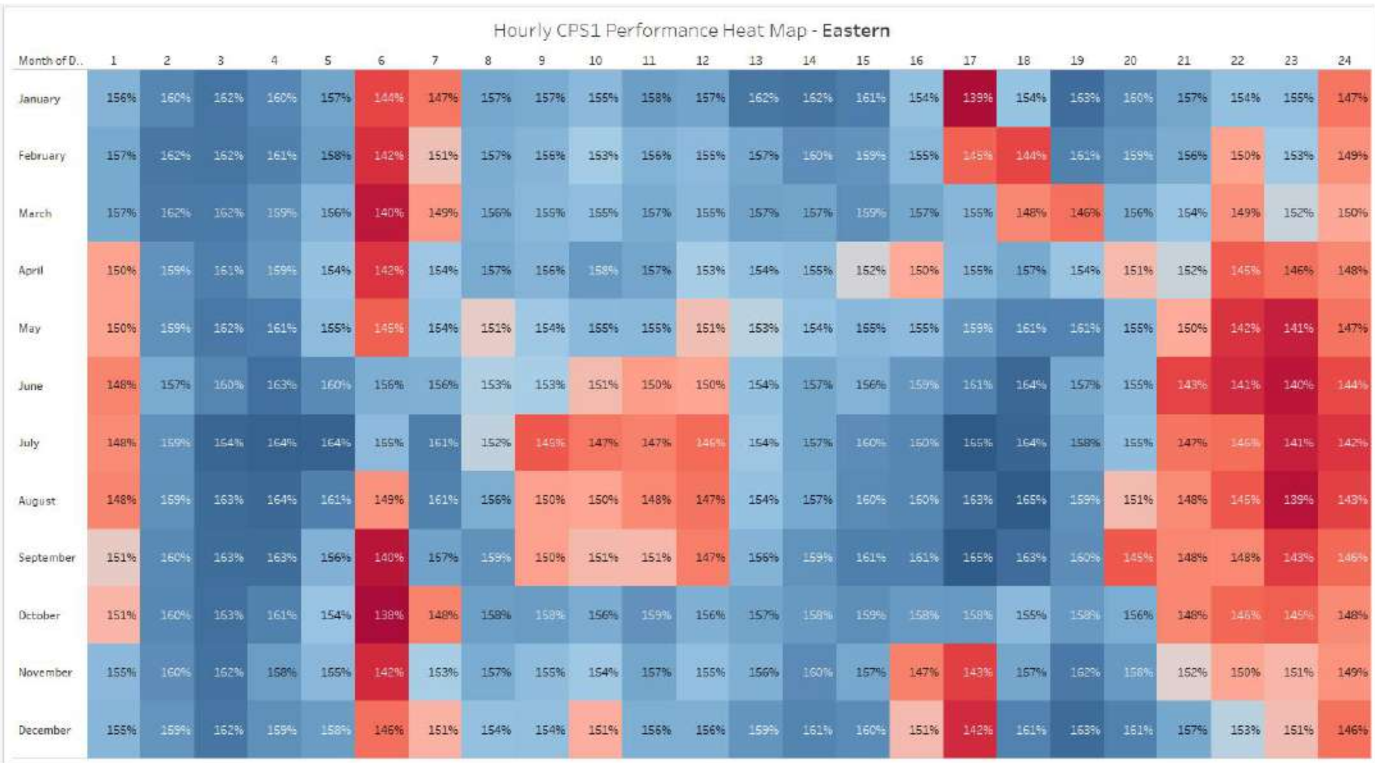
Hourly CPS1 Performance Heat Map - **Western**

Month of D..	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
January	160%	165%	164%	166%	158%	135%	149%	129%	140%	141%	147%	152%	151%	148%	139%	104%	143%	157%	171%	170%	168%	161%	156%	158%
February	164%	165%	166%	169%	159%	154%	139%	140%	133%	132%	142%	141%	138%	136%	111%	91%	99%	157%	162%	165%	163%	157%	151%	154%
March	165%	174%	172%	172%	164%	147%	144%	130%	142%	125%	137%	137%	126%	122%	124%	113%	87%	77%	134%	166%	169%	171%	163%	158%
April	159%	155%	165%	155%	153%	147%	132%	121%	121%	129%	135%	129%	121%	134%	129%	117%	114%	55%	57%	139%	153%	154%	152%	147%
May	147%	159%	160%	160%	149%	149%	121%	111%	128%	142%	138%	138%	131%	132%	125%	120%	108%	87%	52%	136%	159%	162%	149%	149%
June	151%	163%	163%	156%	158%	145%	122%	119%	137%	144%	141%	146%	139%	132%	121%	133%	119%	128%	119%	148%	142%	150%	152%	146%

Eastern Interconnect

Takeaways:

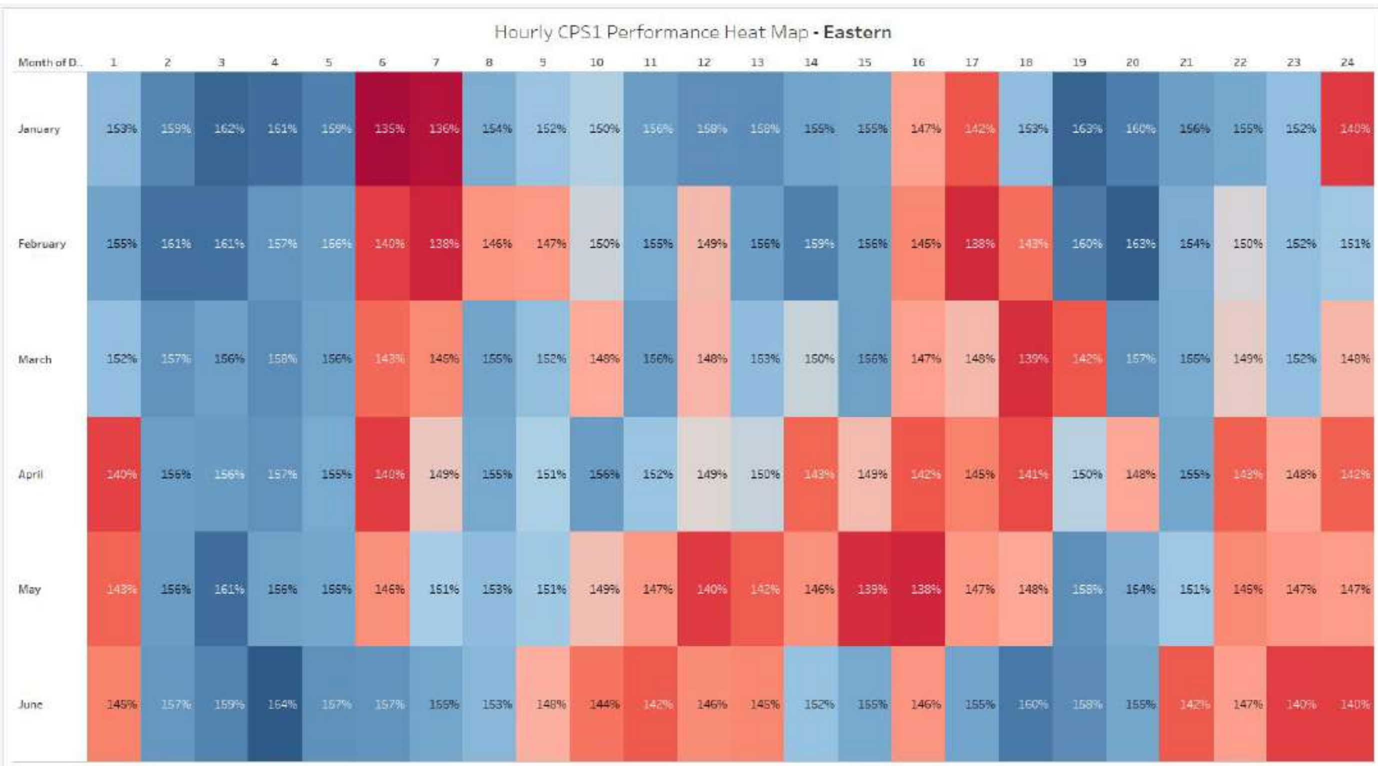
1. This chart represents data from 2015-2024.
2. HE 21-HE 24 have historically shown lower CPS1 performance in the Eastern Interconnect.
3. The succeeding page will show YTD performance for comparison.



Takeaways (2023):

1. **HE 6-7** continue to be an issue in 2024.
2. The Spring months are redder than in the overall plot. *This could be weather-related.*

2024



<Public>

WECC

Changes in Interconnection Frequency Control

9/11/2024

Greg Park – WECC, Manager
Risk Analysis and Data Services

NERC RS Chair

Simplified Interconnection

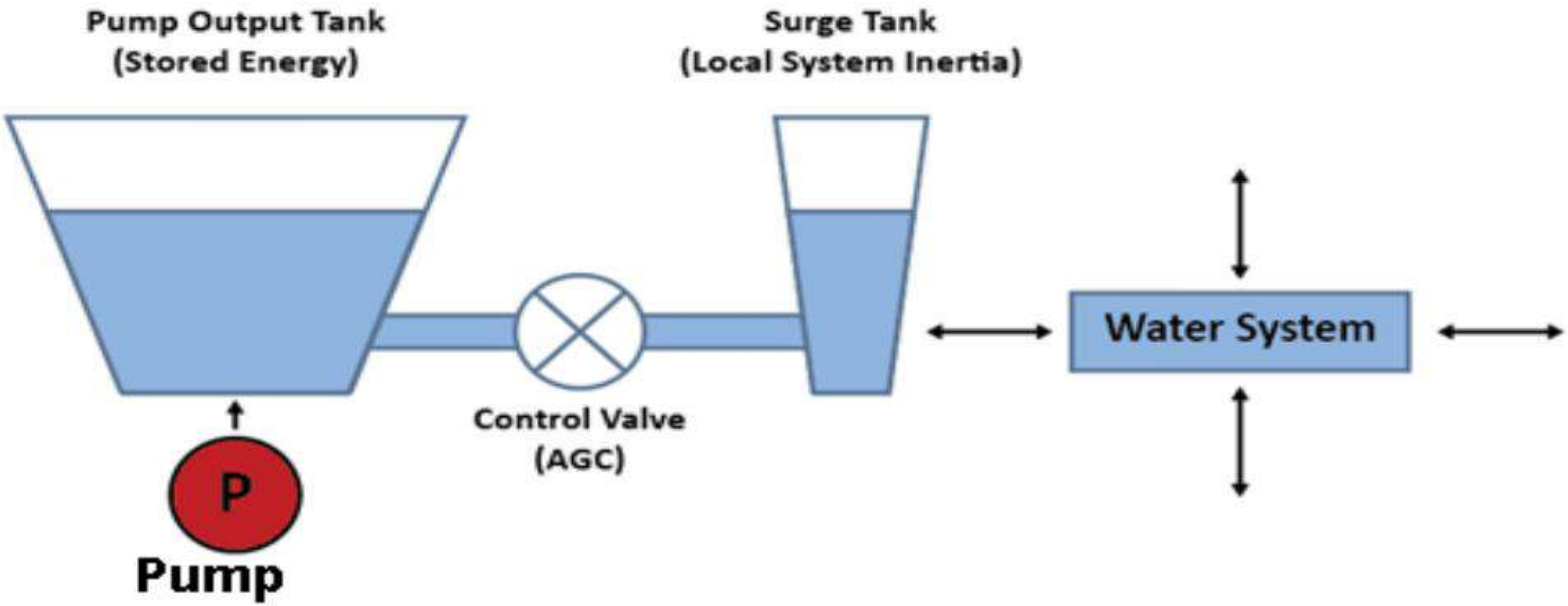


Figure 1.4: Generator | Pump Analogy

Multi BA – Interconnections

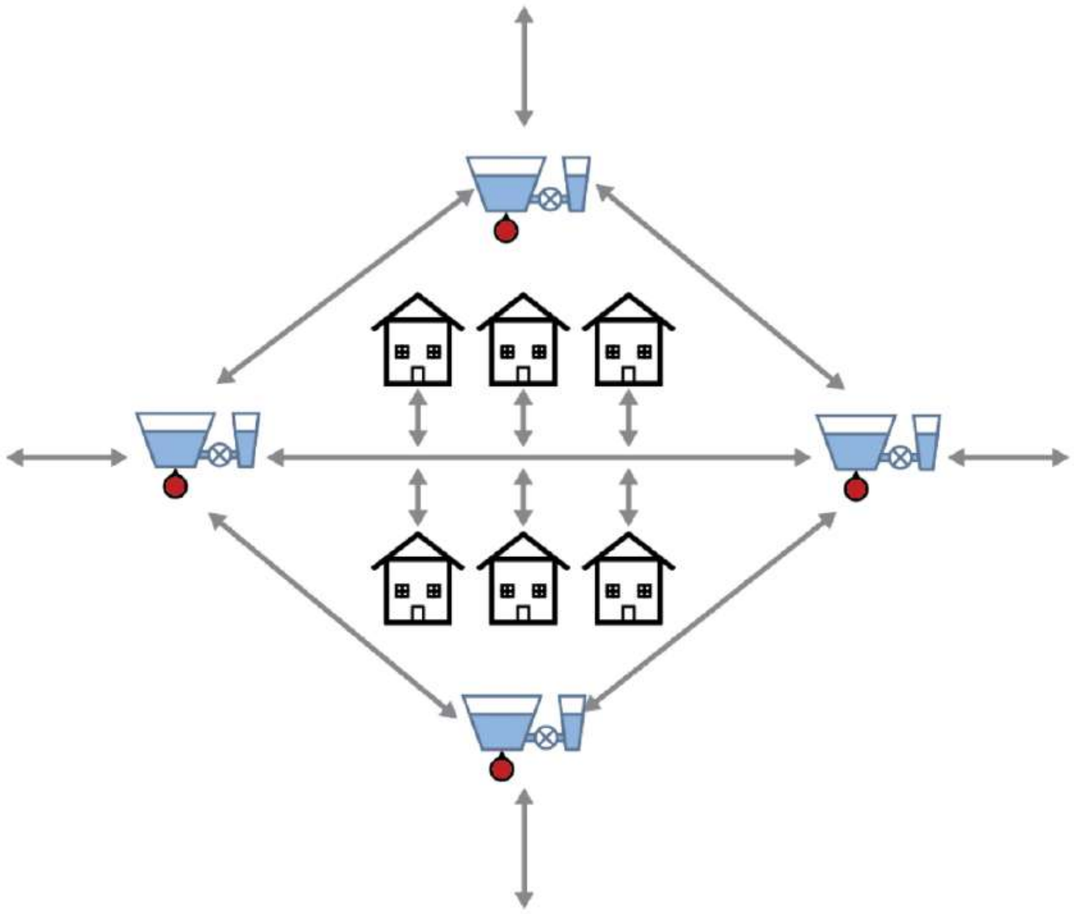
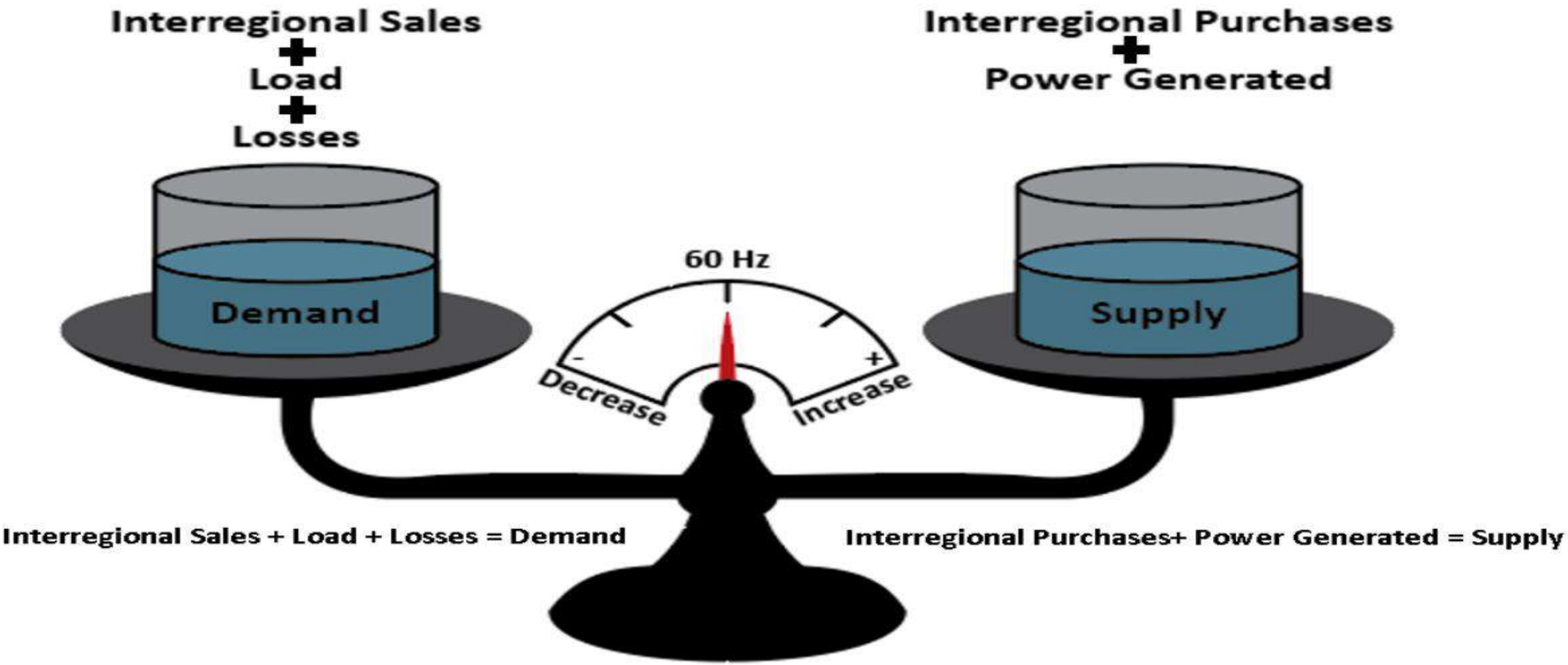


Figure 1:5: BA Analogy

What is Frequency Control



Multi BA – Interconnections

There are two inputs to the BAs control process:

- **Interchange Error**: the net outflow or inflow compared to the scheduled sales or purchases (The units of interchange error are in megawatts.)
- **Frequency Error**: the difference between actual and nominal frequency (The units of frequency error are hertz.)

