Agenda
Reliability and Security Technical Committee

Conference Call

March 2, 2021 | 1:00–4:30 p.m. Eastern Time

Attendee Webex Link: Join Meeting

Call to Order

NERC Antitrust Compliance Guidelines and Public Announcement

Introductions and Chair's Remarks

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

Consent Agenda

2. **Minutes – Approve**
   a. December 15-16, 2020 RSTC Meeting*

Regular Agenda

3. **Remarks and Reports**
   a. Remarks – Greg Ford, RSTC Chair
      i. Subcommittee Reports*
   b. Report of February 4, 2021 Member Representatives Committee (MRC) Meeting and Board Meeting – Chair Ford
4. **Security and Reliability Training Working Group (SRTWG) Disposition - Approve –** David Zwergel, Vice Chair, RSTC

   The RSTC Executive Committee (EC) reviewed the draft scope and deliverables of the SRTWG and noted that much of the proposed scope involved work that is currently being done within other industry groups such as Regional Entities and Forums. The RSTC EC recommends disbanding the SRTWG.

5. **Performance Analysis Subcommittee (PAS) Scope* - Approve –** Brantley Tillis, PAS Chair

   The PAS revised their scope document as part of the RSTC transition planning activities. A redline is include in the agenda package. The PAS is seeking approval of the scope document.

6. **Event Analysis Subcommittee (EAS) Scope* - Approve – Vinit Gupta, EAS Chair**

   The EAS revised their scope document as part of the RSTC transition planning activities. A redline is include in the agenda package. The EAS is seeking approval of the scope document.

7. **Security Working Group (SWG) Draft Scope* - Approve – Brent Sessions, SWG Chair**

   The SWG was formed by the RSTC by expanding the scope of the Compliance Input Working Group. The SWG has developed a draft scope document to reflect its expanded scope. The SWG requests approval of the scope document.

8. **Energy Reliability Assessment Task Force (ERATF) Scope and Work Plan* - Approve –** Peter Brandien, ISO-NE

   At the December, 2020 RSTC meeting, information was presented regarding the NERC/IRC Whitepaper on Ensuring Energy Adequacy which made a number of recommendations for mitigating risks to energy adequacy. A small group of RSTC members and industry experts reviewed the issues and are recommending that the ERATF be formed to provide oversight and address the eleven issues identified in the report.

2:30 P.M. - BREAK – 10 MINS

9. **RSTC Work Plan* - Approve – David Zwergel, Vice Chair, RSTC**

   The RSTC subgroup work plans have been consolidated and updated into a single work plan. The RSTC Executive Committee (EC) is seeking approval of the work plan.

10. **Special Assessment: NERC Energy Management System Performance Special Assessment (2018–2019)* – Endorse –** Phil Hoffer, Chair EMSWG

    Loss of situational awareness is one of ten risks identified in the 2019 ERO Reliability Risk Priorities Report. Loss or degradation of situational awareness poses BPS challenges as it affects the ability of personnel or automatic control systems to perceive and anticipate degradation of system reliability and take pre-emptive action. To gain a better resolution on the contribution of EMS outages to the loss of situational awareness risk and the effect of EOP-004-4, the NERC EMSWG decided to conduct an assessment as an interim activity between recurring updates to its EMS reference document using 2018–2019 EMS events reported through the ERO EAP. This document includes assessments for three factors (outage duration, EMS functions, and entity reliability functions), examining associated trends, event root causes, and contributing causes identified through the ERO Cause Code Assignment Process (CCAP) for the 2018–2019 period.

11. **Geomagnetic Disturbance Research Work Plan Results and Recommendations – Approve to Disband GMDTF -** Emanuel Bernabeu, PJM, GMDTF Chair

    Over the period of 2018-2020, the Electric Power Research Institute (EPRI) has led a research program with industry and research partners to address objectives related to Reliability Standard TPL-007 (GMD Vulnerability Assessments). The research plan was developed by NERC with input from the GMDTF and NERC Planning Committee to address research directives in FERC Order No.

830. GMDTF leadership will inform the RSTC leadership of the research results summary and ERO recommendations. The Chair will make a formal request to disband the GMDTF as they have completed their work.

12. **Data Collections Technical Reference Document | Approaches for Probabilistic Assessments and 2020 Probabilistic Assessment | Regional Risk Scenario Sensitivity Case Report – Request RSTC Reviewers -** Andreas Klaube, NPCC, PAWG Chair

    The Data Collections Technical Reference document describes demand, resource, environmental, and system data as they can be applied to resource adequacy probabilistic studies, along with sources and processes for obtaining data. The document will benefit reliability by providing a reference of data practices for industry planners to draw from as probabilistic studies become increasingly important to studying the resource adequacy in many parts of North America (see Findings and Recommendations from NERC LTRA in 2020 and earlier). It complements the Probabilistic Adequacy and Measures Technical Report (approved by the PC in 2018) in promoting the use of sound probabilistic study practices. PAWG developed the document per the PAWG work plan and RAS endorsed the document in December 2020. Following review by RSTC members, PAWG and RAS will incorporate feedback and return the document to the RSTC for approval. Once approved, the PAWG will post the report on its website, encourage PAWG members to apply the concepts to future probabilistic assessments, and refer to the document in Reliability Assessments.

    The draft Regional Risk Scenario Sensitivity Case Report was prepared by the PAWG during the 2020 Probabilistic Assessment (ProbA) cycle with inputs from the six Regional Entities and 20 Assessment Areas. Assessment Areas developed tailored risk scenarios (e.g., ERCOT examined impacts of abnormally frequent low wind events) and assessed the effect that the scenarios would have on the probabilistic indices reported in the 2020 ProbA Base Case. This scenario analysis provides insights into area-specific reliability risk using probabilistic methods. Following review by RSTC members, PAWG and RAS will incorporate feedback and return the report to the RSTC for approval. RAS will review findings and consider them for addition to the 2021 Long-Term Reliability Assessment (LTRA).

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

*Background materials included.

Antitrust Compliance Guidelines

I. General

It is NERC's policy and practice to obey the antitrust laws and to avoid all conduct that unreasonably restrains competition. This policy requires the avoidance of any conduct that violates, or that might appear to violate, the antitrust laws. Among other things, the antitrust laws forbid any agreement between or among competitors regarding prices, availability of service, product design, terms of sale, division of markets, allocation of customers or any other activity that unreasonably restrains competition.

It is the responsibility of every NERC participant and employee who may in any way affect NERC's compliance with the antitrust laws to carry out this commitment.

Antitrust laws are complex and subject to court interpretation that can vary over time and from one court to another. The purpose of these guidelines is to alert NERC participants and employees to potential antitrust problems and to set forth policies to be followed with respect to activities that may involve antitrust considerations. In some instances, the NERC policy contained in these guidelines is stricter than the applicable antitrust laws. Any NERC participant or employee who is uncertain about the legal ramifications of a particular course of conduct or who has doubts or concerns about whether NERC's antitrust compliance policy is implicated in any situation should consult NERC's General Counsel immediately.

II. Prohibited Activities

Participants in NERC activities (including those of its committees and subgroups) should refrain from the following when acting in their capacity as participants in NERC activities (e.g., at NERC meetings, conference calls and in informal discussions):

- Discussions involving pricing information, especially margin (profit) and internal cost information and participants' expectations as to their future prices or internal costs.
- Discussions of a participant's marketing strategies.
- Discussions regarding how customers and geographical areas are to be divided among competitors.
- Discussions concerning the exclusion of competitors from markets.
- Discussions concerning boycotting or group refusals to deal with competitors, vendors or suppliers.

- Any other matters that do not clearly fall within these guidelines should be reviewed with NERC's General Counsel before being discussed.

III. Activities That Are Permitted

From time to time decisions or actions of NERC (including those of its committees and subgroups) may have a negative impact on particular entities and thus in that sense adversely impact competition. Decisions and actions by NERC (including its committees and subgroups) should only be undertaken for the purpose of promoting and maintaining the reliability and adequacy of the bulk power system. If you do not have a legitimate purpose consistent with this objective for discussing a matter, please refrain from discussing the matter during NERC meetings and in other NERC-related communications.

You should also ensure that NERC procedures, including those set forth in NERC's Certificate of Incorporation, Bylaws, and Rules of Procedure are followed in conducting NERC business.

In addition, all discussions in NERC meetings and other NERC-related communications should be within the scope of the mandate for or assignment to the particular NERC committee or subgroup, as well as within the scope of the published agenda for the meeting.

No decisions should be made nor any actions taken in NERC activities for the purpose of giving an industry participant or group of participants a competitive advantage over other participants. In particular, decisions with respect to setting, revising, or assessing compliance with NERC reliability standards should not be influenced by anti-competitive motivations.

Subject to the foregoing restrictions, participants in NERC activities may discuss:

- Reliability matters relating to the bulk power system, including operation and planning matters such as establishing or revising reliability standards, special operating procedures, operating transfer capabilities, and plans for new facilities.
- Matters relating to the impact of reliability standards for the bulk power system on electricity markets, and the impact of electricity market operations on the reliability of the bulk power system.
- Proposed filings or other communications with state or federal regulatory authorities or other governmental entities.
- Matters relating to the internal governance, management and operation of NERC, such as nominations for vacant committee positions, budgeting and assessments, and employment matters; and procedural matters such as planning and scheduling meetings.

RSTC Meetings – Governance Management

Chair will state the governance management of the meeting as follows:

- For each topic, the Chair will state the primary motion, ask for first/second, speaker will present, committee then has discussion.
- **At the conclusion of the discussion,** a secondary motion can be offered, the Chair will ask for first/second, discussion/debate; the Chair will then call for a vote.
- If the secondary motion does not receive a second or is voted down, the Chair will go back and restate the primary motion. At this point, the following actions may proceed:
    - Debate on that primary motion again;
    - Another secondary motion can be offered;
    - Motion could be offered to postpone, table, etc. Management of next action will follow the first two bullets.

The Chair is able to initiate a motion to end a debate.

Motions can encompass accepting minor revisions as provided during the discussions and reflected in the words of the motion.

Guiding principle is one thing at a time.

In all cases, a final report may be considered for approval, endorsement, or acceptance if the RSTC, as outlined above, decides to act sooner.

Possible Actions for other 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.

Draft Minutes
Reliability and Security Technical Committee

December 15-16, 2020

Webinar

A regular meeting of the NERC Reliability and Security Technical Committee (RSTC) was held on December 15-16, 2020, via webinar. The meeting presentations are posted in a separate file at RSTC presentations.

RSTC Chair Greg Ford convened the meeting at 1:00 p.m. Eastern on Tuesday, December 15, 2020 and led introductions of RSTC members, Observers and NERC Staff.

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

Meeting Highlights

1. The RSTC was presented information on the NERC/IRC Whitepaper on Ensuring Energy Adequacy. Volunteers are being sought to form a task force to address the issues raised in the whitepaper.
2. The committee accepted six Reliability Guidelines and Reference Documents to be posted for a 45-day comment period.
3. The RSTC approved scope documents for:
   a. Reliability Assessments Subcommittee (RAS)
   b. Probabilistic Assessments Working Group (PAWG)
   c. EMP Working Group (EMPWG)
   d. Supply Chain Working Group (SCWG) Scope
   e. Real Time Operating Subcommittee (RTOS)
   f. Inverter-based Resources Performance Working Group (IRPWG)
   g. Security Integration and Technology Enablement Subcommittee (SITES)
4. The RSTC endorsed the *Framework to Address Known and Emerging Reliability and Security Risk.*
5. The RSTC approved a scope revision of the Facility Ratings Task Force to form it as a joint CCC/RSTC task force and expand its membership to include RSTC members.

Introductions and Chair's Remarks

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

Chair Ford called on Nina Johnston to review the meeting governance guidelines which were included in the advance materials package.

Tina Buzzard reviewed the procedures for the meeting, reviewed the Antitrust Compliance Guidelines, and confirmed quorum, as well as provided an overview of the polling actions to be used for Committee actions during the meeting.

Consent Agenda

Chair Ford reviewed the Consent Agenda and asked RSTC members if they concurred with the items on it. Venona Greaff made a motion to approve the consent agenda. Upon motion duly made and seconded, the Committee approved the Consent Agenda.

Regular Agenda

Remarks and Reports

Chair Ford provided opening remarks noting highlights from the November MRC and Board meetings, and that the Subcommittee reports and RSTC Work Plan were included in the advance materials package. In addition, Chair Ford stated the Executive Committee received a raised concern regarding the number of documents to be posted for comments simultaneously, assuming the RSTC accepts all for posting. The Executive Committee agreed that they would review and prioritize the postings to mitigate the impact to the reviewers.

Reliability Guideline: Gas and Electrical Operational Coordination Considerations

Motion to accept posting the *Reliability Guideline: Gas and Electrical Operational Coordination Considerations* for a 45-day public comment period was made by Todd Lucas. Chair Pilong reminded the RSTC that the document was revised by the Real Time Operating Subcommittee and they coordinated with the Electric Gas Working Group which did not provide any comments. Upon motion duly made and seconded, the Committee accepted posting for a 45-day public comment period.

Battery Energy Storage Systems (BESS) and Hybrid Power Plant Modeling and Performance Guideline

Motion to accept posting the Battery Energy Storage Systems (BESS) and Hybrid Power Plant Modeling and Performance Guideline for a 45-day public comment period was made by Jody Green. Vice Chair Billo presented information on the document background and creation.

A concern was raised that the guideline referenced equipment not under NERC jurisdiction given there is no set registration requirement for BESS equipment. It was noted that the NERC Rules of Procedure are pretty clear in that we address BPS reliability issues, not just BES. Upon motion duly made and seconded, the Committee accepted posting for a 45-day public comment period.

Security Guideline for the Electricity Sector: Assessing and Reducing Risk

Motion to accept posting the *Security Guideline for the Electricity Sector: Assessing and Reducing Risk* for a 45-day public comment period was made by Venona Greaff.

Chair Sessions discussed the purpose of this Guideline is to help organizations determine their current security and compliance posture and develop an improvement plan for addressing any gaps that are identified. The tool for that analysis maps requirements of the CIP Reliability Standards to the National Institute of Standards and Technology (NIST) Cybersecurity Framework (hereafter referred to as “the framework”), and it can help a responsible entity identify areas that may require further action.

A suggestion was made to put language back in the Guideline template relating that guidelines are “non-binding norms” to be sure this isn’t viewed as a standard or something compliance related.

Upon motion duly made and seconded, the Committee accepted posting for a 45-day public comment period.

Resources Subcommittee (RS) Documents

Motion to accept posting the three documents to for a 45-day public comment period was made by Todd Lucas. Chair Greg Park reviewed the Reliability Guideline: ACE Diversity Interchange, the Reliability

DRAFT

Guideline: Operating Reserve Management, and the Balancing and Frequency Control Reference Document noting all three are a three-year review of an existing, posted document and that redlines were included in the advanced material package. Upon motion duly made and seconded, the Committee accepted posting for a 45-day public comment period.

Reliability Guideline: Generating Unit Winter Weather Readiness – Current Industry Practices – Version 3

Chair Gupta presented that the Event Analysis Subcommittee updated the Reliability Guideline and posted it for a 45-day comment period. The Subcommittee responded to the comments received and presented the final document to the RSTC for review and consideration. Upon motion duly made and seconded, the Committee accepted posting for a 45-day public comment period.

In advance of the review and consideration of the scope documents presented to the RSTC, Mr. Crutchfield reviewed the redline changes proposed by NERC Legal Staff. Mr. Crutchfield noted the two suggested additions for each scope document: 1) reference that the subgroup will develop or review reliability/security guidelines as assigned by the RSTC and also 2) a statement that the membership will consist “of members that bring an expertise to the group and the work being completed.”

Reliability Assessments Subcommittee (RAS) Scope and Probabilistic Assessments Working Group (PAWG) Scope

Chair De La Rosa presented the Reliability Assessments Subcommittee (RAS) Scope and Probabilistic Assessments Working Group (PAWG) Scope as presented in the advance materials package. Upon motion duly made and seconded, the Committee approved the RAS and PAWG scopes.

Supply Chain Working Group (SCWG) Guideline and Scope

Chair Eddleman presented the Supply Chain Working Group (SCWG) Guideline and Scope The Guideline for the Electricity Sector: Supply Chain Procurement Language was posted for a 45-day industry comment period and conforming revisions were made. The responses to comments received was included in the advance materials package. The Supply Chain Working Group Scope Document was revised as part of the RSTC transition planning activities. A redline was included in the advance materials package. Upon motion duly made and seconded, the Committee approved the guideline and scope as presented.

EMP Task Force (EMPTF) Scope and Work Plan

Chair Shaw presented the EMP Working Group (EMPWG) Scope and Work Plan. Mr. Brian Evans-Mongeon noted that the NERC Board approved the 15 recommendations of the EMP Initiative and the work scope/duration would likely exceed that of the definition of a task force, and recommended that it be created as a working group instead. Upon motion duly made and seconded, the Committee approved the scope and work plan as amended to a working group.

Real Time Operating Subcommittee (RTOS) Scope

Chair Pilong presented the Real Time Operating Subcommittee (RTOS) scope. Upon motion duly made and seconded, the Committee approved the scope.

GMD Data Collection Program Update

Ms. Donna Pratt presented on the GMD Data Collection Program noting that FERC Order No. 830 directed NERC to collect GMD data to "improve our collective understanding" of GMD risk. In response, NERC developed the GMD Data Request with GMD Task Force (GMDTF) and technical committee input and in August 2018, NERC Board approved Rules of Procedure Section 1600 data request for collecting GMD data. Ms. Pratt noted there are three types of data to be reported: GMD monitoring equipment (GIC Monitor, Magnetometer), GIC measurement data for designated GMD events, and Geomagnetic field measurement data for designated GMD events. Concluding, Ms. Pratt provided an implementation update noting data reporting training sessions were held in October and that as of mid-November, 125 registered entities have indicated that they meet the reporting criteria for GMD. In addition, there will be a system user training to be conducted in mid-2021.

Chair's Closing Remarks and Adjournment

Chair Ford noted that he believed with the new governance and voting polls the day seemed more orderly and efficient. In addition, he provided an overview of the next day's agenda which would encompass additional scope document reviews and a request from CCC for technical collaboration on the Facility Ratings Task Force.

The meeting was adjourned at 3:51 Eastern.

Wednesday, December 16, 2020

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

Chair Ford called on Nina Johnston to review the meeting governance guidelines which were included in the advance materials package.

Tina Buzzard reviewed the procedures for the meeting, reviewed the Antitrust Compliance Guidelines, and confirmed quorum, as well as provided an overview of the polling actions to be used for Committee actions during the meeting.

Inverter-based Resources Performance Working Group (IRPWG) Scope and Work Plan

Mr. Allen Schriver presented IRPWG scope and work plan. Mr. Schriver outlined the proposed changes to the scope and updates to the anticipated work products. Upon motion duly made and seconded, the Committee approved the scope.

Security Integration and Technology Enablement Subcommittee (SITES) Scope and Draft Work Plan* - Approve – David Zwergel, Chair SITES

Chair Zwergel presented the SITES scope and draft work plan outlining the process for updating the scope developing a preliminary work plan. The Committee agreed with the preliminary work plan and upon motion duly made and seconded, the Committee approved the scope.

Facility Ratings Collaboration: Compliance and Certification Committee (CCC) and Reliability and Security Technical Committee (RSTC)

Chair Flandermeyer presented on behalf of the CCC the recommendation that the Facility Ratings Task Force (FRTF) be expanded into a Joint Task Force to include members of both the CCC and the RSTC. It

DRAFT

was noted that the RSTC members would identify technical participants to provide technical expertise to address facility ratings concerns to support the goals of the FRTF. Chair Ford requested RSTC members submit technical participants recommendations to Stephen Crutchfield, as well as those wishing to serve on the task force should submit an email to Chair Ford and Vice Chair Zwergel. Upon motion duly made and seconded, the Committee approved expanding the FRTF into a Joint Task Force to include members of the CCC and the RSTC.

Framework to Address Known and Emerging Reliability and Security Risk – Endorse – Mark Lauby, Chief Engineer and Senior VP
Mr. Mark Lauby presented the Framework to Address Known and Emerging Reliability and Security Risk reviewing the process development with the RISC, and the RISC's acceptance of the Framework at their December meeting. In addition, Mr. Lauby reviewed the anticipated interaction between the RISC and the RSTC going forward to identify, prioritize and mitigate risk to the reliability, resilience and security of the grid. Upon motion duly made and seconded, the Committee endorsed the framework as presented.

Forum and Group Reports
NAGF
Mr. Schriver referenced the written report in the advance materials package and provided an update on recent and on-going NAGF activities.

NATF
Mr. Roman Carter referenced the written report in the advance materials package and provided an update on recent and on-going NATF activities.

Energy Storage System: Lessons Learned Defining Design
Mr. Anthony Natale presented on the lessons learned associated with the McMicken failure. Mr. Natale noted this incident drove many changes in design concepts that focused on managing the primary risk which is an explosion. To ensure success, utilities must work with their local fire departments to develop a response policy. This policy will serve as the training platform for the hazards and response tactics training associated with ESS emergencies. This coupled with semi-annual familiarization tours for the fire services sets the stage for success in managing these low frequency high hazard events.

NERC/IRC Whitepaper on Ensuring Energy Adequacy
Mr. Lauby and Mr. Peter Brandien briefed the RSTC on the NERC/IRC Whitepaper on Ensuring Energy Adequacy and the issues that were identified concerning energy adequacy in the operating, operations planning and mid-to-long term planning timeframes. Mr. Lauby stated they are seeking volunteers to work with them on where the identified work should be assigned within RSTC structure (e.g., IRPWG, SPIDERWG, etc.) and come back with a proposal in March. Chair Ford requested those wishing to volunteer should send an e-mail to Stephen Crutchfield.

RSTC 2020 Calendar Review
Stephen Crutchfield reviewed the calendar noting that the March meeting is confirmed virtual and would be from 1:00-4:00 p.m. Eastern on March 2 and 3. Mr. Crutchfield noted the remaining meeting dates will be determined based on the restrictions and guidance associated with the pandemic.

Chair's Closing Remarks and Other Matters
Chair Ford thanked everyone for their participation and mentioned the Reliability Leadership Summit on January 26-27, 2021.

Chair Ford asked if there were any other matters to be brought before the Committee and a question was raised concerning subgroup reports in Agenda item 3 going forward. Chair Ford stated that the written reports will always be in the agenda package and that the Executive Committee, during their review of the package in advance of the meetings, will determine if any items within the reports should be identified on the Regular Agenda.

Chair Ford wished everyone safe and happy holidays and there being no further business before the RSTC, Chair Ford adjourned the meeting at 4:00 p.m. Eastern.

Stephen Crutchfield
Stephen Crutchfield
Secretary

DRAFT

RSTC Status Report – Probabilistic Assessment Working Group (PAWG)

Chair: Andreas Klaube
Vice-Chair: Alex Crawford
March XX, 2021

- On Track
- Schedule at risk
- Milestone delayed

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

Items for RSTC Approval/Discussion:
- **Request for Review**: *Data Collection Approaches for Probabilistic Assessments Technical Reference Document*
- **Request for Review**: *2020 Probabilistic Assessment Scenario Case*

Recent Activity

- Presented draft of 2020 Probabilistic Assessment Scenario Case for RAS review.
- Began planning of 2021 Probabilistic Analysis Forum

Upcoming Activity

- *2020 Probabilistic Assessment Scenario Case* – Plan to request approval at June, 2021 RSTC meeting
- *Data Collection Approaches for Probabilistic Assessments Technical Reference Document* – Plan to request approval at June, 2021 RSTC meeting

Workplan Status *(6 month look-ahead)*

Milestone	Status	Comments
Data Collection Approaches for Probabilistic Assessments Technical Reference Document	On Track	Targeting Approval request in Q2 2021 RSTC Meeting
2020 Probabilistic Assessment Scenario Case	On Track	Targeting Approval request in Q2 2021 RSTC Meeting
2021 NERC Probabilistic Analysis Forum	On Track	In progress, planned Q2 2021 announcement

Internal Use Only

RSTC Status Report – Event Analysis Subcommittee (EAS)

Chair: Vinit Gupta
Vice-Chair: Ralph Rufrano
March 2,2021

On Track
Schedule at risk
Milestone delayed

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

Recent Activity

- The EAS has published 2 new lesson learned since the December 2020 RSTC meeting.
- Received RSTC approval for the revised Generating Unit Winter Weather Readiness Reliability Guideline.

Items for RSTC Approval/Discussion:

- **Approval**: EAS *Scope Document*
- ***Approval***: *2021 Work Plan*
- ***Endorsement:*** NERC Energy Management System Performance Special Assessment (2018–2019)

Upcoming Activity

- Webinar for the *NERC EMS Performance Special Assessment*
- 9th annual Monitoring and Situational Awareness Technical Conference.
- *Development of Lessons Learned*

Workplan Status *(6 month look-ahead)*

Milestone	Status	Comments
Pandemic Response lessons learned	On Track	EAS is coordinating development with RTOS .
EA Chapter of 2021 SOR	On Track	Coordinating development with PAS
	On Track	

Internal Use Only

EGWG Status Report

● On Track
● Schedule at risk
● Milestone delayed

Chair: Michelle Thiry
Vice-Chair: Mike Knowland
February 8, 2021

Purpose: The EGWG was formed to address fuel assurance issues as a result of the RISC identified Grid Transformation. Additionally the EGWG is developing metrics to gauge effectiveness of its recent Fuel Assurance Guideline

Items for RSTC Approval/Discussion:

- **Discuss**: Driving the EGWG toward developing design basis for TPL standards around natural gas and fuel assurance

Recent Activity

- Sub –groups of the EGWG have been convening to develop appropriate measurements and processes for determining fuel assurance guideline efficacy.

Upcoming Activity

- Meet as a larger group to discuss effectiveness measurement and to reach consensus on design basis for natural gas fuel assurance as it relates to transmission planning standards.

Workplan Status *(6 month look-ahead)*

Milestone	Status	Comments
2021 development of metrics to determine effectiveness of Fuel Assurance Guideline	● (green)	In progress
2021 – Gas/Electric guideline review, improvement and measurement	● (green)	In progress
2021 Design basis development	● (yellow)	Potential challenges in reaching consensus

Internal Use Only

RSTC Status Report – Electromagnetic Pulse Working Group (EMPWG)

On Track
Schedule at risk
Milestone delayed

Chair: Aaron Shaw
Vice-Chair: Rey Ramos
February 9th, 2021

Purpose: The purpose of the EMPWG is to address key points of interest related to system planning, risks and assessments, modeling, and reliability impacts to the bulk power system (BPS).

Items for RSTC Approval/Discussion:

- **N/A**

Recent Activity

- Solicitation of industry volunteers in EMPWG.

Upcoming Activity

- Formally establish EMPWG team structure by March 31st
- EMP Technical Workshop by end of Q2 2021

Workplan Status *(6 month look-ahead)*

Milestone	Status	Comments
Expand Membership	On Track	Industry solicitation was sent out on January 21, 2021
Establish Team Structure and Nominate Team leads	On Track	EMPWG Leadership is reviewing incoming nominations received by industry.

Internal Use Only

RSTC Status Report – Inverter-Based Resource Working Group (IRPWG)

Chair: Allen Schriver
Vice-Chair: Julia Matevosyan
February 9, 2021

- On Track
- Schedule at risk
- Milestone delayed

Purpose: IRPWG explores the performance characteristics of BPS-connected inverter-based resources and provides technical support to any analyses of disturbances involving these resources. IRPWG focuses on developing technical documents to support BPS planning and operations.

Items for RSTC Approval/Discussion:

- **Approve**: Reliability Guideline: Performance, Modeling, and Simulations of BPS-Connected Battery Energy Storage Systems and Hybrid Power Plants

Recent Activity

- Reliability Guideline: Recommended Improvements to Interconnection Requirements for BPS-Connected Inverter-Based Resources
- White Paper and SARs regarding Standards Modifications for BPS-Connected Inverter-Based Resources

Upcoming Activity

- Reliability Guideline: Electromagnetic Transient Modeling and Studies
- White Paper: BPS-Connected IBR and Hybrid Plant Capabilities for Frequency Response

Workplan Status *(6 month look-ahead)*

Milestone	Status	Comments
Reliability Guideline: Electromagnetic Transient Modeling and Studies	On Track (green)	On track.
White Paper: BPS-Connected IBR and Hybrid Plant Capabilities for Frequency Response	On Track (green)	On track.

Internal Use Only

RSTC Status Report – Load Modeling Working Group (LMWG)

Chair: Kannan Sreenivasachar,
Vice-Chair:

- On Track
- Schedule at risk
- Milestone delayed

Purpose:
The LMWG is transitioning utilities from the CLOD model to the CMLD Composite Load Model. The CLOD model lacks the capability to model events like FIDVR, which can have significant consequences on planning decisions.

Items for RSTC Approval/Discussion:

- **Approve**: LMWG *Work Plan*

Recent Activity

- Completed CMLD Phased Field Tests

Upcoming Activity

- *CMLD Field Test Survey Summary*
- *CMLD Field Test Report*

Workplan Status *(6 month look-ahead)*

Milestone	Status	Comments
Industry outreach - working with NERC MMWG on data management processes	Green (On Track)	In progress
Field Test Summary	Green (On Track)	In progress
Field Report		In progress
	Yellow (Schedule at risk)	

RSTC Status Report – Performance Analysis Subcommittee (PAS)

Chair: Brantley TIllis
Vice-Chair: David Penney
September 16, 2020

On Track
Schedule at risk
Milestone delayed
Not started

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:

- **Approve**: *PAS scope and work plan*

Recent Activity

- Revised scope

Upcoming Activity

- RSTC
  - June time frame
    - Accept State of Reliability Report
    - Endorse Section 1600 Data Request
- PAS
  - Accept revised Severity Risk Index (SRI) whitepaper
  - Review GADS wind analysis

Workplan Status *(6 month look-ahead)*

Milestone	Status	Comments
2021 State of Reliability Report	On Track	March - PAS kick off
Section 1600 Data Request	On Track	• NERC RoP GADS Section 1600 Data Reporting to collect and analyze conventional, wind and solar data.
Conduct annual metric review	Not started	2H 2021
Review proposed new metrics	Not started	2H 2021

Internal Use Only

RSTC Status Report – Resources Subcommittee (RS)

Chair: Greg Park
Vice-Chair: Rodney O'Bryant
March xx, 2021

On Track
Schedule at risk
Milestone delayed

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

Items for RSTC Approval/Discussion:

- **Approve**: None

Recent Activity

- Frequency Event selection along with minimum Frequency Bias settings updated in FRS Form 1, which includes collection of data needed by the ERO to determine the RLPC
- Continue to work on items to sunset the Inadvertent Interchange Working Group
- Endorse the BAL-003 SDT whitepaper prior to posting for industry comment

Upcoming Activity

- RS to review and integrate comments received for the following documents posted for industry review.
  - Operating Reserve Management Guideline
  - ACE Diversity Interchange Guideline
  - Integrating Reporting Ace with the NERC Reliability Guideline

Workplan Status *(6 month look-ahead)*

Milestone	Status	Comments
Review Frequency Bias Settings and L10 values	On Track	BAL-003-2 pushes out the implementation of Hz Bias changes to June of each OY
ACE Definition SAR	On Track	RS has approved SAR but delay filing due to SME availability for drafting team formation
RS M6 outreach to BAs indicating a year over year decline in performance.	On Track	RS leadership and regional representatives will be meeting with identified BAs during the upcoming quarter

RSTC Status Report – Supply Chain Working Group (SCWG)

Chair: Tony Eddleman
Vice-Chair: Charles Abell | February 9, 2021

On Track
Schedule at risk
Milestone delayed

Purpose: Enhancing Bulk Electric System (BES) reliability by implementing the goals and objectives of the RSTC Strategic Plan with respect to issues in the area of supply chain risk management.

Items for RSTC Approval/Discussion:

- **None**

Recent Activity

- Met virtually on January 11th and February 8th
- Reviewed NERC Alerts and DOE order
- SCWG agreed the Cyber Supply Chain Risk Management Practical Guide (December 2020) by LPPC, TAPS, APPA covered a task from NERC to do a Security Guideline on applying supply chain risk management plans to low impact BES Cyber Systems

Upcoming Activity

- Guidance documentation on supply chain risk management issues and topics
  - Identifying priority tasks
- Input and feedback associated with the development of supply chain documents to NERC staff
  - Monitor NIC Controller pilot project
- Monitor Software Bill of Materials (SBoM) Project by NTIA

Workplan Status *(6 month look-ahead)*

Milestone	Status	Comments
Guidance documentation on supply chain risk management issues and topics	On Track (green)	In progress
Input and feedback associated with the development of supply chain documents to NERC staff	On Track (green)	In progress

Work Look Ahead

- On Track
- Schedule at risk
- Milestone delayed

Workplan Status (6 month look-ahead)

Milestone	Status	Comments
C6 – NERC Reliability Standards Review	On Track	Initial draft underway and nearing completion. Requesting RSTC review in Q2 2021
C8 – White Paper FERC Order 2222 and BPS Reliability Perspectives	On Track	Initial draft in review by SPDIERWG. Targeting RSTC review in Q2 2021
M1 – DER Modeling Survey	On Track	Initial draft of white paper developed from survey findings. Targeting document review by RSTC in Q2 2021.
S4A – Reliability Guideline: Recommended Approaches for Developing Underfrequency Load Shedding Programs with Increasing DER Penetration.	On Track	Initial draft in review by SPIDERWG. Targeting RSTC request to post for industry comment in Q2 2021.
V2 - Reliability Guideline: DER Forecasting Practices and Relationship to DER Modeling for Reliability Studies	On Track	Initial draft in review by SPIDERWG. Targeting RSTC request to post for industry comment in Q2 2021.