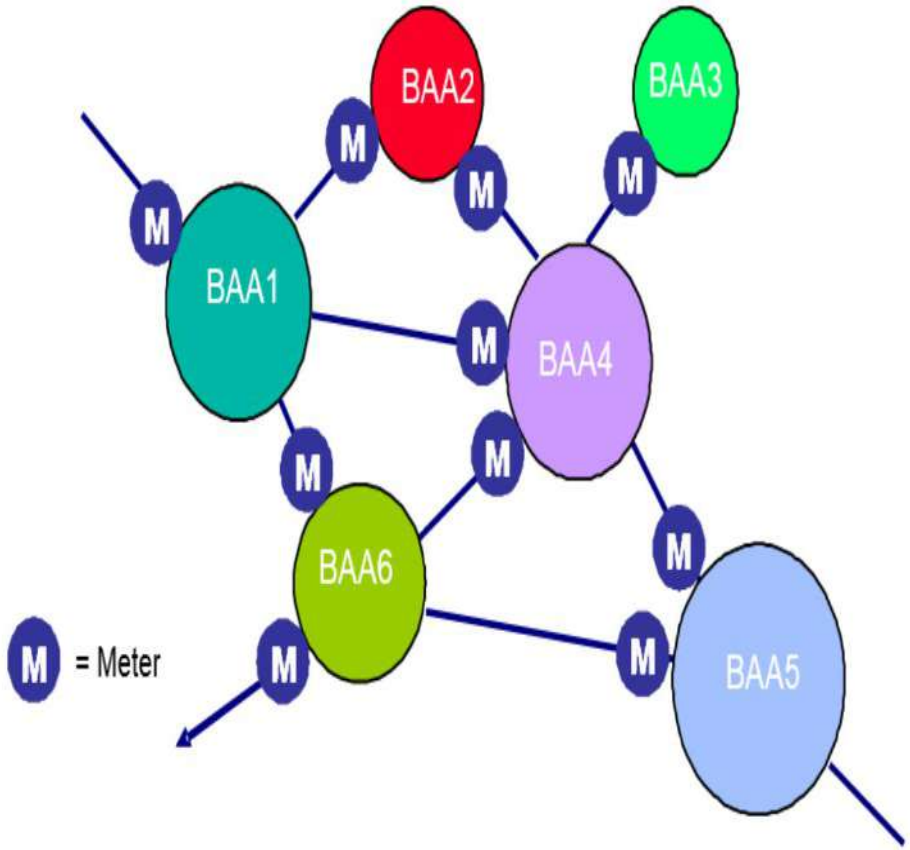


Figure 1:6: Interconnected BA Areas

BA Control Fundamentals

- BAL-001 dictates the limits that apply to control of frequency over longer durations. Compliance limits are 30 minutes and a rolling 12-month average (BAAL and CPS1).
- BAL-002 dictates the limits that apply to control frequency over intermediate durations that generally occur due to unplanned losses of resources. Compliance limits are 15 minutes (RBCE Recovery “DCS”).
- BAL-003 dictate the limits that apply to control frequency during short durations. Compliance limits are measured at 20-52 seconds after an event occurs. (Frequency Response Measure – FRM)

BA Control Fundamentals

- Demand and supply are constantly changing within all BAAs. This means that a BA will usually have some unintentional outflow or inflow at any given instant. This mismatch in meeting a BA's internal obligations, along with the small additional "bias" obligation to maintain frequency, is represented via a real-time value called Reporting Area Control Error (ACE), with units of MW.
- Frequency bias (β) is used to translate the frequency error into megawatts. β is the BAs obligation to provide or absorb energy to assist in maintaining frequency. In other words, if frequency goes low, each BA is asked to contribute a small amount of extra generation in proportion to its system's relative size.

Reporting ACE

$$\textbf{Reporting ACE} = \boxed{(NI_A - NI_S)} - \boxed{10B\,(F_A - F_S)} - I_{ME} + \color{red}{\underline{I_{IM}}}$$

Interchange Error

Frequency Error

Where:

- NI_A = Actual Net Interchange.
- NI_S = Scheduled Net Interchange.
- B = Frequency Bias Setting.
- F_A = Actual Frequency.
- F_S = Scheduled Frequency.
- I_{ME} = Interchange Meter Error.
- I_{IM} = Inadvertent Interchange Management. (Term is expressed if a regional procedure exists, otherwise is null and is not included in the Balancing Authority's Reporting ACE.)
    - In the Western Interconnection this term is I_{ATEC}

BA Control Fundamentals – BAL-001 and BAL-002

- BAs fulfill their NERC obligations by monitoring Reporting ACE and keeping the value within limits that are generally proportional to BA size. This balancing is typically accomplished through a combination of adjustments of supply resources, **purchases and sales** of electricity with other BAs, and possibly adjustments of demand.
- Reporting ACE is to a BA what frequency is to the Interconnection.
- Over-generation makes Reporting ACE go positive and puts upward pressure on Interconnection frequency.
- A large negative Reporting ACE can cause Interconnection frequency to drop.
- A highly variable or "noisy" Reporting ACE tends to contribute to similarly "noisy" frequency.

BA Control Continuum

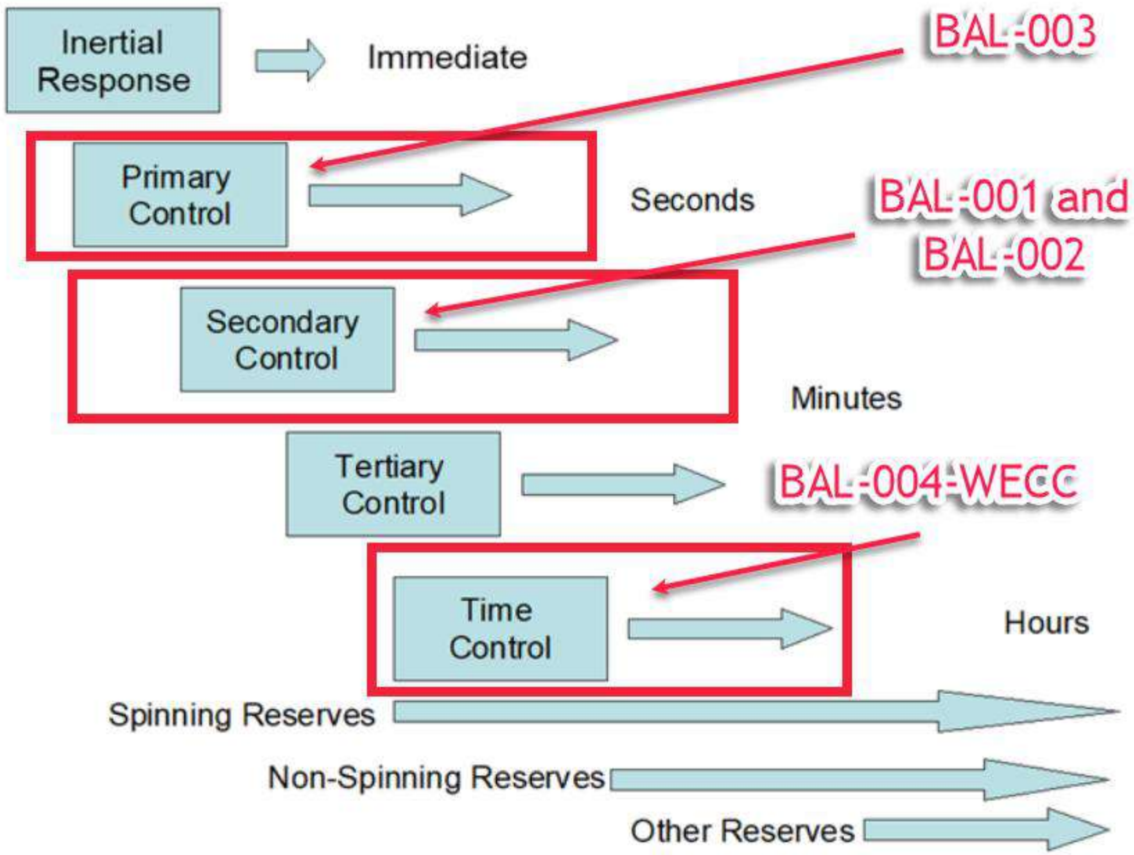


Figure 1.7: Control Continuum

BA Control Continuum

Table 1.1: Control Continuum Summary			
Control	**Ancillary Service/ERS**	**Timeframe**	**NERC Measurement**
Inertial Control	Inertial Control	0–12 Seconds	N/A
Primary Control	Frequency Response	10–60 Seconds	FRM
Secondary Control	Regulation	1–10 Minutes	CPS1 – DCS - BAAL
Tertiary Control	Imbalance/Reserves	10 Minutes–Hours	BAAL - DCS
Time Control	Time Error Correction	Hours	N/A

Problem Statement

- With the increase of non-dispatchable Variable Energy Resources, the ability to control frequency has become much more difficult during periods of large solar ramps both morning and late afternoon.
- Many BAs are experiencing an increasing more difficult time with meeting the regulation requirements of BAL-001 while not themselves having a significant change to their resource mix.
- Review of Western Interconnection Hz data indicated that certain hours of certain months, the average Hz was outside of prescribed governor deadbands (.036 mHz) for the entire hour.

Problem Statement

- Traditional metrics of monitoring interconnection frequency performance did **NOT** indicate any significant changes in year over year regulation control issues.
  - Daily average Frequency
  - Frequency RMS (Noise of normal random movement of frequency)
  - M6 Metric (3-hour ramping by BA)

What is “CPS1”

CPS1 is the metric defined in BAL-001 which sets the compliance limit for every BA

CPS1 is calculated every minute through comparison of a BAs Reporting ACE to any deviation from scheduled frequency.

If ACE is Positive and Frequency is above nominal, a BA will receive a low score (less than 100%)

If ACE is Negative and Frequency is below nominal, a BA will receive a low score (less than 100%)

If ACE is Positive and Frequency is below nominal, a BA will receive a high score (greater than 100%)

If ACE is Negative and Frequency is above nominal, a BA will receive a high score (greater than 100%)

What is “BAAL”

BAAL is mathematically equivalent to a “One-Minute” CPS1 Score more negative than -700%

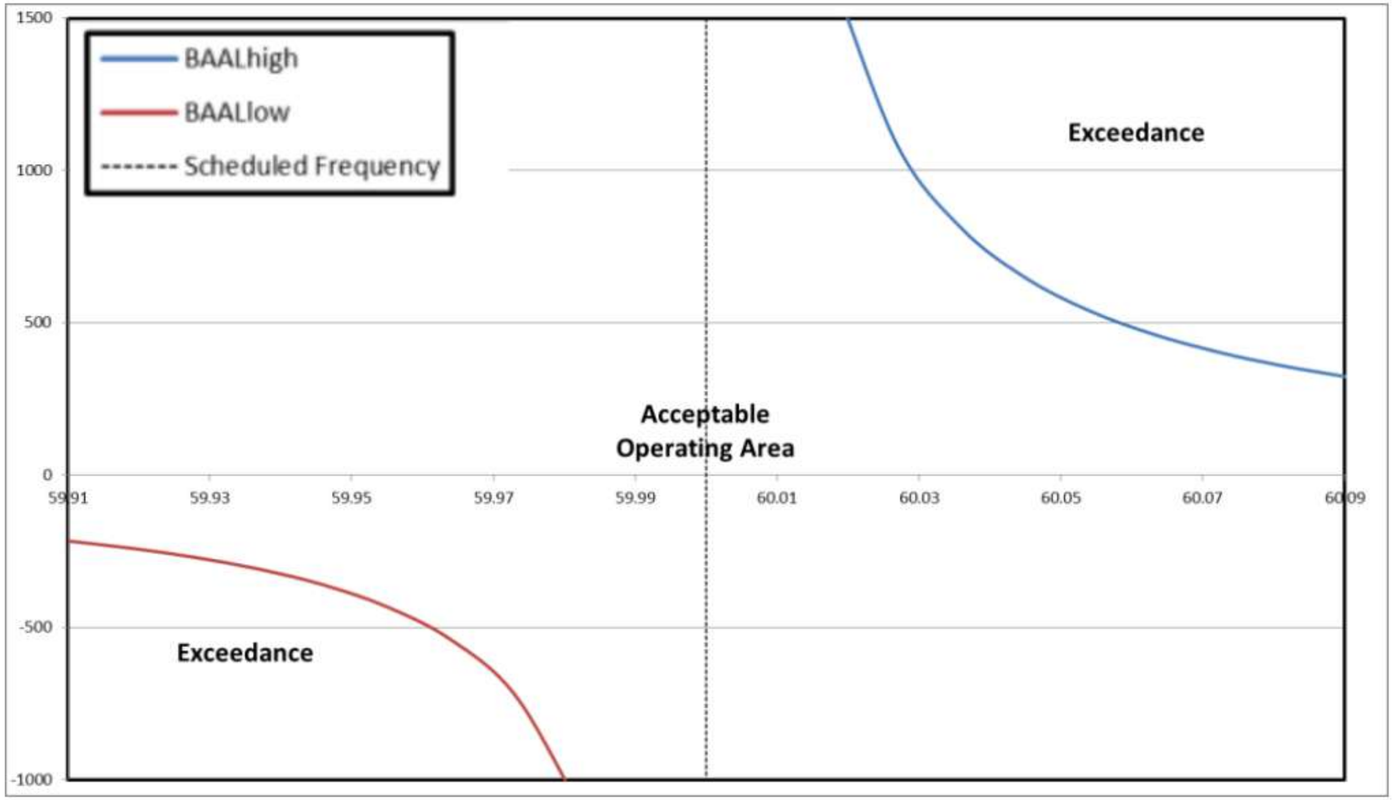
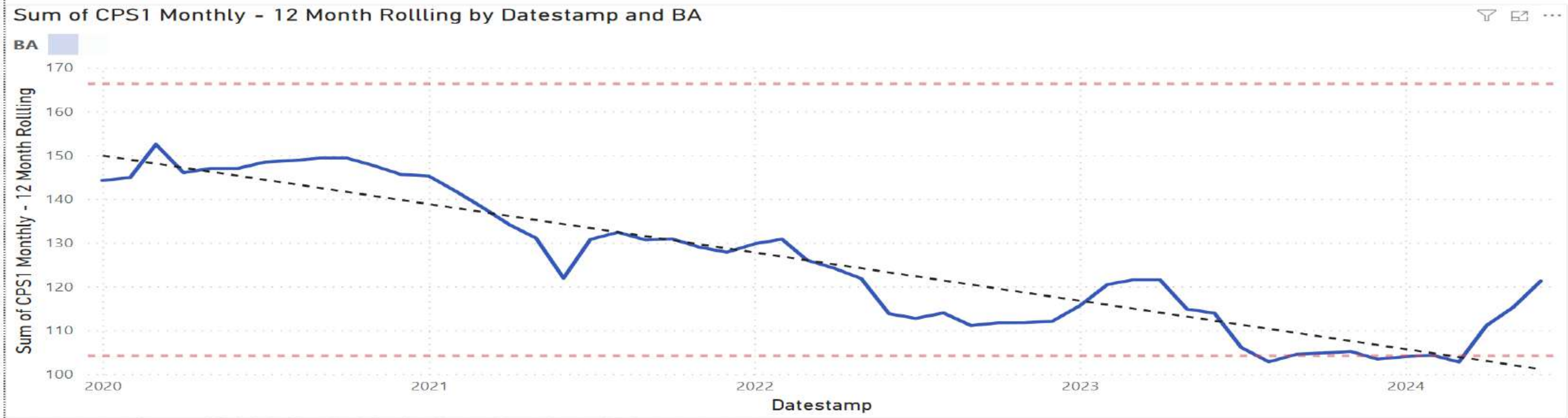
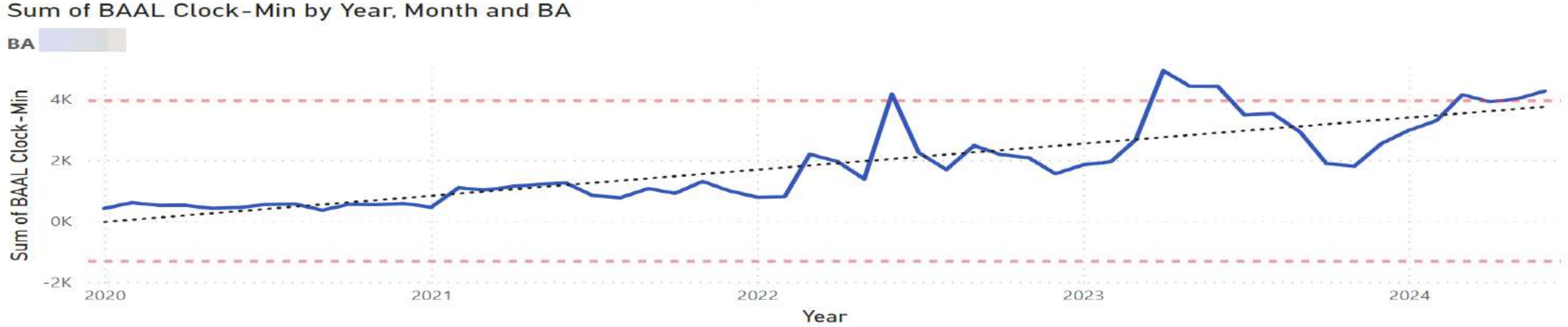


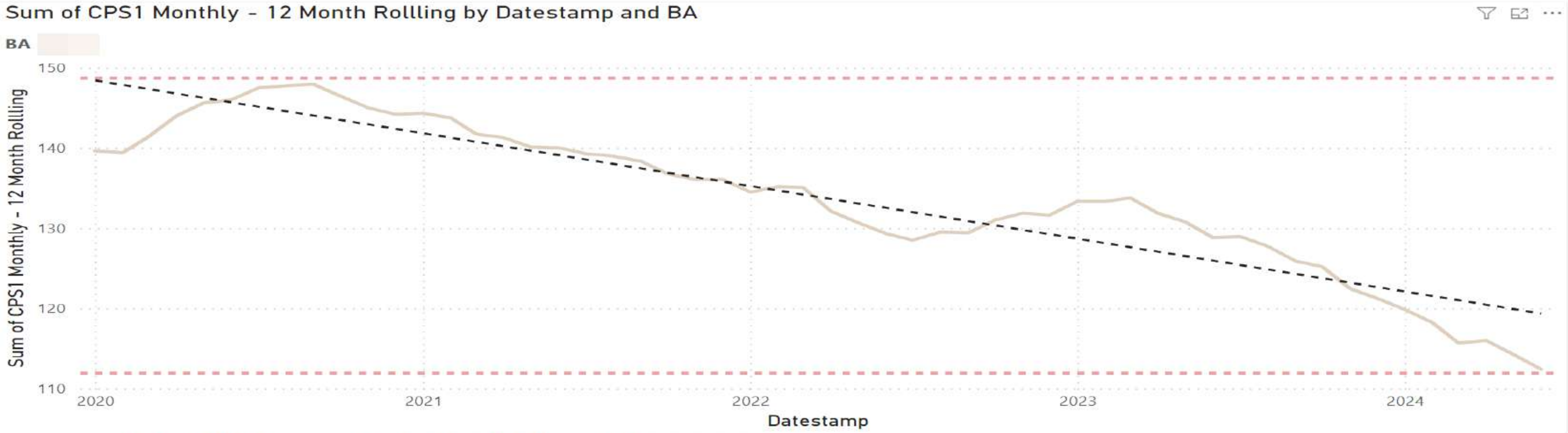
Figure 3.4: Acceptable Operating Area and the BAAL limit exceedance area

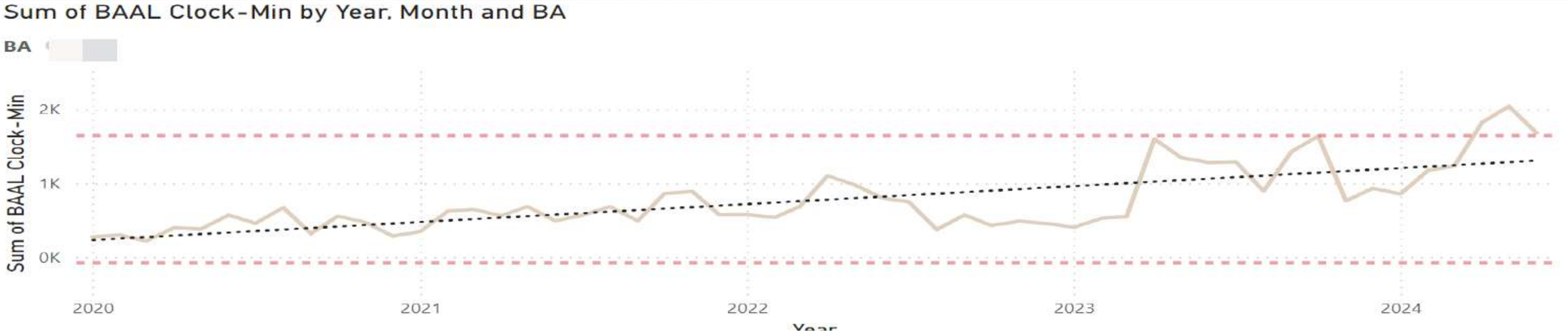
Examples of BA’s Struggles



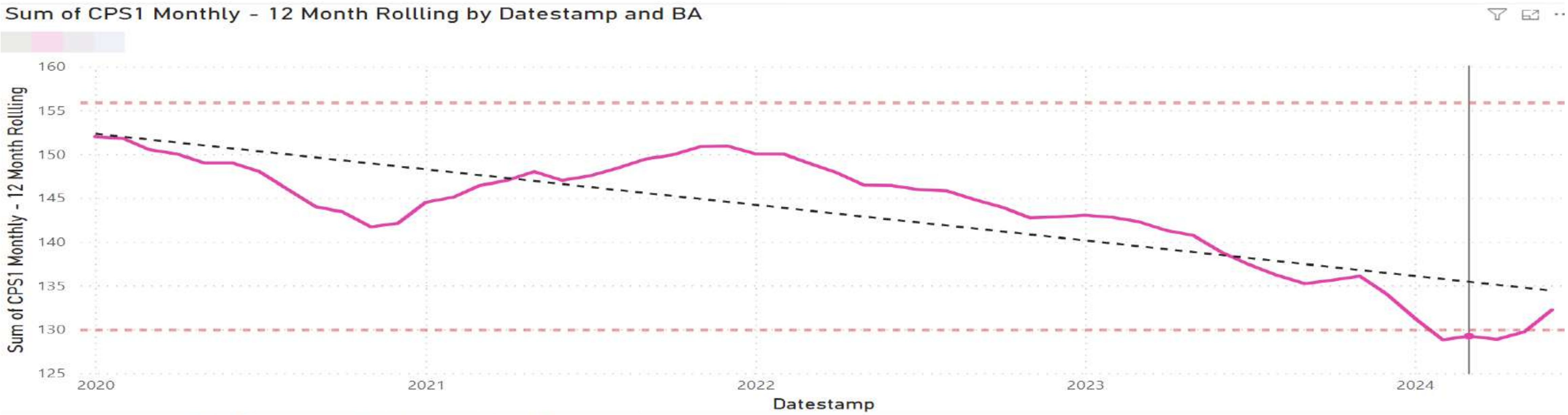


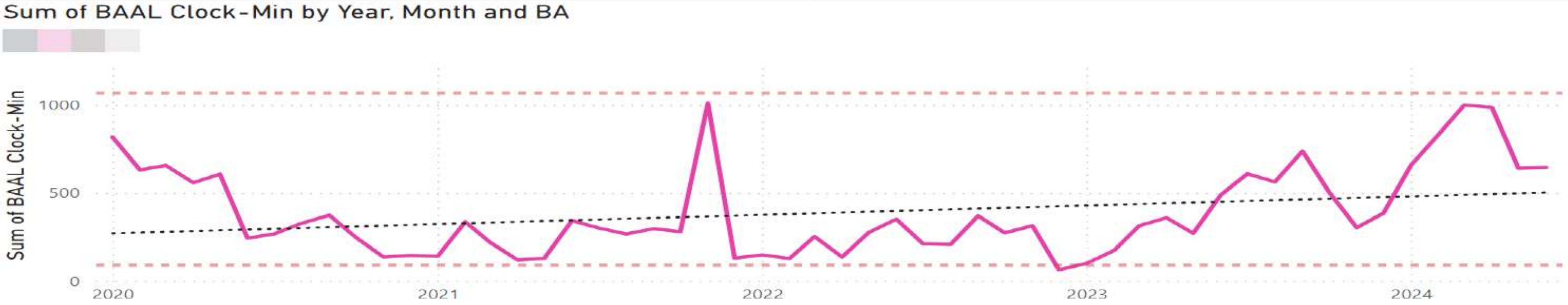
Examples of BA’s Struggles





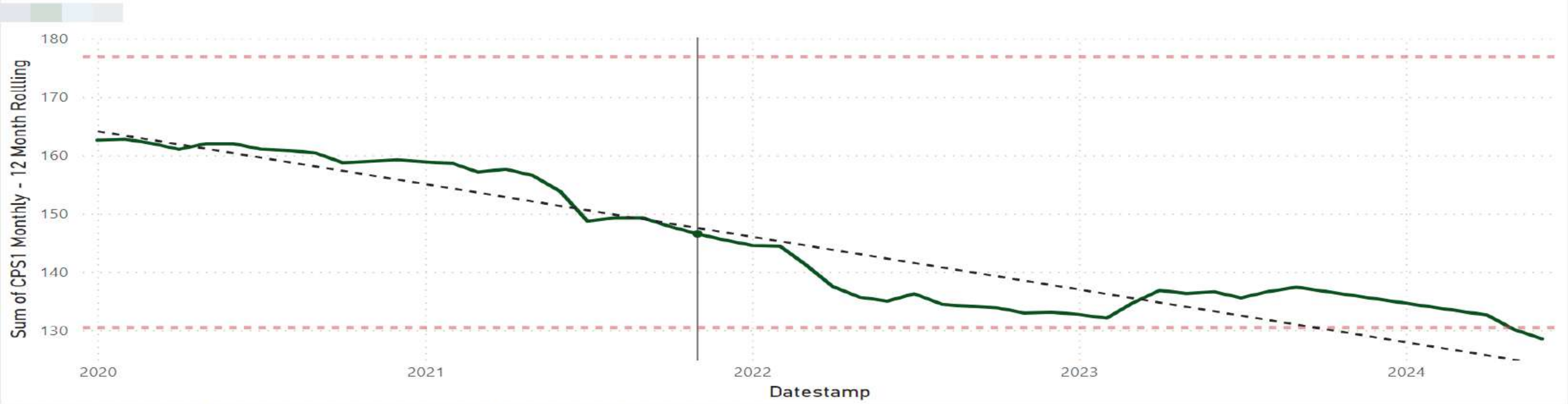
Examples of BA's Struggles



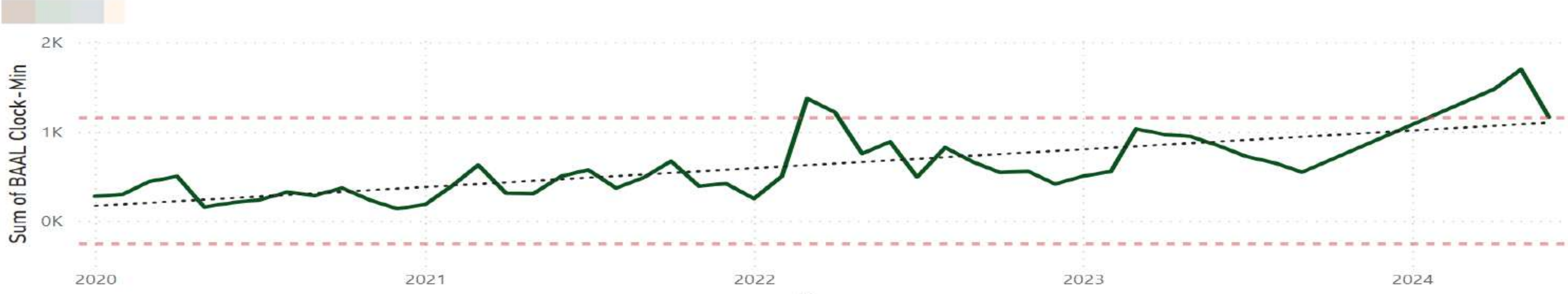


Examples of BA's Struggles

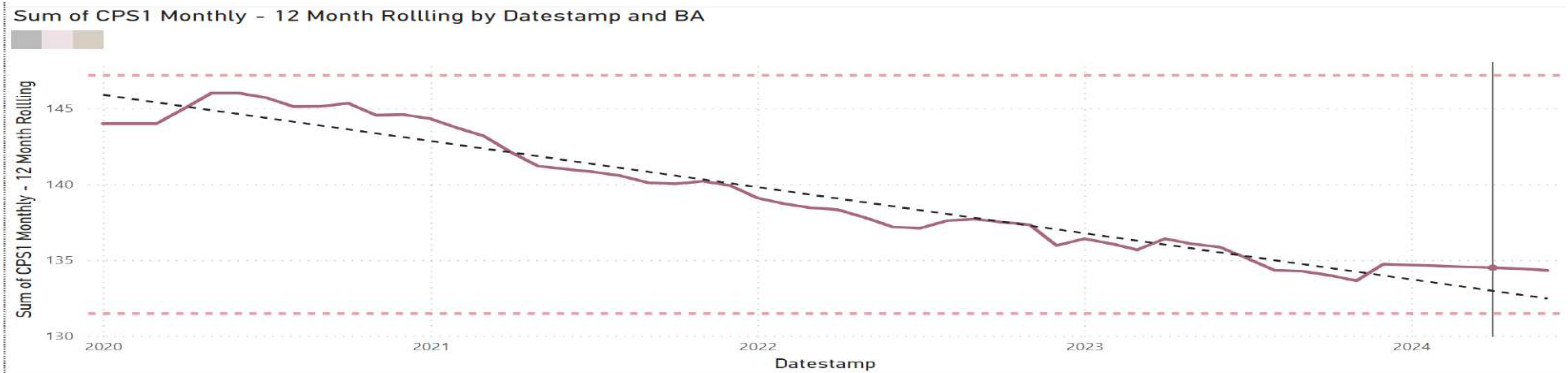
Sum of CPS1 Monthly - 12 Month Rollling by Datestamp and BA

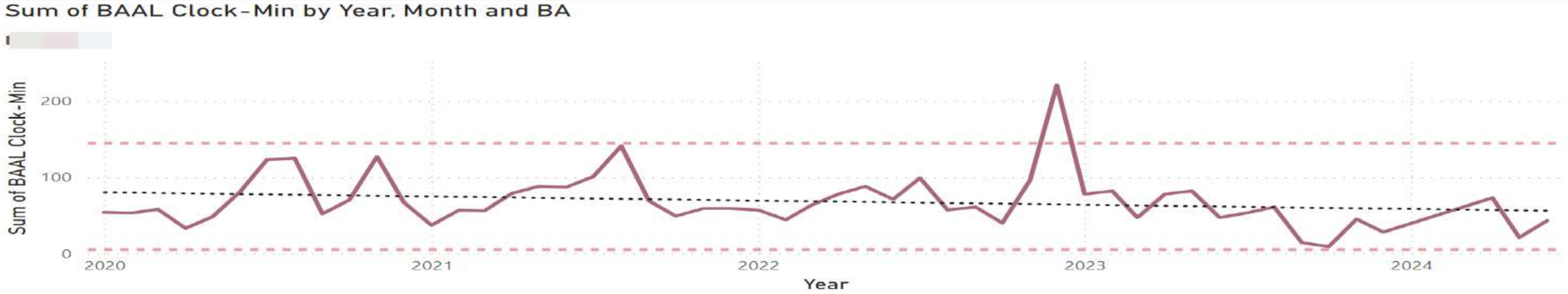


Sum of BAAL Clock-Min by Year, Month and BA

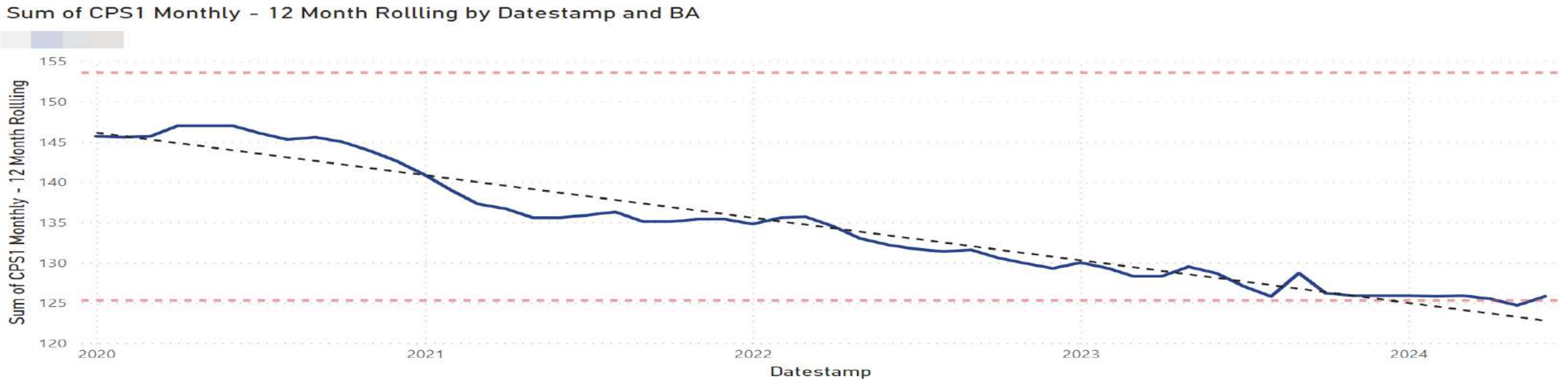


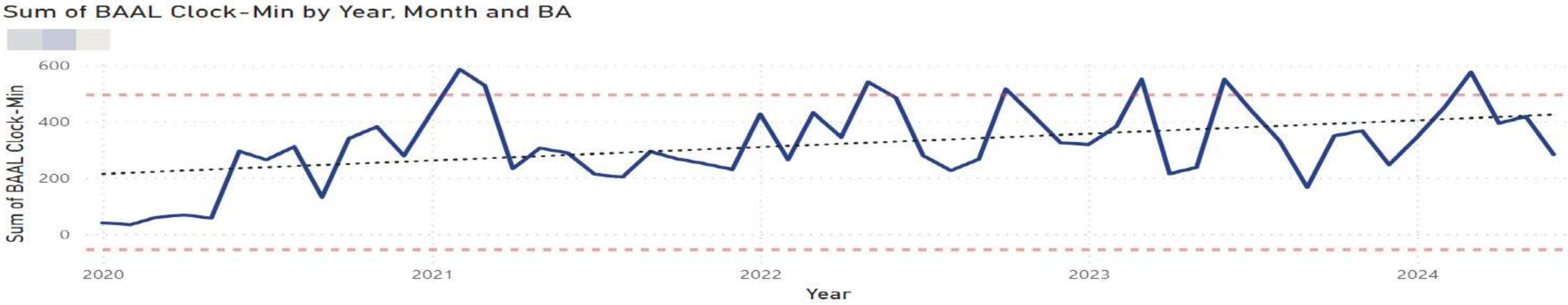
Examples of BA's Struggles





Examples of BA's Struggles

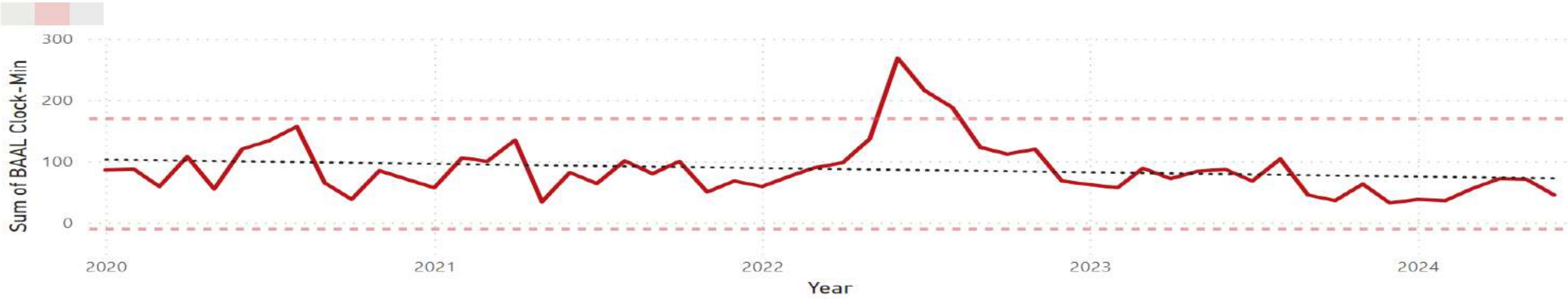




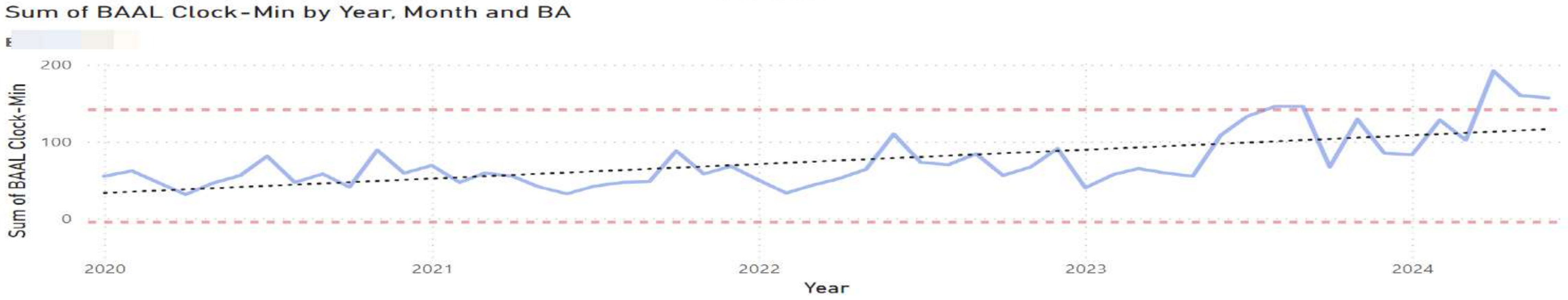
Examples of BA's Struggles

Sum of CPS1 Monthly - 12 Month Rollling by Datestamp and BA

Sum of BAAL Clock-Min by Year, Month and BA



Examples of BA's Struggles



Solution

- The NERC RS wanted to develop a methodology to determine if frequency control was becoming more difficult from year to year and if the control was being impacted by the integration of Photovoltaic resources.
- The metric that BAs utilize to determine how "well" they perform their regulation responsibilities is "CPS1"

Which led to the next question…Can CPS1 be calculated on the interconnection level?