Internal Use Only

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

On Track
Schedule at risk
Milestone delayed

Chair: Jeff Iler
Vice-Chair: Bill Crossland
March 2,2021

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:

- **Information**: SPCWG Review and Approval Process Document

Recent Activity

- Developing PRC-023-4 SAR
- Developing PRC- 019-2 CIG
- Commissioning Testing Lessons Learned Webinar
- IBR Impact on BPS Protection Technical Report

Upcoming Activity

- Revising Scope Document
- Developing 2021 Work plan
- Review roster to identify sector representatives, members, observers and verify contact information

Workplan Status *(6 month look-ahead)*

Milestone	Status	Comments
Revising Scope Document	On Track	On schedule
Developing 2021 Work plan	On Track	On schedule
	On Track	

RSTC Status Report – Security Working Group (SWG)

Chair: Brent Sessions
Vice-Chair: Vacant
March XX, 2021

On Track
Schedule at risk
Milestone delayed

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

Items for RSTC Approval/Discussion:
- **Approve**: SWG Scope Document and Work Plan (CY 2021-2022)

Recent Activity
- Completed 45-day comment period for Assessing and Reducing Risks Tool
- Received feedback from RSTC on Encryption in the Cloud Compliance Implementation. Meeting is scheduled for discussion with ERO.
- BCSI in the Cloud tabletop lessons learned received from ERO.
- New scoping document and work plan submitted for approval

Upcoming Activity
- Develop scope document
- Approval of work plans
- Complete BCSI in the Cloud tabletop lessons learned
- Complete Assessing and Reducing Risks tool
- Complete Encryption in the Cloud Compliance Implementation paper
- FERC CIP Lessons Learned research and determination of product needed
- CIP ERT commenting process
- SWG process/procedures
- External website set-up

Workplan Status *(6 month look-ahead)*

Milestone	Status	Comments
Update "Assess and Reducing Risks Tool" based on industry feedback	On Track	Due Q2 2021
Complete Encryption in the Cloud Compliance Implementation	On Track	Reviewing RSCT feedback and updating. Due Q2 2021
BCSI in the Cloud Tabletop Lessons Learned	On Track	Due Q1, 2021

Internal Use Only

RSTC Status Report – System Planning Impacts from Distributed Energy Resources (SPIDERWG)

On Track
Schedule at risk
Milestone delayed

Chair: Kun Zhu
Vice-Chair: Bill Quaintance
March 2, 2021

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

Items for RSTC Approval/Discussion:

- **Approval**: *SAR TPL-001-5.1 Transmission System Planning Performance Requirements*
- **Approval**: *Reliability Guideline: Model Verification of Aggregate DER Models used in Planning Studies.*

Workplan Status *(6 month look-ahead)*

See next slide

Recent Activity

- Many deliverables went for SPIDERWG review from the sub-group teams.
- Responded to industry comments from Q4 2020 commenting period.
- Developed SAR in accordance with approval of TPL-001 White Paper in Q4 2020.
- Met in February 2021 to update work products and refocus on high priority items.
- New sub-group leaders

Upcoming Activity

- *Many deliverables targeted for RSTC action in Q2 and Q3 of 2021. Currently consisting of:*
    - *Two White Papers for review/ approval*
    - *Two Reliability Guidelines to request posting for industry comment periods.*

Internal Use Only

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Work Look Ahead

- On Track
- Schedule at risk
- Milestone delayed

Workplan Status (6 month look-ahead)

Milestone	Status	Comments
C6 – NERC Reliability Standards Review	On Track	Initial draft underway and nearing completion. Requesting RSTC review in Q2 2021
C8 – White Paper FERC Order 2222 and BPS Reliability Perspectives	On Track	Initial draft in review by SPDIERWG. Targeting RSTC review in Q2 2021
M1 – DER Modeling Survey	On Track	Initial draft of white paper developed from survey findings. Targeting document review by RSTC in Q2 2021.
S4A – Reliability Guideline: Recommended Approaches for Developing Underfrequency Load Shedding Programs with Increasing DER Penetration.	On Track	Initial draft in review by SPIDERWG. Targeting RSTC request to post for industry comment in Q2 2021.
V2 - Reliability Guideline: DER Forecasting Practices and Relationship to DER Modeling for Reliability Studies	On Track	Initial draft in review by SPIDERWG. Targeting RSTC request to post for industry comment in Q2 2021.

Internal Use Only

RSTC Status Report – Real Time Operating Subcommittee (RTOS)

Chair: Chris Pilong
Vice-Chair: Jimmy Hartmann
March 2, 2021

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.

Items for RSTC Approval/Discussion:

Recent Activity

- *Posted Reliability Guideline Gas and Electrical Operational Coordination Considerations for comments*
- *Formed a GSE Task Force to work on updating Grid Security Emergency Communications documents*

Upcoming Activity

- Review comments for the Reliability Guideline Gas and Electrical Operational Coordination Considerations

Workplan Status *(6 month look-ahead)*

Milestone	Status	Comments
Monitor development of common tools and act as point of contact for EIDSN.	On Track (green)	In Progress
Frequency Monitor Reporting (Standing RTOS agenda item to discuss).	On Track (green)	In Progress
Reliability Guideline: Cyber Intrusion Guide for System Operators (Approved by the Operating Committee on June 5, 2018)	On Track (green)	In Progress

Internal Use Only

Security and Reliability Training Working Group (SRTWG) Disposition

Action
Approve

Summary
The RSTC Executive Committee (EC) reviewed the draft scope and deliverables of the SRTWG and noted that much of the proposed scope involved work that is currently being done within other industry groups such as Regional Entities and Forums. The RSTC EC recommends disbanding the SRTWG.

Performance Analysis Subcommittee (PAS) Scope and Work Plan

Action

Approve

Summary

The PAS revised their scope document as part of the RSTC transition planning activities. A redline is include in the agenda package. The PAS is seeking approval of the scope document.

Performance Analysis Subcommittee (PAS) Scope

Purpose

The Performance Analysis Subcommittee (PAS) will review, assess, and report on reliability of the North American Bulk Power System (BPS) based on historic performance, risk and measures of resilience. The key findings and recommendations will serve as technical input to NERC, FERC, and industry reliability activities[1]. The PAS will assess available performance metrics, develop any necessary guidelines and protocols for determining new metrics, and develop appropriate reliability performance benchmarks in support of the NERC Reliability Assessment and Performance Analysis[2] program.

Activities

1. Annually review, assess and report the state of reliability based on metric trends and technical analysis, and emerging issues. The results are provided to NERC's Reliability and Security Technical Committee (RSTC), Board of Trustees, and the public;
2. Develop and enhance performance metrics and indices that align with an Adequate Level of Reliability (ALR);
3. Develop methods to recognize the reliability risks to the industry and develop measurement methods to quantify those risks;
4. Develop methods to recognize the relationship between risks, standards, and performance including identification of data requirements;
5. Develop methods that will provide key performance indicators to a variety of audiences about the reliability of the bulk power system performance using metric information and trends;
6. Define data collection and reporting guidelines;
7. Publish periodic website updates, webinars, and high level assessments on bulk power system reliability performance;
8. Coordinate with the NERC RSTC, Standards Committee (SC), Reliability Issues Steering Committee (RISC), and other appropriate groups to provide an integrated view of reliability performance.
9. Request user groups, as required, to support analysis and work products; provide direction to and prioritize areas of investigation by the user groups.

---

[1] For example, NERC's Reliability Standards and project prioritization, compliance process improvement, event analysis, reliability assessment, Reliability Issues Steering Committee and critical infrastructure protection.

[2] Defined in Section 809 of the NERC Rules of Procedure, available at http://www.nerc.com/FilingsOrders/us/RulesofProcedureDL/NERC_RoP_EFFECTIVE_20160504.pdf

User Groups

User groups that support the PAS may include, and are not limited to, the following:

1. Generating Availability Data System User Group (GADSUG)
2. Transmission Availability Data System User Group (TADSUG)
3. Demand Response Availability Data System User Group (DADSUG)
4. Misoperations Information Data Analysis System User Group (MIDASUG)*

Deliverables

On an annual basis, PAS will develop a report summarizing the reliability performance of the BPS for the industry. This report will also identify any areas of potential reliability risks for further analysis.

Annually, PAS will review the set of approved performance metrics, consider changes to standards, guidelines and other recent changes in the industry to propose development of additional metrics and retirement or modifications to improve existing metrics or indices as needed.

On a special request basis, PAS may have responsibility for investigating specific reliability risks to the industry. These requests may originate from NERC or RSTC. Studies may result in additional metrics or indices.

Membership

The subcommittee is comprised of the following:

- Chair
- Vice chair
- At least two representatives to represent an operations perspective of BPS performance
- At least one member-at-large representing Canada
- User group chairs or designee
- Industry experts in the areas of performance metrics, benchmarking, and risk analysis
- NERC staff coordinator(s)
- Additional members may be added at the request of PAS

The PAS chair and vice chair are nominated by the PAS membership and appointed by the chair of the NERC Planning Committee for one two-year term. The vice chair should be available to succeed to the chair.

Order of Business

In general, the desired, normal tone of PAS business is to strive to develop technically sound solutions using constructive methods that achieve consensus. In situations where the desired outcome does not reach consensus, the PAS will defer to a vote by the RSTC, providing recommendations and consequences for each alternative.

In like manner, observers and NERC staff is expected to adhere to similar approaches, including the requirement to strive for constructive technically sound solutions, building consensus, as well as documenting alternatives and consequences.

Reporting

The subcommittee is responsible to the RSTC for the completion of work associated with the scope items outlined above, and as necessary, the RSTC and the Board of Trustees approve final work products of the PAS. The subcommittee chair will periodically apprise the RSTC on the subcommittee's activities, assignments, analysis results, and recommendations.

Meetings

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

Approved by the NERC RSTC: *Date*

**Addition of MIDASWG under Performance Analysis Subcommittee approved June 5, 2018*

Prior draft is located in the August meeting material folder, https://extranet.nerc.net/PAS/Shared%20Documents/Meeting%20material/2020-08/Item%201.%20PAS%20Scope%202020%20Draft.docx

Performance Analysis Subcommittee (PAS) Scope

Purpose

The Performance Analysis Subcommittee (PAS) will review, assess, and report ~~the state of~~on reliability of the North American Bulk Power System (BPS) based on historic performance, risk and measures of resilience. The key findings and recommendations will serve as technical input to NERC, FERC, and industry reliability activities[1]. The PAS will assess available performance metrics, develop any necessary guidelines and protocols for determining new metrics, and develop appropriate reliability performance benchmarks in support of the NERC Reliability Assessment and Performance Analysis[2] program.

Activities

1. Annually review, assess and report the state of reliability based on metric trends and technical analysis, and emerging issues. The results are provided to NERC's ~~Planning~~Reliability and Security Technical Committee~~, Operating Committee,~~ (RSTC), Board of Trustees, and the public;
2. Develop and enhance performance metrics and indices that align with an Adequate Level of Reliability (ALR);
3. ~~Devise~~Develop methods to recognize the reliability risks to the industry and develop measurement methods to quantify those risks;
4. Develop methods to recognize the relationship between risks, standards, and performance including identification of data requirements;
5. Develop methods that will provide key performance indicators to a variety of audiences about the reliability of the bulk power system performance using metric information and trends;
6. Define data collection and reporting guidelines;
7. Publish periodic website updates, webinars, and high level assessments on bulk power system reliability performance;
8. Coordinate with the NERC ~~Critical Infrastructure Protection Committee (CIPC),~~RSTC, Standards Committee (SC), ~~Compliance and Certification Committee (CCC),~~ Reliability Issues Steering Committee (RISC), ~~Operating Committee (OC),~~ and other appropriate groups to provide an integrated view of reliability performance.
9. ~~Establish working~~Request user groups, as required, to support analysis and work products; provide direction to and prioritize areas of investigation by the ~~working~~user groups.

[1] For example, NERC's Reliability Standards and project prioritization, compliance process improvement, event analysis, reliability assessment, Reliability Issues Steering Committee and critical infrastructure protection.
[2] Defined in Section 809 of the NERC Rules of Procedure, available at http://www.nerc.com/FilingsOrders/us/RulesofProcedureDL/NERC_RoP_EFFECTIVE_20160504.pdf

Formatted: Footer

~~Working~~User Groups

~~Working~~User groups that support the PAS may include, and are not limited to, the following:

1. Generating Availability Data System ~~Working~~User Group (~~GADSWG~~GADSUG)
2. Transmission Availability Data System ~~Working~~User Group (~~TADSWG~~TADSUG)
3. Demand Response Availability Data System ~~Working~~User Group (~~DADSWG~~DADSUG)
4. Misoperations Information Data Analysis System ~~Working~~User Group (~~MIDASWG~~MIDASUG)*

Deliverables

On an annual basis, PAS will develop a report ~~which summarizes~~summarizing the reliability performance of the BPS for the industry. ~~Also, this~~This report will also identify any areas of potential reliability risks for further analysis.

Annually, PAS will review the set of approved performance metrics, consider changes to standards, guidelines and other recent changes in the industry to propose development of additional metrics and retirement or modifications to improve existing metrics or indices as needed.

On a special request basis, PAS may ~~be assigned~~have responsibility for investigating specific reliability risks to the industry. These requests may originate from NERC~~, the OC~~ or ~~PC~~RSTC. Studies may result in additional metrics or indices.

Membership

The subcommittee is comprised of the following:

- Chair
- Vice chair
- At least two representatives to represent an operations perspective of BPS performance
- At least one member-at-large representing Canada
- ~~PAS working~~User group chairs or designee
- Industry experts in the areas of performance metrics, benchmarking, and risk analysis
- NERC staff coordinator(s)
- Additional members may be added at the request of PAS

The PAS chair and vice chair are nominated by the PAS membership and appointed by the chair of the NERC Planning Committee for one two-year term. The vice chair should be available to succeed to the chair.

Order of Business

In general, the desired, normal tone of PAS business is to strive to develop technically sound solutions using constructive methods that achieve ~~general~~ consensus. In situations where the desired outcome does not reach consensus, the PAS will defer to a vote by the ~~Planning Committee~~RSTC, providing recommendations and consequences for each alternative.

In like manner, observers and NERC staff ~~are~~is expected to adhere to similar approaches, including the requirement to strive for constructive technically sound solutions, building consensus, as well as documenting alternatives and consequences.

Reporting

The subcommittee is responsible to the ~~Planning Committee~~RSTC for the completion of work associated with the scope items outlined above, and ~~final work products of the PAS will be approved~~ as necessary ~~by,~~ the ~~Planning Committee~~RSTC and the Board of Trustees~~.~~ approve final work products of the PAS. The subcommittee chair will periodically apprise the ~~Operating Committee~~RSTC on the subcommittee's activities, assignments, analysis results, and recommendations.

Meetings

~~Four to six meetings per year, or~~Meetings occur as needed. The meetings are open and encourage participation by observers. Observers may include participants from the Federal Energy Regulatory Commission, the United States Department of Energy and the National Energy Board, Canada.

Approved by the NERC ~~Planning Committee: March 7, 2017~~RSTC: Date

Formatted: Indent: Left: 0.75"

**Addition of MIDASWG under Performance Analysis Subcommittee approved June 5, 2018*

Prior draft is located in the August meeting material folder, https://extranet.nerc.net/PAS/Shared%20Documents/Meeting%20material/2020-08/Item%201.%20PAS%20Scope%202020%20Draft.docx

Formatted: Indent: Left: 0"

Event Analysis Subcommittee (EAS) Scope

Action
Approve

Summary
The EAS revised their scope document as part of the RSTC transition planning activities. A redline is include in the agenda package. The EAS is seeking approval of the scope document.

Event Analysis Subcommittee Scope

Purpose

The Event Analysis Subcommittee (EAS) assists the NERC Reliability and Security Technical Committee (RSTC) in enhancing Bulk Electric System (BES) reliability by implementing the goals and objectives of the RSTC Strategic Plan.

The EAS is a cross-functional group of industry experts that will support and maintain a cohesive and coordinated event analysis (EA) process across North America with industry stakeholders. The EAS will support development of lessons learned, promote industry-wide sharing of event causal factors, and assist NERC in implementation of related initiatives to lessen reliability risks to the BES.

Functions

1. The EAS, in coordination with NERC Staff, will:
   a. Manage Event Analysis Process document updates and annual review.
   b. Manage and coordinate the development and publishing of Lessons Learned.
   c. Identify improvements to event analysis reporting.
   d. Provide feedback to industry on Event Analysis Process topics.
   e. Solicit feedback from industry stakeholders to improve the Event Analysis Process.
2. To facilitate the sharing of EA information with the NERC RSTC and its subcommittees/working groups, the EAS will:
   a. Facilitate registered entity event analysis presentations at RSTC meetings.
   b. Provide status of and direction on implementation of Lessons Learned.
   c. Provide trending updates as needed.
3. The EAS, in coordination with NERC subcommittees and working groups, will share information, identify trends through analysis of events, and make recommendations to the industry which address:
   a. Reliability risks
   b. Human performance
   c. Need for training
   d. Lessons Learned
   e. Good industry practices and recommendations
4. The EAS will partner with Regional Entities, registered entities and other industry forums to:
   a. Obtain input of Regional Entity personnel and reliability stakeholder groups as resources to the EAS, leveraging their experience and knowledge.
   b. Address reliability issues and trends from reported events.

c. Based on Lessons Learned and trends drawn from events, recommend enhancement to existing Reliability Standards or development of new Reliability Guidelines or Reliability Standards where gaps are identified.

d. Annually survey the Regional Entities to assess the value of published Lessons Learned.

Deliverables

- Conduct an annual review of the Event Analysis Process document.
- Recommend need for training in coordination with Security and Reliability Training Working Group (SRTWG)
- Publish Lessons Learned
- Develop and review of Reliability Guidelines as directed by the RSTC
- Identify significant risk and the need for NERC Alerts
- Provide updates to the RSTC as needed.
- Provide input to the NERC Performance Analysis Subcommittee's (PAS) annual State of Reliability Report
- Provide event information and recommendations related to the Event Analysis Process

Reporting

The EAS reports to the RSTC, and shall maintain communications with the RSTC, EAS Sponsor, and other groups as necessary on relevant issues. The EAS will regularly submit a work plan for approval of tasks. The EAS will review its scope and work plan regularly.

All work products (with the exception of Lessons Learned and Failure Modes & Mechanisms) intended for industry use (such as a Scope document, Work Plans, Reliability Guidelines, Reference Documents, Compliance Implementation Guidance, reports, whitepapers, etc.) should be approved by the RSTC.

The EAS will report to the RSTC for the completion of work associated with the scope items outlined above, and final work products of the EAS will be reviewed and considered by the RSTC and or the NERC Board of Trustees. The EAS chair will periodically apprise the RSTC on the subcommittee's activities, assignments, and recommendations.

Officers

The RSTC Chair appoints the EAS officers (Chair and Vice Chair) for a specific term (generally two-years). The subcommittee officers may be reappointed for additional terms. The vice chair is considered an important part of succession planning with the anticipation that the vice chair will be appointed as subcommittee chair for the next term. The EAS may recommend officer candidates for the RSTC Chair's consideration following a supporting motion.

The subcommittee Chair or Vice chair should attend the regular RSTC meetings to report on assignments, or provide a summary report of the group's activities, and advise the RSTC on important issues at as needed.

The EAS officers are considered members of the EAS and may vote.

Membership

The voting members of the EAS will consist of:

- One (1) voting member from each of the Regional Entities, approved by the RSTC.
- One (1) voting member from each of the Regions to represent industry stakeholder interests. Members may be recommended by the EAS and will be approved by the RSTC.
    - These members must have a signed Non-Disclosure Agreement on file in order to participate in the confidential sessions described below.

Meeting Procedures

The desire is to strive for consensus in normal EAS business. If consensus cannot be achieved, the EAS will hold a vote as noted below. If any strong minority opinions develop, those opinions may be documented as desired by the minority and forwarded to the RSTC Chair for future meeting consideration.

- Quorum: 50 percent of subcommittee members eligible to vote.
- Actions requiring a vote shall require a quorum and a simple majority vote of those members present.
- All other procedures follow those of the of the RSTC Charter and Standard Operating Procedure.

Confidential Sessions

The chair of the subcommittee may limit attendance at a meeting or portion of a meeting, based on confidentiality of the information to be disclosed at the meeting. Such limitations should be applied sparingly and on a non-discriminatory basis as needed to protect information that is sensitive to one or more parties.

Subgroups

The EAS may form working groups and task forces as needed to assist the subcommittee in carrying out standing or ad hoc assignments. Task group chairs (or delegates) are expected to attend the regular subcommittee meetings to report on assignments or provide a summary report of the group's activities.

Meetings

Four to six open meetings per year, or as needed, with supplemental telephone conferences.

Version #	Date	Reviewers/Approval	Revision Description
1.0	6/19/2013	Developed by: Event Analysis Working Group Approved by OC: September 10, 2013	Transitioned the EAWG into the EAS.
1.1	6/10/2013	Developed by: Event Analysis Subcommittee Approved by OC: December 10 2013	Updated EAS Scope to reflect changes in the OC Strategic Plan.
1.2	6/4/2018	Developed by: Event Analysis Subcommittee Approved by OC: September 11, 2018	Updated EAS Scope to reflect seven NERC Regions due to the dissolution of SPP RE.
1.3	02/09/2021	Developed by: Event Analysis Subcommittee Approved by RSTC: XXXXXXX XX, 2021	Updated EAS Scope to reflect transformation of the RSTC

Redline Event Analysis Subcommittee Scope

Purpose

The Event Analysis Subcommittee (EAS) assists the NERC Reliability and Security Technical Committee (RSTC) in enhancing Bulk Electric System (BES) reliability by implementing the goals and objectives of the RSTC Strategic Plan.

The EAS is a cross-functional group of industry experts that will support and maintain a cohesive and coordinated event analysis (EA) process across North America with industry stakeholders. The EAS will support development of lessons learned, promote industry-wide sharing of event causal factors, and assist NERC in implementation of related initiatives to lessen reliability risks to the BES.

Functions

1. The EAS, in coordination with NERC Staff, will:
   a. Manage Event Analysis Process document updates and annual review.
   b. Manage and coordinate the development and publishing of Lessons Learned.
   c. Identify improvements to event analysis reporting.
   d. Provide feedback to industry on Event Analysis Process topics.
   e. Solicit feedback from industry stakeholders to improve the Event Analysis Process.
2. To facilitate the sharing of EA information with the NERC RSTC and its subcommittees/working groups, the EAS will:
   a. Facilitate registered entity event analysis presentations at RSTC meetings.
   b. Provide status of and direction on implementation of Lessons Learned.
   c. Provide trending updates as needed.
3. The EAS, in coordination with NERC subcommittees and working groups, will share information, identify trends through analysis of events, and make recommendations to the industry which address:
   a. Reliability risks
   b. Human performance
   c. Need for training
   d. Lessons Learned
   e. Good industry practices and recommendations
4. The EAS will partner with Regional Entities, registered entities and other industry forums to:
   a. Obtain input of Regional Entity personnel and reliability stakeholder groups as resources to the EAS, leveraging their experience and knowledge.
   b. Address reliability issues and trends from reported events.

c. Based on Lessons Learned and trends drawn from events, recommend enhancement to existing Reliability Standards or development of new Reliability Guidelines or Reliability Standards where gaps are identified.

d. Annually survey the Regional Entities to assess the value of published Lessons Learned.

Deliverables

- Conduct an annual review of the Event Analysis Process document.
- Recommend need for training in coordination with Security and Reliability Training Working Group (SRTWG)
- Publish Lessons Learned
- Develop and review of Reliability Guidelines as directed by the RSTC
- Identify significant risk and the need for NERC Alerts
- Provide updates to the RSTC as needed.
- Provide input to the NERC Performance Analysis Subcommittee's (PAS) annual State of Reliability Report
- Provide event information and recommendations related to the Event Analysis Process

Reporting

The EAS reports to the RSTC, and shall maintain communications with the RSTC, EAS Sponsor, and other groups as necessary on relevant issues. The EAS will regularly submit a work plan for approval of tasks. The EAS will review its scope and work plan regularly.

All work products (with the exception of Lessons Learned and Failure Modes & Mechanisms) intended for industry use (such as a Scope document, Work Plans, Reliability Guidelines, Reference Documents, Compliance Implementation Guidance, reports, whitepapers, etc.) should be approved by the RSTC.

The EAS will report to the RSTC for the completion of work associated with the scope items outlined above, and final work products of the EAS will be reviewed and considered by the RSTC and or the NERC Board of Trustees. The EAS chair will periodically apprise the RSTC on the subcommittee's activities, assignments, and recommendations.

Officers

The RSTC Chair appoints the EAS officers (Chair and Vice Chair) for a specific term (generally two-years). The subcommittee officers may be reappointed for additional terms. The vice chair is considered an important part of succession planning with the anticipation that the vice chair will be appointed as subcommittee chair for the next term. The EAS may recommend officer candidates for the RSTC Chair's consideration following a supporting motion.

The subcommittee Chair or Vice chair should attend the regular RSTC meetings to report on assignments, or provide a summary report of the group's activities, and advise the RSTC on important issues at as needed.

The EAS officers are considered members of the EAS and may vote.

Membership

The voting members of the EAS will consist of:

- One (1) voting member from each of the Regional Entities, approved by the RSTC.
- One (1) voting member from each of the Regions to represent industry stakeholder interests. Members may be recommended by the EAS and will be approved by the RSTC.
  - These members must have a signed Non-Disclosure Agreement on file in order to participate in the confidential sessions described below.

Meeting Procedures

The desire is to strive for consensus in normal EAS business. If consensus cannot be achieved, the EAS will hold a vote as noted below. If any strong minority opinions develop, those opinions may be documented as desired by the minority and forwarded to the RSTC Chair for future meeting consideration.

- Quorum: 50 percent of subcommittee members eligible to vote.
- Actions requiring a vote shall require a quorum and a simple majority vote of those members present.
- All other procedures follow those of the of the RSTC Charter and Standard Operating Procedure.

Confidential Sessions

The chair of the subcommittee may limit attendance at a meeting or portion of a meeting, based on confidentiality of the information to be disclosed at the meeting. Such limitations should be applied sparingly and on a non-discriminatory basis as needed to protect information that is sensitive to one or more parties.

Subgroups

The EAS may form working groups and task forces as needed to assist the subcommittee in carrying out standing or ad hoc assignments. Task group chairs (or delegates) are expected to attend the regular subcommittee meetings to report on assignments or provide a summary report of the group's activities.

Meetings

Four to six open meetings per year, or as needed, with supplemental telephone conferences.

Version #	Date	Reviewers/Approval	Revision Description
1.0	6/19/2013	Developed by: Event Analysis Working Group Approved by OC: September 10, 2013	Transitioned the EAWG into the EAS.
1.1	6/10/2013	Developed by: Event Analysis Subcommittee Approved by OC: December 10 2013	Updated EAS Scope to reflect changes in the OC Strategic Plan.
1.2	6/4/2018	Developed by: Event Analysis Subcommittee Approved by OC: September 11, 2018	Updated EAS Scope to reflect seven NERC Regions due to the dissolution of SPP RE.
1.3	02/09/2021	Developed by: Event Analysis Subcommittee Approved by RSTC: XXXXXXX XX, 2021	Updated EAS Scope to reflect transformation of the RSTC

Security Working Group (SWG) Draft Scope and Work Plan

Action
Approve

Summary
The SWG was formed by the RSTC by expanding the scope of the Compliance Input Working Group. The SWG has developed a draft scope document to reflect its expanded scope. The SWG requests approval of the scope document.

Security Working Group Scope

Purpose

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

SWG Objectives/Duties

RSTC oversees the Security Working Group (SWG).

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

- Develop a process for handling requests from ERO Enterprise compliance assurance staff
- Provide feedback from industry to the ERO Enterprise compliance assurance staff to improve the Compliance Monitoring and Enforcement Program (CMEP), including a process to deliver that feedback
- Provide guidance to the RSTC on prioritization of compliance assurance products under development
- Provide guidance and feedback for CMEP materials brought before the RSTC for discussion
- Provide timely technical reports to RSTC on CMEP matters related to cyber and physical security
- Attend the RSTC face-to-face meetings to facilitate discussion and allow discourse on CMEP topic areas
- Promote registered entity involvement in the NERC reliability standards review and comment process
- Develop materials from organized industry activities (such as tabletop exercises) led by or in collaboration with the SWG
- Review lessons learned published by NERC where the RSTC seeks additional industry feedback to help determine whether additional guidance to industry is necessary
- Coordinate with other industry technical groups

- Collaborate with other NERC stakeholder groups within the RSTC to eliminate potential overlaps, avoid duplicative efforts, and ensure alignment of assignments and responsibilities by coordinating and leveraging expertise across groups to the best extent possible. This includes:
  - Coordination with the NERC Security Integration and Technology Enablement Subcommittee (SITES) regarding compliance products being developed and other issues that should inform their discussions about security matters.
  - Coordination with other NERC technical groups focused on security and compliance issues to provide useful perspectives on security-related issues that may affect them.

Members, Structure, and Roles and Responsibilities

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

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

The SWG will consist of a chair and optionally a vice chair with a two-year term limit, nominated by the SWG and approved by the RSTC leadership. The chair and vice chair may be reappointed as necessary, provided that none may serve longer than two consecutive terms. The SWG sub-team leads may be reappointed as necessary. NERC staff will be assigned as coordinator (secretary).

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

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

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

Reporting and Duration

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

SWG Deliverables and Work Plan

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

- Technical reference documents, technical reports, white papers, best practices, and tools
- Reliability guidelines and security guidelines as assigned by the RSTC or through periodic review
- Compliance implementation guidance
- Lessons learned
- Standard authorization requests
- Supporting materials and expertise to other NERC work products

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

Meetings

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

The SWG chair/vice chair or their designee will provide a report at each RSTC quarterly meeting. A process for handling RSTC requests will be developed in consultation with the RSTC sponsor and NERC staff coordinator.

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

Sub-team meetings are conducted by the sub-team leads on a frequency determined by the sub-teams that are appropriate to the project and workload. Sub-team updates are given at the periodic SWG meetings.

Appendix A: Roles and Responsibilities

Table A.1: SWG RACI (Responsible, Accountable, Consulted, Informed)									
Description	RSTC Sponsor	SWG Chair	SWG Co-Chair	Sub-Team Lead	Sub-Team Member	NERC Staff (Secretary)	NERC Staff (Support)	SWG Member	SWG Observer
Organize monthly/quarterly SWG Meetings	I	A, R	A, R	I	I	C	I	C	I
Organize Sub-team meetings	I	A	A	A, R	C	C	I	I	I
Coordinate Sub-team activities, ensure completion of Sub-team tasks	I	I	I	A	R	I	I	I	I
Administrative review of products completed	C	A	A	R	C	C	I	I	I
Drive RSTC review/acceptance process	C	A, R	A, R	C	C	C	I	I	I
Perform sub-team tasks	N/A	I	I	A	R	I	I	I	I
Coordinate with other working groups	I	A, R	A, R	C	C	I	I	I	I
Meet with SWG chair/co-chair for status, problem-solving	C	C	C	A, R	C	I	I	N/A	N/A
POC for SWG for industry groups	C	A, R	A, R	C	I	I	I	I	I
Problem-solve for delivery dates	I	C	C	A, R	R	C	I	I	I
Maintain extranet site	I	A, R	A, R	A, R	R	I	I	I	I
Send out and collect calls for volunteers	I	A, R	A, R	C	C	C	C	I	I
Drive continuous improvement for SWG processes	C	A, R	A, R	R	C	C	C	C	I
Endorse SWG products	C	A, R	A, R	C	I	C	I	I	I
Provide SWG Scope Guidance	A	R	R	C	C	I	I	I	I
Provide daily guidance to sub-teams	N/A	A	A	R	C	I	I	I	I
Extranet design changes, tools	I	A, R	A, R	C	C	I	I	I	I
Manage project input process	C	A, R	A,R	C	C	I	I	I	I
Maintain and monitor work processes	I	A	A	R	C	C	I	I	I
Approve SWG Work Plan	C	A	A	R	C	C	I	I	I
Manage mailing lists and overall SharePoint environment (extranet)	N/A	A	A	C	C	C	R	I	I

Appendix B: Version History

Table B.2: SWG Scope Version History			
Date	**Page**	**Description**	**Version**
2/3/2021	All	Draft SWG Scope Approved by the Security Working Group	0.1
X/X/2021	All	SWG Scope approved by the Reliability and Security Technical Committee	1.0

Energy Reliability Assessment Task Force (ERATF) Scope and Work Plan

Action
Approve

Summary
At the December, 2020 RSTC meeting, information was presented regarding the NERC/IRC Whitepaper on Ensuring Energy Adequacy which made a number of recommendations for mitigating risks to energy adequacy. A small group of RSTC members and industry experts reviewed the issues and are recommending that the ERATF be formed to provide oversight and address the 11 issues identified in the report.