CPS1 – Show me the math

$$CPS1 = (2 - CF) * 100\%$$

$$CF = \frac{CF_{\text{12-month}}}{(\varepsilon 1_I)^2}$$

$$CF_{\text{clock-minute}} = \left[\left(\frac{RACE}{-10B} \right)_{\text{clock-minute}} * \Delta F_{\text{clock-minute}} \right]$$

CPS1$_{\text{Interconnection}}$ – Show me the math

Expand ACE:

$$CF = \frac{(NAI - NSI) - 10\beta(\Delta F) * \ \Delta F}{-10\beta * \ \varepsilon_1^2}$$

Assume NAI-NSI = 0 for interconnection level:

$$CF = \frac{(0) - 10\beta(\Delta F) * \ \Delta F}{-10\beta * \ \varepsilon_1^2}$$

$CPS1_{Interconnection}$ – Show me the math

Cancel and simplify:

$$CF = \frac{\Delta F^2}{\varepsilon_1^2}$$

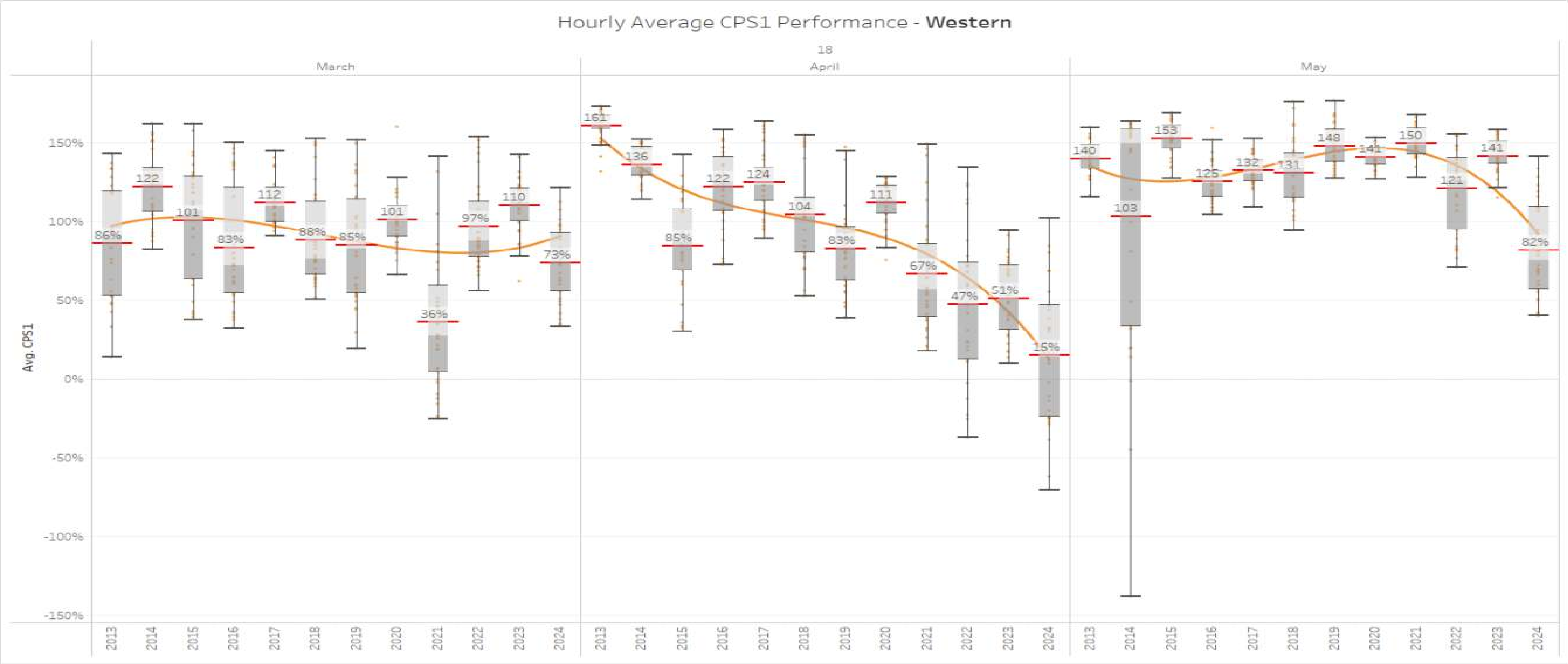
$$CPS1_{Interconnection} = 100 * \left(2 - \frac{\Delta F^2}{\varepsilon_1^2}\right)$$

$CPS1_{Interconnection}$ – Show me the math

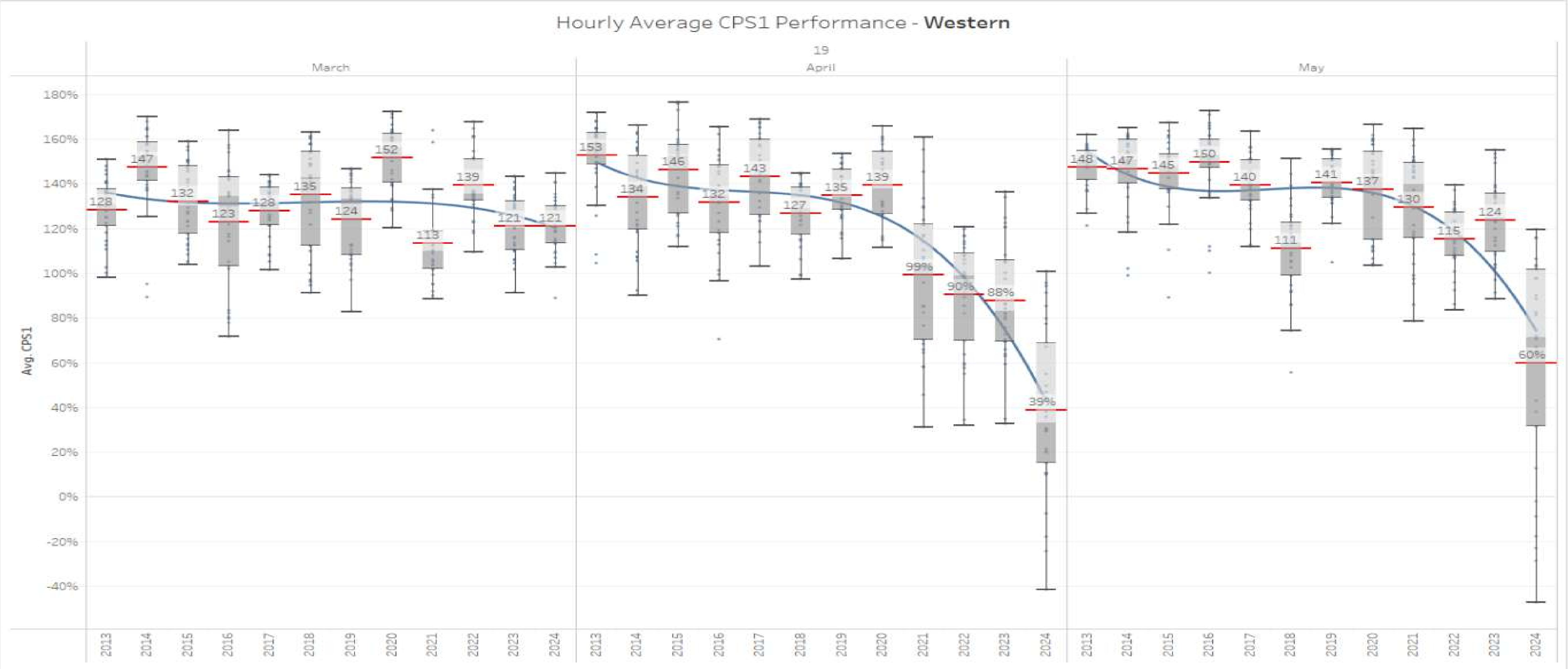
This is the only remaining Variable. Epsilon is a "variable" that hasn't changed in decades

$$CPS1_{Interconnection} = 100 * \left(2 - \frac{\boxed{\Delta F^2}}{\varepsilon_1^2}\right)$$

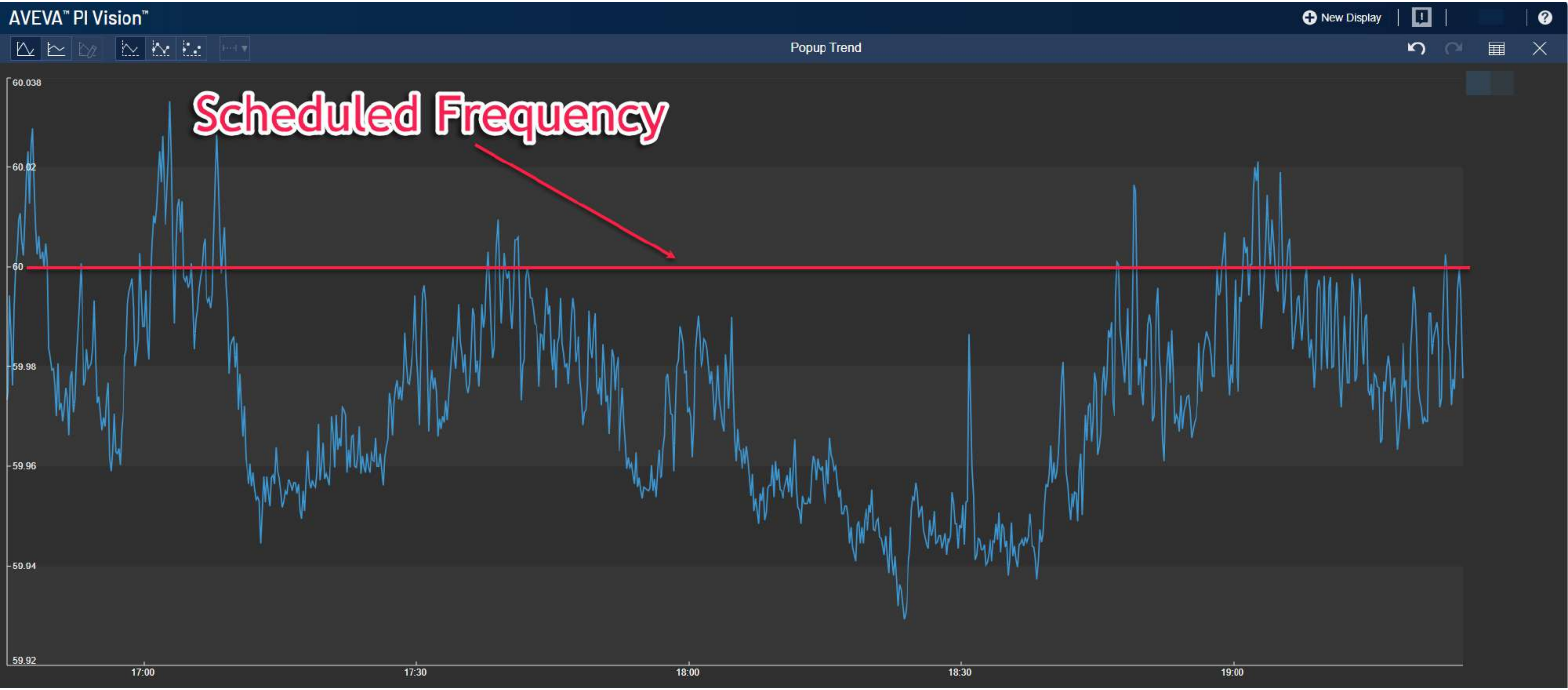
Hour Ending 1800



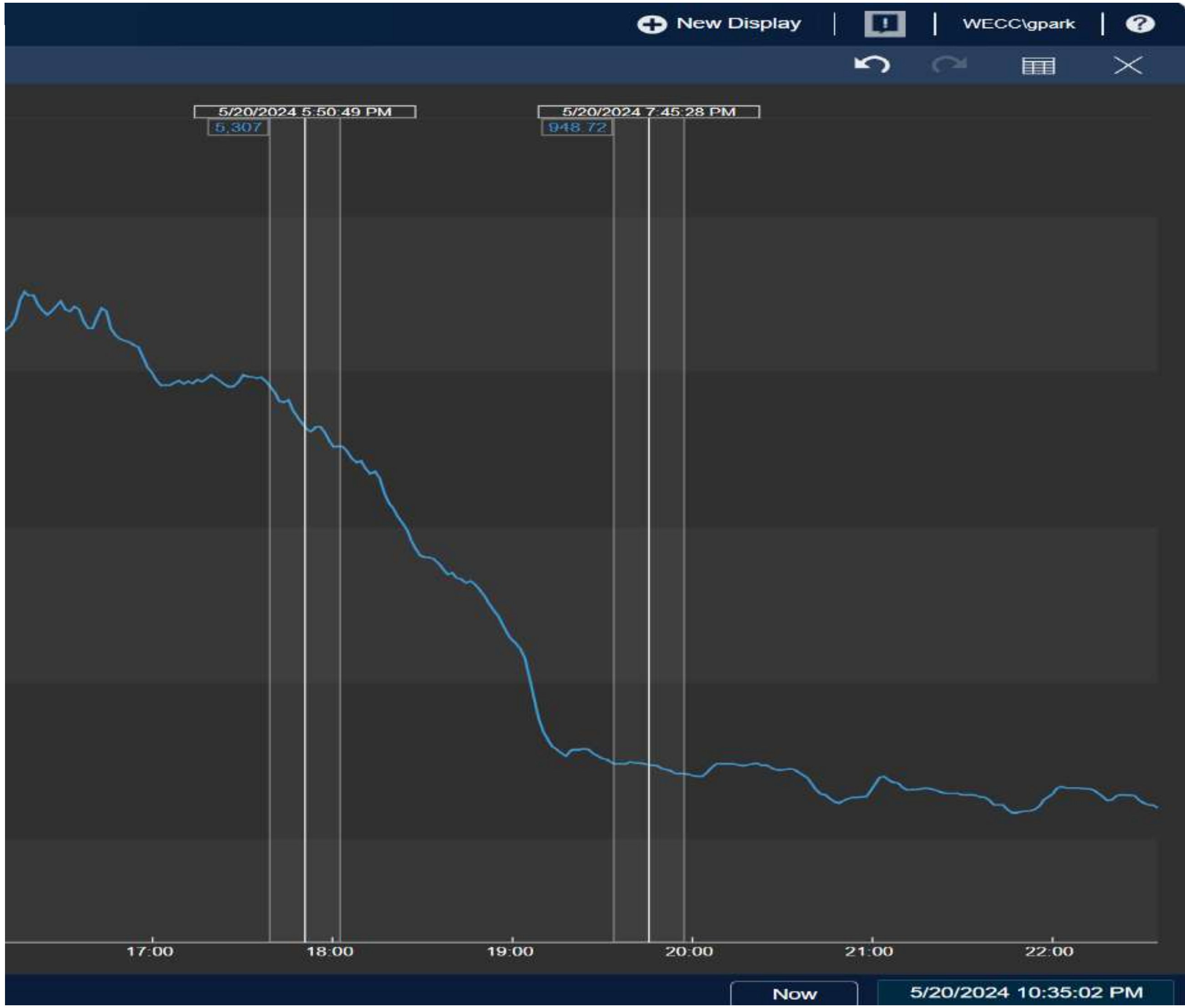
Hour Ending 1900



Frequency Profile

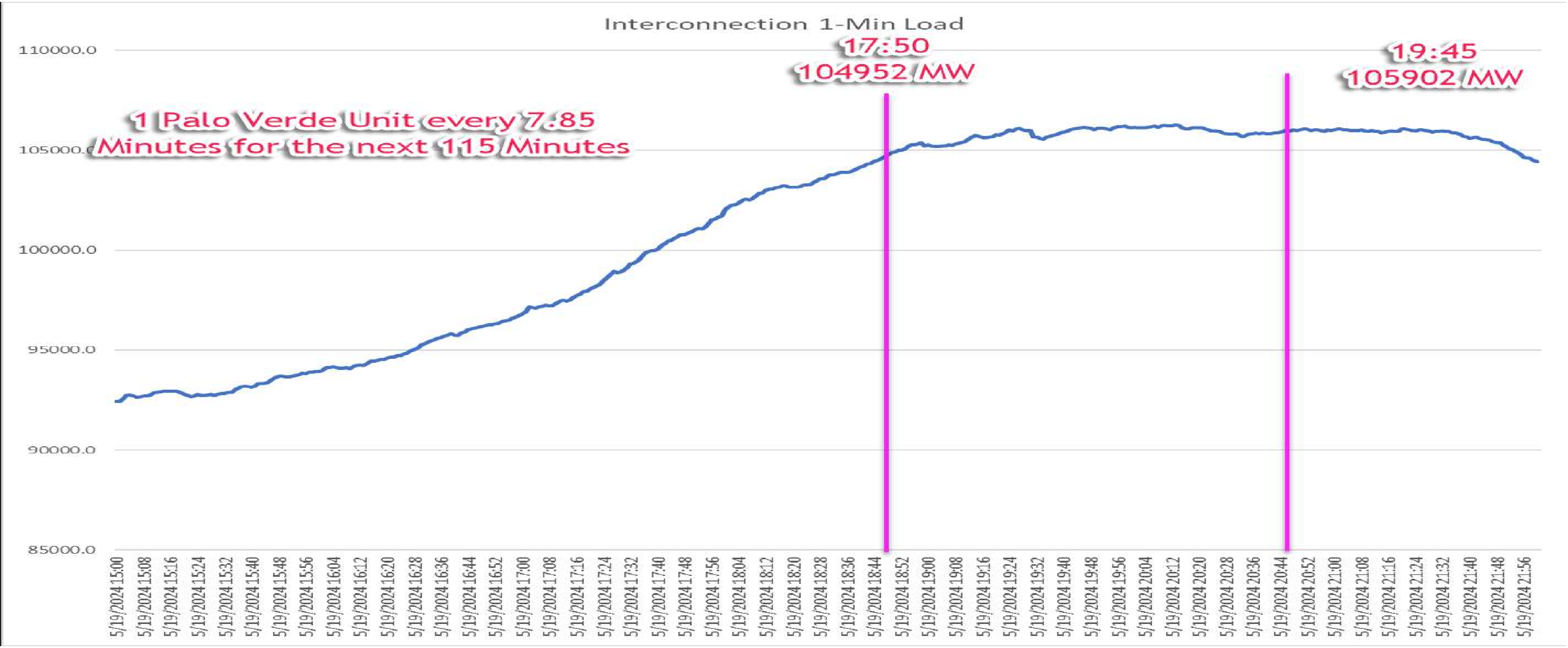


Solar Ramp 164 MW/Min for 115 Min (18,870MW Loss)