Energy Reliability Assessment Task Force Scope

February 2021

Purpose

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

- Creating a forum for aggregating ideas and interests, drawing from diverse industry stakeholder expertise, to support the ERO Enterprise's mission; and,
- Leveraging such expertise to identify solutions to study, mitigate, and/or manage emerging risks to the BPS for the benefit of industry stakeholders, the NERC Board of Trustees (Board) and ERO Enterprise staff and leadership.

Electricity is fundamental to the quality of life for over 400 million people in North America. Electrification continues apace as new applications are developed for use in advanced technologies. For example, advanced computing now permeates every aspect of our economy, and policy makers are seeking to electrify transportation and heating in order to decarbonize the economy. The bulk power system is undergoing an unprecedented change requiring rethinking the way in which generating capacity, energy supply, and load serving needs are understood.

Layered into this uncertainty, in some areas natural gas fueled resources may, depending on the contract for fuel acquisition,[1] be subject to fuel curtailment or interruption during peak fuel demands. Additionally, gas pipeline design and how gas generators interconnect with the pipeline can vary, which can result in significantly different impacts to the generator and the Bulk Electric System (BES) under gas pipeline disruption scenarios. Further, in some areas, variable energy resources require that there are sufficient flexible energy resources available to quickly respond to off-set ramping requirements. To some extent, the impacts can be mitigated with the supply and geographical diversity from renewable and smaller distributed resources. However, these uncertainties are already causing many system operators to consider scheduling, optimization and commitment of resources over a multi-day timeframe. Replacing the existing generation fleet with energy limited resources requires industry to consider both capacity requirements and energy, and by extension fuel, availability. Even if sufficient capacity is available, a level of certainty in the delivery of fuel is required to ensure that energy is available to support demand.

[1] Contracts here should be considered in the broadest sense. Namely, beyond just firm/interruptible gas, but logistics of gas and fuel oil acquisition, transportation and delivery in a timely fashion to address emerging and projected energy requirements.

The Energy Reliability Assessment Task Force (ERATF) will assess risks associated with unassured energy supplies[2] including the timing and inconsistent output from variable renewable energy resources, fuel location, and volatility in forecasted load can result in insufficient amounts of energy on the system to serve electrical demand and make recommendations to ensure the reliable operation of the bulk power system throughout the year.

Roles and Activities

The "Ensuring Energy Adequacy with Energy-Constrained Resources" whitepaper reviewed by the RSTC identified energy availability concerns related to operations, operations planning and mid-to-long-term planning horizons. This has also been a source of discussion within the industry. Future considerations related to the reliability of energy are more complex and consider use of utility and non-utility assets in different manners as compared to a historical view. In order to effectively accommodate that type of conversation, the industry needs to assess the current processes and expectations to ensure the "basics" are covered. The RSTC, in its role obtaining stakeholder engagement and feedback, will delegate responsibility to the ERATF to carry out activities to:

- Provide information to industry on the issues,
- Support industry readiness and success on this topic,
- Foster, coordinate and facilitate activities of industry and RSTC sub-groups around the issues, risk and potential mitigations or course corrections,
- Gather industry feedback around recommended solutions that are actionable by either registered entities or industry groups (membership forums, trade associations, technical committees, etc.).
- Evaluate options for industry outreach.
- Develop suggested recommendations related to the issues.
- Present work outcomes to the RSTC for awareness.
- Determine appropriate path for recommendations to be considered and action taken.
- For the planning, operational planning, and operations time horizons, identify the parameters for tools and methods that can identify the right mix of resources to ensure sufficient amounts of energy are available
    - to serve demand
    - meet ramping requirements at all times
    - ensure the required energy can be delivered from the source to the end user.

The ERATF will provide suggestions on issues for discussion and recommendations to NERC. Understanding energy availability, and by extension, fuel availability compared to capacity requires advanced

[2] Some examples are: lack of firm gas transportation, pipeline maintenance or disruption, compressor station failures, emission limitations on fossil fuels. All resources have some degree of fuel uncertainty due to unavailability including coal (onsite stock-piles can be frozen) and nuclear (during some tidal conditions affecting cooling intake).

consideration of multiple technologies and concepts. The ERATF will evaluate and recommend solutions for topics including, but not limited to:

1) What flexibility is required to balance volatility in resource and load uncertainty through multiple operating horizons and seasons of the year?
2) Should emergency procedures be revised to reflect current fleet structure and operating needs?
3) When and how should demand response be considered when assessing fuel availability and energy adequacy?
4) How should the fuel availability / energy adequacy of battery or long-duration storage be evaluated?
5) Does there need to be common practices on how Effective Load Carrying Capability (ELCC)[3] or other useful metrics are determined?
6) Does there need to be common planning practices for how forced outages are incorporated into resource adequacy analysis?
7) How does the availability of the interconnection's import transfer capability factor into the resource adequacy analysis?
8) Are there new tools needed to address not only the traditional capacity adequacy, but energy adequacy and meeting reliable operational requirements?
9) Could strategically overbuilding a similar technology (i.e. solar) augmented by either storage or some portion of the firm capacity fleet (albeit operating at low capacity factors only when needed) could provide for a resilient and reliable transition?
10) How should fuel availability through long-term fuel contracts (commodity plus transportation capacity) and on-site storage (e.g. oil, coal and reservoir-based hydro) be incorporated as part of the analysis, looking at a simultaneous demand on transportation capabilities over an extended period?
11) How should gas pipeline disruption scenarios be modeled, realizing that individual gas pipeline design and gas generators interconnections vary, which result in different impacts to the generator and the Bulk Power System?

The ERATF will report its work and deliverables to RSTC, and the RSTC maintains ultimate responsibility for decisions and recommendations to NERC.

Advancing the above concepts with industry requires discussions with appropriate NERC technical committees. In addition, the following actions should be initiated:

1. Coordinate developments of energy reliability assessment activities with industry working groups.
2. Subject matter experts should be assembled (e.g. task forces or working groups), or existing groups should be leveraged to develop:

[3] ELCC results in a derating factor that is applied to a facility's maximum output (Pmax) towards its expected capacity value.

   a. the technical foundation for energy assurance and assessment in each of the three time horizons
   b. ways to identify the levels of energy that are required to meet the operational needs
   c. the tool specifications needed to incorporate energy considerations into planning, operational planning and operations assessments

3. Engage industry R&D organizations (e.g. EPRI, DOE, Natural Resources Canada, national laboratories, etc.) to validate the technical foundation(s) and development of the tool(s), metrics and methods.

4. Coordinate studies and plans with adjacent Balancing Authorities to identify enhanced collaborative regional support.

5. Evaluate the NERC Standards for omissions to address fuel assurance and resulting energy limitations for the planning timeframe.

Membership

The ERATF membership will be comprised of those RSTC members and observers appointed by the RSTC Chair

1. Composition
   a. RSTC Members
   b. RSTC Active Participants and Observers
2. Leadership
   a. The ERATF will have a chair appointed by the RSTC Chair.
3. Observers
   a. The ERATF Chair may invite observers to participate in meetings, which may include additional NERC or Regional Entity staff, as well as other RSTC members. Observers may actively participate in the discussion and ERATF deliverables.

Meetings

The ERATF meetings will be scheduled based on workload, as determined by the members. Meetings may also occur in conjunction with the regular RSTC meetings. The ERATF meetings will be open to other participants. The ERATF Chair will approve this participation and work with the RSTC Chair for any necessary appointments.

NERC

NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

NERC Energy Reliability Assessment Task Force (ERATF)

2020-2022 Work Plan

February 19, 2021

RELIABILITY | RESILIENCE | SECURITY




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

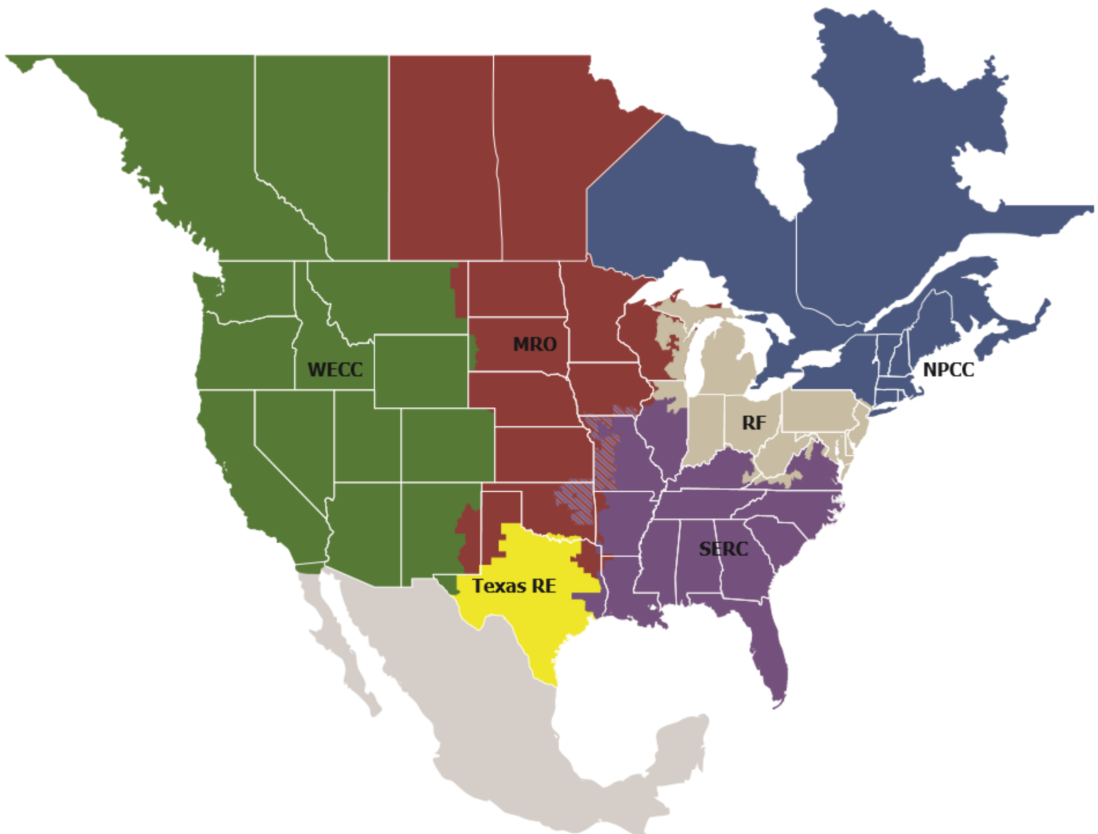
Table of Contents

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

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

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



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

Task Description / Deliverables

	Task Description/Deliverables	Target Completion	Resource (s)
1	Coordinate work activities with industry working groups	Ongoing	ERATF
2a	Assemble the subject matter experts for Focus Areas	Q1-2021	ERATF
2b	The subject matter experts complete the deliverables as outlined in Table 2	Q4-2021	Various working groups as assigned
2c	Engage industry R&D organizations to validate work from Focus Areas	Ongoing	TBD
3	Coordinate studies and plans with adjacent Balancing Authorities to identify enhanced collaborative regional support.	Ongoing	ERATF/RS

The Energy Reliability Assessment Task Force will coordinate energy assurance activities with industry working groups. We will identify subject matter experts and assemble them to develop the work (stated in the deliverables).

Focus Area Details

Focus Area	Task Description	Deliverables	Target Completion	Resource (s)	Status
1	Energy Adequacy and Flexibility for Evolving Resource Mix • As the mix of resources trends toward more renewable energy, primarily with variable and intermittent supplies of fuel (e.g. sunshine, wind, and water), maintaining a balanced power system will require a more flexible approach to energy and capacity adequacy in order to maintain operational awareness. • Traditionally, peak-hour capacity can be solved in an isolated case that ignores all other hours, but in a limited energy situation, the utilization of system resources affects the availability during peak hours. Generator flexibility is gaining importance as load ramps begin to stress the existing infrastructure.	1. Develop the technical foundation for the three time horizons. 2. Determine the ways to identify the levels of energy that are required to meet the operational needs. 3. Develop tool specifications needed to incorporate energy considerations into planning, operational planning and operations assessments. Evaluate the NERC Standards for omissions to address fuel assurance and resulting energy limitations for the planning timeframe.	Q4-2021	TBD	New
2	Gas Delivery Security • Maintaining system balance in cooperation with a limited	1. Develop the technical foundation	Q4-2021	EGWG	New

Focus Area	Task Description	Deliverables	Target Completion	Resource (s)	Status
	energy set of resources will require some level of controllability with the remaining fleet, which will most likely be gas fired generation. • The variability of the renewable resources will likely change how gas is utilized, requiring a higher precision of understanding to determine if the existing system is capable to serve the changing needs (e.g. larger swings of gas demand due to higher overall gas generation ramp rates and shorter periods of online time, burning 24 hours of gas in 8 hours instead of 16) Forces external to power system operators may influence gas delivery security, such as policies and procedure developments from FERC, NAESB, natural gas pipeline companies, or other entities	for the three time horizons. 2. Determine how fuel availability is incorporated as part of an analysis. 3. Develop the specifications for models for gas pipeline disruption scenarios. 4. Evaluate the NERC Standards for omissions to address fuel assurance and resulting energy limitations for the planning timeframe.			
3	Metrics, Procedures and Analysis • Determine whether emergency procedures need to be revised to reflect the current fleet structure and operating needs. • Determine when and how demand response should be considered when assessing fuel availability and energy adequacy. • Determine if we need common practices on how Effective Load Carrying Capability (ELCC) or other useful metrics are calculated. • Determine if we need common planning practices for how forced outages are incorporated into resource adequacy analysis.	1. Develop the technical foundation for the three time horizons. 2. Develop the specifications for non-fuel dependent and variable energy resources. 3. Develop metric specifications needed to incorporate energy considerations that are not dependent on fuel delivery into planning, operational planning and operations assessments.	Q4-2021	TBD	New

Focus Area	Task Description	Deliverables	Target Completion	Resource (s)	Status
	• Determine how the availability of the interconnection's import transfer capability factors into the resource adequacy analysis.	Evaluate the NERC Standards for omissions to address fuel assurance and resulting energy limitations for the planning timeframe.			

Resource Map

	Mid to Long Term Planning	Operational Planning	Operations
1	RAS	RTOS	RTOS/RS
2	RAS	RTOS	RTOS/RS
3	RAS	RTOS	RTOS/RS
4	SPIDERWG	SPIDERWG	IRPWG
5	RAS	RTOS/SPIDERWG	RTOS/IRPWG
6	RAS	RTOS	RTOS
7	RAS	RTOS	RTOS
8	RAS	IRPWG/RTOS	IRPWG/RTOS
9	SPIDERWG	SPIDERWG	IRPWG
10	EGWG	EGWG	EGWG
11	EGWG	EGWG	EGWG

*Note: We may want to see how PAS and SITES may assist as well.

The focus areas from the eleven questions are as follows:

- Focus #1: 1, 4, 8, 9
- Focus #2: 10, 11
- Focus #3: 2, 3, 5, 6, 7

Understanding energy adequacy, and by extension, fuel availability compared to capacity requires advanced consideration of multiple technologies and concepts. For example:

- What flexibility is required to balance volatility in resource and load uncertainty through multiple operating horizons and seasons of the year?
- Should emergency procedures be revised to reflect current fleet structure and operating needs?
- When and how should demand response be considered when assessing fuel availability and energy adequacy?
- How should the fuel availability / energy adequacy of battery or long-duration storage be evaluated?
- Does there need to be common practices on how Effective Load Carrying Capability (ELCC) or other useful metrics are determined?
- Does there need to be common planning practices for how forced outages are incorporated into resource adequacy analysis?

- How does the availability of the interconnection's import transfer capability factor into the resource adequacy analysis?
- Are there new tools needed to address not only the traditional capacity adequacy, but energy adequacy and meeting reliable operational requirements?
- Could strategically overbuilding a similar technology (i.e. solar) augmented by either storage or some portion of the firm capacity fleet (albeit operating at low capacity factors only when needed) could provide for a resilient and reliable transition?
- How should fuel availability through long-term fuel contracts (commodity plus transportation capacity) and on-site storage (e.g. oil, coal and reservoir-based hydro) be incorporated as part of the analysis, looking at a simultaneous demand on transportation capabilities over an extended period?
- How should gas pipeline disruption scenarios be modeled, realizing that individual gas pipeline design and gas generators interconnections vary, which result in different impacts to the generator and the Bulk Power System?

Acronym	Subcommittee, working group or task force
EGWG	Electric-Gas Working Group
IRPWG	Inverter-Based Resource Performance Working Group
PAS	Performance Analysis Subcommittee
RAS	Reliability Assessment Subcommittee
RS	Resources Subcommittee
RTOS	Real Time Operating Subcommittee
SPIDERWG	System Planning Impacts from Distributed Energy Resources Working Group
SITES	Security Integration and Technology Enablement Subcommittee

RSTC Work Plan

Action
Approve

Summary
The RSTC subgroup work plans have been consolidated and updated into a single work plan which is included as **Attachment** 2. The RSTC Executive Committee (EC) is seeking approval of the work plan.

Task Name	Description	Due Date	Sub-Committee	Task Status	Priority	% Complete	Status Comments
CMLD Deployment (Phase1)-04B	Industry Outreach - working with NERC MMWG on data management processes		Load Modeling Working Group (LMWG)	In Progress	(1) High	50.00%	IN PROGRESS - NERC LMTF presented and discussed CMLD model and data management processes at NERC MMWG meeting in March of 2019 and 2020. Ultimate goal is to make CMLD available in 2021 MMWG series of cases
CMLD Deployment (Phase1)-05	Field Test		Load Modeling Working Group (LMWG)	In Progress	(1) High	50.00%	IN PROGRESS - NERC Regional Entities, Planning Coordinators and Transmission Planners are performing CMLD field test to make a decision on their CMLD deployment plans. Recent Benchmarking results have shown critical parameter changes and would require another round of field tests.
CMLD Deployment (Phase1)-06	Regional Support		Load Modeling Working Group (LMWG)	In Progress	(1) High	50.00%	NERC LMWG to work with Regions to develop support and feedback structure with CMLD deployment
CMLD Deployment (Phase2)-13	Load Composition Analysis		Load Modeling Working Group (LMWG)	In Progress	(2) Normal	50.00%	On-going effort to improve our understanding of load composition
CMLD Deployment (Phase2)-14	Dynamic Load Monitoring		Load Modeling Working Group (LMWG)	In Progress	(2) Normal	50.00%	Deployment of dynamic data records in distribution substations and commercial buildings for purpose of load monitoring. DOE will provide resources to support data analysis
CMLD Deployment (Phase2)-15	Coordination with SPIDERWG		Load Modeling Working Group (LMWG)	In Progress	(2) Normal	50.00%	Coordinate with SPIDERWG on DER modeling for dynamic load model, ensure that SPRIDERWG-develop models and data sets are updated in Load Model Data Tool
CMLD Deployment (Phase2)-17	System Event Benchmarking		Load Modeling Working Group (LMWG)	In Progress	(2) Normal	50.00%	Encourage entities to benchmark actual events with the composite load model and report to the group
C2-Reliability Guideline: Communication and Coordination Strategies for Transmission Entities and Distribution Entities regarding Distributed Energy Resources	Develop recommended strategies to encourage coordination between Transmission and Distribution entities on issues related to DER such as information sharing, performance requirements, DER settings, etc.		System Planning Impacts from Distributed Energy Resources Working Group Coordination (SPIDERWG-COORDINATION)	On Hold	(2) Normal	25.00%	Tabled to align with standards review (C6 activity) activity.
C5-SPIDERWG Terminology: Working Definitions Document	Review of existing definitions and terminology and development and coordination of new terms, for consistent reference across sub-groups.		System Planning Impacts from Distributed Energy Resources Working Group Studies (SPIDERWG-STUDIES)	In Progress	(2) Normal	80.00%	Initial draft complete; will update RSTC as necessary. Subsequent revisions will be explored by team, as needed.
C7-Tracking and Reporting DER Growth	Coordinated review of information regarding DER growth, including types of DER, size of DER, etc. Consideration for useful tracking techniques for modeling and reliability studies.		System Planning Impacts from Distributed Energy Resources Working Group Studies (SPIDERWG-STUDIES)	In Progress	(2) Normal	50.00%	In monitoring and data collection stage.
3-IEEE p2800 Monitoring and Support	Monitor and support the activities of IEEE p2800, and provide technical expertise and input as requested.		Inverter-Based Resource Performance Working Group (IRPWG)	In Progress	(2) Normal	50.00%	Ongoing, as needed.
6-Seasonal Assessment Improvements	Assist RAS with incorporation of probabilistic metrics in the RAS seasonal reports		Probabilistic Assessment Working Group (PAWG)	Not Started	(2) Normal	0.00%	New work plan item based on ERO-RAPA and RAS discussion. Joint effort with RAS following RAS schedule
Protection considerations for information traditionally shared between entities (modeling, load-flow, one-lines)	Perhaps a joint effort with OC?		Compliance Input Working Group (CIWG)	In Progress	(2) Normal	50.00%	
Security or implementation guidance for cloud-based EAMS and PAMS	In support of CIP development efforts pertaining to virtualization issues		Compliance Input Working Group (CIWG)	In Progress	(2) Normal	50.00%	
Examine high risk violations for implementation guidance opportunities	CIWG can identify opportunities but may leverage Cyber or Physical workgroups to assist development		Compliance Input Working Group (CIWG)	In Progress	(2) Normal	50.00%	
Support ERO internal controls initiatives (whitepapers, compliance guidance)	With additional members of the OC and PC.		Compliance Input Working Group (CIWG)	In Progress	(2) Normal	50.00%	
Utility Essential Security Practices Whitepaper	Guidance for cyber/physical security protections for non-CIP utility technologies such as inverters, synchro-phasers, natural gas SCADA, etc. (Resources aligned with Electric-Gas Working Group (EGWG))		Security Working Group (SWG)	In Progress	(2) Normal	50.00%	Include members with security expertise on Operating Reliability Subcommittee (ORS), Electric-Gas Working Group (EGWG), and possibly others
Attack scenarios on midstream or interstate natural gas pipelines	Joint effort with OC/PC		Security Working Group (SWG)	In Progress	(2) Normal	50.00%	Include members with security expertise on Electric-Gas Working Group (EGWG), Reliability Assessment Subcommittee (RAS) and/or Probabilistic Assessment Working Group (PAWG), with collaboration by E-ISAC
Planning approaches, models and simulation approaches that reduce the number of critical facilities	Joint effort with PC/OC		Security Working Group (SWG)	In Progress	(2) Normal	50.00%	Include members with security expertise on Electric-Gas Working Group (EGWG), Reliability Assessment Subcommittee (RAS) and/or Probabilistic Assessment Working Group (PAWG), with collaboration by E-ISAC
Response to GridEx V lessons learned	Placeholder for anticipated work items stemming from the bi-annual GridEx lessons learned		Security Working Group (SWG)	In Progress	(2) Normal	50.00%	Add members with security expertise to Operating Reliability Subcommittee (ORS)
Update CIPC remote access guideline	Update remote access guideline taking (as input) the NERC remote access study, filed with FERC in 201x		Remote Access Guideline Task Force (RAGTF)	In Progress	(2) Normal	50.00%	
Develop SAR to consolidate Glossary definitions of ACE	Develop SAR to consolidate Glossary definitions of ACE		Resources Subcommittee (RS)	In Progress	(2) Normal	50.00%	This is a continuation of the SAR initiated by T Bilke in 2019
Support the efforts of the BAL-003-1 SDT	Support the efforts of the BAL-003-1 SDT		Resources Subcommittee (RS)	In Progress	(2) Normal	50.00%	In Progress - Is this the same as Item 9?
Determine a more efficient method to collect CPS1, BAAL, and DCS data to eliminate voluntary submittal forms	Determine a more efficient method to collect CPS1, BAAL, and DCS data to eliminate voluntary submittal forms		Resources Subcommittee (RS)	In Progress	(2) Normal	50.00%	This effort is still not fully scoped.
Technical Report on Methods for Analyzing and Mitigating Forced Oscillations	To address potential reliability impacts from forced oscillation events (e.g., January 2019 EI event), SMS will provide guidance on how RC/TOPs can determine the quantities to be monitored, thresholds to be monitored and the corresponding mitigation actions for consistency in developed operating procedures and mitigation plans.		Synchronized Measurement Working Group (SMWG)	In Progress	(2) Normal	50.00%	
Modeling and Simulations Technical Report.	Modeling and Simulations Technical Report. Findings, recommendations, and experiences modeling and studying inverter-based resources; information from NERC Alert data collection; generation interconnection studies; IRPTF stability studies		Inverter-Based Resource Performance Working Group (IRPWG)	In Progress	(2) Normal	50.00%	
Canyon 2 NERC Alert Follow Up	Canyon 2 NERC Alert Follow Up – Modeling and Simulation. Follow up work to ensure accurate and appropriate models are being used for local and interconnection-wide studies and base case creation. Engagement with MOD-032 Designees, Planning Coordinators, Transmission Planners, and Generator Owners to ensure accurate modeling. Follow up with the proposed changes and execution of those changes.		Inverter-Based Resource Performance Working Group (IRPWG)	In Progress	(2) Normal	50.00%	
IEEE p2800 Monitoring and Support.	IEEE p2800 Monitoring and Support. Monitor and support the activities of IEEE p2800, and provide technical expertise and input as requested.		Inverter-Based Resource Performance Working Group (IRPWG)	In Progress	(2) Normal	50.00%	
Coordinated Review of NERC Reliability Standards	Develop a technical report outlining a roadmap to ensuring BPS reliability under increasing penetration of inverter-based resources; discussion of issues and possible solutions to these issues.		Inverter-Based Resource Performance Working Group (IRPWG)	In Progress	(2) Normal	50.00%	
Technical Report: Energy Transition to Higher Penetrations of Inverter-Based Resources	Continuation of "Tabled Issues" . Discussion of IRPTF and NERC activities beyond those captured in the PRC-024-2 White Paper, as documented in the white paper. Discussion, analysis, and recommendations for continued improvements to inverter-based resource performance and NERC standards		Inverter-Based Resource Performance Working Group (IRPWG)	In Progress	(2) Normal	50.00%	

Task Name	Description	Due Date	Sub-Committee	Task Status	Priority	% Complete	Status Comments
Reliability Guideline: EMT Modeling and Studies	Reliability Guideline: EMT Modeling and Studies Positive-sequence models are utilized to represent generator resources in typical dynamic stability tools used by power system engineers in various studies. However, these models contain certain simplifications for inverter-based resources (IBRs) that may lead to erroneous results under certain system conditions (e.g., low system strength). The reliability guideline will provide guidance on when and how an entity should be performing EMT analysis. This reliability guideline will build off of the previously developed reliability guidelines by IRPTF.		Inverter-Based Resource Performance Working Group (IRPWG)	In Progress	(2) Normal	50.00%	
Reliability Guideline: Battery Energy Storage and Hybrid Plant Performance and Modeling	Battery storage systems are increasing in size and number. Further, use of hybrid resources is increasing. There is lack of guidance and expertise on how to model and simulate these types of new resources in interconnection studies and planning assessments. The IRPTF will develop a reliability guideline that outlines recommended practices.		Inverter-Based Resource Performance Working Group (IRPWG)	In Progress	(2) Normal	50.00%	
Load Composition Analysis (e.g, Buildings, end uses)	Load Composition Analysis (e.g, Buildings, end uses)		Load Modeling Working Group (LMWG)	In Progress	(2) Normal	50.00%	
EIDSN Tool Development Monitoring	Monitor development of common tools and act as point of contact for EIDSN		Real Time Operating Subcommittee (RTOS)	In Progress	(2) Normal	50.00%	On-going
Parallel Flow Visualization too	RTOS to act as lead on development of, and recommendation to implement, Parallel Flow Visualization tool		Real Time Operating Subcommittee (RTOS)	In Progress	(2) Normal	50.00%	Q3 2022
Time Monitors	Notify RSTC of Time Monitors for 2022 and 2023		Real Time Operating Subcommittee (RTOS)	In Progress	(2) Normal	50.00%	Q4 Annually
GMD Monitors	Notify RSTC of changing GMD Monitors		Real Time Operating Subcommittee (RTOS)	In Progress	(2) Normal	50.00%	Q4 Annually
Frequency Monitor Reporting	Frequency Monitor Reporting (StandingRTOSagenda item to discuss)		Real Time Operating Subcommittee (RTOS)	In Progress	(2) Normal	50.00%	On-going
Reliability Guideline: Cyber Intrusion Guide for System Operators	Reliability Guideline: Cyber Intrusion Guide for System Operators (Approved by the Operating Committee on June 5, 2018)		Real Time Operating Subcommittee (RTOS)	Not Started	(2) Normal	0.00%	On-going
Reliability Coordinator Plan Reference Document	Reliability Coordinator Plan Reference Document		Real Time Operating Subcommittee (RTOS)	In Progress	(2) Normal	50.00%	Q4 2021
Reliability Guideline: Gas and Electrical Operational Coordination Considerations	Periodic review of the Reliability Guideline: "Gas and Electrical Operational Coordination Considerations"		Real Time Operating Subcommittee (RTOS)	In Progress	(2) Normal	50.00%	Q2 2021
State of Reliability Report (SOR)	State of Reliability Report (SOR), using ERO-Enterprise metrics		Performance Analysis Subcommittee (PAS)	In Progress	(2) Normal	50.00%	
Review proposed new metrics	Review proposed new metrics		Performance Analysis Subcommittee (PAS)	In Progress	(2) Normal	50.00%	
Conduct annual metric review	Implement annual metric review		Performance Analysis Subcommittee (PAS)	In Progress	(2) Normal	50.00%	
Section 1600 Data Request	NERC RoP GADS Section 1600 Data Reporting to collect and analyze GADS data: • Conventional - relevant design data and enhanced event reporting • Wind - connected energy storage and event reporting • Solar - plant configuration, performance and event data as well as equipment outage detail		Performance Analysis Subcommittee (PAS)	In Progress	(2) Normal	50.00%	
Annual review of CERTS/NERC (fnet, etc.) real-time applications.	Annual review of CERTS/NERC (fnet, etc.) real-time applications.	9/30/2020	Resources Subcommittee (RS)	In Progress	(2) Normal	50.00%	Annually
Review and approval of the Annual Frequency Response Analysis Report during Q3 of each year.	Review and approval of the Annual Frequency Response Analysis Report during Q3 of each year.	9/30/2020	Frequency Working Group (FWG)	In Progress	(2) Normal	50.00%	Complete for 2019 - NERC Staff Task, RS approval, OC Endorsement
2-San Fernando Disturbance Follow-Up	Discussion of NERC San Fernando Disturbance Report and identification of any next steps for IRPWG to add to work plan.	12/31/2020	Inverter-Based Resource Performance Working Group (IRPWG)	In Progress	(2) Normal	50.00%	IRPWG will meet in November to determine next steps.
Review and vet the Frequency Bias Settings and L10 values; scheduled to be implemented in April of each year. Repeated annual in accordance with the BAL-003-1 standard.	Review and vet the Frequency Bias Settings and L10 values; scheduled to be implemented in April of each year. Repeated annual in accordance with the BAL-003-1 standard.	12/31/2020	Frequency Working Group (FWG)	In Progress	(2) Normal	50.00%	Ongoing
Quarterly review of BA's control performance.	Quarterly review of BA's control performance.	12/31/2020	Resources Subcommittee (RS)	In Progress	(2) Normal	50.00%	Ongoing
V1-Reliability Guideline: DER Performance and Model Verification	Reliability Guideline covering aggregate DER model verification, including recommended measurement practices, executing model verification activities, model benchmarking, relation to MOD-033 activities, and conversion of data sources for verification.	3/2/2021	System Planning Impacts from Distributed Energy Resources Working Group Verification (SPIDERWG-VERIFICATION)	In Progress	(1) High	90.00%	Responded to Q4 2021 comment period. (High priority task for SPIDERWG)
S2a-SAR: Updates to TPL-001 Regarding DER Considerations	*Sub-team is developing a SAR that incorporates the recommendations put forth in the approved white paper, considering the items that need standards revisions to improve reliability. This activity will also be coordinated with IRPWG to address the issues identified in their recently approved white paper identifying issues with TPL-001.*	3/2/2021	System Planning Impacts from Distributed Energy Resources Working Group Studies (SPIDERWG-STUDIES)	In Progress	(1) High	50.00%	New task as follow-on to S2 white paper approval by RSTC. Sub-group beginning work. (High priority task for SPIDERWG)
S3-Recommended Simulation Improvements and Techniques	*Guidance (white paper) to software vendors on tools enhancements for improved accounting and study of aggregate DER.*	3/31/2021	System Planning Impacts from Distributed Energy Resources Working Group Studies (SPIDERWG-STUDIES)	In Progress	(1) High	80.00%	On track; nearing completion of white paper providing vendor guidance.
4-Reliability Guideline: BPS-Connected BESS and Hybrid Plant Performance, Modeling, and Studies	Reliability Guideline on recommended performance, modeling, and studies for BPS-connected BESS and hybrid power plants.	3/31/2021	Inverter-Based Resource Performance Working Group (IRPWG)	In Progress	(2) Normal	50.00%	Seeking RSTC authorization to post for industry comment at December 2020 meeting.
4-Probabilistic Assessment - Scenario Case	Develop and present findings in a Scenario report that expands upon the Base Case LTRA 2019 Rec 1	3/31/2021	Probabilistic Assessment Working Group (PAWG)	In Progress	(2) Normal	50.00%	PAWG results due December 18th. First draft planned Jan 2021
Develop Lessons Learned 1st Quater 2021	Publish Lessons Learned. Prepare and facilitate Lessons Learned webinars. Prepare detailed presentation of event for "training" session before RSTC meetings.	3/31/2021	Event Analysis Subcommittee (EAS)	In Progress	(2) Normal	25.00%	Two lesson learned have been published in 2021. A lesson learned summary presentation for published lesson learned will be developed and provided in all 2021 RSTC agendas. A lesson learned webinars will be conducted as needed.
1. Scope Document	Develop Scope Document	3/31/2021	Security Working Group (SWG)	Not Started	(2) Normal	0.00%	
2. Work Plan	Develop and recommend a multi-year work plan for NERC to pursue (2021 – 2022)	3/31/2021	Security Working Group (SWG)	Not Started	(2) Normal	0.00%	
6. BCSI in the Cloud Tabletop Lessons Learned	Lessons learned and supporting documentation from WAPA/Microsoft Azure BCSI in the Cloud Tabletop	3/31/2021	Security Working Group (SWG)	Not Started	(2) Normal	0.00%	
M1-DER Modeling Survey	*Perform industry survey of SPIDERWG members regarding use of DER planning models in BPS studies, dynamic load models and DER modeling guidelines.*	6/8/2021	System Planning Impacts from Distributed Energy Resources Working Group Modeling (SPIDERWG-MODELING)	In Progress	(2) Normal	80.00%	Survey results complete; white paper being created to capture key takeaways from survey. To be presented to RSTC at appropriate time.
V2-Reliability Guideline: DER Forecasting Practices and Relationship to DER Modeling for Reliability Studies	Guidance providing how forecasting practices are linked to DER modeling for reliability studies. DER forecasting practices are important for accurately representing the correct amount and type of DER, particularly at an aggregate level representation for BPS studies.	6/8/2021	System Planning Impacts from Distributed Energy Resources Working Group Verification (SPIDERWG-VERIFICATION)	In Progress	(2) Normal	65.00%	Nearing completion of SPIDERWG review. Planned to request approval to post for industry comment in Q2 2021 RSTC meeting.
S4A-Reliability Guideline: Recommended Approaches for Developing Underfrequency Load Shedding Programs with Increasing DER Penetration	Guidance on how to study UFLS programs and ensure their effectiveness with increasing penetration of DER represented	6/8/2021	System Planning Impacts from Distributed Energy Resources Working Group Studies (SPIDERWG-STUDIES)	In Progress	(2) Normal	75.00%	On track. SPIDERWG Review period.
C6-NERC Reliability Standards Review	White Paper reviewing NERC Reliability Standards and impacts of DER.	6/8/2021	System Planning Impacts from Distributed Energy Resources Working Group Studies (SPIDERWG-STUDIES)	In Progress	(1) High	70.00%	On track; initial reviews complete, consolidating responses into draft white paper; white paper in review by SPIDERWG.
C8-White Paper: FERC Order 2222 and BPS Reliability Perspectives	Short white paper identifying key BPS reliability perspectives with the recently released FERC Order 2222. Being developed by SPIDERG sub-group leadership and Dan Kopin, and will get full review and input from overall SPIDERWG once initial draft complete.	6/8/2021	System Planning Impacts from Distributed Energy Resources (SPIDERWG)	In Progress	(1) High	60.00%	Draft in review and in progress in SPIDERWG. Targeting Q2 2021 RSTC for initial review.
1-Data collection approaches and recommendations techincal report	Develop a technical report that describes industry approaches and best practices for probabilistic assessment	6/8/2021	Probabilistic Assessment Working Group (PAWG)	In Progress	(2) Normal	80.00%	PAWG responded to RAS comments from RAS commenting period. Going to RSTC to request RSTC reviewers.