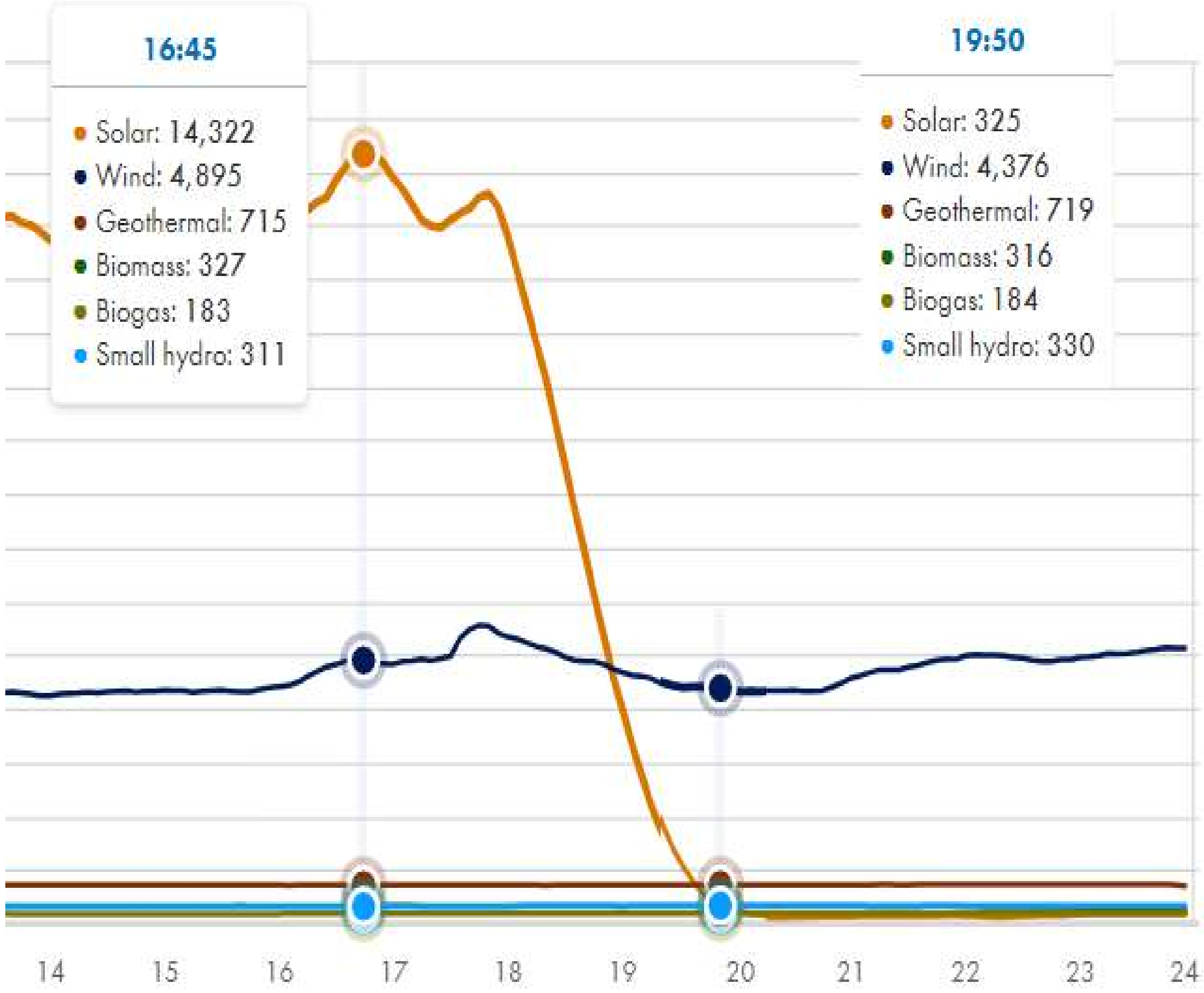
<Public>

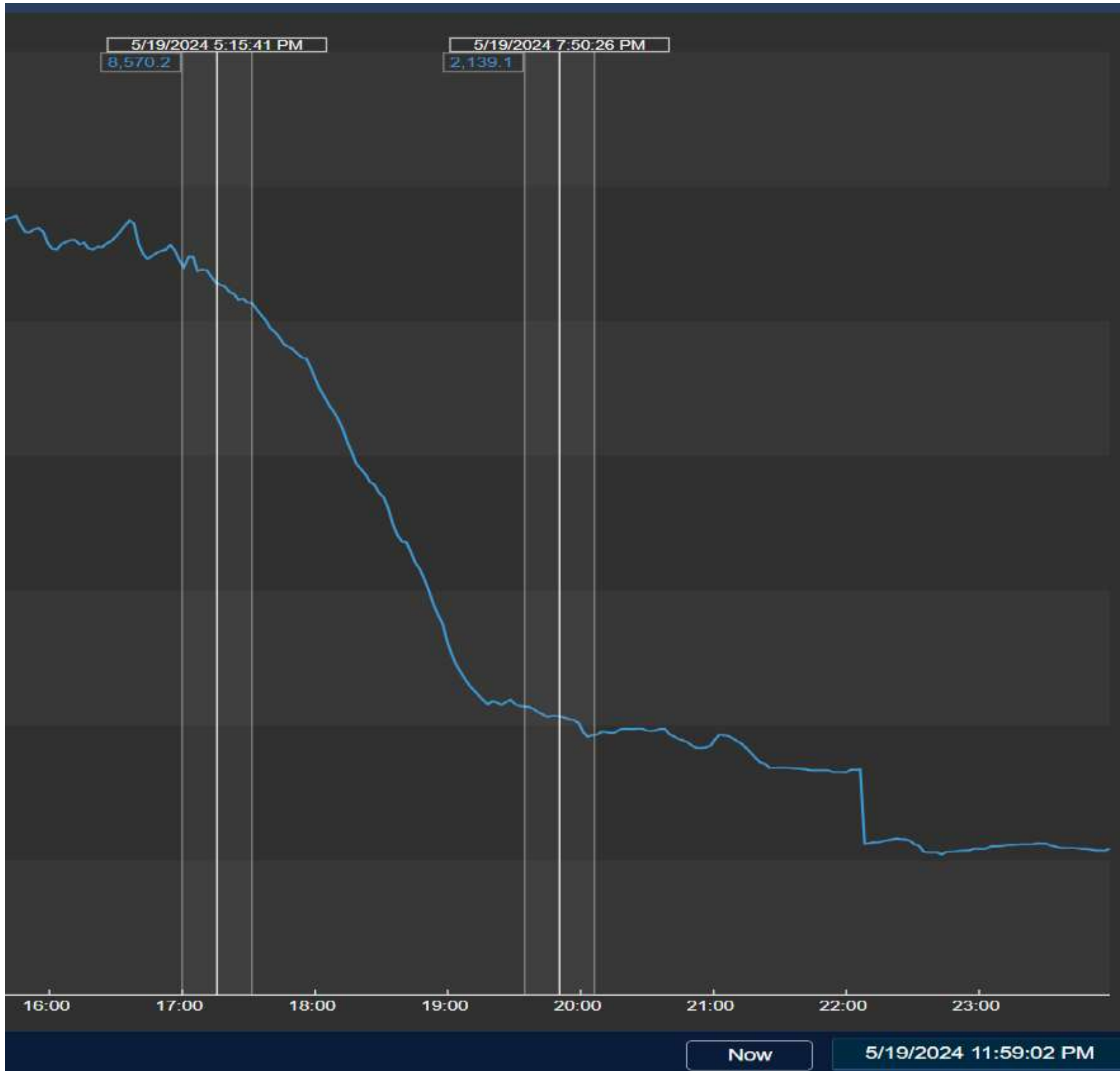
Interconnection Load (Increased by 950 MW) 172 MW/Min for 115 minutes



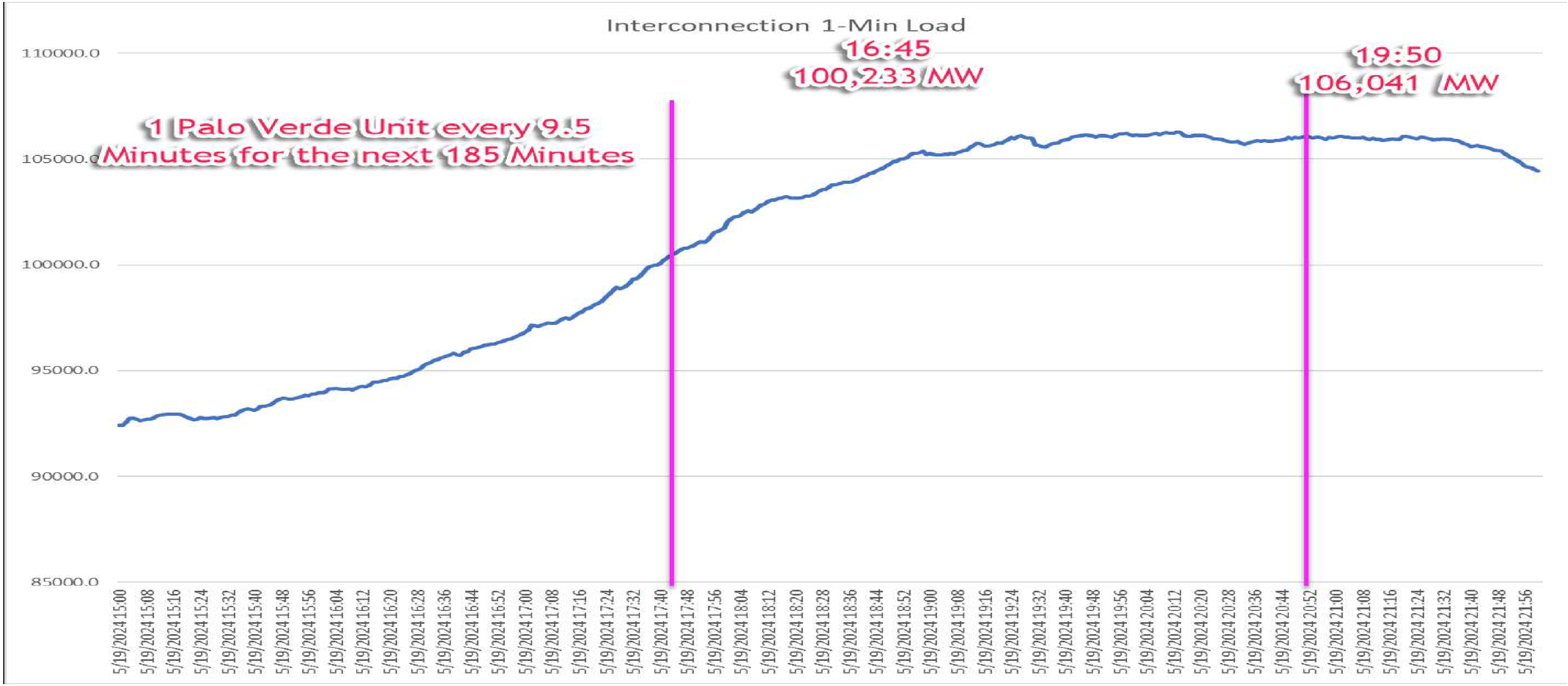
<Public>

Solar Ramp 110 MW/Min for 185 Min (20428MW Loss)

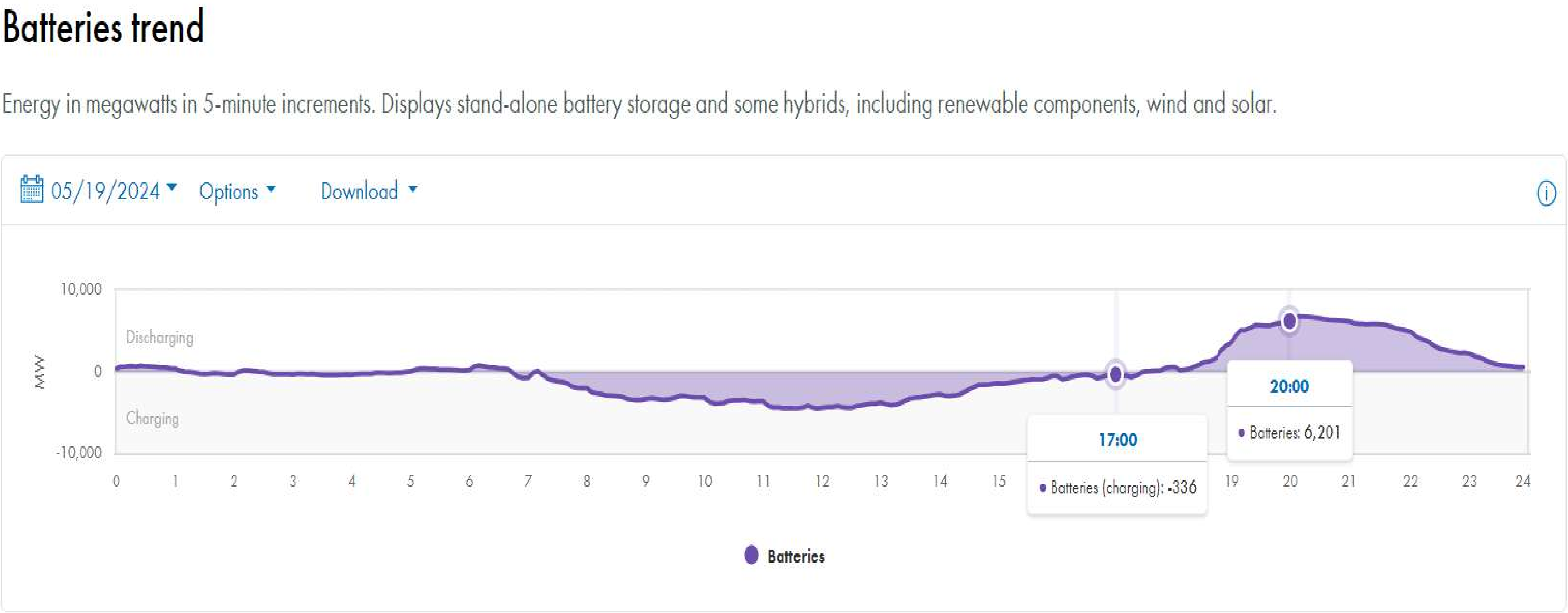




Interconnection Load (Increased by 5,808 MW) 142 MW/Min for 185 minutes



What Were Batteries Doing (CAISO Only)



Monthly Average CPS1 Scores

Month/Hour	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	Total
Jan	149.79%	159.56%	169.11%	153.26%	135.07%	100.81%	118.91%	144.55%	155.69%	163.50%	154.16%	161.40%	152.27%	164.40%	168.63%	150.44%	96.24%	144.52%	164.15%	163.34%	140.92%	112.96%	121.22%	123.19%	144.50%
Feb	140.25%	158.40%	164.31%	160.18%	134.37%	80.64%	114.82%	152.25%	155.39%	154.45%	143.83%	151.22%	149.01%	165.20%	163.99%	143.92%	106.52%	76.58%	163.53%	163.13%	134.76%	112.50%	105.93%	119.32%	138.10%
Mar	130.47%	155.67%	163.61%	149.16%	123.57%	83.51%	118.36%	135.85%	152.08%	158.87%	151.77%	157.20%	153.43%	154.60%	162.13%	161.65%	149.08%	112.41%	119.59%	133.04%	157.30%	128.44%	105.56%	120.35%	139.07%
Apr	148.52%	158.60%	162.72%	158.54%	132.64%	91.17%	130.67%	138.78%	143.48%	155.01%	148.53%	157.66%	152.96%	147.93%	156.92%	152.06%	151.33%	157.21%	154.18%	142.87%	142.15%	112.94%	97.37%	106.62%	141.70%
May	118.34%	151.10%	159.71%	164.37%	141.83%	126.59%	120.10%	140.50%	143.63%	154.33%	146.00%	153.44%	154.84%	150.55%	148.14%	147.63%	116.63%	139.97%	148.52%	151.53%	146.41%	117.99%	93.84%	89.48%	138.56%
Jun	137.88%	154.55%	156.22%	163.00%	148.00%	123.99%	109.49%	137.15%	142.41%	143.13%	141.72%	166.08%	156.36%	160.11%	154.06%	154.77%	167.02%	151.31%	151.46%	155.40%	156.82%	146.21%	112.26%	112.23%	145.90%
Jul	127.96%	144.14%	148.45%	168.53%	151.58%	119.88%	119.70%	121.52%	133.15%	140.56%	119.10%	141.06%	159.17%	153.18%	160.00%	165.16%	162.18%	143.12%	147.54%	158.99%	145.63%	144.38%	107.87%	104.42%	141.14%
Aug	125.97%	152.17%	161.28%	164.53%	142.83%	117.52%	125.73%	136.14%	138.98%	130.65%	139.62%	144.63%	154.32%	156.09%	161.02%	163.99%	137.70%	150.10%	144.46%	153.45%	149.41%	101.33%	106.54%	116.35%	140.62%
Sep	125.12%	144.41%	152.90%	159.61%	136.41%	74.82%	119.38%	138.15%	144.45%	130.57%	145.94%	145.38%	150.79%	155.65%	159.66%	150.60%	159.59%	157.88%	130.10%	128.77%	116.96%	83.14%	101.91%	99.09%	133.80%
Oct	131.42%	154.92%	156.33%	168.01%	106.59%	85.29%	104.24%	146.43%	138.65%	133.92%	153.86%	155.69%	161.19%	159.03%	157.67%	149.37%	124.95%	111.19%	108.33%	143.24%	115.79%	105.76%	109.85%	111.55%	133.05%
Nov	130.78%	159.53%	149.74%	152.07%	117.97%	104.61%	130.62%	147.32%	151.03%	151.81%	149.24%	152.59%	154.29%	158.98%	154.59%	129.41%	90.77%	142.59%	148.07%	152.34%	129.70%	109.68%	81.22%	107.31%	135.68%
Dec	139.61%	158.49%	164.18%	158.04%	129.80%	90.79%	122.30%	149.04%	150.31%	152.94%	151.88%	148.52%	147.61%	154.46%	156.31%	112.30%	94.45%	154.90%	158.14%	158.82%	140.31%	123.13%	104.92%	123.44%	139.36%

Year

2013	2015	2017	2019	2021	2023
2014	2016	2018	2020	2022	2024

Monthly Average CPS1 Scores

Month/Hour	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	Total
Jan	146.86%	152.72%	155.95%	145.99%	116.98%	90.77%	101.38%	138.06%	141.32%	138.14%	142.53%	145.99%	151.83%	155.48%	160.07%	148.69%	103.46%	135.51%	151.39%	158.61%	135.92%	119.77%	116.18%	126.55%	136.67%
Feb	121.08%	139.76%	136.31%	137.74%	108.18%	71.61%	123.65%	159.07%	149.37%	158.00%	149.71%	135.48%	152.58%	133.74%	145.69%	124.33%	95.28%	114.27%	143.95%	154.06%	133.81%	109.54%	101.36%	116.47%	129.79%
Mar	131.79%	149.16%	138.48%	134.71%	120.24%	110.75%	102.37%	140.80%	147.13%	151.71%	143.17%	140.50%	146.49%	154.71%	140.01%	135.72%	134.04%	117.85%	140.13%	128.49%	147.79%	113.02%	104.88%	96.79%	132.11%
Apr	135.42%	153.51%	157.72%	160.09%	131.51%	129.62%	117.94%	135.73%	144.01%	147.69%	147.04%	146.64%	145.23%	149.77%	153.43%	151.98%	125.14%	136.53%	138.79%	123.65%	149.04%	111.85%	97.56%	97.53%	136.97%
May	148.51%	153.24%	145.24%	137.27%	119.40%	117.56%	106.83%	132.76%	147.64%	151.21%	143.61%	140.13%	145.48%	149.08%	142.63%	145.93%	143.66%	128.36%	148.61%	159.37%	155.05%	137.11%	124.49%	110.21%	138.89%
Jun	140.95%	155.32%	158.96%	150.76%	150.41%	140.15%	119.54%	145.02%	141.55%	153.63%	140.33%	150.21%	148.72%	156.72%	159.70%	155.31%	148.90%	144.45%	144.16%	142.25%	157.32%	148.42%	125.36%	123.81%	145.91%
Jul	136.84%	147.40%	161.76%	167.42%	160.18%	125.72%	129.42%	109.60%	133.26%	131.83%	146.21%	138.24%	149.92%	163.08%	156.38%	151.66%	147.35%	154.91%	146.06%	143.03%	142.54%	131.13%	95.47%	112.85%	140.93%
Aug	126.84%	142.04%	154.09%	161.36%	144.61%	123.74%	137.43%	127.44%	144.51%	138.00%	137.45%	141.99%	153.11%	150.51%	153.46%	155.68%	153.87%	140.42%	143.62%	147.92%	149.62%	101.99%	114.09%	94.95%	139.11%
Sep	133.84%	149.91%	156.99%	154.31%	131.20%	85.30%	128.76%	128.81%	145.44%	137.77%	148.11%	141.35%	137.31%	145.65%	153.18%	154.39%	149.51%	149.08%	129.72%	130.72%	119.91%	85.68%	107.75%	100.92%	133.57%
Oct	139.20%	151.26%	151.19%	141.75%	124.18%	75.67%	115.28%	141.39%	142.53%	149.17%	143.28%	141.82%	153.18%	153.05%	133.29%	130.78%	108.46%	129.73%	119.72%	143.52%	123.18%	95.45%	106.55%	102.97%	129.86%
Nov	122.67%	145.52%	142.94%	142.22%	102.10%	98.32%	115.74%	141.18%	124.75%	132.19%	145.79%	134.98%	146.19%	146.30%	109.64%	40.29%	77.09%	122.78%	146.03%	145.95%	118.47%	108.97%	109.51%	111.57%	122.13%
Dec	141.16%	155.70%	159.73%	156.57%	126.12%	129.92%	117.45%	123.91%	152.74%	147.71%	144.82%	135.07%	140.18%	139.43%	139.85%	104.63%	78.33%	143.42%	163.85%	164.78%	135.99%	116.39%	110.87%	112.06%	135.03%

Year

2013	2015	2017	2019	2021	2023
2014	2016	2018	2020	2022	2024

Monthly Average CPS1 Scores

Month/Hour	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	Total
Jan	136.97%	168.69%	167.27%	156.39%	126.51%	115.02%	126.39%	145.43%	152.75%	153.68%	151.39%	150.99%	149.84%	136.92%	161.84%	-374.35%	79.98%	139.62%	165.76%	161.00%	135.73%	115.24%	109.21%	123.52%	**118.99%**
Feb	152.96%	161.21%	169.15%	142.25%	130.47%	120.42%	123.80%	152.16%	141.66%	152.48%	156.20%	154.62%	150.29%	153.76%	144.21%	147.62%	81.04%	118.22%	163.78%	158.58%	144.15%	128.97%	128.34%	131.38%	**141.99%**
Mar	137.07%	163.39%	164.13%	150.28%	139.34%	108.61%	129.58%	153.78%	151.76%	150.91%	161.61%	160.96%	154.29%	156.09%	154.26%	143.80%	128.20%	122.53%	126.10%	147.16%	148.48%	105.28%	98.64%	96.29%	**139.69%**
Apr	120.00%	152.18%	130.15%	130.44%	123.20%	94.52%	123.68%	144.41%	131.20%	142.20%	147.57%	152.70%	150.97%	156.25%	153.91%	136.06%	125.75%	99.93%	131.79%	122.37%	144.38%	119.71%	108.51%	114.99%	**131.54%**
May	137.75%	160.36%	166.76%	158.83%	137.64%	120.64%	149.49%	156.02%	154.12%	149.25%	151.77%	157.79%	165.27%	154.86%	147.13%	156.07%	157.93%	145.49%	141.89%	148.15%	153.45%	124.13%	102.42%	90.80%	**145.33%**
Jun	114.66%	140.52%	145.78%	149.00%	136.09%	116.71%	118.71%	125.10%	128.57%	131.03%	140.57%	143.38%	149.22%	161.39%	146.67%	131.44%	131.65%	131.35%	140.87%	135.96%	113.56%	125.87%	98.51%	92.09%	**131.20%**
Jul	119.04%	154.24%	159.22%	168.74%	142.59%	141.28%	129.07%	131.80%	138.54%	122.67%	136.72%	142.58%	146.98%	146.47%	150.15%	154.41%	142.88%	149.37%	152.99%	146.01%	142.11%	139.31%	100.91%	116.36%	**140.60%**
Aug	138.14%	154.60%	164.11%	155.52%	139.91%	123.77%	132.88%	133.93%	146.58%	138.27%	137.74%	141.80%	139.70%	150.08%	141.87%	146.26%	149.17%	147.73%	145.32%	139.08%	138.06%	97.84%	99.06%	107.60%	**137.88%**
Sep	119.59%	153.86%	157.79%	160.07%	135.39%	87.29%	131.61%	143.70%	140.05%	158.48%	153.18%	50.56%	145.90%	155.97%	149.71%	143.58%	134.72%	130.66%	129.93%	138.12%	125.35%	84.86%	76.29%	91.39%	**129.08%**
Oct	119.99%	139.74%	156.39%	134.26%	126.40%	78.00%	125.98%	141.23%	129.68%	139.73%	153.20%	149.87%	151.68%	145.74%	136.29%	149.80%	121.86%	125.30%	133.44%	141.21%	112.21%	90.93%	118.14%	109.65%	**130.45%**
Nov	140.62%	149.18%	151.64%	139.08%	124.20%	108.24%	138.46%	134.00%	141.45%	145.71%	137.94%	141.20%	147.49%	136.91%	125.86%	61.06%	96.44%	152.93%	151.98%	148.26%	136.21%	132.21%	127.70%	122.87%	**132.98%**
Dec	147.67%	159.93%	153.04%	161.55%	127.78%	114.09%	140.63%	132.22%	126.81%	131.10%	138.40%	133.51%	143.09%	147.20%	144.03%	88.51%	79.54%	143.91%	159.64%	162.04%	153.45%	120.43%	125.69%	112.60%	**135.29%**