Task Name	Description	Due Date	Sub-Committee	Task Status	Priority	% Complete	Status Comments
EGWG - Reliability Guideline Metrics	Develop a method to measure the Fuel Assurance Reliability Guideline effectiveness including the following goals set forth for 2021Run metrics and analysis around design basis for potential TPL 001 enhancements;Complete surveys and measurement criteria and results to determine efficacy of Fuel Assurance Guideline implemented in 2020Provide additional criteria for measuring effectiveness of 2017 Guideline: Gas and Electrical Operational ConsiderationsDevelop a summary of effectiveness of guidelines results that can be used to the purposes of SAR(s) or enhancements to existing guidelinesMonitor effectiveness of new GADS cause codes that provide for more visibility into root cause analysis of gas generator outages due to lack of fuel	6/30/2021	Electric Gas Working Group (EGWG)	In Progress	(2) Normal	5.00%	Kick off meeting held by Entergy on June 22, 2020. No further activity thus far.
5-White Paper: BPS-Connected IBR and Hybrid Plant Capabilities for Frequency Response	White paper on utilizing the full capabilities of inverter-based resources and hybrid plants for providing frequency response.	6/30/2021	Inverter-Based Resource Performance Working Group (IRPWG)	In Progress	(2) Normal	50.00%	New task; on track.
1-2021 Summer Reliability Assessment	Seasonal Reliability Assessment Required by NERC RoP Sect 800.	6/30/2021	Reliability Assessment Subcommittee (RAS)	In Progress	(2) Normal	50.00%	Data and narrative input request sent to Regions and Assessment Areas.
Develop EA Chapter of the State of 2021 Reliability Report	Develop EA Chapter of the State of 2021 Reliability Report in coordination with PAS.	6/30/2021	Event Analysis Subcommittee (EAS)	In Progress	(2) Normal	10.00%	
4. Complete Assessing and Reducing Risks Tool	Update tool and support document based on 45-day commenting from industry, deliver for final approval	6/30/2021	Security Working Group (SWG)	Not Started	(2) Normal	0.00%	
5. Complete Encryption in the Cloud Compliance Implementation Document	Complete changes to document based on RSTC feedback	6/30/2021	Security Working Group (SWG)	Not Started	(2) Normal	0.00%	
7. FERC CIP Lessons Learned from Commission-Led CIP Reliability Audits, CIP-002-5.1a R1 Att 1 Criteria 2.5	Action to ensure FERC CIP Lessons Learned and determine if deliverable needed, e.g. white paper, SAR, etc. Researching existing guidance is also part of this activity.	6/30/2021	Security Working Group (SWG)	Not Started	(2) Normal	0.00%	
CMLD Deployment (Phase1)-05A	Field Test Report	9/30/2021	Load Modeling Working Group (LMWG)	In Progress	(1) High	50.00%	NERC LMWG to develop the field test report for RSTC approval, Update the Reference Document (task 5 is a pre-requisite)
CMLD Deployment (Phase2)-10	Improvements to three-phase motor models	9/30/2021	Load Modeling Working Group (LMWG)	In Progress	(1) High	50.00%	GE PSLF implemented better three-phase motor models. The next step is to compare the model against the existing model to make the determination whether to proceed with it in all other programs (task 7 is pre-requisite). NERC LMWG found issues with frequency response of the existing three-phase models.
6-Reliability Guideline: Electromagnetic Transient Modeling and Simulations	Reliability Guideline on EMT modeling and simulations of BPS-connected inverter-based resources.	9/30/2021	Inverter-Based Resource Performance Working Group (IRPWG)	In Progress	(2) Normal	50.00%	On track
8-Reliability Guideline: Recommended Approach to Interconnection Studies for BPS-Connected Inverter-Based Resources	Focused guidance on improving the study process for BPS-connected inverter-based resources, particularly with increasing penetrations of these resources and the growing complexity of performing sufficient studies to ensure BPS reliability.	9/30/2021	Inverter-Based Resource Performance Working Group (IRPWG)	In Progress	(2) Normal	50.00%	New task, on track
3-Winter Reliability Assessment	Seasonal Reliability Assessment Required by NERC RoP Sect 800.	11/30/2021	Reliability Assessment Subcommittee (RAS)	Not Started	(2) Normal	0.00%	Planning begins in June.
2-Long Term Reliability Assessment	Annual Reliability Assessment Required by NERC RoP Sect 800.	12/9/2021	Reliability Assessment Subcommittee (RAS)	In Progress	(2) Normal	50.00%	Regional Entity and Assessment Area Input Request is In Development
M6-Modeling Distributed Energy Storage and Multiple Types of DERs	SPIDERWG will dig into technical considerations of modeling distributed energy storage, specifically distributed battery energy storage (D-BESS). The group will also consider how to model multiple types of DERs, including D-BESS and distributed solar PV (D-PV). Lastly, the group will focus on forecasting and dispatch assumptions for D-BESS. SPIDERWG will determine the level of guidance or reference materials needed once discussions begin. Task to be coordinated with Studies sub-group.	12/14/2021	System Planning Impacts from Distributed Energy Resources Working Group Modeling (SPIDERWG-MODELING)	In Progress	(1) High	25.00%	New work task, getting underway.(High priority task for SPIDERWG)
S1-Reliability Guideline: Bulk Power System Planning under Increasing Penetration of Distributed Energy Resources	*Reliability Guideline providing recommended practices for performing planning studies considering the impacts of aggregate DER behavior – study approaches, analyzing BPS performance criteria incorporating DER models into studies, developing study assumptions, etc.*	12/14/2021	System Planning Impacts from Distributed Energy Resources Working Group Studies (SPIDERWG-STUDIES)	In Progress	(1) High	60.00%	On track; nearing completion of initial draft, completing some final sections. (High priority task for SPIDERWG)
S4B-White Paper: DER Impacts to UVLS Programs	*Short white paper on potential impacts of DERs on UVLS program design; leverage work of PRC-010 standards review (C6 task).*	12/14/2021	System Planning Impacts from Distributed Energy Resources Working Group Studies (SPIDERWG-STUDIES)	In Progress	(2) Normal	50.00%	On track.
S5-White Paper: Beyond Positive Sequence RMS Simulations for High DER Penetration Conditions	*Considerations for high penetration DER systems and the need for more advanced tools (e.g., co-simulation tools) for studying DER impacts on the BPS.*	12/14/2021	System Planning Impacts from Distributed Energy Resources Working Group Studies (SPIDERWG-STUDIES)	In Progress	(2) Normal	55.00%	On track. Draft nearing completion
CMLD Deployment (Phase2)-07	Dynamic Load model for Real-Time Transient Stability Assessment	12/31/2021	Load Modeling Working Group (LMWG)	In Progress	(2) Normal	50.00%	NERC LMWG reached out to PowerTech Labs and RC West on testing load model in TSAT for real-time studies
CMLD Deployment (Phase2)-08	Modular implementation of the dynamic load model	12/31/2021	Load Modeling Working Group (LMWG)	In Progress	(1) High	50.00%	GE PSLF and PowerWorld aready implemented dynamic load models in their software packages. PTI PSS®E will require the next release of the software - Version 35.
CMLD Deployment (Phase2)-09	Improvements to single-phase motor models	12/31/2021	Load Modeling Working Group (LMWG)	In Progress	(1) High	50.00%	GE PSLF implemented dynamic phasor models of single-phase motor models. The next step is to compare the model against the existing performance model to make the determination whether to proceed with dynamic phasor model in all other programs (task 8 is a pre-requisite)
CMLD Deployment (Phase2)-11	Improved protection and control models - progressive tripping	12/31/2021	Load Modeling Working Group (LMWG)	In Progress	(2) Normal	50.00%	GE PSLF implemented a motor model version with progressive tripping. The next step is to test the model to make the determination whether to proceed with it in all other programs (task 8 is pre-requisite)
CMLD Deployment (Phase2)-12	Power Electronic Loads	12/31/2021	Load Modeling Working Group (LMWG)	In Progress	(2) Normal	50.00%	EPRI and BPA tested a number of VFD, ECM drives, as well as charging loads. EPRI is working on more detailed models. The next step is to develop and implement the model in GE PSLF, and compare the model against the existing model to make the determination whether to proceed with it in all software programs (task 8 is pre-requisite)
CMLD Deployment (Phase2)-16	Transient Voltage Response Criteria	12/31/2021	Load Modeling Working Group (LMWG)	In Progress	(1) High	50.00%	Coordinate with LMWG members and ascertain their inputs and provide guidance on transient voltage response criteria that is required under TPL-001-4 R5
7-White Paper: Energy Transition to Increasing Penetrations of BPS-Connected Inverter-Based Resources	Brief strategic white paper of ensuring BPS reliability with increasing BPS-connected inverter-based resources.	12/31/2021	Inverter-Based Resource Performance Working Group (IRPWG)	In Progress	(2) Normal	50.00%	On track
SITES Industry Workshop	SITES will hold an industry-wide technical workshop (likely remotely) to highlight strategic areas of focus related to new technologies, technology enablement, and security integration. (Scope Activity Technology Enablement #2)	12/31/2021	Security Integration and Technology Enablement Subcommittee (SITES)	In Progress	(2) Normal	50.00%	Initial work plan item for team consideration.
Reliability / Security Guideline: Integration of Cyber and Physical Security with BPS Planning, Operations, Design, and System Restoration	Recommendations for industry regarding ways that BPS planning, operations, design, and restoration activities can be enhanced by considering cyber and physical security aspects to improve BPS reliability and resilience; recommendations regarding the convergence of IT and OT networks. (Scope Activity Security Integration #1 and #2)	12/31/2021	Security Integration and Technology Enablement Subcommittee (SITES)	In Progress	(2) Normal	50.00%	Initial work plan item for team consideration.

Task Name	Description	Due Date	Sub-Committee	Task Status	Priority	% Complete	Status Comments
White Paper: Review and Enhancement of Cybersecurity Maturity Metrics	Review and enhancement of metrics to track the capabilities and maturity of cybersecurity and its integration with BPS reliable operation on a broad level; considerations at a macro-scale, integrating all aspects of overall BPS security, reliability, and resilience. (Scope Activity Security Integration #3 and #5)	12/31/2021	Security Integration and Technology Enablement Subcommittee (SITES)	In Progress	(2) Normal	50.00%	Initial work plan item for team consideration.
White Paper: Risk-Based Physical and Cybersecurity Threats and their Impacts to BPS Reliability and Resilience	Guidance and reference materials providing information about possible security threats and ways that Registered Entities can plan, design, and operate the system to mitigate these potential risks. High-level recommendations for industry to consider in their own engineering and security practices for mitigating potential BPS reliability risks. Considerations for generation, transmission, and distribution-level risks as well as such as the natural gas infrastructure, and end-use (Scope Activity Security Integration #4)	12/31/2021	Security Integration and Technology Enablement Subcommittee (SITES)	In Progress	(2) Normal	50.00%	Initial work plan item for team consideration.
Coordination Activities	Ongoing coordination with other RSTC technical groups to avoid any overlap or duplication; engagement with external stakeholders and industry groups to gather information and share SITES developments; coordination with E-ISAC, ESCC, IEEE, NATF, NAGF, EPRI, and other technical groups. (Scope Activity Coordination #1, #2, #3, and #4)	12/31/2021	Security Integration and Technology Enablement Subcommittee (SITES)	In Progress	(2) Normal	50.00%	Initial work plan item for team consideration.
Analysis of cause codes looking for common threads and trends.	Analysis of cause codes looking for common threads and trends. Provide update to RSTC on trends, threads, etc. as required	12/31/2021	Event Analysis Subcommittee (EAS)	In Progress	(2) Normal	50.00%	
Events Analysis Program Review and Update	Events Analysis Program Review and Update	12/31/2021	Event Analysis Subcommittee (EAS)	In Progress	(2) Normal	25.00%	
Develop Lessons Learned Webinars	Publish Lessons Learned. Prepare and facilitate Lessons Learned webinars. Prepare detailed presentation of event for "training" session before RSTC meetings.	12/31/2021	Event Analysis Subcommittee (EAS)	In Progress	(2) Normal	25.00%	
10. Develop external website organization and content	Develop organization and content for the SWG external website (new) along with process for publishing (including approvals). This includes leveraging tools to collect input from industry.	12/31/2021	Security Working Group (SWG)	Not Started	(2) Normal	0.00%	
State of Technology Report	Technical report providing industry with strategic guidance regarding new or emerging technology solutions and risk-based considerations for their successful implementation. (Scope Activity Technology Enablement #1)	3/31/2022	Security Integration and Technology Enablement Subcommittee (SITES)	In Progress	(2) Normal	50.00%	Initial work plan item for team consideration.
3. Expand Membership	Solicit additional membership and recruit subject matter experts for future projects	6/30/2022	Security Working Group (SWG)	Not Started	(2) Normal	0.00%	
8. CIP Evidence Request Tool Improvements	Develop and execute new communication process to implement ongoing reviews between NERC Compliance and SWG Evidence Request Tool (ERT) sub-team	6/30/2022	Security Working Group (SWG)	Not Started	(2) Normal	0.00%	
9. SWG Processes/Procedures	Develop and implement procedures for project requests, deliverable reviews, roles/responsibilities, website collaboration, scope and work plan reviews, document templates, organizing meetings, and training that will help sustain the SWG	6/30/2022	Security Working Group (SWG)	Not Started	(2) Normal	0.00%	

Special Assessment: NERC Energy Management System Performance Special Assessment (2018–2019)

Action
Endorse

Summary
Loss of situational awareness is one of 10 risks identified in the 2019 ERO Reliability Risk Priorities Report. Loss or degradation of situational awareness poses BPS challenges as it affects the ability of personnel or automatic control systems to perceive and anticipate degradation of system reliability and take pre-emptive action. To gain a better resolution on the contribution of EMS outages to the loss of situational awareness risk and the effect of EOP-004-4, the NERC EMSWG decided to conduct an assessment as an interim activity between recurring updates to its EMS reference document using 2018–2019 EMS events reported through the ERO EAP. This document includes assessments for three factors (outage duration, EMS functions, and entity reliability functions), examining associated trends, event root causes, and contributing causes identified through the ERO Cause Code Assignment Process (CCAP) for the 2018–2019 period.

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

NERC Energy Management System Performance Special Assessment (2018–2019)

March 2021

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

Reliability | Resilience | Security

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

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

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

Executive Summary

Loss of situational awareness is one of ten risks identified in the *2019 ERO Reliability Risk Priorities Report*.[1] Loss or degradation of situational awareness pose BPS challenges as they affect the ability of personnel or automatic control systems to perceive and anticipate degradation of system reliability and take pre-emptive action.

An energy management system (EMS) is an automatic control system used by many entities that supports situational awareness. The primary objective of the EMS is to help system operators maintain situational awareness through automated means and enable remote control of devices to ensure secure and stable operations of the Bulk Electric System (BES).

The NERC Energy Management System Working Group (EMSWG) published the reference document *Risk and Mitigations for Losing EMS Functions*[2] in December 2017 and published a revision[3] in March 2020. The reference document contains analysis of 521 EMS events reported through the voluntary ERO Event Analysis Process (EAP) between October 2013 and April 2019. 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.

Of particular importance when considering the role of the EMS on the BES is the recent modification of the standard EOP-004-4, which clarified the reporting task concerning the loss of situational awareness as being the complete loss of monitoring or control capability at a staffed BES control center for 30 continuous minutes or more. The clarifying 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.

To gain a better resolution on the contribution of EMS outages to the loss of situational awareness risk and the effect of EOP-004-4, the NERC EMSWG decided to conduct an assessment as an interim activity between recurring updates to its EMS reference document by using 2018–2019 EMS events reported through the ERO EAP. This document includes assessments for three factors (outage duration, EMS functions, and entity reliability functions), examining associated trends, event root causes, and contributing causes identified through the ERO Cause Code Assignment Process (CCAP) for the 2018–2019 period.

Key Findings

Based on data and information collected for this assessment, the following key findings were identified:

- **EMS was highly reliable in 2018 and 2019.**
  In 2018 and 2019, the loss of EMS functions did not directly lead to the loss of generation, transmission lines, or customer load. The number of the EMS events reported declined from 88 in 2018 to 74 in 2019. The overall median outage duration remained steady, 60 minutes, in 2018 and 2019. Supervisory control and data acquisition (SCADA) is the most critical function in current EMS architecture. The number of SCADA losses was stable over these two years, but the median outage duration of SCADA loss decreased from 63 minutes in 2018 to 48 minutes in 2019.

[1] *2019 ERO Reliability Risk Priorities Report:* https://www.nerc.com/comm/RISC/Related%20Files%20DL/RISC%20ERO%20Priorities%20Report_Board_Accpeted_November_5_2019.pdf

[2] *Risk and Mitigations for Losing EMS Functions Reference Document—Version 1*: https://www.nerc.com/comm/OC/ReferenceDocumentsDL/Risks_and_Mitigations_for_Losing_EMS_Functions_Reference_Document_20171212.pdf

[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

- **EOP-004-4 is likely affecting EMS event reporting.**
  The number of state estimator/real time contingency analysis (SE/RTCA) and inter-control center protocol (ICCP) losses declined by 12 and 5 in 2019, respectively. NERC Reliability Standard EOP-004-4 went into effect on April 1, 2019, in the United States and some Canadian provinces. One major modification to the standard is that the reporting is now clearly only required 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 now interpreting that partial loss events (such as loss of SE/RTCA, 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 CCAP.
- **Entities minimized the operational degradation from the loss of situational awareness risk due to EMS outage.**
  The number of EMS events reported by Reliability Coordinators (RCs) remained steady in 2018 and 2019. United States RCs reported only three EMS events in 2019. There were zero loss of supervisory control and data acquisition (SCADA) events reported by an RC for 2019. TOs/TOPs reported 83% of all EMS events reported in 2018 and 2019. The median outage duration of the TO/TOP EMS events was 60 minutes in 2018 and 2019. Although Balancing Authorities (BAs) started reporting EMS events in 2019, the associated median outage duration was 42.5 minutes. Automatic generation control (AGC) was affected once in 2019 with an outage duration of 31 minutes, just 1 minute beyond the reporting threshold (30 minutes).
- **The loss of SE/RTCA was the most prevalent EMS failure in 2018 and 2019.**
  The loss of SE/RTCA was the most prevalent EMS failure with 52% or 84 events, of all reported EMS events in 2018 and 2019. Although the number of SE/RTCA events declined from 48 in 2018 to 36 in 2019, the median outage duration of SE/RTCA events increased from 46 minutes in 2018 to 61 minutes in 2019.
- **The Management/Organization cause coding category was identified as the leading root cause.**
  Management/Organization was identified as the leading root cause in 45 of all 98 processed EMS events. It suggests a need for the industry to focus on improving the management and organization areas within their companies to reduce the likelihood of EMS events from happening again in the future.

Recommendations

Based on these key findings, the following high-level recommendations are offered to improve the reliability, resilience, and security of the grid:

- The ERO Enterprise must reinforce, during all applicable/associated regulatory and reliability interactions, entity development and implementation of communication and response processes between RCs, BAs, and TOPs to improve overlapping coverage of situational awareness.
- The ERO Enterprise must reinforce, during all applicable/associated regulatory and reliability interactions, development and implementation of system recovery and restoration plans to specifically include scenarios in which the EMS and decision-support tools are unavailable. These plans must include drills and training on the procedures plus real-life practice implementing the procedures.
- The ERO Enterprise must reinforce, during all applicable/associated regulatory and reliability interactions, that entities keep their on-line model up-to-date and communicate BES changes (including new substations, new facilities, and removed facilities) to neighboring entities in advance.
- It is essential that entities maintain network devices on a planned schedule in accordance with the latest vendor information, security bulletins, technical bulletins, and other recommended updates. It is also essential that utilities build an asset management system to manage the entire life cycle of assets to identify and manage risks.

- It is essential that entities create routines for regularly testing and maintaining the backup generator, uninterruptible power supply (UPS), and associated power switches to verify and ensure that power supply redundancy has been implemented in control rooms, data centers, and substations.
- It is essential that entities develop dedicated and skilled in-house personnel who can troubleshoot and correct issues and provide in-house staff with real time tools and training to improve/increase knowledge transfer from the vendor.
- Entities are encouraged to participate in the ERO EAP to help prevent event/issue reoccurrence and share lessons learned across industry.

Introduction

Background

An EMS is a system of computer-aided tools used by system operators to monitor, control, and optimize the performance of the generation and/or transmission system. The primary objective of the EMS is to provide situational awareness to the system operators[4] and enable remote control of devices to ensure secure and stable operation of the BES. Situational awareness includes, but is not limited to, the ability to do the following:

- Monitor frequency within the system operator's area
- Monitor 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
- Monitor/control voltage and reactive resources
- Monitor the status of applicable EMS applications, such as RTCA and/or alarm management

Situational awareness is necessary to maintain reliability and security by anticipating events and responding appropriately when or before events occur. Without tools and data, system operators may have degraded situational awareness for making decisions that ensure reliability and security 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 coordination or oversight can leave system operators with impaired system visibility.

The ERO EAP is intended to promote a structured and consistent approach to performing event analyses. The events analyzed in the ERO EAP come from mandatory processes like EOP-004 and 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.

It is notable that one major modification to the standard EOP-004-4 is that only the complete loss of monitoring or control capability at a BES control center for 30 continuous minutes or more is required to be reported. The modified standard went into effect on April 1, 2019, in the United States and some Canadian provinces. This may have resulted in many partial loss EMS events not being reported since EOP-004-4 became effective.

To better understand the contribution of EMS outage to loss of situational awareness risk and the effect from the EOP-004-4, the NERC EMSWG decided to conduct an assessment by using the EMS events reported through the ERO EAP for 2018–2019.

Scope and Purpose

The reference document *Risk and Mitigations for Losing EMS Functions* is published biennial and contains analysis and recommendations based on 521 EMS events reported through the ERO EAP between October 2013 and April 2019. Because the publication/implementation of EOP-004-4 occurred in between reference document updates, the NERC EMSWG identified a need to explore the impact to partial loss of EMS functions reporting via the ERO EAP and to improve resolution on the contribution of these losses to the loss of situational awareness. Consequently, using EMS events reported through the ERO EAP for 2018–2019, the purpose of this special assessment is as follows:

- Evaluate the effect of EOP-004-4 on EMS partial function loss reporting

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

- Update the EMS performance based on outage duration, EMS functions, and entity reliability functions
- Offer recommendations[5] to improve EMS reliability, security, and resiliency of the BPS

Commonly Used Terms within This Document

The terms in **Table I.1** used in this document are not defined within or intended to be included in the NERC Glossary of Terms.[6] These particular definitions are identified to ensure a common industry understanding of how they are applied solely within this document.

Table I.1: Commonly Used Terms

Term	Definition
Supervisory Control and Data Acquisition	A category of software application programs for processing control and gathering data in real-time from remote locations in order to control devices and monitor conditions
Inter-Control Center Protocol	A protocol that allows for data exchange over wide area networks (WANs) between a utility control center and other control centers, other utilities, power pools, regional control centers, and non-utility generators. Data exchange information consists of real-time and historical power system monitoring and control data, including measured values, scheduling data, energy accounting data, and operator messages.
Remote Terminal Unit	A microprocessor-controlled electronic device that interfaces devices in the physical world to a distributed control system or SCADA system by transmitting telemetry data to a master system and using messages from the master supervisory system to control connected devices
Real-time Contingency Analysis	An application used to predict electrical system conditions after simulating specific contingencies. It relies on a base case from a state estimator or power flow case
State Estimator	An application used to calculate the current state of the electrical 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 of real-time system conditions for use by other network applications programs, such as power flow and contingency analysis
Automatic Generation Control	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. The AGC software uses real-time data such as frequency, actual generation, tie-line load flows, and plant controller status to determine generation changes

[5] It does not reflect binding norms or mandatory requirements.
[6] Glossary of Terms Used in NERC Reliability Standards: https://www.nerc.com/pa/Stand/Glossary%20of%20Terms/Glossary_of_Terms.pdf

Chapter 1: Approach and Data

The ERO Event Analysis Program[7] was established to facilitate the evaluation of events on the BPS in a systematic manner for reliability improvement purposes. The program provides insight and guidance by identifying and disseminating valuable information to owners, operators, and users of the BPS who enable improved and more reliable system operations. The program includes the ERO EAP[8] and the ERO CCAP.[9] The ERO EAP involves identifying what happened and is used to drive the ERO CCAP, which helps to understand "why it happened." The ERO CCAP allows events to have descriptive codes, characteristics, and attributes assigned that can be used to identify and study trends.

Based on the ERO EAP analysis, this document assesses the following factors to evaluate the contribution of EMS outage to loss of situational awareness risk and the effect from the EOP-004-4:

- **Outage Duration**
  Outage duration demonstrates the resilience of an EMS to recover the system or function(s). The shorter the outage duration, the stronger the resilience.
- **EMS Functions**
  SCADA is the heart of current EMS architecture. Loss or degradation of SCADA means that system operators would not have an indication of the status of devices or critical substation data points nor would they be able to open and close breakers or switch via remote operator control. Therefore, the loss of SCADA would likely be the most impactful EMS failure.

The impact of the loss of other EMS functions also depends on the roles that these EMS functions play in performing an entity's reliability functions.

- **Entity Reliability Functions**
  Entities use various EMS functions based on their reliability functions. For example, AGC and SCADA are critical for BAs to monitor and control generation output and calculate area control error. However, a TOP may use SCADA, SE, and RTCA to monitor and control the transmission network to keep the system in a reliable and secure operating condition.

This assessment also examines trends, event root causes, and contributing causes identified through the ERO CCAP for the 2018–2019 period. The top five contributing causes for the same period will be discussed in detail throughout this assessment document. EMS events analyzed in this assessment were Category 1h[10] events reported through the ERO EAP from 2018 to 2019.

Category 1h: Loss of monitoring or control at a Control Center such that it significantly affects the entity's ability to make operating decisions 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 RTUs
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

[7] The ERO Event Analysis Program: https://www.nerc.com/pa/rrm/ea/Pages/EA-Program.aspx
[8] The ERO Event Analysis Process: https://www.nerc.com/pa/rrm/ea/ERO_EAP_Documents%20DL/ERO_EAP_v4.0_final.pdf
[9] The ERO Cause Code Assignment Process: https://www.nerc.com/pa/rrm/ea/EA%20Program%20Document%20Library/CCAP_2020_02.pdf
[10] For the latest category definition: https://www.nerc.com/pa/rrm/ea/ERO_EAP_Documents%20DL/ERO_EAP_v4.0_final.pdf

Chapter 2: Analysis and Assessment

This section provides details regarding analysis results based on 162 EMS events reported in 2018 and 2019.

Overview Analysis

There were a total of 162 EMS events reported during the 2018–2019 time horizon through the ERO EAP. **Figure 2.1** shows the number of EMS events reported per year. United States entities reported 149 EMS events in these two years, encompassing approximately 92% of all EMS events reported. The number of entire EMS events reported declined from 88 in 2018 to 74 in 2019.

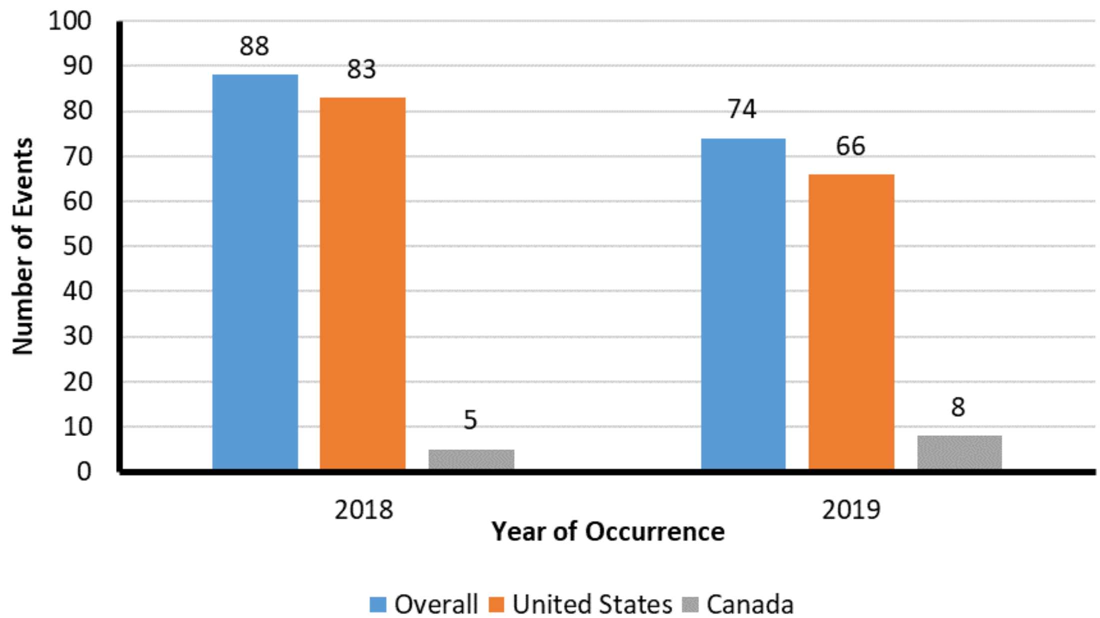


Figure 2.1: Number of Reported EMS Events (2018–2019)

These EMS events include the loss of SCADA, ICCP, remote terminal unit (RTU), AGC, SE, or RTCA for 30 or more continuous minutes. Over these two years, the loss of SE/RTCA was the most prevalent EMS failure totaling 52% or 84 events (see **Figure 2.2**). The loss of SCADA was the second leading failure in 29% or 47 events (see **Figure 2.2**) during the same period.

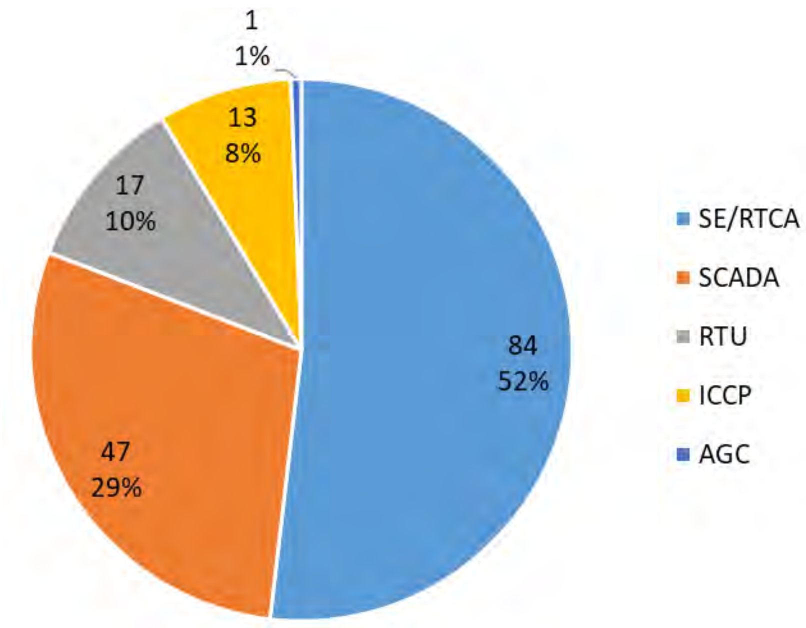


Figure 2.2: Percentage of Loss of EMS Functions (2018–2019)

Figure 2.3 shows a comparison of the reported EMS events by loss of EMS functions in 2018 and 2019. The number of loss of SE/RTCA and loss of ICCP events declined by 12 and 5 in 2019, respectively. Of note, the loss of SCADA and RTU remained stable. Only 1 loss of AGC was reported during these two years.

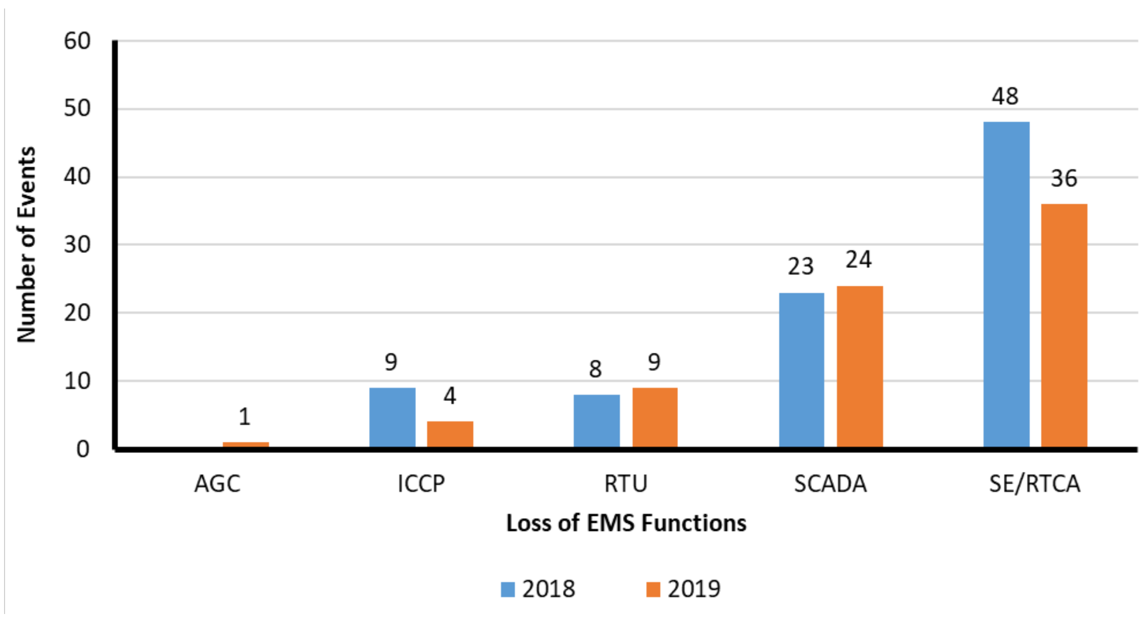


Figure 2.3: Number of Reported EMS Events by Loss of EMS Functions (2018–2019)

Outage duration indicates the resilience of an EMS to recover the system or function(s). Recall that the shorter the outage duration, the stronger its resilience. Figure 2.4 shows the median outage durations for all EMS events reported and all individual types of EMS functions. The median outage duration for all analyzed EMS events was 60 minutes for both 2018 and 2019. The median outage duration for the analyzed loss of SE/RTCA increased from 46 minutes in 2018 to 61 minutes in 2019 while the median outage durations for the loss of other EMS functions declined. The outage duration for the loss of AGC events was 31 minutes, just 1 minute beyond the reporting threshold (30 minutes).

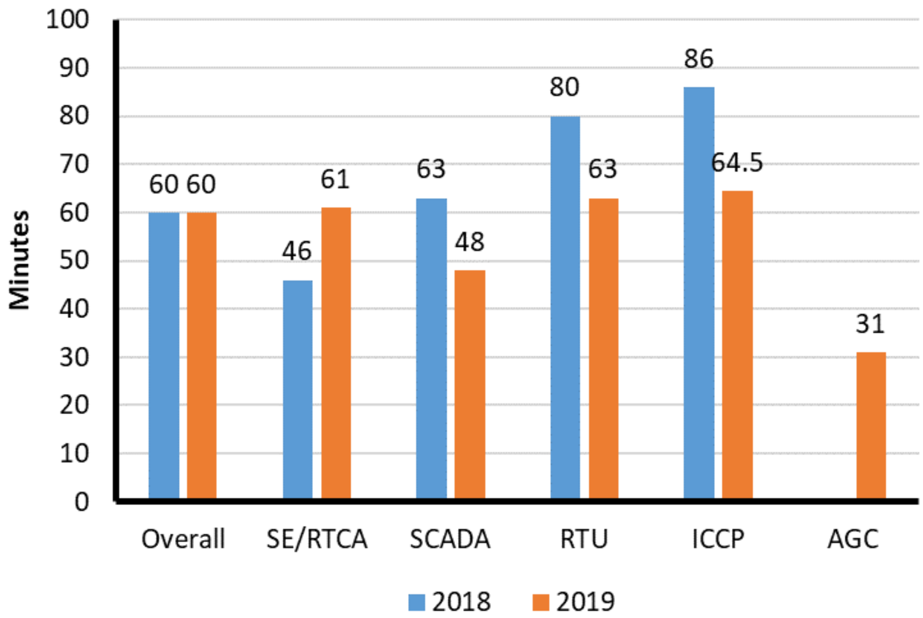


Figure 2.4: Median Outage Duration by Loss of EMS Functions (2018–2019)

It is notable that the median outage duration of the analyzed loss of SCADA decreased from 63 minutes in 2018 to 48 minutes in 2019. As previously mentioned, SCADA is the most critical function in the current EMS architecture. Over these two years, the loss of SCADA was stable while the associated median outage duration declined; it indicates that EMS reliability and resilience are continuously improving.

Analysis of Entity Reliability Functions

Entities use various EMS capabilities to perform their reliability functions. According to the NERC Compliance Registry (NCR) Active Entities List, as of March 27, 2020, there are 16 RCs, 341 TOs/TOPs, and 104 BAs for unique entities and reliability functions.[11] **Table 2.1** shows the number of entity reliability functions[12] that reported EMS events and participated in the ERO EAP in 2018 and 2019. **Table 2.2** shows the number of loss of EMS functions reported by entity reliability functions. Notably, TOs/TOPs reported 83% of all EMS events reported in these two years. Of the 136 EMS events reported by TOs/TOPs, a large portion of EMS events (50%) included the loss of SE/RTCA.

Table 2.1: Entity Reliability Functions with Reported EMS Events (2018-2019)

	2018		2019	
	Count	**Percentage**	**Count**	**Percentage**
RCs	8	**50%** (8/16)	3	**18.8%** (3/16)
TOs/TOPs	40	**11.7%** (40/341)	37	**10.9 %** (37/341)
BAs			3	**2.9%** (3/104)
Total	**48**		**43**	

[11] Each entity and reliability function is counted once regardless of how many regional CEA jurisdictions it may span.
[12] Based on the NCR Active Entities List as of March 27, 2020

Table 2.2: Number of Loss of EMS Functions Reported by Entity Reliability Functions						
	AGC	ICCP	RTU	SCADA	SE/RTCA	Total
RCs		5		1	16	**22**
TOs/TOPs		8	17	43	68	**136**
BAs	1			3		**4**

Reliability Coordinators

RCs are the highest level of authority responsible for the reliable operation of the BES and have a wide area view of the BES and have the operating tools, processes, procedures, and authority to prevent or mitigate emergency operating situations in both next-day analysis and real-time operations. Therefore, RCs will use all EMS capabilities to perform their reliability functions.

There were 22 EMS events reported by RCs over these two years. The number of EMS events reported by RCs slightly declined—12 events in 2018 and 10 in 2019 (see **Figure 2.5**). The number of EMS events reported by United States RCs notably declined from 8 in 2018 to 3 in 2019 while the number of EMS events reported by Canadian RCs increased from 4 in 2018 to 7 in 2019. It was noted that a few Canadian entities continue to report the partial loss events because the standard EOP-004-4 is not effective in some Canadian provinces.[13]

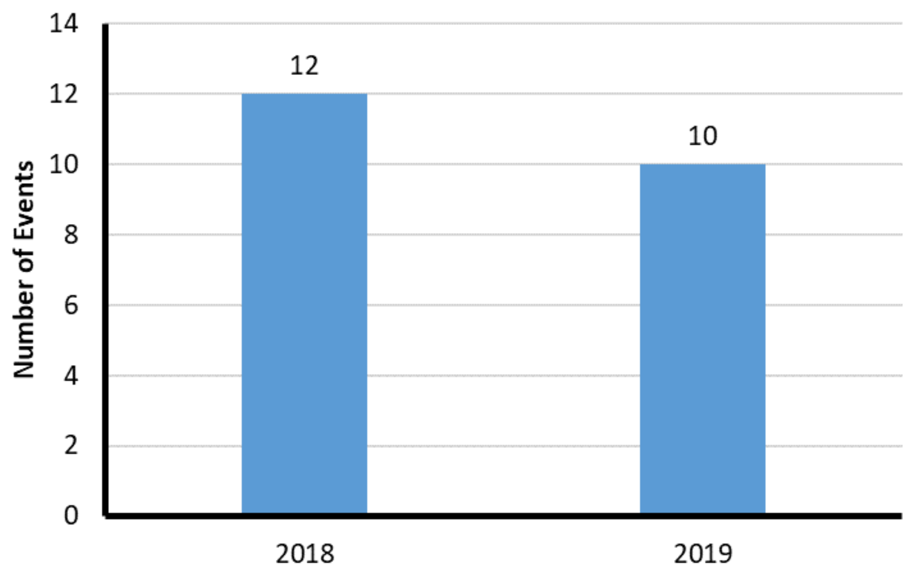


Figure 2.5: Number of EMS Events Reported by RCs (2018–2019)

Figure 2.6 shows the number of Canadian RC's EMS events by loss of EMS functions from 2018 to 2019. Canadian RCs reported the loss of SE/RTCA in both 2018 and 2019. The amount of loss of SE/RTCA increased from 3 in 2018 to 7 in 2019. The median number for Canadian RC's events analyzed increased from 61 minutes in 2018 to 90 minutes in 2019. It was observed that several EMS events reported by Canadian RCs in 2019 were due to two factors: modeling issues that led to a more prolonged troubleshooting and improper alarm configurations that caused a longer delay until system operators became aware of the issue.

[13] https://www.nerc.com/pa/Stand/Pages/ReliabilityStandards.aspx

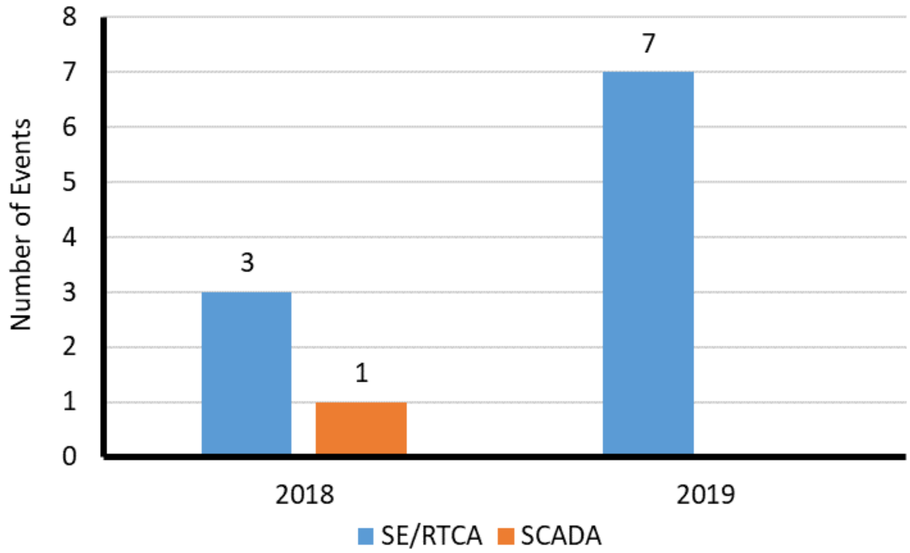


Figure 2.6: Canadian RC EMS Events by Loss of EMS Functions (2018–2019)

Figure 2.7 shows the number of United States RC EMS events by loss of EMS functions from 2018 to 2019. United States RCs reported the loss of SE/RTCA and loss of ICCP in both 2018 and 2019. However, the number of both failure-related events decreased. The median outage duration of United States RC's EMS events analyzed slightly declined from 55 minutes in 2018 to 48 minutes in 2019.

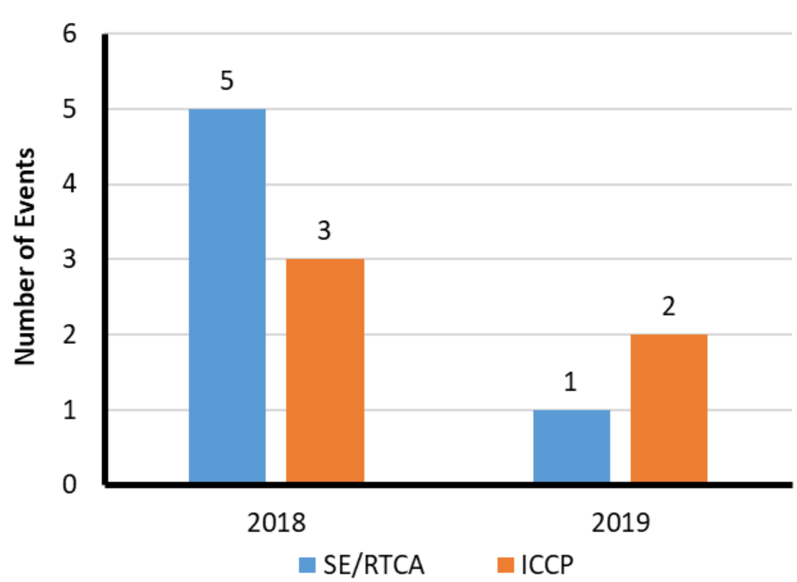


Figure 2.7: United States RC EMS Events by Loss of EMS Functions (2018–2019)

Notably, there was no loss of SCADA reported for 2019 by RCs. Based on the analysis of the EMS events reported by RCs, the following recommendations are made to reduce the loss of situational awareness risks due to EMS outage:

- **Maintaining models up to date**
  The models of the electrical 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 in service or aged devices are retired; otherwise, EMS functions cannot present

proper real-time changes (such as topology, MW output, etc.) related to these devices and sequentially yield unsolved or wrong solutions.

- **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. Therefore, to ensure redundant physical circuit separation and independence of supporting equipment and power, it is recommended that the duration of the service is specified in the contract. Also, to validate independence, it is recommended that testing is performed simulating this failure to ensure that the redundancy in place covers this scenario. More details on this topic can be found in the lessons learned titled *Telecom Provider Failure Induced Loss of ICCP from Regional Neighbors.*[14]

Transmission Owners and Transmission Operators

TOs are the entities that own and maintain transmission facilities. TOPs are the entities responsible for the reliability of "local" transmission systems and that operate or direct the operations of transmission facilities.

There were 136 EMS events reported by TOs/TOPs from 2018 to 2019. Over these two years, the loss of SE/RTCA was the most prevalent EMS failure in 50% or 68 events of all reported EMS events by TOs/TOPs (see **Figure 2.8**). **Figure 2.9** shows a detailed breakdown by the loss of EMS functions reported by TOs/TOPs. The loss of SE/RTCA events declined by 30% from 40 in 2018 to 28 in 2019, and the loss of ICCP events dropped by 67% over the same period. Of particular note, the loss of SCADA events remained stable in these two years.

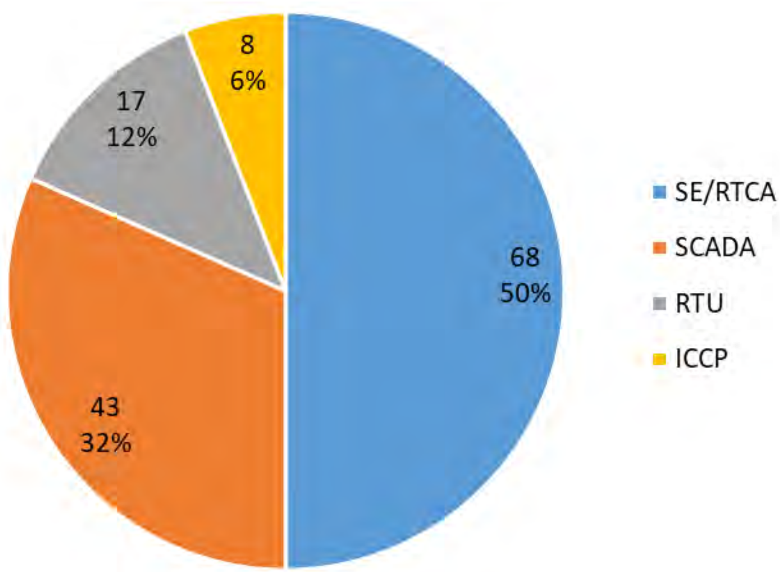


Figure 2.8: Percentage of Loss of EMS Functions Reported by TOs/TOPs (2018–2019)

[14] 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

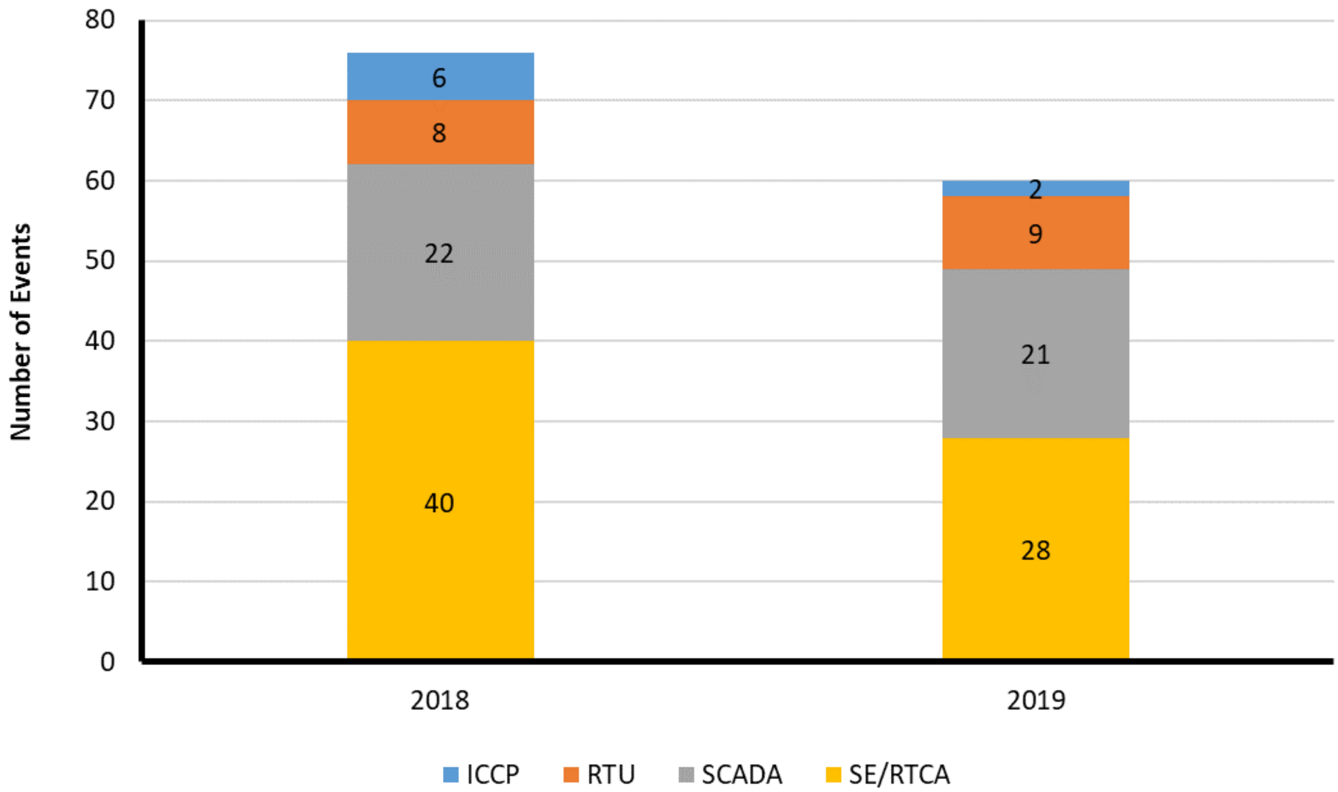


Figure 2.9: Breakdown of Loss of EMS Functions Reported by TOs/TOPs (2018–2019)

There are two reasons for the declining direction of loss of SE/RTCA and loss of ICCP:

- Partial loss events (such as loss of SE/RTCA, loss of ICCP) are no longer required as part of EOP-004-4 reporting. NERC standard EOP-004-4 was modified to only require 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, some entities still report partial EMS loss.
- The industry has made significant effort 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 to SE and RTCA. This action has significantly reduced the outage duration resulting in many SE/RTCA issues not being reportable.

Figure 2.10 shows the median outage durations for all TOs/TOP's EMS events and all individual types of EMS functions. The median outage duration for all TOs/TOP's EMS events was 60 minutes in 2018 and 2019. Of particular importance is that the median outage duration for the loss of SCADA reported by TOs/TOPs notably decreased from 71.5 minutes in 2018 to 46 minutes in 2019.

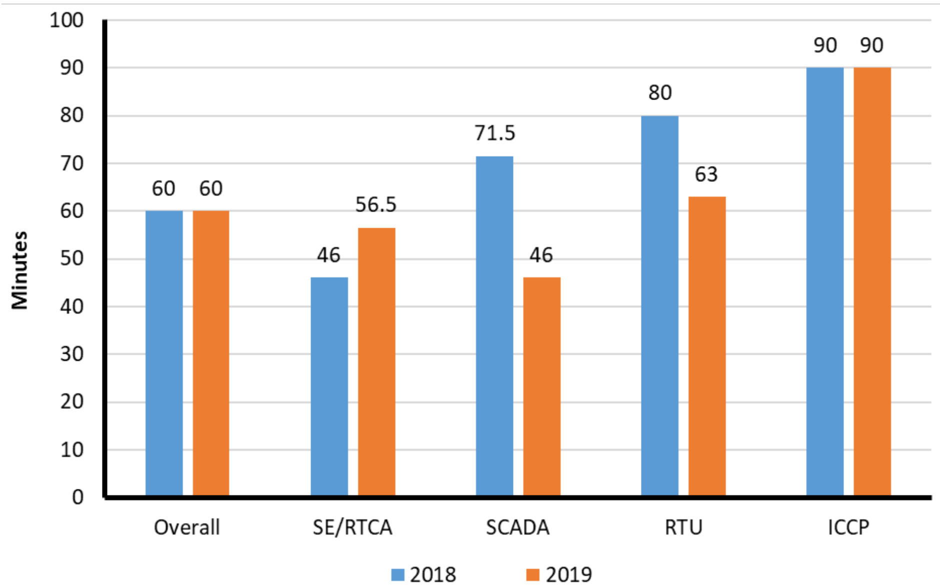


Figure 2.10: Median Outage Duration by Loss of EMS Functions—TOs/TOPs (2018–2019)

The following observations and recommendations were made during analysis of the EMS events reported by TOs/TOPs:

- **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, inaccurate topology modeling, and communication issues that may cause EMS events. There were 29 EMS events reported due to modeling issues, 22 of which were because of external modeling problems. 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.[15]

- **Network communications configuration**
  EMS related communications network moves from a point-to-point serial communication infrastructure to a packet-based network. The main advantage of the packet-based network is to transmit data from one node to many other nodes simultaneously and avoid the complete system failure caused by a breakdown of the single node. Consequently, the correct configuration is critical to ensure 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 (VoIP), and external facing networks is preferred over virtual local area network (VLAN) to avoid network traffic congestion and security issues.[16]

---

[15] 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

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

- **Alarming**
  Alarming has not initiated any EMS events. However, an improper configuration can degrade the system operator's situational awareness. Risk assessment should be performed to determine any gaps in alarming. Alarming regarding quantity, visualization, and even sound effects 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.[17]

- **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 created for monthly testing and maintenance of the backup generator, UPS, and associated power switches. More recommendations can be found in the lessons learned titled *Loss of Monitoring or Control Capability due to Power Supply Failure*[18] and *Loss of SCADA Operating and Monitoring Ability*.[19]

Balancing Authorities

BAs are the responsible entities that integrate resource plans ahead of time, maintain load-interchange-generation balance within a BA area, and support Interconnection frequency in real time. Consequently, AGC and SCADA are two essential EMS components for BAs to support their functions.

There were four EMS events reported by BAs in 2019 but none in 2018: One event was loss of AGC and three were loss of SCADA (see **Figure 2.11**). The median outage duration for these four analyzed events was 42.5 minutes. This is comparable to the median outage duration for entire events, RC's events, and TOs/TOP's events.

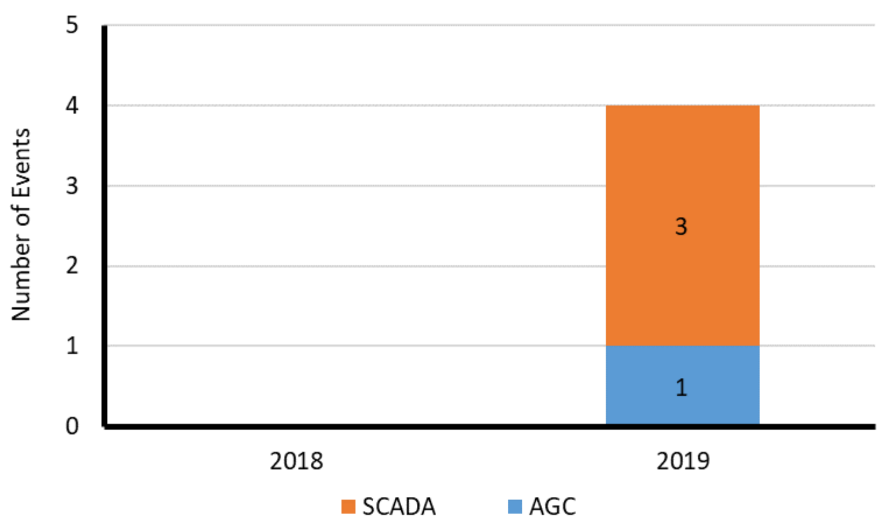


Figure 2.11: Number of EMS Events by Loss of EMS Functions—BAs (2018–2019)

[17] 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

[18] 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

[19] Lessons learned *Loss of SCADA Operating and Monitoring Ability:* https://www.nerc.com/pa/rrm/ea/Lessons%20Learned%20Document%20Library/LL20170503_Loss_of_SCADA_Operating_and_Monitoring_Ability.pdf

The loss of AGC event was resolved in 31 minutes, just 1 minute beyond the reporting threshold (30 minutes). The event was caused by a software glitch introduced during a weekly AGC software update. Although the event was resolved within a short duration, NERC recognizes AGC as a critical function for a BA and published a lesson learned titled *Loss of Automatic Generation Control during Routine Update* [20] to emphasize that a completed software testing process is critical to guarantee that products meet intended requirements.

All three loss of SCADA events were related to firewall issues. Two events were caused by firewall hardware failure, and another one was due to an improper firewall configuration. To prevent recurrence of the events, entities should maintain network devices on a scheduled basis in accordance with the latest vendor information, security bulletins, technical bulletins, and other recommended updates.

Analysis of Root Causes and Contributing Causes

This section will discuss the event root causes and contributing causes identified through the ERO CCAP for the years 2018 and 2019. Of the 162 EMS events reported from 2018 to 2019, 147 EMS events were processed through the ERO CCAP because the processing of 2019 EMS events is ongoing.

Event Root Causes

A root cause is the fundamental reason for the occurrence of a problem or event. Analysts identify the root cause of an event in order to prevent it from happening again in the future; if it were not for the root cause, an event would not take place. It is important to determine roots causes so that corrective actions can be implemented to avoid a repeat of the event.

Of the 147 EMS events processed, 49 events did not yield a root cause, resulting in dependence on the contributing causes for insights into the associated events. The top three common reasons for the less-than-optimal root cause yield include the following:

- **Vendor cited as involved in event**
  Some EMS events were due to defects in software, firmware, or hardware provided by vendors. This is beyond the entity's control/direction. The entity does not know why it is wrong, but a patch, fix, or upgrade provided by the vendor resolves the issue.

  To prevent this type of event, entities may consider the following:

  - Maintaining network devices on a planned schedule in accordance with the latest vendor information, security bulletins, technical bulletins, and other recommended updates
  - Periodically reviewing system parameters and settings with the vendor's help (there are different flags and weighting levels that may need to be adjusted as models are expanded or system conditions change.)
  - Continuing to develop dedicated in-house expertise and/or acquire third party services onsite (more skilled in-house personnel who can troubleshoot and correct these issues can lead to shorter EMS outage durations, including additional knowledge transfer from the vendor to the in-house staff.)

- **Report stops at failure or error mode**
  For some EMS events, the entity knows what happened but does not understand why it happened due to a lack of information. For example, SE failed to converge for more than 30 minutes due to bad data from a select RTU. After testing and inspection of the RTU, no defects were found. Because the root cause was not identified, the same problem likely will occur in the future. The entity should install enhanced detective controls to discover the issue and recover quickly.