Year

2013	**2015**	2017	2019	2021	2023
2014	2016	2018	2020	2022	2024

Monthly Average CPS1 Scores

Month/Hour	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	Total
Jan	145.90%	160.86%	164.09%	160.54%	118.63%	105.04%	115.81%	140.44%	136.13%	150.09%	147.24%	143.20%	143.08%	155.17%	144.16%	103.55%	65.88%	118.73%	159.01%	154.76%	143.68%	122.60%	124.79%	117.09%	**135.02%**
Feb	149.21%	164.69%	163.05%	149.90%	130.80%	115.00%	126.33%	130.56%	129.55%	145.82%	156.18%	153.07%	151.76%	155.93%	158.92%	125.35%	53.24%	109.61%	150.15%	159.74%	138.32%	126.17%	126.64%	123.83%	**137.24%**
Mar	144.01%	152.94%	152.08%	157.57%	137.86%	111.34%	91.95%	140.04%	122.34%	145.02%	137.72%	155.57%	151.19%	145.97%	144.11%	136.22%	122.18%	98.13%	109.65%	132.78%	150.19%	112.12%	113.41%	116.42%	**132.53%**
Apr	138.56%	139.48%	155.82%	149.97%	146.04%	110.60%	126.27%	147.67%	136.94%	149.96%	155.32%	150.21%	153.39%	148.22%	164.25%	140.69%	150.58%	130.77%	125.31%	131.89%	140.05%	92.67%	79.93%	97.06%	**135.90%**
May	141.40%	158.65%	160.40%	153.56%	114.59%	109.41%	135.08%	148.16%	134.86%	139.60%	157.92%	155.69%	156.99%	150.18%	154.94%	140.54%	135.27%	132.39%	137.93%	141.73%	151.05%	92.97%	85.49%	114.21%	**137.63%**
Jun	141.51%	155.00%	154.54%	161.77%	147.60%	127.29%	147.27%	130.34%	146.65%	151.76%	142.58%	147.94%	144.20%	150.85%	149.67%	155.31%	162.25%	147.42%	142.51%	125.62%	134.92%	125.60%	105.26%	112.28%	**142.09%**
Jul	133.93%	151.76%	158.33%	152.30%	111.60%	123.59%	151.07%	138.98%	128.89%	135.37%	123.28%	147.79%	143.07%	150.06%	151.68%	151.26%	154.10%	153.86%	157.03%	137.59%	153.41%	118.80%	93.89%	113.96%	**138.98%**
Aug	130.43%	148.62%	159.67%	166.00%	126.25%	85.18%	140.23%	145.36%	134.28%	131.78%	141.71%	117.99%	127.18%	130.58%	148.60%	144.76%	148.84%	151.46%	140.45%	125.00%	125.03%	80.72%	90.25%	92.93%	**130.55%**
Sep	141.72%	152.43%	151.69%	148.04%	115.59%	69.67%	125.40%	142.18%	141.14%	157.06%	157.55%	152.50%	154.65%	149.53%	148.96%	147.31%	151.54%	126.67%	138.92%	145.21%	130.93%	103.69%	81.82%	105.47%	**134.99%**
Oct	137.85%	151.82%	155.79%	156.74%	129.44%	88.22%	113.59%	141.72%	131.83%	150.95%	159.82%	158.57%	147.24%	152.40%	151.90%	139.18%	112.71%	118.73%	132.59%	152.93%	140.25%	130.15%	116.68%	124.26%	**137.31%**
Nov	148.14%	157.79%	158.43%	158.01%	136.18%	88.48%	115.20%	124.43%	119.62%	144.31%	157.78%	141.19%	156.47%	119.79%	136.39%	86.21%	96.40%	147.08%	148.88%	162.80%	152.34%	133.15%	119.82%	124.13%	**134.71%**
Dec	158.98%	164.35%	166.12%	160.54%	151.88%	130.61%	119.82%	149.04%	136.68%	142.96%	145.53%	154.16%	156.85%	153.12%	139.62%	111.25%	110.06%	160.66%	170.66%	166.08%	151.68%	126.71%	130.29%	132.13%	**145.41%**

Year

2013	2015	2017	2019	2021	2023
2014	**2016**	2018	2020	2022	2024

Monthly Average CPS1 Scores

Month/Hour	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	Total
Jan	154.34%	169.12%	168.16%	169.33%	157.35%	134.16%	138.60%	144.14%	125.34%	129.53%	142.27%	147.94%	144.60%	150.61%	156.37%	132.90%	98.44%	146.64%	166.04%	170.03%	155.92%	130.31%	126.99%	138.53%	145.74%
Feb	155.11%	164.09%	167.05%	169.20%	156.51%	139.33%	131.62%	136.53%	128.51%	132.14%	140.09%	149.65%	139.78%	122.54%	128.39%	117.48%	118.52%	116.73%	162.61%	171.42%	142.74%	143.04%	129.72%	133.12%	141.50%
Mar	146.26%	159.33%	164.93%	159.00%	144.02%	136.45%	140.80%	129.87%	130.40%	126.17%	127.04%	153.15%	146.68%	149.88%	138.57%	134.11%	119.57%	117.02%	128.48%	142.06%	144.75%	138.69%	132.32%	131.94%	139.23%
Apr	150.34%	160.13%	158.48%	161.71%	156.91%	143.93%	160.15%	135.92%	122.54%	142.76%	135.29%	153.19%	155.21%	154.46%	154.35%	146.55%	139.98%	127.53%	130.60%	141.36%	160.05%	137.37%	128.63%	113.47%	144.62%
May	144.73%	163.88%	160.23%	168.90%	155.59%	139.67%	139.62%	137.67%	145.05%	140.84%	147.23%	152.25%	156.86%	150.81%	149.92%	151.51%	141.29%	134.81%	130.63%	147.02%	155.03%	136.10%	132.20%	122.59%	146.02%
Jun	145.86%	151.38%	161.06%	172.20%	160.52%	110.66%	150.34%	146.92%	159.40%	157.92%	126.29%	163.00%	153.54%	152.68%	142.66%	148.28%	152.24%	144.63%	156.62%	160.30%	139.76%	145.64%	139.15%	123.30%	148.51%
Jul	140.62%	151.92%	162.32%	169.03%	149.96%	132.25%	132.63%	149.62%	136.40%	128.41%	139.13%	140.90%	142.45%	140.45%	152.79%	136.45%	151.48%	141.33%	155.53%	144.31%	138.45%	140.75%	111.61%	125.63%	142.27%
Aug	147.55%	155.43%	163.31%	158.11%	134.40%	128.97%	130.28%	143.73%	153.69%	156.87%	156.24%	128.04%	131.06%	130.52%	145.51%	133.97%	148.37%	152.24%	156.80%	132.01%	150.63%	118.32%	100.72%	115.63%	140.52%
Sep	136.73%	158.14%	162.97%	163.24%	151.93%	109.38%	138.94%	155.55%	120.11%	149.06%	130.04%	148.47%	152.65%	136.21%	141.85%	144.11%	123.48%	124.01%	133.73%	146.99%	127.59%	114.94%	126.15%	125.01%	138.39%
Oct	126.68%	153.70%	161.98%	161.45%	127.20%	100.82%	115.35%	128.74%	96.10%	142.22%	146.07%	155.37%	159.47%	153.42%	149.20%	141.53%	84.48%	115.03%	136.21%	135.36%	118.54%	117.49%	121.55%	121.37%	132.05%
Nov	141.19%	158.99%	156.81%	152.75%	131.30%	106.86%	144.24%	120.81%	142.26%	146.41%	149.87%	152.54%	125.45%	138.54%	123.11%	106.04%	96.09%	142.80%	155.10%	159.60%	147.44%	129.12%	124.62%	144.80%	137.36%
Dec	166.36%	172.53%	171.63%	156.09%	137.61%	123.82%	148.30%	136.95%	139.64%	152.82%	154.53%	160.29%	161.35%	166.68%	142.82%	77.90%	121.94%	158.46%	168.07%	170.46%	166.33%	142.37%	145.41%	153.11%	149.81%

Year

2013	2015	**2017**	2019	2021	2023
2014	2016	2018	2020	2022	2024

Monthly Average CPS1 Scores

Month/Hour	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	Total
Jan	165.40%	173.75%	165.22%	160.27%	138.20%	135.77%	146.45%	149.22%	137.99%	153.74%	164.96%	161.47%	164.45%	163.36%	147.78%	111.10%	112.66%	158.01%	168.18%	169.28%	148.54%	141.54%	141.64%	152.82%	151.33%
Feb	144.42%	161.90%	167.02%	163.56%	160.62%	141.60%	128.43%	133.06%	118.97%	143.57%	152.92%	161.62%	157.83%	140.47%	145.05%	136.59%	102.95%	109.67%	166.21%	159.96%	153.80%	138.12%	147.53%	140.98%	144.87%
Mar	155.23%	167.24%	153.32%	155.50%	131.60%	121.06%	141.48%	131.81%	115.33%	129.87%	146.13%	150.80%	148.89%	145.51%	134.93%	129.76%	102.64%	103.33%	125.33%	148.97%	154.57%	142.16%	141.55%	140.80%	138.24%
Apr	151.42%	160.89%	170.77%	168.34%	151.23%	136.26%	139.18%	131.98%	147.95%	143.22%	149.82%	154.30%	155.80%	147.68%	152.69%	142.68%	133.82%	110.59%	122.01%	159.90%	144.78%	123.29%	125.12%	130.18%	143.91%
May	151.99%	172.18%	166.72%	169.91%	162.82%	143.31%	146.75%	132.59%	151.85%	159.09%	150.54%	153.71%	157.53%	155.29%	153.02%	140.35%	132.76%	129.68%	107.55%	157.76%	156.72%	136.61%	132.59%	135.11%	148.18%
Jun	143.08%	167.27%	167.30%	174.49%	162.29%	159.82%	158.71%	154.71%	169.47%	158.53%	150.09%	155.51%	165.45%	154.04%	161.28%	150.69%	162.07%	160.42%	138.13%	158.32%	157.10%	158.37%	139.98%	144.16%	157.14%
Jul	151.15%	164.16%	166.24%	175.91%	158.78%	157.51%	161.29%	163.11%	150.58%	143.27%	133.21%	148.93%	151.54%	136.95%	153.54%	151.69%	155.17%	144.12%	163.22%	153.90%	146.41%	132.49%	114.00%	135.73%	150.54%
Aug	152.79%	163.22%	167.33%	167.28%	161.96%	142.41%	163.97%	143.75%	152.68%	147.25%	144.17%	136.56%	125.29%	144.33%	147.08%	145.40%	147.11%	149.93%	155.07%	142.30%	139.27%	131.61%	123.24%	131.89%	146.91%
Sep	146.93%	166.17%	166.60%	161.64%	146.92%	124.16%	149.71%	136.49%	144.37%	161.51%	141.04%	150.77%	153.05%	149.79%	154.62%	161.98%	144.58%	122.84%	134.45%	145.84%	131.30%	135.64%	140.64%	150.52%	146.73%
Oct	151.73%	171.30%	173.01%	171.72%	154.73%	135.88%	144.50%	132.35%	130.77%	152.56%	148.66%	153.92%	159.17%	155.15%	156.94%	136.52%	102.83%	108.38%	160.86%	143.94%	145.08%	146.63%	137.73%	148.66%	146.79%
Nov	154.31%	168.79%	171.57%	167.73%	159.50%	149.54%	149.80%	134.00%	151.07%	151.19%	160.93%	160.83%	148.03%	156.87%	131.42%	117.75%	133.00%	162.10%	162.88%	168.38%	158.99%	156.56%	157.55%	149.08%	153.41%
Dec	157.76%	166.13%	171.51%	168.36%	159.54%	152.95%	158.30%	142.76%	147.25%	150.25%	149.63%	159.73%	158.96%	160.20%	154.97%	106.08%	141.75%	170.57%	167.92%	164.86%	158.01%	152.67%	147.62%	151.48%	154.97%

Year

2013	2015	2017	2019	2021	2023
2014	2016	**2018**	2020	2022	2024

Monthly Average CPS1 Scores

Month/Hour	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	Total
Jan	165.40%	173.75%	165.22%	160.27%	138.20%	135.77%	146.45%	149.22%	137.99%	153.74%	164.96%	161.47%	164.45%	163.36%	147.78%	111.10%	112.66%	158.01%	168.18%	169.28%	148.54%	141.54%	141.64%	152.82%	**151.33%**
Feb	144.42%	161.90%	167.02%	163.56%	160.62%	141.60%	128.43%	133.06%	118.97%	143.57%	152.92%	161.62%	157.83%	140.47%	145.05%	136.59%	102.95%	109.67%	166.21%	159.96%	153.80%	138.12%	147.53%	140.98%	**144.87%**
Mar	155.23%	167.24%	153.32%	155.50%	131.60%	121.06%	141.48%	131.81%	115.33%	129.87%	146.13%	150.80%	148.89%	145.51%	134.93%	129.76%	102.64%	103.33%	125.33%	148.97%	154.57%	142.16%	141.55%	140.80%	**138.24%**
Apr	151.42%	160.89%	170.77%	168.34%	151.23%	136.26%	139.18%	131.98%	147.95%	143.22%	149.82%	154.30%	155.80%	147.68%	152.69%	142.68%	133.82%	110.59%	122.01%	159.90%	144.78%	123.29%	125.12%	130.18%	**143.91%**
May	151.99%	172.18%	166.72%	169.91%	162.82%	143.31%	146.75%	132.59%	151.85%	159.09%	150.54%	153.71%	157.53%	155.29%	153.02%	140.35%	132.76%	129.68%	107.55%	157.76%	156.72%	136.61%	132.59%	135.11%	**148.18%**
Jun	143.08%	167.27%	167.30%	174.49%	162.29%	159.82%	158.71%	154.71%	169.47%	158.53%	150.09%	155.51%	165.45%	154.04%	161.28%	150.69%	162.07%	160.42%	138.13%	158.32%	157.10%	158.37%	139.98%	144.16%	**157.14%**
Jul	151.15%	164.16%	166.24%	175.91%	158.78%	157.51%	161.29%	163.11%	150.58%	143.27%	133.21%	148.93%	151.54%	136.95%	153.54%	151.69%	155.17%	144.12%	163.22%	153.90%	146.41%	132.49%	114.00%	135.73%	**150.54%**
Aug	152.79%	163.22%	167.33%	167.28%	161.96%	142.41%	163.97%	143.75%	152.68%	147.25%	144.17%	136.56%	125.29%	144.33%	147.08%	145.40%	147.11%	149.93%	155.07%	142.30%	139.27%	131.61%	123.24%	131.89%	**146.91%**
Sep	146.93%	166.17%	166.60%	161.64%	146.92%	124.16%	149.71%	136.49%	144.37%	161.51%	141.04%	150.77%	153.05%	149.79%	154.62%	161.98%	144.58%	122.84%	134.45%	145.84%	131.30%	135.64%	140.64%	150.52%	**146.73%**
Oct	151.73%	171.30%	173.01%	171.72%	154.73%	135.88%	144.50%	132.35%	130.77%	152.56%	148.66%	153.92%	159.17%	155.15%	156.94%	136.52%	102.83%	108.38%	160.86%	143.94%	145.08%	146.63%	137.73%	148.66%	**146.79%**
Nov	154.31%	168.79%	171.57%	167.73%	159.50%	149.54%	149.80%	134.00%	151.07%	151.19%	160.93%	160.83%	148.03%	156.87%	131.42%	117.75%	133.00%	162.10%	162.88%	168.38%	158.99%	156.56%	157.55%	149.08%	**153.41%**
Dec	157.76%	166.13%	171.51%	168.36%	159.54%	152.95%	158.30%	142.76%	147.25%	150.25%	149.63%	159.73%	158.96%	160.20%	154.97%	106.08%	141.75%	170.57%	167.92%	164.86%	158.01%	152.67%	147.62%	151.48%	**154.97%**

Year

2013	2015	2017	2019	2021	2023
2014	2016	2018	2020	2022	2024

Monthly Average CPS1 Scores

Month/Hour	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	Total
Jan	169.66%	168.35%	174.66%	164.60%	158.78%	145.83%	146.67%	139.98%	141.08%	151.35%	151.77%	159.72%	164.48%	153.24%	152.28%	125.59%	129.85%	155.09%	171.25%	164.58%	165.77%	155.76%	153.14%	156.72%	**155.01%**
Feb	158.99%	173.98%	174.03%	171.65%	162.50%	157.26%	145.30%	129.16%	143.36%	143.09%	154.51%	146.06%	146.04%	145.53%	156.27%	143.14%	104.68%	142.25%	168.84%	175.54%	162.66%	151.15%	152.96%	149.81%	**152.45%**
Mar	157.42%	170.96%	164.93%	165.14%	160.67%	145.35%	152.07%	140.19%	121.50%	131.99%	141.71%	143.30%	147.81%	153.86%	158.06%	145.43%	125.06%	106.34%	125.43%	163.00%	165.46%	154.82%	154.88%	150.81%	**147.76%**
Apr	156.07%	164.41%	163.93%	172.34%	137.32%	138.95%	139.28%	129.00%	136.09%	145.94%	149.08%	145.34%	152.63%	143.96%	137.17%	128.05%	121.79%	109.41%	123.25%	165.98%	163.89%	143.03%	125.57%	141.38%	**143.08%**
May	155.47%	166.13%	168.08%	168.29%	153.67%	141.65%	152.21%	142.72%	151.07%	153.49%	154.93%	158.81%	153.03%	154.92%	153.48%	146.49%	145.31%	146.11%	139.38%	168.06%	157.70%	145.43%	138.09%	139.11%	**152.23%**
Jun	143.26%	161.12%	166.61%	170.94%	159.53%	138.13%	151.74%	156.47%	147.71%	160.23%	147.84%	156.22%	154.79%	159.38%	155.88%	149.37%	147.26%	147.80%	147.15%	153.28%	142.30%	151.41%	141.58%	135.85%	**151.91%**
Jul	147.07%	161.50%	169.77%	169.80%	160.59%	142.86%	156.66%	152.53%	156.63%	150.87%	138.70%	146.05%	153.78%	151.18%	152.84%	146.80%	155.77%	149.12%	148.28%	152.05%	153.63%	138.65%	144.87%	141.60%	**151.73%**
Aug	149.00%	164.83%	162.45%	165.39%	163.45%	131.78%	157.64%	150.79%	157.59%	162.76%	135.65%	138.80%	152.04%	159.69%	154.75%	153.71%	156.06%	152.23%	148.64%	121.92%	148.87%	135.85%	132.61%	146.65%	**150.13%**
Sep	143.84%	158.02%	152.99%	161.98%	154.48%	128.83%	154.12%	132.84%	142.40%	150.73%	143.71%	144.43%	145.22%	149.94%	140.73%	140.48%	138.36%	137.40%	147.82%	136.13%	139.76%	132.16%	135.77%	134.39%	**143.61%**
Oct	154.02%	163.50%	157.28%	163.21%	149.21%	124.97%	138.21%	124.64%	132.07%	140.93%	157.05%	155.63%	157.77%	149.01%	151.51%	137.29%	68.62%	98.71%	153.44%	158.71%	148.81%	149.07%	148.34%	155.87%	**143.24%**
Nov	160.31%	157.01%	167.33%	172.03%	153.43%	144.68%	146.81%	129.92%	147.93%	149.76%	146.99%	146.68%	151.18%	151.55%	130.06%	125.13%	156.50%	153.11%	154.93%	162.54%	158.12%	150.42%	153.62%	157.72%	**151.16%**
Dec	163.91%	170.75%	170.10%	163.11%	148.00%	145.79%	140.05%	135.64%	147.19%	155.76%	147.95%	142.60%	154.06%	145.37%	136.56%	106.81%	151.73%	159.30%	166.77%	168.65%	159.57%	158.07%	157.44%	153.23%	**152.02%**

Year

2013	2015	2017	2019	2021	2023
2014	2016	2018	2020	2022	2024

Monthly Average CPS1 Scores

Month/Hour	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	Total
Jan	169.79%	172.50%	172.46%	166.53%	152.00%	148.39%	150.67%	142.66%	138.06%	146.56%	150.90%	160.84%	151.74%	153.22%	138.10%	98.15%	128.78%	164.33%	171.72%	169.59%	158.28%	153.49%	155.77%	160.47%	153.13%
Feb	166.53%	177.90%	169.74%	169.51%	164.85%	155.28%	151.10%	132.09%	137.50%	150.09%	151.55%	156.32%	164.90%	158.67%	145.68%	119.67%	70.70%	150.91%	173.23%	165.27%	159.22%	154.03%	159.95%	156.97%	152.57%
Mar	162.99%	172.22%	163.23%	169.66%	165.13%	163.03%	160.13%	147.88%	135.74%	150.81%	144.97%	147.12%	137.42%	148.95%	137.03%	133.92%	117.11%	117.16%	150.22%	170.02%	162.13%	150.89%	159.11%	160.78%	151.15%
Apr	157.27%	159.81%	161.51%	169.64%	160.02%	168.43%	154.62%	138.93%	148.40%	151.34%	138.37%	130.98%	148.70%	149.81%	146.18%	137.03%	130.62%	112.24%	138.50%	159.81%	158.57%	153.92%	145.53%	141.93%	148.42%
May	157.38%	166.27%	168.34%	164.30%	164.69%	157.37%	151.77%	147.31%	146.69%	150.14%	136.03%	141.43%	152.23%	146.35%	146.18%	157.12%	147.51%	144.88%	144.71%	160.43%	160.48%	145.19%	140.32%	147.91%	151.88%
Jun	152.66%	165.11%	159.66%	167.81%	163.52%	146.26%	158.38%	153.67%	147.71%	148.69%	141.45%	141.19%	146.12%	153.70%	152.83%	146.83%	147.47%	148.25%	151.16%	151.79%	142.09%	149.47%	135.70%	128.64%	150.01%
Jul	156.94%	171.07%	173.68%	179.91%	166.86%	151.07%	162.71%	165.87%	153.66%	138.38%	137.06%	144.47%	158.28%	156.89%	156.16%	152.85%	151.36%	149.51%	151.74%	135.41%	142.20%	120.99%	128.04%	142.65%	151.99%
Aug	159.34%	158.39%	161.18%	170.41%	163.83%	150.82%	158.17%	153.68%	152.54%	139.80%	128.94%	142.22%	143.99%	143.84%	135.51%	145.55%	130.57%	151.01%	137.54%	121.24%	136.87%	136.27%	130.61%	149.46%	145.91%
Sep	142.82%	155.83%	155.99%	164.19%	148.34%	126.84%	160.19%	142.49%	148.77%	143.29%	146.92%	129.42%	150.20%	137.32%	132.53%	144.82%	142.75%	133.92%	119.21%	133.24%	127.44%	139.55%	138.91%	144.46%	142.06%
Oct	139.36%	154.36%	160.67%	158.06%	154.94%	145.35%	153.28%	132.42%	122.27%	133.54%	139.29%	136.52%	129.06%	135.43%	145.65%	152.20%	102.52%	133.44%	136.96%	138.29%	130.67%	148.00%	141.17%	134.20%	139.90%
Nov	164.20%	168.35%	167.56%	163.72%	154.36%	135.36%	148.31%	141.20%	151.84%	146.11%	148.41%	141.07%	146.75%	150.29%	142.00%	78.65%	146.63%	158.31%	155.71%	164.22%	158.83%	153.67%	149.68%	148.52%	149.32%
Dec	158.59%	164.99%	167.01%	167.55%	158.88%	141.31%	140.47%	144.92%	146.33%	156.53%	148.39%	143.66%	157.36%	154.95%	143.92%	83.95%	130.76%	173.28%	168.72%	164.35%	164.46%	153.64%	156.23%	155.75%	151.92%

Year

2013	2015	2017	2019	2021	2023
2014	2016	2018	**2020**	2022	2024

Monthly Average CPS1 Scores

Month/Hour	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	Total
Jan	171.27%	172.15%	168.63%	167.55%	161.94%	154.72%	135.61%	132.40%	147.24%	146.17%	157.85%	155.71%	151.72%	161.77%	137.58%	113.38%	115.02%	152.60%	172.81%	170.87%	172.41%	159.80%	156.62%	150.90%	**153.61%**
Feb	162.47%	162.47%	170.98%	166.40%	153.49%	146.89%	139.45%	135.22%	135.19%	140.15%	143.24%	147.50%	149.54%	146.16%	155.42%	125.95%	19.74%	134.23%	167.90%	163.97%	169.20%	157.64%	150.56%	152.10%	**145.66%**
Mar	161.70%	165.32%	165.64%	172.75%	148.68%	129.00%	140.39%	135.75%	125.27%	131.32%	149.60%	147.91%	154.99%	156.54%	146.70%	136.48%	89.83%	75.11%	126.68%	158.77%	163.06%	155.60%	140.50%	149.22%	**142.78%**
Apr	154.66%	162.48%	168.16%	169.75%	145.92%	145.07%	151.31%	127.40%	147.70%	141.06%	154.25%	153.26%	155.21%	158.84%	149.85%	139.49%	145.36%	85.05%	84.58%	154.08%	160.08%	153.74%	138.65%	144.66%	**145.44%**
May	161.09%	168.80%	171.43%	160.90%	164.38%	163.79%	148.81%	136.86%	155.57%	162.90%	159.97%	161.60%	151.91%	156.98%	153.96%	152.56%	150.19%	144.04%	132.55%	151.82%	156.51%	144.82%	138.29%	143.04%	**153.87%**
Jun	157.48%	162.86%	162.13%	168.74%	161.92%	145.45%	156.72%	154.48%	157.53%	162.90%	155.51%	154.19%	146.29%	148.82%	155.78%	148.75%	159.71%	152.56%	147.63%	151.64%	142.41%	152.07%	133.22%	145.19%	**153.50%**
Jul	155.30%	163.79%	166.99%	173.44%	168.41%	149.15%	161.66%	158.21%	164.49%	159.94%	158.99%	152.13%	153.22%	145.27%	156.60%	148.05%	149.44%	146.15%	161.00%	151.16%	144.54%	151.26%	136.78%	147.49%	**155.14%**
Aug	146.38%	166.56%	166.50%	173.32%	163.10%	142.06%	158.85%	158.67%	164.31%	160.25%	147.39%	150.91%	152.71%	154.18%	163.35%	150.47%	153.85%	148.25%	154.44%	150.64%	150.77%	140.39%	140.04%	142.96%	**154.18%**
Sep	153.76%	165.47%	165.41%	168.25%	160.27%	126.06%	143.95%	145.14%	134.35%	151.35%	152.00%	147.13%	142.47%	144.21%	149.76%	144.01%	137.20%	116.96%	155.76%	147.31%	156.13%	150.74%	151.19%	153.45%	**148.43%**
Oct	151.69%	164.37%	164.71%	158.53%	156.05%	134.58%	120.49%	133.76%	126.28%	139.41%	144.58%	156.87%	145.00%	144.66%	139.86%	118.17%	67.87%	117.20%	157.64%	156.63%	165.51%	155.73%	151.41%	154.30%	**142.72%**
Nov	164.85%	162.14%	163.50%	164.00%	151.82%	135.78%	130.36%	128.71%	147.25%	142.55%	155.98%	161.59%	154.53%	155.47%	112.07%	89.28%	148.95%	162.14%	165.68%	170.06%	167.55%	164.35%	163.45%	167.01%	**151.21%**
Dec	164.11%	172.10%	175.58%	176.12%	166.80%	149.36%	146.54%	149.69%	143.28%	147.03%	148.15%	148.14%	156.39%	154.42%	147.85%	117.53%	154.86%	168.57%	171.99%	172.72%	167.61%	164.04%	159.18%	160.53%	**157.61%**

Year

2013	2015	2017	2019	2021	2023
2014	2016	2018	2020	2022	2024

Monthly Average CPS1 Scores

Month/Hour	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	Total
Jan	171.79%	171.68%	176.55%	164.68%	157.49%	147.65%	144.06%	144.26%	135.46%	154.04%	157.08%	167.50%	162.36%	156.09%	154.70%	110.44%	133.77%	165.06%	172.34%	174.35%	175.43%	168.17%	160.61%	164.85%	157.93%
Feb	173.73%	178.92%	174.88%	172.82%	161.08%	150.54%	159.80%	127.64%	141.04%	147.54%	157.95%	166.47%	162.31%	160.55%	160.68%	116.51%	73.45%	153.42%	169.30%	173.33%	173.88%	172.48%	163.82%	167.39%	156.65%
Mar	164.78%	171.38%	171.87%	168.85%	158.93%	141.76%	142.31%	136.47%	132.29%	128.10%	138.83%	147.96%	152.70%	145.31%	147.78%	137.38%	88.03%	99.19%	148.99%	173.72%	172.24%	160.43%	159.58%	156.38%	147.72%
Apr	162.04%	167.82%	172.17%	166.51%	149.35%	140.28%	152.19%	113.25%	118.25%	147.10%	150.92%	154.68%	156.10%	154.13%	144.15%	136.90%	121.08%	79.55%	94.79%	154.66%	165.24%	160.06%	153.90%	163.11%	144.93%
May	162.21%	167.18%	170.33%	166.26%	156.04%	149.01%	142.71%	116.14%	148.52%	152.13%	153.31%	159.37%	147.35%	154.83%	155.77%	145.18%	138.57%	132.11%	110.49%	161.94%	160.87%	155.77%	149.12%	153.22%	150.35%
Jun	154.57%	163.62%	164.29%	164.29%	159.82%	152.20%	149.80%	151.33%	149.48%	160.10%	157.15%	151.35%	146.98%	153.01%	150.36%	151.93%	147.14%	148.60%	135.37%	151.18%	150.40%	155.76%	142.94%	136.86%	152.02%
Jul	152.88%	161.69%	174.91%	174.12%	170.03%	166.59%	168.29%	155.47%	164.91%	157.91%	165.37%	164.35%	166.75%	163.36%	161.19%	154.29%	152.36%	157.71%	152.43%	163.86%	145.41%	149.87%	153.44%	157.32%	160.60%
Aug	157.71%	160.94%	170.80%	174.00%	169.03%	164.82%	162.28%	160.42%	158.38%	161.56%	158.55%	157.91%	159.10%	155.01%	148.71%	149.99%	143.63%	146.48%	158.96%	143.72%	162.66%	148.07%	146.68%	153.65%	157.21%
Sep	147.55%	162.84%	159.83%	168.65%	159.12%	145.10%	152.65%	142.22%	158.31%	159.11%	142.83%	135.83%	143.81%	146.44%	141.37%	143.41%	136.94%	129.47%	152.49%	156.39%	144.03%	153.16%	151.44%	154.74%	149.49%
Oct	155.42%	161.82%	162.34%	165.39%	153.97%	137.24%	133.52%	117.50%	141.03%	154.09%	154.05%	154.48%	157.07%	148.13%	148.23%	137.23%	77.87%	134.95%	152.93%	159.89%	157.35%	150.82%	160.92%	149.66%	146.91%
Nov	167.66%	167.26%	168.06%	167.36%	140.79%	133.63%	146.25%	145.22%	140.54%	152.08%	153.07%	151.78%	149.19%	154.42%	147.03%	75.32%	120.67%	154.33%	162.54%	169.49%	167.81%	162.37%	156.52%	157.41%	150.45%
Dec	163.57%	174.62%	174.35%	173.55%	158.44%	151.49%	145.62%	148.81%	152.94%	161.37%	161.61%	167.77%	165.90%	162.42%	138.33%	121.04%	155.66%	172.22%	177.77%	170.12%	172.71%	165.95%	160.36%	161.74%	160.77%

Year

2013	2015	2017	2019	2021	2023
2014	2016	2018	2020	**2022**	2024

Monthly Average CPS1 Scores

Month/Hour	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	Total
Jan	160.21%	173.90%	173.05%	166.30%	152.16%	150.23%	147.23%	137.60%	145.72%	150.10%	158.90%	165.57%	160.26%	156.91%	151.28%	132.27%	132.78%	166.71%	175.64%	172.03%	173.02%	168.27%	157.26%	165.39%	158.03%
Feb	163.48%	172.71%	172.62%	170.96%	163.30%	159.81%	149.31%	129.46%	148.75%	163.47%	156.91%	156.90%	158.48%	155.39%	150.11%	107.79%	84.91%	157.60%	162.49%	169.40%	172.36%	161.27%	154.66%	160.93%	154.29%
Mar	169.45%	166.67%	167.17%	169.72%	153.89%	142.74%	140.95%	132.35%	131.20%	130.24%	139.20%	149.44%	141.40%	144.00%	139.43%	126.20%	102.30%	114.26%	139.29%	171.01%	167.51%	162.01%	157.21%	157.60%	146.47%
Apr	151.74%	161.53%	165.87%	164.50%	160.33%	148.22%	129.37%	106.67%	125.99%	141.90%	148.86%	145.37%	133.15%	137.84%	138.14%	130.19%	126.51%	70.08%	101.40%	157.03%	156.01%	150.78%	140.53%	138.36%	138.77%
May	154.12%	167.82%	168.80%	175.46%	169.22%	153.16%	146.41%	126.85%	154.30%	164.98%	155.01%	163.76%	158.07%	148.92%	143.32%	124.21%	123.52%	136.58%	123.20%	156.46%	170.20%	152.52%	147.99%	155.77%	151.69%
Jun	155.61%	165.26%	169.09%	171.43%	161.53%	161.56%	142.24%	129.73%	155.98%	161.39%	159.41%	156.62%	148.90%	152.31%	141.31%	153.67%	121.30%	119.11%	122.58%	147.64%	155.24%	159.70%	147.77%	148.00%	150.31%
Jul	142.73%	158.09%	166.43%	161.31%	158.45%	155.61%	148.77%	147.90%	152.68%	148.97%	155.98%	154.17%	149.65%	139.96%	145.57%	155.15%	139.60%	146.86%	136.73%	125.88%	122.18%	136.03%	140.70%	148.20%	147.40%
Aug	152.01%	155.63%	158.27%	169.13%	159.01%	155.91%	146.50%	150.64%	154.18%	151.56%	159.57%	157.47%	154.15%	150.16%	139.36%	130.34%	144.40%	139.55%	153.51%	137.99%	153.34%	142.85%	135.12%	149.56%	150.01%
Sep	143.59%	170.85%	167.08%	168.16%	167.65%	148.05%	139.45%	118.44%	131.27%	145.91%	156.87%	152.58%	138.82%	137.48%	137.37%	130.94%	108.91%	100.63%	138.04%	146.76%	158.34%	153.28%	143.13%	149.84%	143.89%
Oct	137.49%	147.20%	146.91%	133.87%	131.92%	89.40%	97.64%	122.94%	139.71%	122.64%	116.75%	126.62%	133.88%	128.11%	101.72%	92.33%	-24.28%	73.21%	152.05%	142.71%	130.82%	141.57%	148.64%	147.11%	120.04%
Nov	128.36%	142.38%	136.03%	139.57%	112.26%	93.50%	102.12%	133.18%	137.10%	139.93%	136.94%	145.28%	141.74%	127.48%	79.13%	21.64%	99.93%	141.97%	158.49%	146.74%	149.60%	159.50%	154.80%	158.58%	128.59%
Dec	145.34%	161.25%	157.07%	146.72%	136.33%	111.22%	109.20%	133.38%	141.13%	138.47%	135.13%	138.47%	134.25%	129.45%	72.79%	36.33%	110.65%	154.51%	157.75%	155.57%	149.84%	154.35%	153.64%	162.53%	134.39%

Year

2013	2015	2017	2019	2021	2023
2014	2016	2018	2020	2022	2024

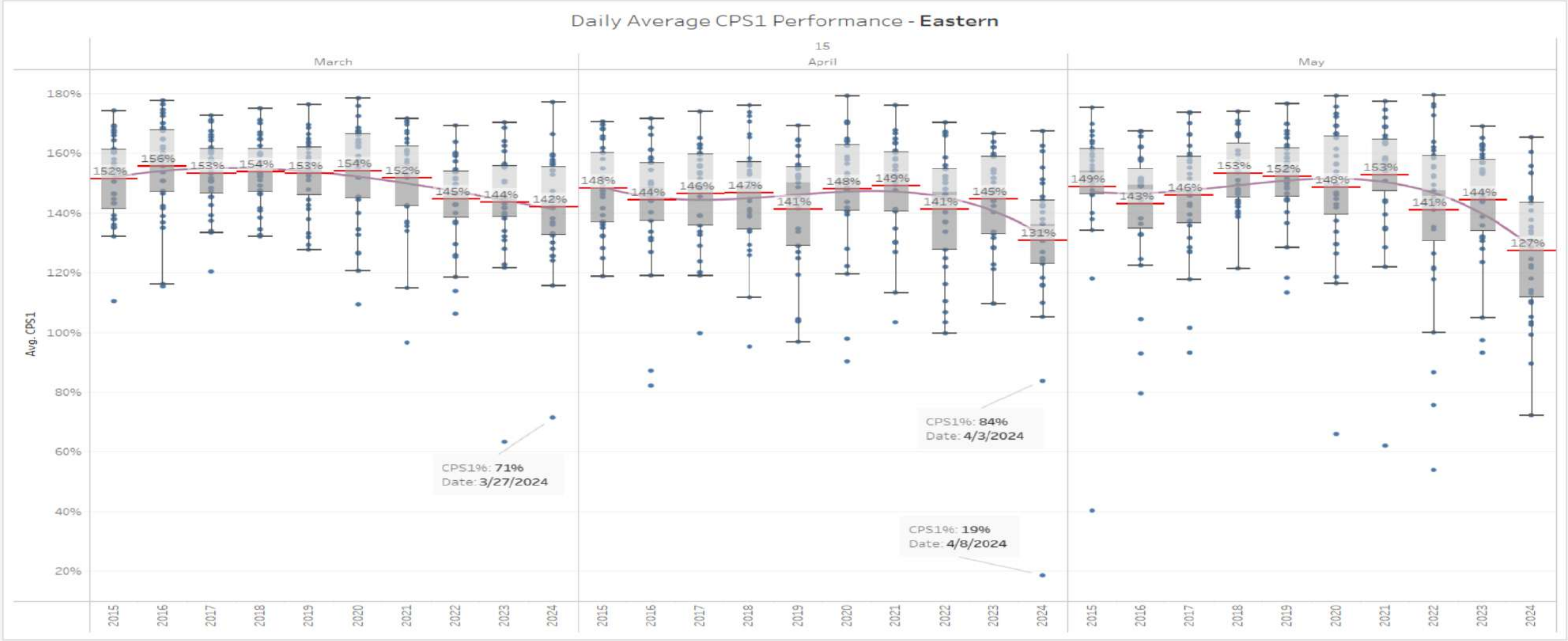
Monthly Average CPS1 Scores

Month/Hour	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	Total
Jan	159.81%	165.04%	164.30%	166.15%	158.24%	134.72%	149.13%	129.04%	139.76%	140.87%	146.55%	152.42%	150.66%	147.53%	138.53%	104.46%	142.77%	156.84%	170.78%	170.00%	167.78%	160.73%	156.38%	157.90%	**151.27%**
Feb	164.06%	165.29%	166.06%	169.37%	159.22%	153.65%	139.34%	139.50%	132.89%	131.96%	142.22%	140.60%	137.99%	135.79%	110.75%	91.45%	98.84%	156.78%	161.57%	165.02%	162.78%	157.08%	151.37%	154.40%	**145.33%**
Mar	165.08%	173.58%	172.22%	172.44%	163.86%	146.92%	144.28%	129.93%	141.75%	124.80%	136.51%	137.26%	125.90%	122.05%	124.24%	112.66%	86.85%	76.76%	133.63%	166.19%	169.10%	171.49%	163.20%	158.22%	**142.45%**
Apr	159.01%	155.09%	164.59%	154.81%	152.83%	147.42%	131.89%	121.39%	120.61%	129.12%	134.50%	129.16%	121.41%	134.25%	128.70%	117.39%	114.39%	55.23%	57.07%	139.38%	153.05%	154.29%	151.77%	147.11%	**132.27%**
May	147.04%	159.38%	159.99%	160.38%	149.41%	148.57%	121.37%	111.18%	128.17%	142.31%	137.62%	138.31%	130.60%	132.11%	124.81%	128.07%	107.62%	86.94%	52.08%	135.79%	158.62%	162.05%	148.93%	148.54%	**134.16%**
Jun	150.76%	162.52%	162.66%	155.61%	157.80%	144.96%	122.29%	118.68%	136.56%	144.22%	140.62%	146.32%	139.00%	132.22%	120.74%	132.67%	118.76%	128.07%	119.04%	147.70%	142.29%	149.97%	152.03%	146.40%	**140.50%**