[20] 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

- **Other NERC-registered entity cited as involved in event**
  This type of event usually is data related. For example, a neighboring entity sends data that indicates a unit generates 3,000 MVar reactive power, unreasonable for this type of unit. This data causes the entity's SE failure.

  To prevent this type of event, entities may consider the following:

  - Entities should implement or enhance a tool or feature that prevents, detects, and corrects the data error before it is used in EMS functions, especially in SE. As an example of the unreasonable 3,000 MVar reactive power, a bad data detector would be implemented in the SE module. Firstly, the detector identifies the bad data based on the pre-defined unit MVar limit and labels it for the system operator's awareness. Secondly, the detector excludes the bad data from the SE computation. Finally, it replaces the bad data with the last-good value, a unit MVar limit, or a value calculated from good surrounding measurements.
  - Entities should communicate with RC and neighbor entities about the data error to understand why the data error was sent and how they resolved it.

Management/Organization was identified as the leading root cause in 46% (see **Figure 2.12**) of the 98 identified root cause events. Some topics considered in Management/Organization causes are management/supervisory methods, resource management, work organization and planning, and change management efforts. Some examples of these causes are as follows:

- Management/Organization had the correct identification of a cause for a previous event but failed to implement a good corrective action plan prior to another similar event occurring.
- Management/Organization did not identify a special circumstance that needed to be addressed during work, and failed to recognize that a second system might be impacted by work currently being performed. For example, an entity updated its external model based on the Common Information Model from its RC. However, the project scope failed to identify a special circumstance that the Common Information Model was exported from the RC's market system. Many parameters related to the voltage control were neither correct nor up-to-date in the market system. As a result, the entity's SE failed to converge at the external area due to low voltage.

Design/Engineering was the second leading cause in 30% (see **Figure 2.12**) of the 98 identified root cause events. Cause considerations include design input, design output, documentation, installation, verification, and operability of design and/or environment issues. Some examples of these causes are a shortfall in the scoping of the design failing to realize that an alarm system was not configured to account for stale SCADA data or obsolete SE/RTCA solutions.

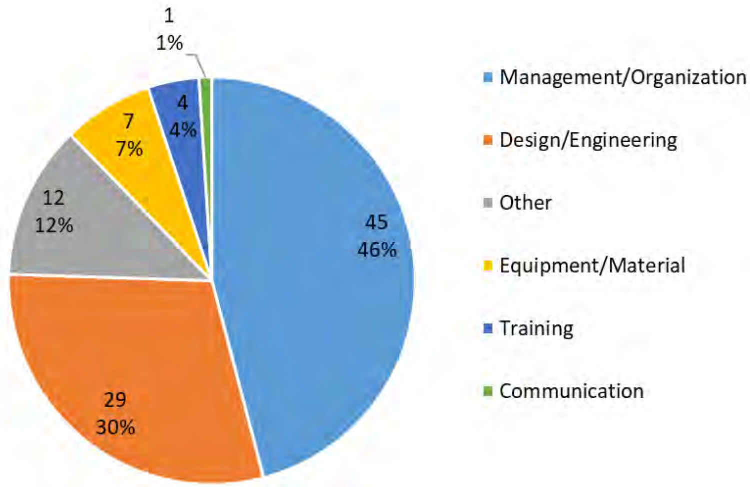


Figure 2.12: 2018–2019 Identified EMS Event Root Causes (Processed to date)

Contributing Causes

A contributing cause is not a single factor that drives an event. Tracking and trending of contributing causes may identify the need to take action. **Figure 2.13** shows a trend of identified contributing causes for all processed EMS events from 2018–2019.

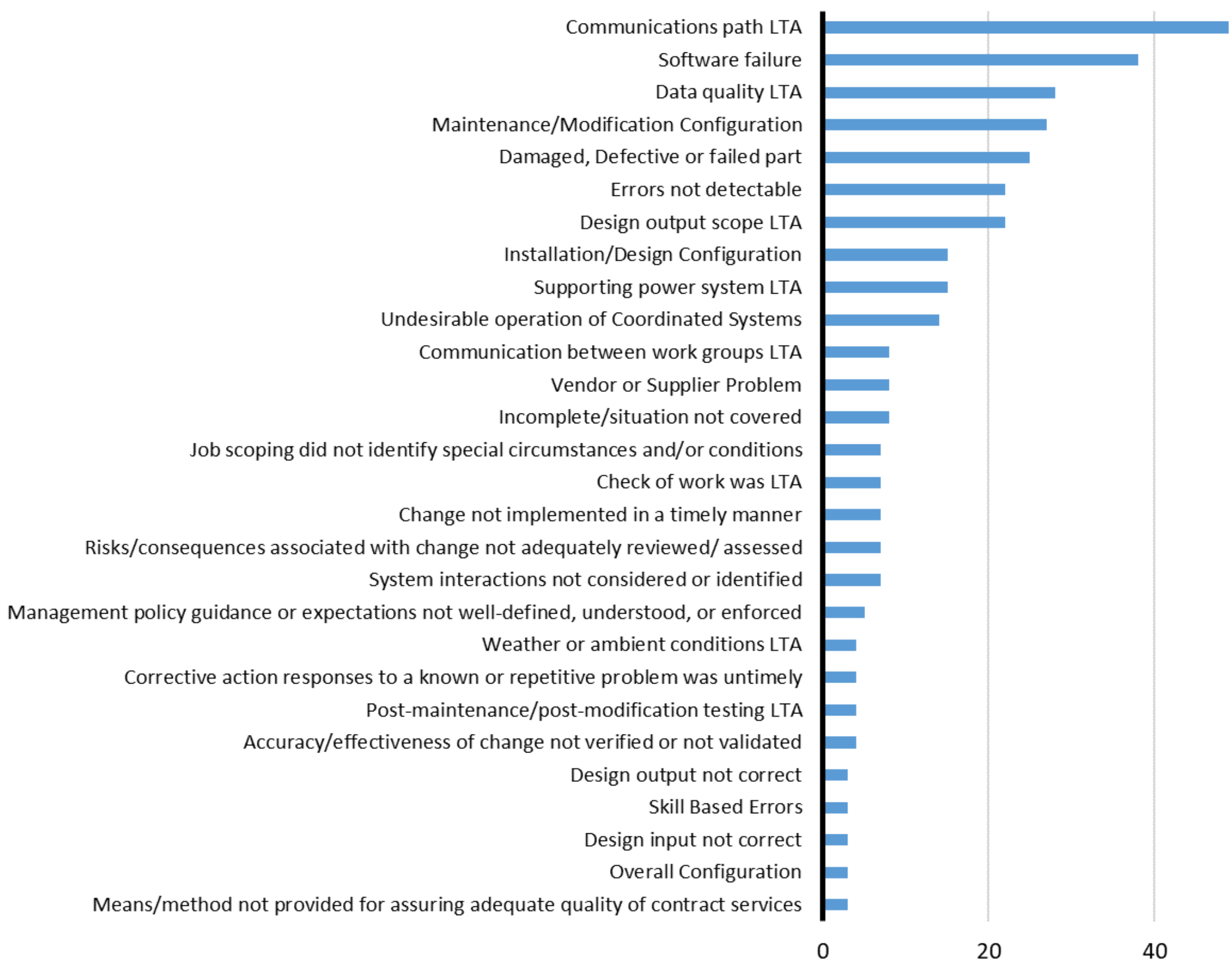


Figure 2.13: Identified Contributing Causes for EMS Events (2018–2019)

The top five detailed contributing causes are listed below:

- **Communications path less than adequate**[21]
  "Communications path less than adequate" was identified as the leading contributing cause. This cause indicates that data exchange was degraded between substations and control rooms or between the entity and its RC/neighboring entities. Internal network configuration error and hardware failure at the telecom company are two major contributors to this cause; it occurred a total of 18 times as a contributing cause due to a network configuration error and a total of 11 times due to an issue arising at a telecom company. An example is spanning-tree protocol implementation in a network switch, causing a loop that generated an exceptionally high volume of traffic. The result was to shut down the communication network supporting the EMS. Another example is that the entity lost RTU data from major substations as the telecom company's staff cut the fiber between the substations and the data center. Entities should maintain network devices on a schedule in accordance with the latest vendor information, security bulletins, technical bulletins, and other recommended updates. Entities must also consider redesigning communications systems such that the most critical BES substations communicate simultaneously over entirely separate physical paths (and possibly separate vendors) to both control centers, eliminating the need for telecom company communication structure.

- **Software failure**
  "Software failure" was the second-leading contributing cause. It occurred 38 times as a contributing cause. A bug either in vendor's applications or in an in-house implementation caused the software failure. No matter what the error source is, a completed software testing process is always recommended to guarantee that the software meets its requirements. In general, the process is considered to have four components:

  - **Test Scope**: define test environment requirements and setup, features/functions that need to be tested, documentation to refer and produce as output, approval workflows, etc.
  - **Test Design**: design test cases that are necessary to validate the system/functions/features being built compared to its design requirements. Typically, regression testing and incremental testing are 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 a release

- **Data quality LTA**
  "Data quality LTA" was identified as a contributing cause 28 times. Bad data from the external area was a major contributor to this cause. The entity was encouraged to implement or enhance a tool or feature that can prevent, detect, and correct the data error before the data error is used in EMS functions, especially in SE. Communications between the entity and its RC/neighboring entities are critical to detect, block, and correct these less-quality data.

- **Maintenance/Modification configuration**
  "Maintenance/Modification Configuration" was identified as a contributing cause 27 times. Besides the network configuration error mentioned in above sections, the error in settings/parameters for SE/RTCA are a major concern. These SE/RTCA settings and parameters are often uniquely programmed for the entity to meet the individual needs based upon the entity's configuration, topology, contingencies, and external model. When the entity expanded or modified its model, the settings/parameters needed to be tuned or calibrated based upon subsequent topology changes. Periodic reviews of SE/RTCA settings and parameters with the vendor's help may be necessary to ensure that the SE/RTCA continues to converge and produce a quality solution. The frequency of these reviews will vary, but consideration to reviewing the settings and

[21] For the purposes of the CCAP, the phrase "Less Than Adequate," or "LTA," does not imply any negligence or fault for the entity; it is solely intended to say that the situation to which the LTA is assigned was not sufficient to prevent the undesired situation from occurring.

parameters following model changes, generation retirements, software upgrades, and any other significant changes made to the EMS system or the model is necessary.

- **Damaged, defective or failed part**
  "Damaged, defective, or failed part" was identified as a contributing cause 25 times. Telecommunication hardware failure and power supply hardware failure are two significant contributors to this cause. The telecommunication hardware failure typically occurred on routers, switches, or fiber. For the failure of power supply hardware, the two main types of equipment were UPS and automatic transfer switch.

  Utilities should build an asset management system to manage the entire life cycle of these devices to identify and manage risks. The life cycle could include design, construction, commissioning, operating, maintaining, repairing, modifying, replacing, and decommissioning/disposal.

Agenda Item 11
Reliability and Security Technical
Committee Meeting
March 2, 2021

Geomagnetic Disturbance Research Work Plan Results and Recommendations

Action
Approve

Summary
Over the period of 2018-2020, the Electric Power Research Institute (EPRI) has led a research program with industry and research partners to address objectives related to Reliability Standard TPL-007 (GMD Vulnerability Assessments). The research plan was developed by NERC with input from the GMDTF and NERC Planning Committee to address research directives in FERC Order No. 830. GMDTF leadership will inform the RSTC leadership of the research results summary and ERO recommendations. The Chair will make a formal request to disband the GMDTF as they have completed their work.

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Order No. 830 GMD Research Work Plan

Results and Recommendations for the ERO

February 2021

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

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

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

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

Executive Summary

Beginning in 2018, NERC and its technical committees partnered with the Electric Power Research Institute (EPRI) and North American utilities in a wide-ranging research project to further the understanding of severe geomagnetic disturbance (GMD) risk to the North American BPS. Launched following the regulatory approval of new GMD Reliability Standards, the project scope included examining the technical underpinnings of the Reliability Standards and advancing the state-of-the-art tools, techniques, and processes used by owners and operators to assess and mitigate severe GMD event risks. Over the course of the three-year project, EPRI has released 17 publications supporting NERC and the industry's efforts to implement effective GMD Reliability Standards.

NERC's GMD Reliability Standards are important tools for reducing the risk of severe, rare GMD events from disrupting the electric grid upon which our North American society depends. NERC and the electric industry, in consultation with research partners at NOAA, NASA, and Space Weather Canada, began development of Reliability Standards in 2013. These standards establish requirements for owners and operators to study and design their systems to be resilient during a severe 100-year GMD, as well as to implement operating procedures during strong GMD events that can reduce system impacts.

In approving GMD Reliability Standards, the Federal Energy Regulatory Commission (FERC) recognized that "the understanding of threats posted by GMD is evolving as additional research and analysis is conducted."[1] FERC directed NERC to submit a research work plan addressing research areas related to the TPL-007 Reliability Standard and provide informational filings. Collectively, the tasks in GMD Research Work Plan were directed at the following areas:

- Evaluate the severe GMD event benchmarks that are the basis for the industry's GMD Vulnerability Assessments with the latest space weather data sets and new space weather simulation models
- Improve the accuracy of ground conductivity models used by BPS planners for GMD Vulnerability Assessments
- Further study the impacts of GIC from severe GMD events on BPS transformers and other BPS equipment
- Develop tools for BPS planners to use in performing GMD Vulnerability Assessments.

Outcomes from this research project affirm the efficacy of the TPL-007 Reliability Standard and provide tools and insights for the ERO, industry, and research partners to use in accurately performing GMD Vulnerability Assessments. Below is a summary of key findings and outcomes that are described in later sections and available in the published reports (see list in the appendix.) EPRI has made all reports in the GMD Research Work Plan available to the public at no cost.

- Analysis of an extensive space weather data set supports the industry's use of the Benchmark GMD Event to represent a severe 100-year GMD event in GMD Vulnerability Assessments. Research into the characteristics and spatial scales of extreme GMD events (i.e., geographic size, locations affected, durations, intensity and direction) provided additional insight about geoelectric field enhancements that can occur during severe GMD events. These details can assist industry planners with how they apply the Supplemental GMD Event to assess the impact that geoelectric field enhancements can have on the system.
- Scaling the peak geoelectric field of the Benchmark GMD Event according to the geomagnetic latitude of the system area is consistent with analysis of space weather data and advanced simulation modeling. Researchers confirmed that the geoelectric field intensity during a severe 100-year GMD event is expected to decrease by an order of magnitude across the 60-degree to 40-degree geomagnetic latitude band.
- Newly-available earth conductivity data for the U.S. was used to better define regional boundaries in conductivity maps used by industry to calculate geoelectric fields. Through the GMD Research Work Plan,

[1] FERC Order No. 830, P. 76

conductivity maps, earth models, and earth conductivity scaling factors are available for industry and software designers to use in performing GMD Vulnerability Assessments. These models cover the North American BPS, with uncertainty only in regions where magnetotelluric (MT) measurements or other modeling information is unavailable to perform comparisons. In addition, EPRI published technical guidance for validating models with GIC and magnetometer data collected during actual GMD events.

- The GMD Research Work Plan improved industry capabilities for assessing transformer thermal impacts from GMD events and provided further technical justification for the 75 A/phase screening criterion used in TPL-007 to mitigate risk to the BPS. The research produced thermal models for over 80 different transformer types and designs which can be used in an industry-available thermal modeling tool. Simulations using the expanded set of models indicate that the TPL-007 thermal impact screening criterion is generally effective, however specific designs were identified that could possibly exceed transformer thermal criteria. The findings enable industry to expand screenings for these designs and perform additional risk analysis.
- EPRI developed an open-source tool that industry can use to perform GMD-related harmonic studies of the power system and made it available at no cost. GMD-related harmonics are caused by the part-cycle saturation of transformers. These harmonic currents and voltages resulting from transformer saturation can impact system operations during severe GMD events. The tool, *GICHarm*, provides planners with capability to perform wide-area harmonic analysis that existing commercial tools did not address.
- Research on transformer mechanical vibrations caused by GIC concluded that severe GMD events are not likely to adversely impact transformer mechanical integrity. EPRI, participating utilities, and transformer manufacturers collaborated to examine factory and field test data on power transformers of various construction types and sizes. Among other findings, the factory data revealed that vibrations reach their maximum at low levels of GIC and do not increase significantly as GIC levels rise.

The completion of the GMD Research Work Plan is an important milestone in the ERO and industry's comprehensive approach to reducing the risks that severe GMD events can pose to the reliability and resilience of the North American grid. Results do not reveal reliability gaps in the approved TPL-007 Reliability Standard and provide technical details that justify its use and support its application in assessing and reducing risk to the electricity grid. The ERO will consider these research results and potential modifications to the standard, however, as part of normal periodic review of standards as prescribed in NERC's Rules of Procedure. Additionally, in 2020, the ERO added another component to the GMD risk reduction effort by implementing its NERC Rules of Procedure Section 1600 Data Request for the collection of GIC and magnetometer data during strong GMD events.[2] GMD data from this program can support industry and researchers as they develop and improve their GIC models and advance the state-of-the-art in GMD vulnerability assessment capabilities.

[2] See the NERC GMD Data Collection page: https://www.nerc.com/pa/RAPA/GMD/Pages/GMDHome.aspx

Introduction

Background

In Order No. 830, FERC approved Reliability Standard TPL-007-1 - Transmission System Planned Performance for Geomagnetic Disturbance Events. In this order, FERC also directed NERC to submit a work plan to conduct research on certain GMD-related topics.[3] NERC's GMD Research Work Plan (Work Plan) was accepted by FERC in Order No. 851.

GMD Work Plan Overview

The Work Plan consisted of the following nine research "Tasks":

1. Further Analyze Spatial Averaging Used in the Benchmark GMD Event[4]
2. Further Analyze Latitude Scaling
3. Improve Earth Conductivity Models for GIC Studies
4. Study Transformer Thermal Impact Assessment Approach
5. Further Analyze the 75 Amps per Phase Criterion Used for Transformer Thermal Impact Assessments
6. Support for Section 1600 Data Request
7. Geoelectric Field Tool Evaluation and Calculation of Beta Factors
8. Improve Harmonics Analysis Capability
9. Harmonic Impact Studies

NERC developed the research activities in coordination with EPRI, NERC's research collaborators, and stakeholders, to advance industry understanding of GMD risk to the BPS and achieve research objectives specified in Order No. 830. The research direction was based on current capabilities, resources, and understanding.

EPRI is a nonprofit corporation organized under the laws of the District of Columbia Nonprofit Corporation Act and recognized as a tax-exempt organization under Section 501(c) (3) of the U.S. Internal Revenue Code of 1986, as amended. EPRI was established in 1972 and has principal offices and laboratories located in Palo Alto, California; Charlotte, North Carolina; Knoxville, Tennessee; and Lenox, Massachusetts. EPRI conducts research and development relating to the generation, delivery, and use of electricity for the benefit of the public. An independent, nonprofit organization, EPRI brings together its scientists and engineers as well as experts from academia and industry to help address challenges in electricity, including reliability, efficiency, health, safety, and the environment.

Work Plan Implementation

NERC and EPRI initiated the Work Plan in November 2017 with funding commitment of $3.5M from participating EPRI members and NERC. The Work Plan was concluded in the first quarter of 2020. NERC and EPRI made technical reports and other deliverables available to the public free of charge. In July 2020, NERC made an informational filings to FERC that contain hyperlinks to the technical reports completed up to that date.[5] This summary report of results and recommendations, and links to all final technical reports, will be filed with FERC.

[3] Order No. 830 at P 22 and P 77.

[4] Benchmark GMD Event white paper: https://www.nerc.com/pa/Stand/Project201303GeomagneticDisturbanceMitigation/Benchmark_Clean_May12_complete.pdf

[5] Informational Filing of NERC Regarding Work Performed Under the Geomagnetic Disturbance Research Work Plan: https://www.nerc.com/FilingsOrders/us/NERC%20Filings%20to%20FERC%20DL/First%20%20Info%20Filing%20re%20%20GMD%20Work%20Plan%20(7-26-2019).pdf

Task 1: Further Analyze Spatial Averaging Used in the Benchmark GMD Event

Summary

The activities in this task consisted of performing further research and analysis on geoelectric field enhancements and the use of spatial averaging in defining benchmark GMD events that entities use when conducting the GMD Vulnerability Assessments required by the TPL-007 standard.

Background

Reliability Standard TPL-007-1 requires entities to conduct initial and ongoing assessments of the potential impact of a defined GMD event on BPS equipment and the BPS as a whole. This defined GMD event, referred to as the benchmark GMD event in TPL-007-1, and relies upon the use of an innovative spatial averaging technique to estimate the wide area impacts of a GMD event on the BPS. In Order No. 830, the Commission approved the benchmark GMD event but noted its concern that a spatially averaged benchmark may not adequately account for localized peak geoelectric fields that could potentially affect reliable operations. Accordingly, the Commission directed NERC, as part of the Work Plan, to "further analyze the area over which spatial averaging should be calculated for stability studies, including performing sensitivity analyses on squares less than 500 km per side (e.g., 100 km, 200 km)."[6]

Broadly speaking, the research falling under **Task 1** would consist of two main components: (i) research to improve understanding of the characteristics and spatial scales of localized geoelectric field enhancements caused by severe GMD events; and (ii) research to determine the impacts of spatial averaging assumptions on BPS reliability.

Task 1 also provides insights for application in subsequent versions of the TPL-007 standard. For example, proposed Reliability Standard TPL-007-2 was developed to address FERC directives including concerns that the benchmark GMD event may not adequately account for localized peak geoelectric fields.[7] The proposed standard requires entities to perform supplemental GMD Vulnerability Assessments in addition to the benchmark GMD Vulnerability Assessments. Supplemental GMD Vulnerability Assessments are based on the supplemental GMD event, a second defined event that accounts for localized peak effects of GMDs and which is based on individual station measurements (i.e. not spatially averaged data). As noted, **Task 1** research also supports understanding characteristics and spatial scales of localized geoelectric field enhancements to inform the supplemental GMD event description.

Activities

Research Task Overview: Perform Research to Improve Understanding of Characteristics and Spatial Scales of Localized Geoelectric Field Enhancements Caused by Severe GMD Events

Product: *Furthering the Understanding of the Characteristics and Scales of Geoelectric Field Enhancements. EPRI, Palo Alto, CA: 2020. 3002017900.*

Summary: EPRI investigators developed and analyzed an extensive data set to address questions regarding the occurrence, strength, and direction of GMD as well as examine the effects of spatial averaging to determine input waveforms. EPRI collaborated with researchers at the Los Alamos National Lab (LANL) to develop a comprehensive data set that will analyze severe GMD event characteristics. Researchers obtained and processed magnetic field data from a global consortium of magnetic observatories to create a single data set to analyze large GMD events across magnetometer stations of interest. [8] The data set was used in subsequent analysis.

[6] Order No. 830 at P 26.
[7] *See* TPL-007-2 Petition at Section IV.
[8] See *Improving Understanding of Characteristics of Geoelectric Field Enhancements Caused by Severe GMD Events: Examining Existing Ground-Based Data.* EPRI, Palo Alto, CA: 2019. 3002016832.

Outcomes: The research findings support the TPL-007 Reliability Standard and add to the body of knowledge for performing accurate GMD vulnerability assessments.

Characteristics of geoelectric field enhancements during strong GMD events:

- **Geographic Size, strength, and direction.** Spatial scales are on the order 200-300km. Enhancements are not expected to cover areas less than 200km. Assessments of the impact of localized enhancements should not use scale sizes smaller than 200 km to represent the localized enhancement; using a 200 x 200 km area for localized enhancement—with the supplemental peak electric field—for impact analysis should provide a conservative estimate of the system impact. The direction of the geoelectric field within the localized region can be treated as independent of the direction of the geoelectric field in the surrounding region.
- **Locations affected.** Peaks in GMD are largely confined to the auroral zone. As the auroral zone expands during strong geomagnetic activity, this exposes locations further equatorward to GMD hazards. Localized enhancements should be considered in impact assessments for regions that would reasonably expect to be in the auroral zone during a severe GMD event.
- **Durations.** Typical durations of around 2.5 minutes, with durations in excess of 8 minutes being rare.

Research Task Overview: Determine the Impacts of Spatial Averaging Assumptions on the BPS

Product: *Furthering the Understanding of the Characteristics and Scales of Geoelectric Field Enhancements. EPRI, Palo Alto, CA: 2020. 3002017900.*

Summary: EPRI investigators performed analysis to compare power system impacts of localized enhancements. The analysis included studying GIC and system voltages with and without a 200 km square geoelectric field enhancement applied to various synthetic planning areas.

Outcomes: The research findings support the TPL-007 Reliability Standard and add to the body of knowledge for performing accurate GMD vulnerability assessments. The presence of a localized enhancement will increase GIC flow, reactive power losses and reduce system voltages in the vicinity of the geoelectric field enhancement. These effects are not limited to within the localized enhancement itself (i.e., other parts of the planning area also exhibited increased GIC and voltage impacts).

ERO Recommendation

The ERO should:

- Monitor further research performed by the space weather community to characterize the characteristics of extreme GMD events including localized geoelectric field enhancements.
- Engage TPL-007 applicable entities through the RSTC and industry forums to promote awareness of these research findings and promote use of best practices

Task 2: Further Analyze Latitude Scaling

Summary

The activities in this task consisted of evaluating the latitude scaling factors in Reliability Standard TPL-007-1, including using existing models and developing new models to extrapolate, from historical data, the potential scaling of a 1-in-100 year GMD event on lower geomagnetic latitudes.

Background

The benchmark GMD event defined in TPL-007-1 includes scaling factors to enable entities to tailor the geoelectric field to their specific location for conducting GMD Vulnerability Assessments. These factors are intended to account for differences in the intensity of a GMD event due to geographical considerations, such as geomagnetic latitude and local earth conductivity. Finding that there are "questions regarding the effects of GMDs at lower geomagnetic latitudes," the Commission directed NERC to reexamine the geomagnetic latitude scaling factors provided in TPL-007-1.[9] Consistent with the Commission's directive, NERC would use existing models and develop new models to extrapolate from historical data the impacts of a large, 1-in-100 year GMD event on lower geomagnetic latitudes under this task.

Task 2 also provides insight for application in subsequent versions of the TPL-007 standard. For example, proposed Reliability Standard TPL-007-2 also uses latitude-scaling factors.

Activities

Research Task Overview: Analyze scaling the geoelectric field of severe GMD events for magnetic latitude

Product: *Magnetohydrodynamic (MHD) Modeling for the Further Understanding of Geoelectric Field Enhancements and Auroral Behavior During Geomagnetic Disturbance Events. EPRI, Palo Alto, CA: 2020. 3002017952.*

Summary: Researchers developed an algorithm to estimate the auroral boundary, which separates the quieter subauroral region from the more geomagntically disturbed auroral region. During the evolution of a large geomagnetic storm, this boundary has been observed using ground-based magnetometers to move toward the equator. Researchers have limited data to understand the phenomenon because the spatial density of magnetometers for these networks is often low. In addition, for high-impact, low-frequency events, there are a limited number of storm examples for digital magnetometer network databases.

MHD simulations of the near-Earth environment (such as the Space Weather Modeling Framework (SWMF)) are now available that can be used to simulate different configurations of large geomagnetic storm events and to specify the resolution of the outputs. Using these, resesearchers investigated the auroral boundary and geoelectric field enhancement characteristics using higher-density magnetic field outputs, as well as larger storm events. Threshold boundaries from simulations were consistent with those calculated from historical geomagnetic field data, indicating that the simulations can reproduce observed boundary behavior.

Outcomes: The research findings support the TPL-007 Reliability Standard and add to the body of knowledge for performing accurate GMD vulnerability assessments.

- Using estimates for a 1-in-100-year geomagnetic storm Dst, the auroral threshold in simulation is between 43° and 50° MLAT.

[9] Order No. 830 at P 57.

- NASA researchers concluded that, taking into account the uncertainties in determining the precise auroral region location, the boundary residing in the 43–50° band is consistent with the current benchmark latitude scaling that indicates an order-of-magnitude increase in the geoelectric field amplitudes across the band of 40–60° of geomagnetic latitude.

ERO Recommendation

The ERO should monitor further research performed by the space weather community to characterize the latitude thresholds of extreme GMD events.

Task 3: Improve Earth Conductivity Models for GIC Studies

Summary

The research activities under this task consist of activities to evaluate the accuracy of existing earth conductivity models for GIC studies, provide updates based on newly-available data, and give guidance where needed.

Background

In Order No. 830, the Commission expressed concerns regarding the ground conductivity models that form the basis for the earth conductivity scaling factors used in TPL-007-1 and directed NERC to study this issue as part of its Work Plan.[10] Accordingly, research activities in **Task 3** address the Commission's specific concerns, including comparing the accuracy of geomagnetically induced current (GIC) calculations derived from available 1D models with 3D models that have recently been developed for some areas of the U.S. and examining modeling to account for "coast effects."

Task 3 research will support accuracy of GIC calculations performed to meet requirements in TPL-007-1 and subsequent versions of the standard.

Activities

Task 3A Research Overview: Use Magnetotelluric Measurement Data to Validate/Improve Existing Earth Conductivity Models Available to Industry and Researchers

Product: *Use of Magnetotelluric Measurement Data to Validate/Improve Existing Earth Conductivity Models. EPRI, Palo Alto, CA: 2020. 3002019425.*

Summary: This report provides the results of EPRI's earth conductivity model evaluation project. Newly-available magnetotelluric data from NSF Earthscope have supported the development of ground response models, also known as three-dimensional or 3D models, that capture directional variability.[11, 12] These new models can also provide more localized information about the induced geolectric fields in comparison to the average response that results from the use of one-dimensional (1D) or scaling factor techniques that have been predominant in GIC estimation and hazard analysis. However, geoelectric field calculations using these 3D models are more complex, and their use in GIC estimation is at an earlier stage. The EPRI analysis compares estimates of electric field peak intensity derived from 3D and 1D conductivity profiles with the goal of identifying differences between these models and potential areas of improvement for their use in GIC estimation and hazard analysis.

EPRI estimated geoelectric fields using existing 1D models[13] and 3D models derived from electromagnetic transfer functions (EMTFs) based on the U.S. National Science Foundation (NSF) Earthscope project measurement data. At the time of EPRI's work the Earthscope project had completed MT mapping of much of the northern half of the contiguous United States (U.S.) (See Figure 1).

[10] Order No. 830 at PP 78-80.

[11] Schultz, A., G. D. Egbert, A. Kelbert, T. Peery, V. Clote, B. Fry, and S. Erofeeva, USArray TA magnetotelluric transfer functions, Technical Report, National Geoelectromagnetic Facility: 2006-2017.

[12] Kelbert, A., G. Egbert, and A. Schultz, IRIS DMC Data Services Products: EMTF, the magnetotelluric transfer functions, Tech. rep. National Geoelectromagnetic Facility, 2011-2017.

[13] *One-Dimensional Earth Resistivity Models for Selected Areas of Continental United States and Alaska.* EPRI, Palo Alto, CA: 2012. 1026430.

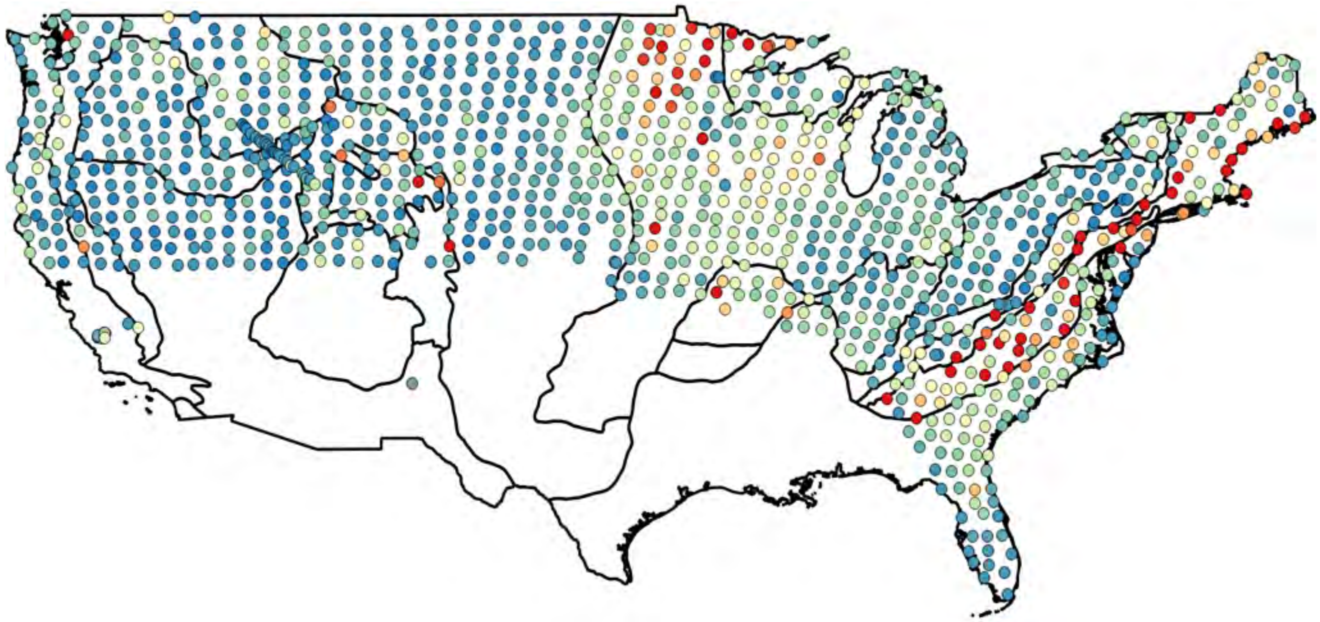


Figure 1: Map of local EMTFs overlaid on the TPL-007-1 physiographic regions

To model realistic extreme geomagnetic disturbance conditions, EPRI calculated electric field response for 1D and 3D models using a scaled extreme geomagnetic storm scenario. The average and median EMTF peak electric field response within each physiographic region is compared to the 1D model response. This comparison indicates how accurately the existing 1D models can reflect average peak geoelectric field response to a severe GMD event and takes into account newly-available MT measurement data, where available. Additionally, the range of electric field values within each region that resulted from the region's EMTFs were examined to understand the degree of non-uniformity.