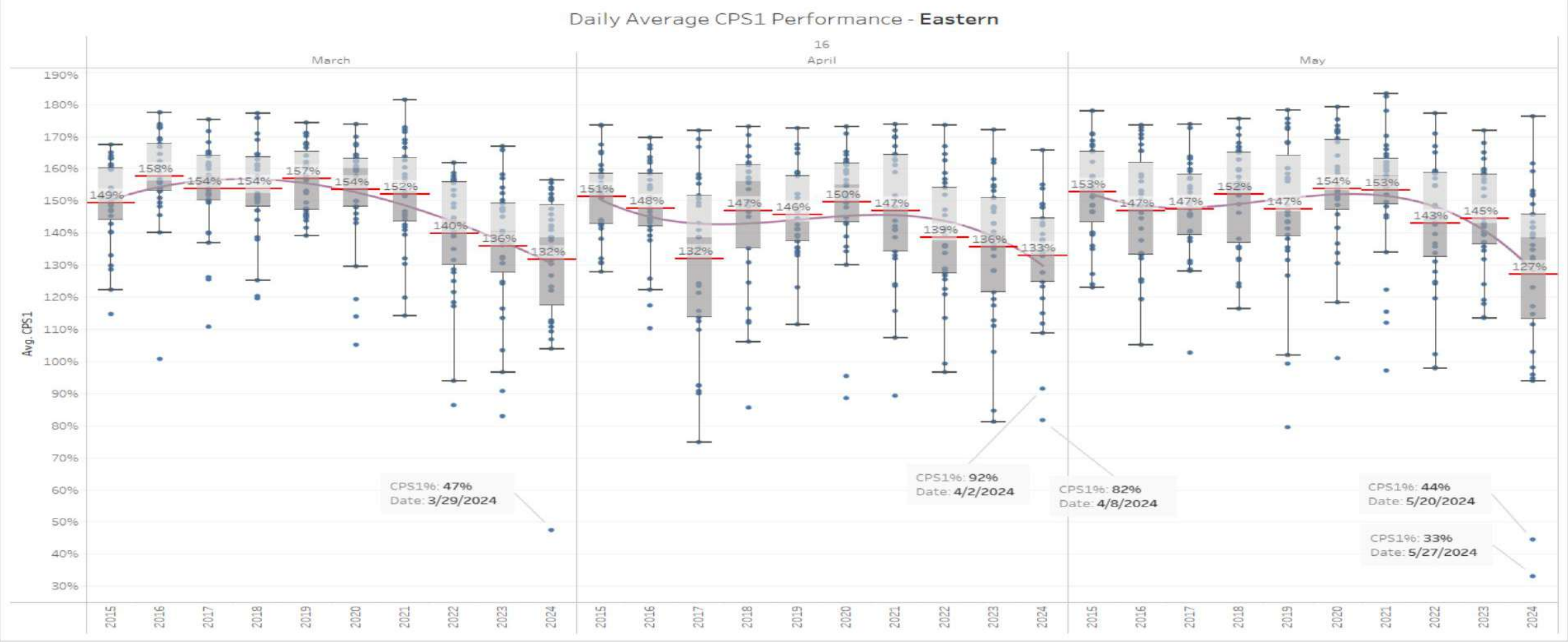
Year

2013	2015	2017	2019	2021	2023
2014	2016	2018	2020	2022	2024

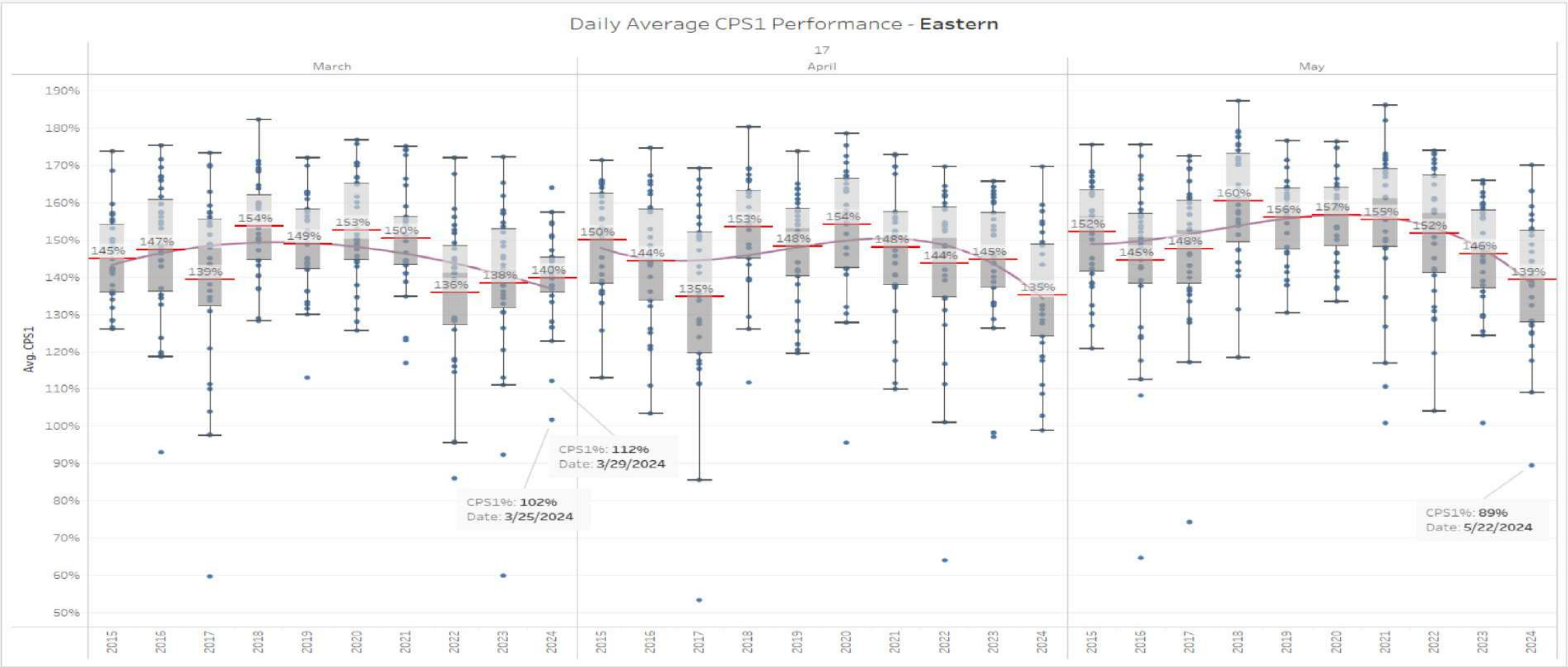
Impacts to the Eastern Interconnection



Impacts to the Eastern Interconnection

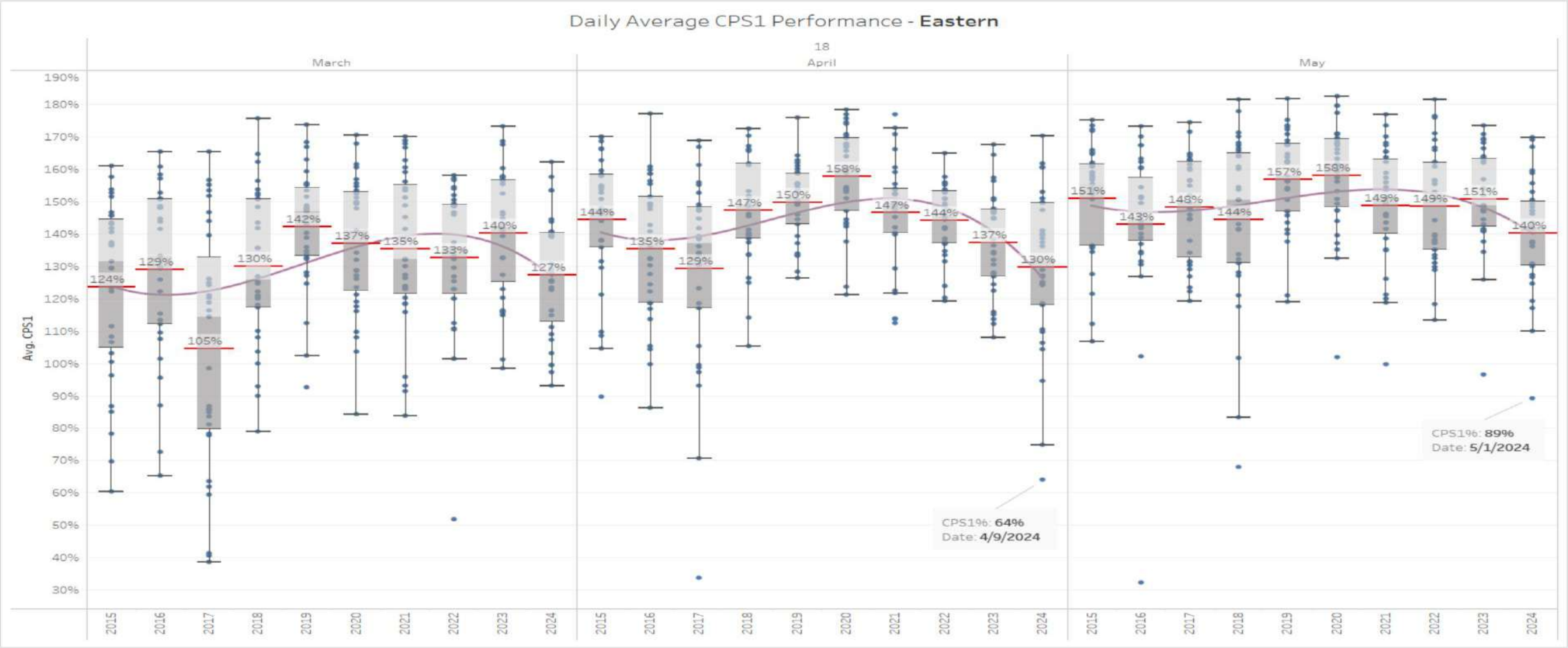


Impacts to the Eastern Interconnection



<Public>

Impacts to the Eastern Interconnection



<Public>

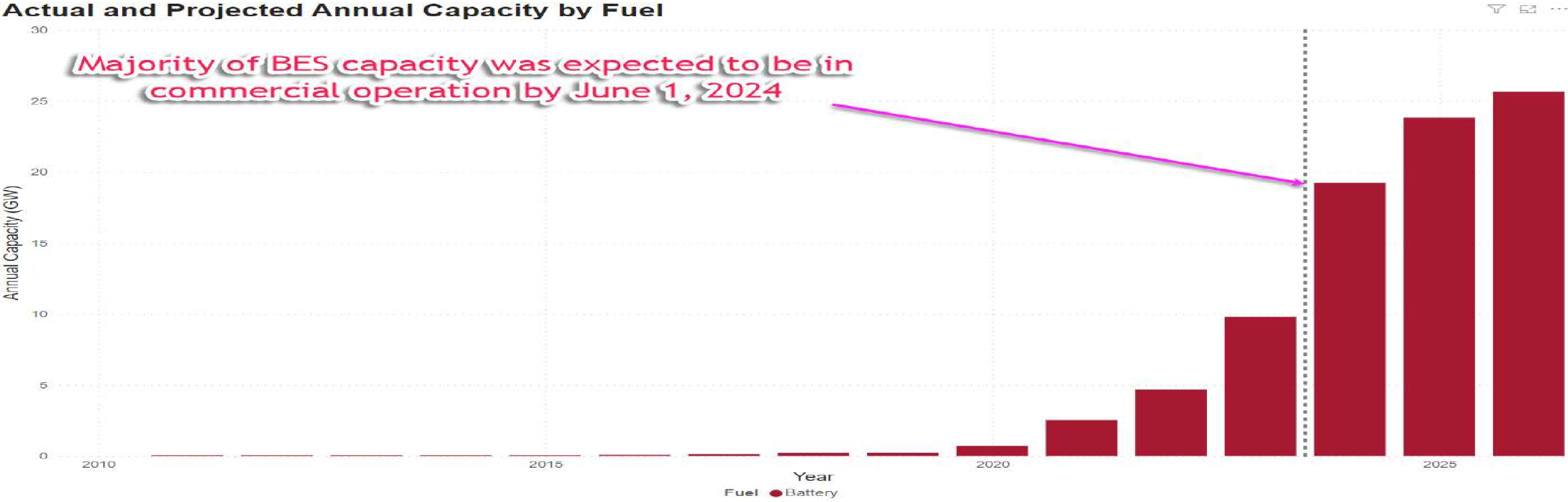
Big Machines Don’t Change Directions Fast

Next Steps

- WECC Performance Subcommittee will evaluate Primary Inadvertent data to determine which BA is the cause of the issue.
- Work with the CAISO and SPP to determine impacts of energy imbalance markets and their impact during these times of low frequency and large interconnection ramps.

Next Steps

- Work with BAs with BES to determine more accurately how these systems are impacting (or not) interconnection frequency.
- BES installed capacity was ~9800 MW on January 1, 2024, expected capacity by June 1, 2024 was over 19,000 MW



Next Steps

- NERC Resources Subcommittee will continue to monitor EI and WI CPS1 performance to identify trends in frequency control.

Next Steps

- WECC has received a State Estimator Snapshot from RC West for the hours in question
- WECC is evaluating the project to build a transmission planning case with the load and unit dispatch from the hour in question.
- WECC can perform analysis to determine if there is a reliability risk that is presenting itself during these periods of relatively low load and fast ramping of PV during solar ramp hours.

WECC

Electric Reliability and Security for the West

www.wecc.org

Interregional Transfer Capability Study (ITCS) Update

Action
Information

Background
Congress passed the Fiscal Responsibility Act of 2023, which included a provision for NERC to conduct a study on the reliable transfer of electric power between neighboring transmission planning areas. NERC, in consultation with the Regional Entities and industry stakeholders, will conduct transfer capability studies for regional transmission areas in the United States and recommend prudent additions to transfer capability needed for reliability.

Who: NERC, in consultation with each regional entity and each transmitting utility[1] in a neighboring transmission planning region.

What: A study of total transfer capability between transmission planning regions.[2] In accomplishing this work, the study should include:

1. "Current total transfer capability, between each pair of neighboring transmission planning regions."[3] [4]
2. "A recommendation of prudent additions to total transfer capability between each pair of neighboring transmission planning regions that would demonstrably strengthen reliability within and among such neighboring transmission planning regions"; and
3. "Recommendations to meet and maintain total transfer capability together with such recommended prudent additions to total transfer capability between each pair of neighboring transmission planning regions."

When: NERC must file the report with FERC within 18 months of enactment of the bill. Public comment period will occur when FERC publishes the study in the Federal Register. After submittal, FERC must provide a report to Congress within 12 months of closure of the public comment period with recommendations (if any) for statutory changes.

ERO study filing deadline: On or before December 2, 2024

---

[1] "means an entity (including an entity described in section 201(f)) that owns, operates, or controls facilities used for the transmission of electric energy—(A) in interstate commerce; (B) for the sale of electric energy at wholesale." [FPA, Section 3(23)]
[2] (a) IN GENERAL.—The Electric Reliability Organization (as that term is defined in section 215(a)(2) of the Federal Power Act), in consultation with each regional entity (as that term is defined in section 215(a)(7) of such Act) and each transmitting utility (as that term is defined in section 3(23) of such Act) that has facilities interconnected with a transmitting utility in a neighboring transmission planning region, shall conduct a study of total transfer capability as defined in section 37.6(b)(1)(vi) of title 18, Code of Federal Regulations, between transmission planning regions that contains the following:" [1-3 bullets quoted above]
[3] **Total transfer capability** means the amount of electric power that can be moved or transferred reliably from one area to another area of the interconnected transmission systems by way of all transmission lines (or paths) between those areas under specified system conditions, or such definition as contained in Commission-approved Reliability Standards. [18 C.F.R. Section 37.6(b)(1)(vi)]
[4] **Neighboring transmission planning region**: implicitly means facilities connecting two adjacent systems or control areas.

Key Activities

- Stakeholder Process
- The ERO Enterprise (NERC and the Regional Entities) developed a comprehensive stakeholder outreach plan to ensure that all North American transmitting utilities are able to provide input into the ITCS. Regional Entities are already working with their technical committees, which will continue throughout 2024. The study directive in Fiscal Responsibility Act requires that NERC perform the ITCS in consultation with all transmitting utilities that have facilities interconnected with a transmitting utility in a neighboring transmission planning region. In addition, a stakeholder Advisory Group meets monthly with the project team to review progress, provide comments on the report, provide input and guidance on the approach. The next Advisory Group meeting is scheduled for September 23, 2024.
- Part I Transfer Capability Analysis
- The project team has completed the transfer capability analysis. The analysis results have been reviewed by respective Planning Coordinators. The report is expected to be published by the end of August.
- Parts II and III Prudent Additions Analysis and Recommendations
- The prudent additions analysis entails utilizing the transfer capability analysis results from Part I, loads and resource projections for year 2033 and analyzing the system through 12 years of weather data. This analysis will provide insights into the regions expected to experience energy shortfalls vs. regions that may have surplus energy which will then inform the prudent addition to transfer capability recommendations. The model has been setup and is currently being fine tuned to run the analysis.
- Report Publication
- The final report will be filed with FERC on or before December 2, 2024. However, individual sections of the report will be published on NERC's ITCS website. A high level timeline is provided below:
    - Overview of Study Need and Approach (published in June 2024)
    - Part I, Transfer Capability Analysis (August 2024)
    - Parts II and III, Prudent Additions (November 2024)
    - Report filed with FERC (December 2024)
    - Canadian Analysis (Q1 2025)

Next Steps

The Advisory Group's next meeting is a WebEx scheduled for September 23, 2024. The Advisory Group's meeting schedule has been set throughout the lifecycle of the project.