Based on the comparisons of 1D model and EMTF-based peak geoelectric field response, regional 1D models and boundaries are updated to improve regional geoelectric field distribution uniformity. The report provides regional 1D transfer functions based on EMTF response and gives guidance on their use.

Finally, EPRI evaluated the differences in GIC estimation to 1D- and EMTF-derived geoelectric response using a synthetic but realistic system model. The comparison of GIC estimates provides insights into modeling sensitivity to local 3D-type characteristics.

Outcomes: The results of this research objective validate existing 1D modeling approaches in most parts of the U.S., and identify areas where more complex modeling or approaches are needed to assess GMD Risk.

Existing 1D-model results range from greater than, within 15% of, and less than the 3D/EMTF median in 40%, 30%, and 30% of the physiographic regions, respectively. The Blue Ridge, Piedmont, New England, Ozark Plateaus, Adirondacks, and Superior Uplands regions are underestimated using existing 1D models. See Figure 2.

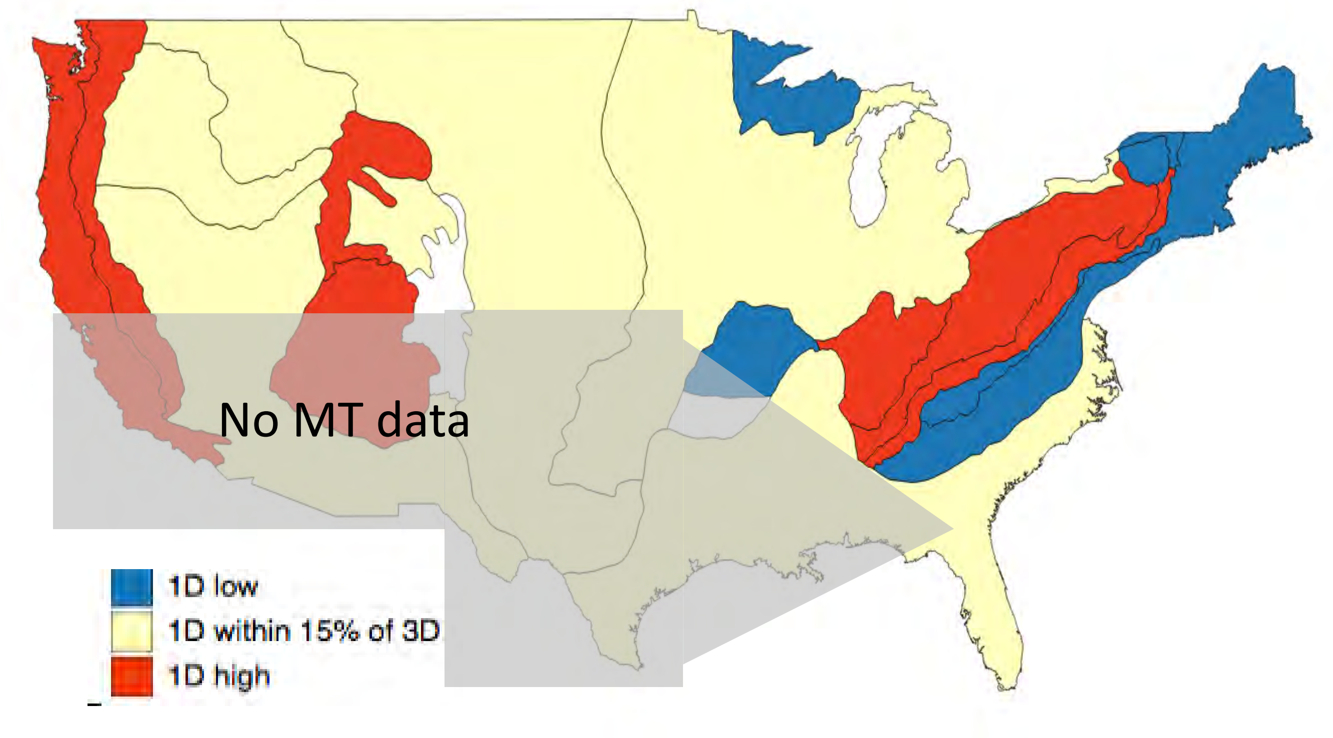


Figure 2: Physiographic regions of the contiguous United States, where geoelectric fields estimated using 1D models are low (blue), within 15% (yellow), and high (red), as compared to EMTF response distribution median. Shaded area indicates no MT data for the region

The analysis shows that MT measurements can be used to update 1D model response and regional boundaries. Some of the larger physiographic regions are not well-represented by a simple 1D model. These larger regions, such as the Interior Plateaus, may be divided into multiple sub-regions to improve estimates of regional peak geoelectric field response. EPRI identified new regional boundaries for 1D modeling shown in Figure 3, that provide better uniformity over the existing 1D physiographic regions for the U.S., as well as updated 1D models for each of these regions.

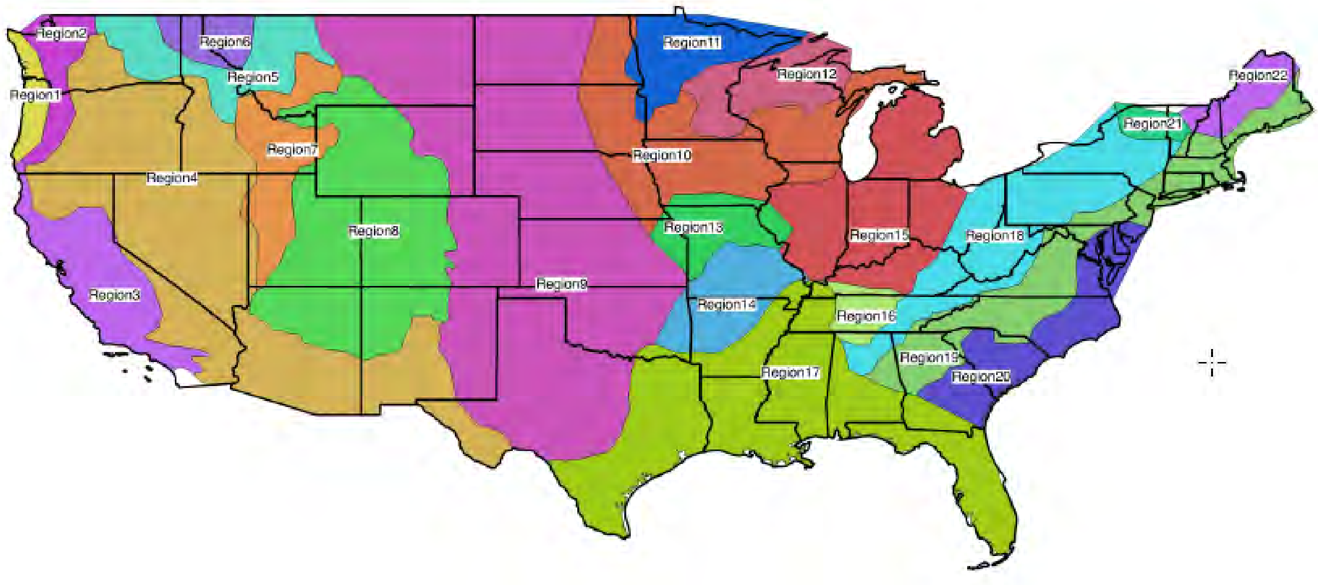


Figure 3: Updated 1D regional boundaries, with state outlines shown for reference. Colors are selected at random to differentiate regions.

Even with the new physiographic boundaries, EPRI identified some areas where 1D models may not be sufficient for GIC estimation due to non-uniform earth structure. The Blue Ridge, Piedmont, and New England physiographic regions (Regions 19 and 22 in Figure 3) exhibit this non-uniformity and have areas in which the ground response to GMD events could produce enhanced geoelectric fields affecting GICs. In regions of greater non-uniformity, more research is needed in these areas to support GIC estimation. System and earth conductivity model validation using GIC measurements, as discussed below, can aid planning entities in assessing the accuracy of the models used in GMD vulnerability assessments.

Task 3B Research Overview: Develop techniques and guidelines for using GIC and magnetometer data to perform model validation.

Product: *Improving Conductivity Models for GIC Estimation: Guidance for Validation of GIC Models. EPRI, Palo Alto, CA: 2020. 3002017897.*

Summary: This report provides a step-by-step approach for performing a model validation study. Such a study uses geomagnetic field time-series data as an input to ground response models and system models for calculating system GICs that are compared with measured GIC values. Reliability Standard TPL-007-4 requires designated planning entities to have processes for obtaining GIC data and geomagnetic field data, which can be used in model validation. The report includes an example study based on a 2015 GMD event using an actual power system model and GIC measurements.

The goal of model validation is to gain confidence in the estimates provided, or reduce the sources of modeling inaccuracies to an acceptable level. Figure 4 describes various error sources and their likely impact on GIC estimates based on analysis using the example study.[14] Other sources of error are also discussed including system parameter estimates and GIC measurements during weak GMD events.

[14] *Improving Conductivity Models for Geomagnetically Induced Current (GIC) Estimation: Guidance for Validation of GIC Models. EPRI, Palo Alto, CA: 2020. 3002017897.*

Parameter	Cause	Uncertainty impact
Substation grounding resistance	Using assumed values of substation grounds	High
Magnetic field	Too far from a magnetometer	High
Conductivity model	Incorrect models or the presence of nonuniform regional effects	Moderate
System configuration	Incorrect system configuration during time of the event	High

Figure 4: Potential Sources of Error in a Model Validation Assessment and Level of Impact

Techniques for reducing the impact of inaccuracies and estimated values to improve GIC study results are included in the report.

Outcomes: Industry planners can use the approach in this report to validate models used to calculate GICs. A model validation study will provide the planner improved confidence in GIC study results used in GMD Vulnerability Assessments. The report identifies best practices for model validation as well as sources of uncertainty and potential ways to improve GIC estimates.

Task 3C Research Overview: Assess the “coast effect” and develop models to capture non-uniform field effects

Product: *Nonuniform Field Modeling: Coast Effect Assessment. EPRI, Palo Alto, CA: 2020. 3002017898.*

Summary: The coast effect refers to an enhancement of the cross-shore (perpendicular to the shoreline) component of the horizontal electric field. It is a response to the along-shore (parallel to the shoreline) component of the magnetic field in the presence of a conductivity gradient between the shore and seawater.

The report provides a regional level assessment of the potential increase in GIC hazard resulting from the geoelectric coast effect and evaluates its presence or absence on the coast of the contiguous United States. EPRI used MT measurements from the USArray Earthscope project, published papers analyzing these data, and an assessment of coastal geometries and conductivity gradients from published sources that are realistic for coastal regions of the United States. The realistic geometries and conductivity gradients described in the report provide the physical reasoning for the relative lack of an observed coast effect in most parts of the contiguous United States and can improve local coast effect assessments and modeling efforts.

Outcomes: The width of the continental shelf—along with the specific coastal geometries, conductivity gradients, and presence of wet sediment shorelines—suggest that the coast effect will be small for much of the contiguous United States. A coast effect is expected for coastal Maine and parts of Massachusetts. Several local sites in California are identified for further study due to complex geological conditions.

ERO Recommendation

NERC Staff and EPRI should continue to work with software vendors to adopt new region boundaries and modeling information in available GIC software. NERC and EPRI should also engage technical experts, researchers, and software vendors to develop advanced modeling techniques that address unique challenges of areas with significant non-uniformity that impact GIC estimates.

The ERO, working collaboratively through NERC and the NPCC and WECC Regional Entities, should support application of this and future research into the described coastal effect through regional technical committees and working groups.

Working through the Reliability and Security Technical Committee (RSTC), Real-time Operations Subcommittee (RTOS), and technical partners, the ERO should (i) promote model validation best practices; (ii) encourage planning entities to validate GMD models with data collected during GMD events of interest; and (iii) support technical groups in continuing to advance GMD modeling disciplines.

Task 4: Study Transformer Thermal Impact Assessment Approach

Summary

The research activities under this task consisted of: 1) evaluating the existing approach used to perform transformer thermal assessments; and 2) examining alternative methods of applying the benchmark geoelectric field time series to individual transformers to represent worst-case hot-spot heating conditions in transformer thermal impact assessments.

Background

Task 4 research focused on performing analysis to evaluate the ability of GIC flow calculated as specified in TPL-007 to represent worst-case transformer hot-spot heating conditions. Reliability Standard TPL-007-1 was designed to identify transformers that are potentially at risk from GIC flows experienced during a severe GMD event. Requirement R6 of the standard requires owners of applicable transformers to perform transformer thermal impact assessments of transformers where the maximum effective GIC value for the benchmark GMD event, as provided in Requirement R5.1, is 75 A per phase or greater. The results of these assessments are then shared so they may be incorporated into the overall GMD Vulnerability Assessment and any necessary Corrective Action Plan. As described in NERC's Screening Criterion for Transformer Thermal Impact Assessment White Paper, this threshold was chosen because healthy transformers with an effective GIC of less than 75 A per phase during the benchmark GMD event are unlikely to exceed known temperature limits indicated in IEEE Std. C57.91-2011 (IEEE Guide for Loading Mineral-Oil-Immersed Transformers and Step-Voltage Regulators).[15]

In Order No. 830, the Commission directed NERC to perform additional research related to the transformer thermal impact assessments required by the TPL-007 standard. Specifically, the Commission directed NERC to study, as part of its Work Plan, how "the geoelectric field time series can be applied to a particular transformer so that the orientation of the geoelectric field time series, over time, will maximize GIC flow in the transformer . . ."[16] **Task 4** therefore consisted of work to determine how the benchmark geoelectric field wave shape can be applied to a particular transformer to determine worst-case hotspot heating.

Activities

Research Task Overview: Examine methods of applying the benchmark geoelectric field time series to represent worst-case hot-spot heating conditions in transformer thermal impact assessments

Product: *Geomagnetically Induced Current (GIC) Transformer Thermal Impact Assessment: Impact of Field Orientation on Transformer Thermal Screenings. EPRI, Palo Alto, CA: 2020. 3002017948.*

Summary: EPRI investigators reviewed approaches for applying the approved Benchmark GMD Event geoelectric field to transformer thermal impact assessments. Simulations techniques enabled investigators to determine the upper bound maximum heating for selected transformers, representing worst-case metallic hot-spot heating for all field orientations of a given severe GMD event relative to the orientation of the equivalent power system seen at the transformer terminals. Using this technique, investigators examined worst-case metallic hot-spot heating for several severe GMD events, each with unique waveforms and field orientations, for comparison with the benchmark GMD event.

---

[15] The *Screening Criterion for Transformer Thermal Impact Assessment* white paper was filed in this proceeding on January 21, 2015 with NERC's petition for approval of TPL-007-1. NERC filed a corrected version of this white paper on June 28, 2016. See https://www.nerc.com/pa/Stand/pages/project-2013-03-geomagnetic-disturbance-mitigation.aspx

[16] Order No. 830 at P 66.

Outcomes: The simulation technique demonstrated by EPRI provides a method for determining the maximum hot-spot heating for all field orientations of the benchmark GMD event relative to the orientation of a notional power system. EPRI determined that the benchmark GMD event is the most conservative (i.e., produces largest metallic hot-spot heating) waveform compared to other severe GMD events for the transformers examined in this report.

ERO Recommendation

The ERO should monitor further technical development supporting transformer thermal modeling and GMD risk assessment. As additional transformer models are developed through industry and research partner efforts, techniques such as those demonstrated in this research task should be used to evaluate the continued efficacy of the benchmark GMD event for GMD Vulnerability Assessments.

Task 5: Further Analyze the 75 A per Phase Criterion Used for Transformer Thermal Impact Assessments

Summary

Research for this task will address the potential impact of the benchmark GMD event or other realistic GMD events on power transformers, which includes analyzing the 75A/phase TPL-007 criterion used for transformer thermal impact assessments. The work will:

- re-examine the screening criteria and if needed, an alternative criterion will be developed; and
- study tertiary winding harmonic heating and determine if this affects the thermal screening criteria.

Background

This task addresses the Commission's directive to "include further analysis of the thermal impact assessment qualifying threshold" of 75 A per phase and to "address the effects of harmonics, including tertiary winding harmonic heating and any other effects on transformers" in NERC's Work Plan.[17]

Task 5 research also provided insights for application in subsequent versions of the TPL-007 standard, which require entities to perform supplemental thermal impact assessments of applicable power transformers based on GIC information for the supplemental GMD event described in **Task 1**.

Activities

Research Task Overview: Create and Document a Transformer Thermal Modeling Tool

Product: *GMD Transformer Thermal Analysis Tool. EPRI, Palo Alto, CA: 2018. 3002014059*

Summary: an accurate thermal transformer model for the estimation of the hotspot heating in the transformer during GMDs has been developed. The tool is referred to as EPRI Transformer Thermal Model (ETTM). The thermal model is based on the transfer function approach which does not require the detailed information about the studied transformers. To obtain the model parameters, the model step response is fitted to the GIC test data. The simulation results of the transformers with available GIC test data are presented, revealing the accuracy of the developed model in duplication of the measurements.

Outcome: The task demonstrates that the EPRI tool is acceptable for use in the Research Work Plan. Additionally, EPRI makes this tool available through the public free of charge from the EPRI website.

Research Task Overview: Assess transformer thermal-limits to GIC, including effects on tertiary windings

Product: *Transformer Thermal Impact Assessments for DC Withstand Capability: Examining the Impacts of GIC on Transformer Thermal Performance. EPRI, Palo Alto, CA: 2019. 3002017708.*

Summary: In this task, EPRI identified transformer designs with the most thermal-limiting capacity to GIC in order to more fully assess the impact of the benchmark GMD event and other realistic GMD events on power transformers. More than 40 transformer design types were evaluated accounting for primary variability in design parameters (see Figure 5 for different core designs, winding geometry, voltage levels, and additional design considerations). Additionally, for each core design, two different tie-bar geometries were investigated that provide a range of achievable temperatures for over 80 total designs. Transformer modeling was performed using a major

[17] Order No. 830 at PP 67-68.

manufacturer's validated modeling approach to predict transformer thermal response to GICs. In the report, EPRI presents the results of that analysis along with the individual transformer design details. In addition, the effects of harmonic currents on tertiary winding (TW) heating resulting from asymmetrical saturation were explored. This was accomplished by examining seven electrical models of typical high-voltage autotransformers with TWs of varying design (i.e., different core designs, winding geometry, voltage levels, rated TW current densities, and additional design considerations).

Transformer No.	Core Type	HV rating	HV voltage	Type
-	-	MVA	kV	-
T1	1	92	526	GSU
T2	1	374	525	Auto
T3	2	500	525	Auto
T4	3	300	525	Auto
T5	3	560	525	Auto
T6	4	292	500	Auto
T7	4	672	500	Auto
T8	4	460	525	Auto
T9	5	840	500	Auto
T10	5	300	525	GSU
T11	2	100	735	GSU
T12	4	373.33	765	Auto
T13	4	750	746	Auto
T14	1	167	400	Auto
T15	1	360	420	Auto
T16	2	121,33	433	GSU
T17	2	94	410	GSU
T18	3	750	420	Auto
T19	3	160	400	GSU
T20	4	570	405	GSU
T21	5	450	405	TRA
T22	5	310	400	GSU
T23	5	910	420	GSU
T24	1	100	335	Auto
T25	1	133.33	345	Auto
T26	3	120	275	TRA

Transformer No.	Core Type	HV Rating	HV Voltage	Type
-	-	MVA	kV	-
T27	3	500	275	Auto
T28	3	200	330	Auto
T29	4	500	345	GSU
T30	5	500	345	Auto
T31	5	800	345	Auto
T32	5	315	345	GSU
T33	1	133.33	230	Auto
T34	1	66,6	231	Auto
T35	2	100	230	GSU
T36	3	160	230	Auto
T37	3	290	230	GSU
T38	3	420	230	Auto
T39	4	300	242	GSU
T40	4	466	240	GSU
T41	5	240	225	GSU
T42	5	560	230	Auto

Figure 5: Overview of Transformer Designs Studied

Core type description:

1. Single-phase, core-form: one wound limb, two-flux return limbs (1LEG)
2. Single-phase, core-form, two wound limbs (2LEG)
3. Three-phase, core-form: three-wound limbs (3LEG)
4. Single-phase, core-form, two-wound limbs, two-flux return limbs (4LEG)
5. Three-phase, core-form: three-wound limbs, two-flux return limbs (5LEG)

Outcome: The report provides the following:

- **<u>Tertiary winding study</u>**

  No critical steady-state temperatures were reached in the seven investigated tertiary winding designs, even with a constant 200 A DC per phase in the high-voltage windings. Nonetheless, some specific designs examined can experience more significant hot-spot heating under DC.

- **Tie bar study**

  The analysis showed that structural parts can be significantly heated with an additional DC current in the high-voltage winding of the transformer. The models provided in the study can be used in simulation of transformer thermal response to GIC signatures.

  The most thermal-limiting transformer was a single-phase, core-form with two-return legs autotransformer. The high number of turns in the 335/√3 kV high-voltage system is a main contributing factor to the very high temperature rise in the tie bars.

Research Task Overview: Assess the 75A/phase thermal impact screening criteria

Product: *GIC Transformer Thermal Impact Assessment: Impact of Field Orientation on Transformer Thermal Screenings. EPRI, Palo Alto, CA: 2020. 3002017948.*

Summary: EPRI used transformer thermal models described above for thermal simulation to determine whether their response to the Benchmark GMD Event could exceed thermal criteria. This report uses eight most thermal-limiting transformers of the 84 to carry thermal analysis to provide a representative range of responses. Table XX shows the relevant physical and electrical characteristics of these transformers.

Transformer no.	Core type	HV rating	HV voltage	Type
		MVA	kV	
T4	Three-phase, core-form, three-limb	300	525	Auto
T5	Three-phase, core-form, three-limb	560	525	Auto
T24	Single-phase, core-form, three-limb	100	335	Auto
T25	Single-phase, core-form, three-limb	133.33	345	Auto
T28	Three-phase, core-form, three-limb	200	330	Auto
T33	Single-phase, core-form, three-limb	133.33	230	Auto
T34	Single-phase, core-form, three-limb	66,6	231	Auto
T36	Three-phase, core-form, three-limb	160	230	Auto

Figure 6: Description of Transformer Designs for 75A/phase Criterion Analysis

Outcome: The 75 A/phase criterion is effective for the majority of transformer designs analyzed, as shown in Figure 7. Six of the eight transformer models used in this report will remain below the temperature limit of 200° C for short-term emergency operation when peak GIC is 75 A/phase for the Benchmark GMD Event. Two unique transformer types could exceed the short-term temperature limits when peak GIC for the Benchmark GMD Event is below 75 A/phase (Transformers T24, T25).

Transformer	Benchmark hotspot heating temperature	
	200° C	180° C
T4 GIC(t) (A)	91	79
T5 GIC(t) (A)	85	75
T24 GIC(t) (A)	53	35
T25 GIC(t) (A)	62	45
T28 GIC(t) (A)	93	81
T33 GIC(t) (A)	92	74
T34 GIC(t) (A)	88	72
T36 GIC(t) (A)	78	65

Figure 7: Summary of Transformer Results

ERO Recommendation

The ERO should continue to prioritize efforts to enable industry to assess and mitigate GMD risk to transformers by:

- Expanding the availability of transformer thermal models to represent more manufacturers. Additionally, field measurement data collected by EPRI and industry should be used to validate theoretical models. EPRI has worked with transformer manufacturers to identify fielded units equipped with fiber-optic-thermal monitoring. New transformers are increasingly being manufactured with thermal hot-spot monitoring capability, which can support operator real-time decision making as well as provide field data for model validation. EPRI will continue to leverage this existing monitoring with plans to continue the expansion of GIC-related monitoring in order to gain further understanding of the thermal impacts on power transformers.
- Update the ERO-Endorsed Implementation Guidance *TPL-007 Transformer Thermal Impact Assessment* with results of EPRI's research in this task.[18]
- Engage TPL-007 applicable entities through the RSTC and industry forums to promote awareness of transformer thermal model availability and best assessment best practices

[18] Specifically, Table 1 provides upper-bound hot spot heating. This table should be revised results of EPRI's analysis, including transformer models T24 and T25.

Task 6: Section 1600 Data Request

Summary

The activities in this task consisted of developing the necessary guidance, technical guidelines, and solutions to support a request for data or information under Section 1600 of the NERC Rules of Procedure for the collection of existing and new GIC data and magnetometer data. The purpose of this data collection is to respond to FERC's Order No. 830 directive to collect GMD monitoring data and to make that data publically available.

Background

The Commission directed NERC to collect GMD monitoring data pursuant to its authority under Section 1600 of the NERC Rules of Procedure for the period beginning May 2013, including data existing as of that date and new data going forward, and to make that information available.[19] The data is intended to promote greater understanding of GMD events and their potential impacts to the reliable operation of the BPS. For example, measured GIC and magnetometer data can help validate various models used in calculating GICs and assessing their impacts in power systems. FERC directed that NERC should make the collected GIC and magnetometer data available to support ongoing research and analysis of GMD risk.[20]

Activities in this task supported development of data reporting instructions, data collection criteria, and development of processes for maintaining a GMD data collection program.

Activities

GMD Data Request

In August 2018, the NERC Board of Trustees approved the NERC Rules of Procedure Section 1600 Data Request for the Collection of GMD Data (GMD Data Request) developed by NERC and the GMDTF.[21] The GMD Data Request is for the collection of GIC monitoring and magnetometer data as required by Order No. 830 and applies to U.S. registered Transmission Owners and Generator Owners. Although not required, Canadian registered Transmission Owners and Generator Owners are encouraged to participate. Many Transmission Owners and Generator Owners collect GMD data and have GMD data for the period beginning in May 2013. The data request applies to entities that have specified GMD data.

NERC and the GMDTF held a public comment period in February - March 2018 that afforded stakeholders with opportunity to provide input on the GMD Data Request.

Under the approved GMD Data Request, reporting entities provide information related to their installed GIC monitor and magnetometer capabilities, and to provide data from these devices to NERC for strong GMD events (K-7 and greater as reported by U.S. Space Weather Prediction Center). The reporting threshold was selected to provide significant data for research and model validation purposes without imposing excess burden on reporting entities. Based on historical data, the reporting threshold is expected to be reached 200 times per 11-year solar cycle. Reporting entities are not expected to report data that is publicly available

---

[19] Order No. 830 at P 89.

[20] *Id.* at P 93. In the Order, FERC stated: "The record in this proceeding supports the conclusion that access to GIC monitoring and magnetometer data will help facilitate GMD research, for example, by helping to validate GMD models." If GIC monitoring and magnetometer data is already publicly available (e.g., form a government entity or university), FERC stated that NERC need not duplicate those efforts. *Id.* at n. 122.

[21] See the approved GMD Data Request: https://www.nerc.com/comm/PC/Geomagnetic%20Disturbance%20Task%20Force%20GMDTF%202013/GMD_data_request_June_2018.pdf

GMD Data Reporting Instructions (GMD DRI)

The GMD DRI contains provisions for establishing and maintaining a GMD data collection program. NERC staff developed the GMD DRI with support from the GMDTF. The purpose of the GMD DRI is to assist NERC and reporting entities in fulfilling reporting requirements of the approved GMD Data Request.

As described in the GMD DRI, reporting entities provide the following types of data to NERC:

- GMD Monitoring Equipment (i.e., GIC monitor, magnetometer) information
- GIC measurement data for designated GMD events
- Geomagnetic field measurement data for designated GMD even

NERC will designate periods during which GMD events K_P = 7 or greater have occurred and request reporting entities provide data to NERC annually. Data are submitted by reporting entities using a GMD data collection portal.

Program Implementation

The GMD Data Collection portal became operational in October 2020. The first annual reporting deadline is June 2021.[22] After the first reporting deadline the ERO will begin making releasable data available.[23]

The ERO will monitor implementation and conduct outreach to identify whether and to what extent additional guidance or support is necessary. The objective is to maintain a high-quality collection of GIC and magnetometer data for industry and research use. Although the NERC GMD Data Collection Program is not a real-time application, industry GIC monitors and magnetometers can provide data to system operators in real-time for enhancing their GMD operating procedures.

[22] GMD data reporting information is available on the NERC website: https://www.nerc.com/pa/RAPA/GMD/Pages/GMDHome.aspx

[23] In Order No. 830, FERC stated, based on the record in the proceeding, that "GIC and magnetometer data typically should not be designated as Confidential Information under the NERC Rules of Procedure." 9 Accordingly, NERC does not anticipate that the requested information will contain Confidential Information as that term is defined by Section 1501 of the NERC Rules of Procedure. Reporting entities may request that NERC handle their data as Confidential Information using the process in the GMD DRI, Appendix E. Data that is designated as Confidential Information cannot be viewed or downloaded except by the submitting entity and the DRO data system administrators.

Task 7: Geoelectric Field Tool Evaluation and Calculation of Beta Factors

Summary

The activities under this task focused on calculating earth conductivity scaling factors (beta factors) as necessary to meet the needs of the industry. This includes the following: benchmark of electric field estimation results using available scientific and industry algorithms; production of beta factor averages over improved 1D regions; and determination of beta factor ranges from differences in magnetic field orientation, spectral content, and 3D contributions.

Background

Task 7 builds upon the other components of NERC's Work Plan to improve scientific understanding and advance the models and tools available for modeling GIC. **Task 7** involved evaluating available tools for calculating geoelectric field from magnetic field data for a given earth conductivity structure and developing guidance as necessary to meet the needs of the industry. This task included work to address "whether additional realistic time series should be selected to perform assessments in order to capture the time series that produces the most vulnerability for an area," consistent with the Commission's guidance.[24]

Activities

Research Task Overview: Evaluate project tools

Product: *Tool Evaluation and Electric Field Estimate Benchmarking Results. EPRI, Palo Alto, CA: 2019. 3002014853*

Summary: This report presents a validation of EPRI tools used for geoelectric field estimation in the GMD Research Work Plan, including conductivity evaluation in Tasks 3 and 7 and scaling factor evaluation in Task 2. This analysis shows that EPRI project tools produce nearly identical results to other frequency and time domain tools available to the industry. The tools were compared using both one-dimensional (1D) model and EMTF representations of ground response.

Outcome: This task indicates that the EPRI tools are acceptable for use in the Research Work Plan.

Research Task Overview: Calculate and evaluate beta scaling factors

Product: *Update of Earth Response Scaling Factors Using Magnetotelluric Measurements EPRI, Palo Alto, CA: 2020. 3002017899*

Summary: To assess system vulnerability to the benchmark GMD event associated with TPL-007-1, planning entities may apply scaling factors that take into account the location of interest with respect to high-latitude electric currents systems (alpha scaling factor) and local geological conditions as specified in TPL-007 Attachment 1. The local geological conditions can be captured in terms of "beta scaling" factors that are used to adjust the benchmark geoelectric field amplitude to account for the variations in the ground response. TPL-007 provides applicable entities with flexibility to use more updated or accurate earth model information and does not prescribe the use of beta

---

[24] *See* Order No. 830 at P 79, in which the Commission stated:

In addition, the large variances described by [United States Geological Survey] in actual 3-D ground conductivity data raise the question of whether one time series geomagnetic field is sufficient for vulnerability assessments. The characteristics, including frequencies, of the time series interact with the ground conductivity to produce the geoelectric field that drives the GIC. Therefore, the research should address whether additional realistic time series should be selected to perform assessments in order to capture the time series that produces the most vulnerability for an area.

scaling factors. The default beta factors are based on approximate 1-dimensional physiographic ground conductivity models that were developed by Fernberg.[25]

Since the Fernberg (2012) work, new information has been provided by the NSF's EarthScope project (Schultz reference), which implemented a magnetotelluric (MT) survey across the contiguous U.S.[26] These measurements have provided significant new insight into local ground conductivity structures and corresponding ground electromagnetic responses. Electromagnetic transfer functions (EMTFs) derived from the MT survey are now available[27] and provide an opportunity to update the ground response β scaling factors used in TPL-007-1. Based on the EMTFs, EPRI provided β scaling factors for the updated contiguous US conductivity regions developed in Task 3. In addition, an assessment of how much beta factors can vary under different conditions was performed.

Outcome: The report provides updated β scaling factors for calculating geoelectric fields used in GMD vulnerability assessments based on newly available MT information. Figure 8 provides these values for each of the 22 conductivity regions in the contiguous United States (discussed in Task 3).

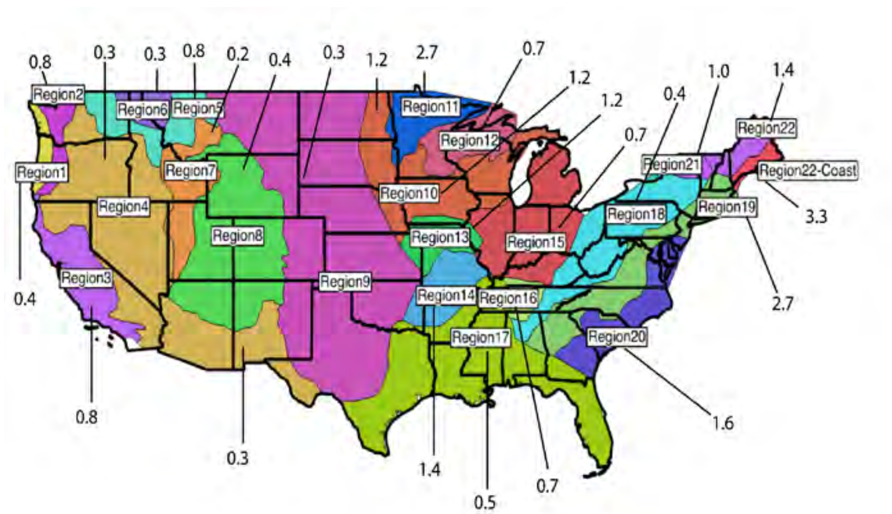


Figure 8: Updated β scaling factors for calculating geoelectric fields used in GMD vulnerability assessments based on newly available MT information

Several methods of describing "typical" ground response over a region as single value are explored using geomagnetic field time series data for a scaled extreme geomagnetic storm scenario based on the March 1989 GMD event as the input geomagnetic storm. The selected method is based on the median value of the calculated nonuniform geoelectric field distribution in each area.

Outcomes: The β-factors for each of the 22 conductivity regions in the contiguous US are updated based on newly-available MT information.

- Scaling factors can be used to produce geo-electric fields that are generally consistent with regionally-averaged models.

[25] EPRI, O*ne-Dimensional Earth Resistivity Models for Selected Areas of Continental United States and Alaska*, EPRI Technical Update 1026430 (2012).

[26] Schultz, A., G. D. Egbert, A. Kelbert, T. Peery, V. Clote, B. Fry, and S. Erofeeva, USArray TA magnetotelluric transfer functions, Technical Report, National Geoelectromagnetic Facility: 2006-2017

[27] Kelbert, A., G. Egbert, and A. Schultz, IRIS DMC Data Services Products: EMTF, the magnetotelluric transfer functions, Tech. rep. National Geoelectromagnetic Facility, 2011-2017.

- The peak geo-electric field derived from the use of scaling factors is usually higher (21 out of 22 cases) than when using regionally-averaged models.
- GICs estimated from geo-electric fields derived using scaling factors are similar to other methods, within the modeling uncertainties discussed in Task 3.

ERO Recommendation

The ERO should collaborate with EPRI and GIC modeling software vendors to incorporate beta scaling factors and/or modeling techniques into the software that is available for industry planners. The ERO should also consider this EPRI report during the Reliability Standards periodic review process for the TPL-007 standard so that steps can be taken to update Attachment 1 to the standard.

Task 8: Improve Harmonics Analysis Capability

Summary

The activities under this task consist of developing harmonics analysis guidelines and tools for entities to use in performing system-wide assessment of GMD-related harmonics.

Background

GMD-related harmonics are caused by the part-cycle saturation of transformers. These harmonic currents and voltages resulting from transformer saturation have had major impact on system operations and security during severe GMD events in the past.[28] Incorporating harmonic impacts is important for assessing system susceptibility to GMD.

Performing harmonic analysis is difficult, and commercial tools did not adequately address nuances of performing GMD-related harmonics studies. Important difficulties and modeling gaps needed to be addressed before the harmonic impacts of benchmark GMD events can be accurately assessed. Such difficulties and gaps include (but are not limited to)[29]:

- The effective GIC flow in all transformers in the network must be known beforehand, and mapping between GIC and the harmonics that are created is required.
- The magnitude and phase angle of the injected harmonic currents of each transformer is affected by local voltage distortion; thus, an iterative technique must be employed.
- The complex interaction of magnitude and phase angles of the injected harmonic currents of multiple transformers must be taken into account.
- Because part-cycle saturation creates zero sequence harmonics, standard positive sequence power flow data cannot be used alone as a basis for assembling the system model.
- Harmonic resonance created by shunt capacitor banks, and the damping effect of loads must be considered.

Task 8 research supported the identification and mitigation of GMD-related harmonic impacts as specified in TPL-007-1 and subsequent versions of the standard.

Activities

Research Task Overview: Develop Open-Source Software Tool for GMD-Related Harmonics Impact Assessment

Product: *Geomagnetically Induced Current Harmonic Tool (GICHarm): GIC Harmonic Analysis. EPRI, Palo Alto, CA: 2019. 3002017447*

Summary:

1. **Step 1**. EPRI performed research necessary to develop models, methods, and algorithms for performing harmonic assessments of benchmark GMD events.

[28] *See, e.g.,* NERC, *March 13, 1989 Geomagnetic Disturbance* white paper, available at http://www.nerc.com/files/1989-quebec-disturbance.pdf.
[29] EPRI, *Analysis of Geomagnetic Disturbance (GMD) Related Harmonics* (2014). 3002002985.

2. **Step 2.** Based on the research conducted in Step 1, EPRI developed an accurate GMD harmonic analysis approach using proper consideration of the closed-loop interactions between the harmonic current injections by the saturated transformers and the voltage distortion that these injections cause.
3. **Step 3.** Based on the results of Step 1 and 2, EPRI developed a GMD analysis tool and a benchmark GMD system model to accurately assess and verify both time-domain models and the newly developed GMD harmonic tool. Step 3 provided confidence in models that EPRI developed as a part of this research activity.
4. **Step 4.** EPRI implemented the models and techniques developed as a part of this research in an open-source software tool, GICHarm. This tool will be used to:
   a. Aid system planners in evaluating impacts of harmonics on reactive power resources (e.g. shunt capacitor banks, static var compensators (SVCs), etc.); and
   b. Facilitate the implementation of GMD harmonic assessments in commercially available software tools.

EPRI provided harmonics modeling demonstrations at GMDTF meetings to facilitate knowledge transfer.

Outcome: This task produced an open source harmonics assessment software tool, GICHarm, and a technical report with guidelines for using GICHarm.

ERO Recommendation

The ERO should engage TPL-007 applicable entities through the RSTC and industry forums to promote awareness of these tools, support development, and promote use of best practices for GMD-related harmonic analysis.

Task 9: Harmonic Impact Studies

Summary

The activities under this task support understanding the impacts of vibrations due to GMD-related harmonics on power system equipment. The impacts of transformer heating are covered in detail in **Task 4** and **Task 5** of the Work Plan. The activities under this task provide insight into the magnitudes of vibrations in power transformer tanks caused by GIC and assess the impact of these vibrations on the health of the transformer. This task is in response to FERC's request to NERC to address the effects of harmonics on transformers.

Background

GMD-related harmonics can cause the phenomenon of magnetostriction in the cores of large power transformers, resulting in noise and vibration during GMD events. In Order No. 830, FERC directed NERC to examine the effects of harmonics on BPS equipment as part of the Work Plan.[30]

Activities

Research Task Overview: Transformer GIC Vibration Analysis

Product: *Impact of Geomagnetically Induced Currents on Transformer Tank Vibrations: Transformer Vibration Analysis.* EPRI, Palo Alto, CA: 2019. 3002014855.

Summary: Working with utilities and transformer manufacturers, EPRI performed analysis to assess potential impacts of vibrations due to GMD-related harmonics on transformers. The analysis is based on factory and field test data of power transformers of various construction types and sizes, and on-site vibration measurement data from six transformers subject to 174 storms K6 and greater.

Outcomes: The research found that long-term exposure to vibrations caused by GIC does not result in increased tank vibration displacements, and therefore is not likely to adversely impact transformer mechanical integrity. Furthermore, the research suggests that a severe GMD event is not likely to lead transformer mechanical damage from vibrations. The basis for this is factory tests indicating that displacement magnitude of tank vibrations reaches its maximum at lower levels of GIC, and does not increase further with higher levels of GIC.

Research Task Overview: Generator Harmonic Impact Assessment

Product: *Assessment Guide: Geomagnetic Disturbance Harmonic Impacts and Asset Withstand Capabilities*. EPRI, Palo Alto, CA: 2019. 3002017707.

Summary: EPRI performed a thorough review of research to improve understanding of harmonic effects on turbine generators that are unique to GMD events. Harmonic currents from severe GMD events have the potential to cause excessive rotor heating and stimulate mechanical vibrations at frequencies turbine generator designers did not anticipate. Results were used to update the generator section of the *Assessment Guide* and enhance the modeling capability in the EPRI GMD harmonics analysis tool *GICHarm* (See Task 8).

Outcomes: The Assessment Guide includes recommended modeling and screening guidelines for industry to use in evaluating thermal risk to turbine generators. In addition, the GICHarm tool developed in Task 8 provides improved generator harmonic analysis capabilities. The screening and analysis techniques developed will aid planners and generator manufacturers the necessary information needed to determine the impacts of GMD-induced harmonics.

[30] *See* Order No. 830 at P 68, and Order No 830-A at P 18.

ERO Recommendation

Industry should continue to support ongoing research and tool development to assess generator risk from severe GMD events. The ERO should request EPRI provide updates periodically to the RSTC on the status of its efforts.

Appendix A: Listing of Research Publications

The following publications developed in this GMD Research Work Plan have been released by EPRI and are available free of charge. Publications may be obtained from the EPRI web site.

- EPRI, "Furthering the Research of Geomagnetic Disturbances Impact on the Bulk Power System," April 2018, 3002013736.
- EPRI, "Furthering the Understanding of the Characteristics and Scales of Geoelectric Field Enhancements," March 2020, 3002017900.
- EPRI, "Magnetohydrodynamic (MHD) Modeling for the Further Understanding of Geoelectric Field Enhancements and Auroral Behavior during Geomagnetic Disturbance Events," March 2020, 3002017952.
- EPRI, "Use of Magnetotelluric Measurement Data to Validate/Improve Existing Earth Conductivity Models Product," June 2020, 3002019425.
- EPRI, "Improving Conductivity Models for Geomagnetically Induced Current (GIC) Estimation: Guidance for Validation of GIC Models," March 2020, 3002017897.
- EPRI, "Non-Uniform Field Modeling: Coast Effect Assessment," March 2020, 3002017898.
- EPRI, "Geomagnetically Induced Current (GIC) Transformer Thermal Impact Assessment: Impact of Field Orientation on Transformer Thermal Screenings," March 2020, 3002017948.
- EPRI,"PRE-SW: EPRI Transformer Thermal Model (ETTM), version 1.0 – Beta," June 2018, 3002014059.
- EPRI, "Transformer Thermal Impact Assessments for DC Withstand Capability: Examining the Impacts of Geomagnetically Induced Current (GIC) on Transformer Thermal Performance," December 2019, 3002017708.
- EPRI, "Tool Evaluation and Electric Field Estimate Benchmarking Results," January 2019, 3002014853.
- EPRI, "Update of Earth Response Scaling Factors using Magnetotelluric (MT) Measurements," March 2020, 3002017899.
- EPRI, "Geomagnetically Induced Current Harmonic Analysis Tool (GICharm): Geomagnetically Induced Current (GIC) Harmonic Analysis," December 2019, 3002017447.
- EPRI, "Impact of Geomagnetically Induced Currents on Transformer Tank Vibrations," January 2019, 3002014855
- EPRI, "Assessment Guide: Geomagnetic Disturbance Harmonic Impacts and Asset Withstand Capabilities," December 2019, 3002017707.

Data Collections Technical Reference Document | Approaches for Probabilistic Assessments – Request RSTC Reviewers

Action
Request for RSTC reviewers.

Summary
The reference document describes demand, resource, environmental, and system data as they can be applied to resource adequacy probabilistic studies, along with sources and processes for obtaining data. The document will benefit reliability by providing a reference of data practices for industry planners to draw from as probabilistic studies become increasingly important to studying the resource adequacy in many parts of North America (see Findings and Recommendations from NERC LTRA in 2020 and earlier). It complements the Probabilistic Adequacy and Measures Technical Report (approved by the PC in 2018) in promoting the use of sound probabilistic study practices. PAWG developed the document per the PAWG work plan and RAS endorsed the document in December 2020. Following review by RSTC members, PAWG and RAS will incorporate feedback and return the document to the RSTC for approval. Once approved, the PAWG will post the report on its website, encourage PAWG members to apply the concepts to future probabilistic assessments, and refer to the document in Reliability Assessments.

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Data Collection

Approaches for Probabilistic Assessments Technical Reference Document

January 2021

RELIABILITY | RESILIENCE | SECURITY




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

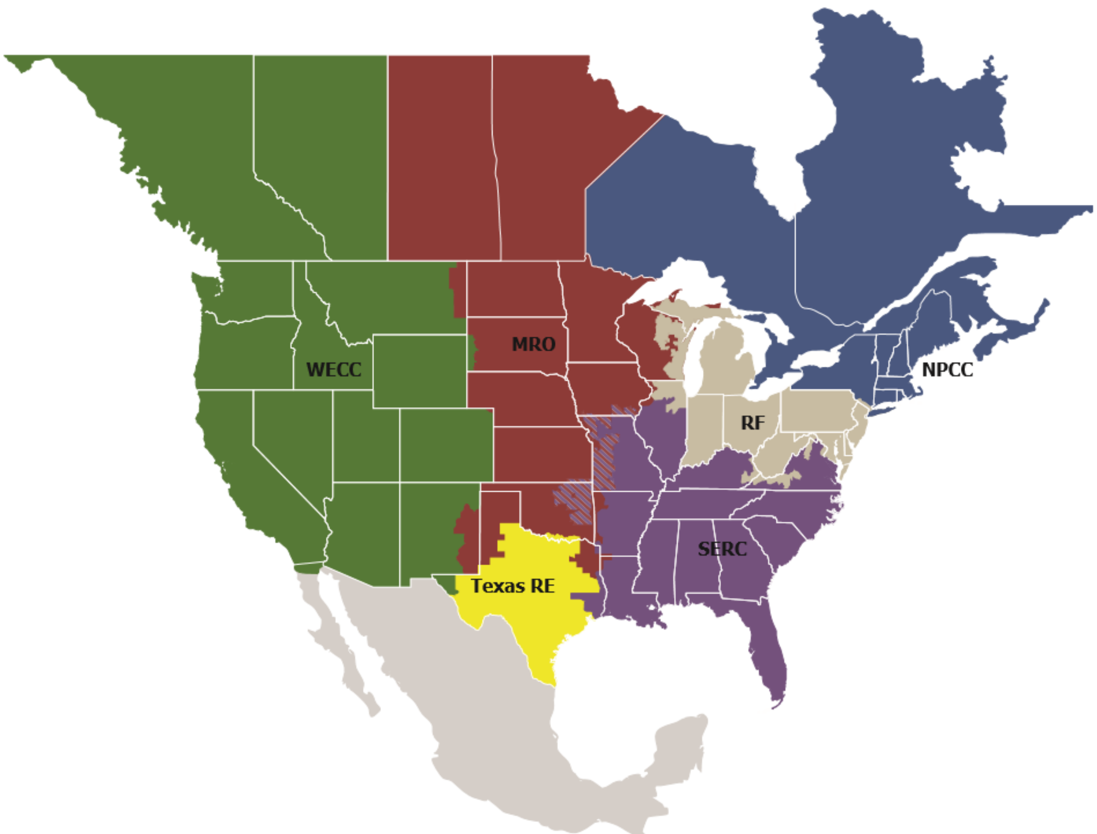
Table of Contents

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

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

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



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

Executive Summary

This document identifies and considers general categories of data inputs commonly used in loss-of-load probabilistic assessments across industry. These include data considerations with focus on parameters and collection methods for demand, thermal resources, energy-limited resources, emergency operating procedures (EOPs), and transmission representation. Entities must consider procuring or obtaining enough data to accurately represent the model parameters or inputs to effectively develop and run a probabilistic reliability study[1]. An entity wishing to conduct a probabilistic study should thoroughly review these data inputs and assumptions, the technical nature and aspects of the model inputs in study, and the soundness of the results with all stakeholders as a standard operating practice. This document separates each of the identified major categories in a resource adequacy study and highlights the types of data, possible sources for the data, and other qualifiers associated with the inclusion of such information in a probabilistic study.

Key Points and Possible Future Work

The Probabilistic Assessment Working Group (PAWG) identified the following key points in data collection across many different portions of a probabilistic resource adequacy study:

- Collection of weather data and any portion of the resource adequacy study related to weather should have the samples taken in the same period. If samples are not able to coincide, a cross-correlation calculation can help reorient when the weather data sample was taken and when, for instance, the demand sample was taken.
- An in-depth understanding of operational characteristics of the resources represented in a study is needed to determine the requested data points in order to study the resource.
- Data collection for transmission systems in probabilistic resource adequacy assessments depends on how detailed of a transmission model is represented in the study. This dependency between quantity of data needed for the transmission elements is over and above the normal dependency that other portions of a probabilistic resource adequacy study.
- Battery energy storage systems (BESSs) can be modeled similarly to other energy-limited resources such as pumped hydro, with an emphasis on understanding the operational characteristics of the BESS.
- Planning Coordinators, Transmission Planners, and other modelers require access to detailed information in order to build and maintain their models for use in probabilistic studies.

The PAWG also highlighted the following objectives for possible future ERO work to be further explored and addressed as needed:

- When utilizing Generation Availability Data System (GADS) or other historical outage reporting data, the thermal resources future outage rate may not be adequately representing by use of this historic data, especially when the facility moves to different operational characteristics. A thorough review should be done before using historic outage data when representing future risk.
- Planning Coordinators, Transmission Planners, and other entities should work to gain access to data not otherwise made available that may affect the results of their resource adequacy studies or assumptions. Some entities do not have access to data sets to feed their models, and the need for more accurate studies may require access to data outside of those publically available. This is paramount as resource planners are not able to perform studies without well-developed models, which require a wide range of data.

[1] In terms of reporting results and the metrics associated with probabilistic studies, the PAWG has published a separate document here. [NEEDS LINK]

- Careful understanding of data source assumptions and restrictions should be used when vetting a new or previous data source.

Introduction

Today's electricity industry is under a period of significant transition. NERC and the ERO note several high-level trends that have affected the North American Bulk Power System's (BPS) planning and operations, such as the continued retirements of traditional baseload resources accompanied with the proliferation of renewable and other forms of variable generation. These trends have highlighted an increasing need for the industry to properly model, study, and plan for the future state and reliability of the grid. NERC and the ERO recognize that these trends are highly variable and carry increasing uncertainties, which further emphasize the need to enhance the traditional and deterministic forms of resource adequacy and reliability assessments. As was identified in the 2019 NERC Long Term Reliability Assessment (LTRA)[2] and the 2019 NERC State of Reliability report (SOR)[3], NERC looks to enhance its resource and transmission adequacy assessments by incorporating more probabilistic approaches in carrying out its mission of a highly secure and reliable BPS. To further that result, NERC continues to promote the use of more probabilistic approaches into reliability assessments providing further insights into assessing the adequacy and reliability of the BPS.

The NERC Probabilistic Assessment Working Group (PAWG) was tasked to explore and highlight the current data collection processes across the industry that are used to produce loss-of-load probabilistic studies that assess emerging reliability risks. This document explores and identifies requirements, sources and techniques for obtaining and modeling data for possible usage in conducting probabilistic assessments. The objective of this document is to discuss and raise awareness of probabilistic methods and techniques available to assist entities in conducting reliability assessments of systems with resources of increasing performance uncertainties. This document supports the group's mission to promote the usage of probabilistic techniques and studies in carrying out NERC's mission.

While NERC has historically assessed resource adequacy using deterministic planning reserve margins, the purpose of this document is to discuss data collection considerations for a probabilistic assessment. The intended audience is the industry at large with the objective of raising the collective awareness of available data collection methods. This report is written as a reference document for industry participants to understand the options available for these data sources and to highlight any benefits or considerations that methods require.

In spring 2017, the PAWG conducted a survey of Registered Entities to better understand their assessment capabilities and identified challenges as they relate to probabilistic resource adequacy assessments. One of the recurring themes of survey responses was the challenges with selecting and managing large sums of data in order to develop realistic inputs to probabilistic models. The 2019 LTRA Key Findings indicate that future probabilistic assessments should incorporate the increasing uncertainty of resources and demand while also considering the increasing amounts or sources of data. The PAWG has developed this document to further assist entities wishing to or whom are actively engaged in conducting probabilistic assessments. The PAWG welcomes and invites subject matter experts' discussion and comments to this document to further develop widespread industry participant knowledge, application and acceptance of probabilistic studies and methodologies to assist in meeting the challenges posed to the electricity sector. This document is intended to complement ongoing industry work as there may be other groups that rest outside of NERC that are engaged in data collection discussions and probabilistic approach developments. As technical discussions and methods evolve further, the PAWG will update this document to meet industry needs.

There are numerous public and private sources of data that entities such as Planning Coordinators or Transmission Planners (TP) can use to develop a probabilistic study. NERC plays a valuable role in providing some of these sources via the NERC Generating Availability Data System (GADS) and Transmission Availability Data System (TADS); however, these are not the sole sources of data for a probabilistic study nor are they sufficient for every

[2] https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_LTRA_2019.pdf
[3] https://www.nerc.com/pa/RAPA/PA/Performance%20Analysis%20DL/NERC_SOR_2019.pdf

probabilistic reliability study. Many NERC Regional and Registered Entities utilize different models for their probabilistic reliability studies and this document attempts to summarize the collective approach and basic data needed to perform this work. Depending on the tools available to the entity, additional data from other sources may be required as the models available to that platform may require more information than the data source collects.

Chapter 1: Demand

Demand modeling in a probabilistic resource adequacy study is typically conducted through a combination of several inputs, including the utilization of historical data, demand forecasts, uncertainties and assumptions specific to the system under study. Demand or load shapes can be modelled based on historical monthly or hourly peak demand profiles and shapes, scaled to reflect forecasted conditions. In many cases in this chapter, the word "demand" and "load" may be used to reflect the modeling of end use customer MW draw. In the case of "demand", the emphasis is on the MW amount and its time distribution, while the term "load" can encompass other complexities outside of "demand," which may indirectly capture demand acting as a resource to offset the electrical system's draw at that time. Some models may not have the complexity to identify the nuances between the two terms, or some definitions may not be as clear as the above distinction. However, in terms of the data, most of the sources and procedures will not vary between "demand" or "load" and the terms can be used in the following chapter interchangeably.

Demand Considerations

In a probabilistic resource adequacy study, accounting for specific assumptions regarding the amount and uncertainty of demand plays a significant impact on probabilistic indices results. Entities should consider the use of multiple demand level scenarios in assessing the resource adequacy of their systems under study. An example of these demand levels could be specific forecasts, such as 50/50 or 90/10 system forecasts that representing the probabilities of exceeding explicit levels. Different techniques can also be employed using statistical calculations, such as probability-weighted averaging. Probability-weighted averages calculate load level indices with corresponding probabilities of occurrence, thus representing the uncertainty in system demand due to external inputs, such as weather and economic factors. An example of this could be by using distributions of monthly peak demands versus the annual system peak demands. The selection and usage of multiple load levels can assist entities in planning against uncertainties, such as the occurrence of more extreme demand conditions or extended stressed system conditions. To gather some of these selections, a demand curve can be developed. To build demand curves, the RTO/ISO can utilize their metered data, as the granular data provides an easy way to sample the demand.

Demand Curve Selection

Demand can follow many different socio-economic causes that would shift the shape of the demand curve in a multitude of ways; however, weather or climate is commonly identified as a primary driver of demand impacts. To help mitigate this, the demand curve should be constructed by considering the impact of differing weather conditions to better capture temperature sensitivity. Some of the considerations for selection can include ambient temperature for seasonal conditions, wind speed, and precipitation. Each of these meteorological markers has demonstrated impact onto the demand curve and should be considered when gathering data surrounding demand during those time periods. Specifically related to the curve construction, the peak, nadir, and ramping rates have substantial influence on the reliability impacts to the system in study[4]. Accurate characterization for those periods is important for the planning and scheduling of generation and ancillary resources during the study.

Because the resource planner desires to capture a full distribution of possible demand conditions, the demand curve selection is important when collecting a proper sample of data. These conditions include cool, average, hot, and extremely hot summers; warm, average, cold, and extremely cold winters; and low, average, and high meteorological conditions such as irradiance or wind speed. These will emphasize some of the peaks, nadirs, and ramping rates. Accurate characterization of the identified risk depends on the samples taken and the selection of the curves those samples produce. For instance, if the demand data collected contains 25 years of curves selecting those curves that accentuate the peaks, nadirs, and ramping rates will allow the resource planner to more accurately capture the

[4] Historically, the planning process typically accentuated peak conditions. As risk moves away from the on-peak periods (over a season or a day), looking at curves that accentuate other aspects of the demand curve is warranted.

anticipated risk conditions of the peaks, nadirs, and ramping rates. In the same light, selecting all the curves will weight all years as equally probable.

Load Scenarios

Loading level directly determines the required amount of resources in the study due to the load and generation balance. In addition, the load level and composition play a significant influence on the system in study. When performing a resource adequacy study, a TP/PC must select the appropriate scenarios that either stress or relate demand to differing extreme conditions. In order to do this, planners will need to gather demand data associated with the weather conditions specified above. More specifically, this will be a distribution of load scenarios across demand curves. One example distribution is cool, average, hot, and extremely hot summers along warm, average, cold, and extremely cold winters. Couple those scenarios with high, average, and low wind speeds as well as high, average, and low precipitation (or water flows) and a diverse amount of scenarios are available for selection in the study. As many of these scenarios are study dependent, the specific study scope can assist in either paring this list down or adding to it. Additionally, sensitivities can also accentuate specific loads and can assist the planner in studying the impact to their system. For example, a load scenario that assumes very aggressive electrification of the transportation system will accentuate the usage of demand during the hours in use, as well as on the days of the week that transportation is more heavily used.

Load Forecast Uncertainty (LFU) Considerations

Realized load can differ from projected load for multiple reasons. First, because weather cannot be exactly predicted and will cause peak load to differ from the normalized-weather forecast (as discussed in the weather related LFU section). Second, because there are uncertainties in population growth, economic growth, energy efficiency adoption rates, and other factors. Data for these topics can be regulatory based and would vary by jurisdiction and program. These non-weather drivers of load forecast uncertainties (LFUs) differ from weather-related LFUs because they increase with the forward planning period, while weather uncertainties will generally remain constant and be independent with the forward period.

Non-Weather Related LFU

From the above, the uncertainties in population growth and the associated demand forecast can be addressed by a statistical approach at quantifying the uncertainty. To best illustrate this, consider this example. For each weather-year load forecast, five non-weather load forecast uncertainty multipliers are applied to all load hours. **Figure 1.1** shows the uncertainty as a percentage of the 50th percentile (P50 or "50/50") peak load forecast, indicating that the forecast uncertainty increases as one moves further into the future. Each multiplier is assigned an associated normal-curve-based probability with the sum of the probabilities totaling 100 percent. **Figure 1.2** shows the three-year forward load forecast uncertainty multipliers[5]. To calculate the weighted-average results across all load scenarios, the weather-year probability weights and the non-weather probability weights are multiplied to create joint probability weights. More details about non-weather load forecast uncertainty can be found in other reports in the industry[6].

[5] While the figure shows symmetric forward LFE, these points may not be symmetric.

[6] A few relevant reports are posted on the Electric Reliability Council of Texas (ERCOT) website, which contains material listed here: http://www.ercot.com/content/wcm/lists/114801/Estimating_the_Economically_Optimal_Reserve_Margin_in_ERCOT_Revised.pdf; http://www.ercot.com/content/wcm/lists/167026/2018_12_20_ERCOT_MERM_Report_Final.pdf; http://www.ercot.com/content/wcm/lists/114801/ERCOT_Study_Process_and_Methodology_Manual_for_EORM-MERM_12-12-2017_v1.0.docx

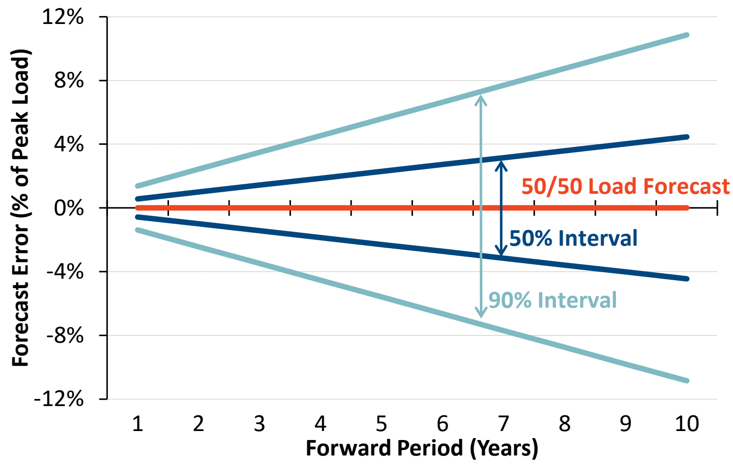


Figure 1.1: Non-Weather Forecast Uncertainty with Increasing Forward Period

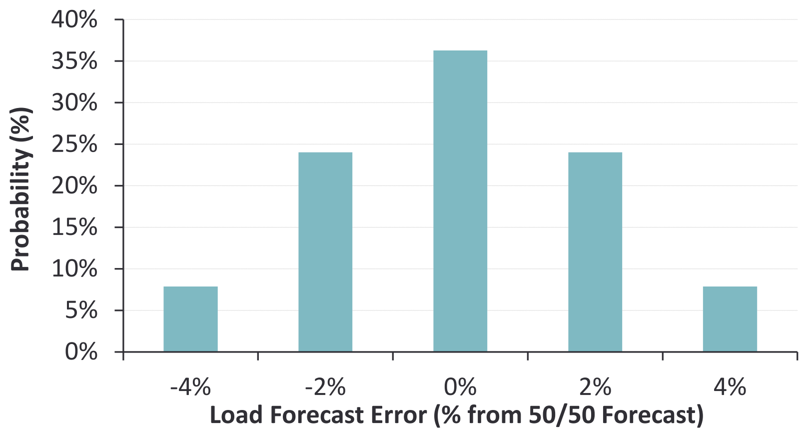


Figure 1.2: Three-Year Forward LFE with Discrete Error Points Modeled

Weather Related LFU

While LFU methods have the ability to capture many uncertainties related to the load, weather factors are a significant driver of load and their uncertainties can be captured when undertaking a probabilistic assessment. The weather related methods described below can be utilized to capture the uncertainty with respect to year-over-year differences.

Some data points to consider are ambient temperature, dew point, wind speed, and cloud cover across a variety of stations in the geographic region associated with the assessment area. These variables have been determined to relate to the variance in load, and one of the sources of data on those variables is at weather stations. To provide enough accuracy to depict the weather related LFU, multiple years of weather are required to capture this uncertainty. The Independent Electricity System Operator (IESO) currently uses 31 weather years and runs the load model forecast on those years shifted up to seven days to account for each numeric day falling on a given day of the week. That is, day 100 will lie on a Monday, Tuesday, Wednesday, Thursday, Friday, Saturday, and Sunday to account for differences the load has based on temporal shifts. This equates to 465 distinct weather simulations[7] and from there, the Load Forecast Uncertainty could be determined. Other entities, such as Argonne National Labs, have taken

[7] Seven days forward, seven days backward, and the day that the historic measurement was taken multiplied by the number of years. For 31 weather years, this is (7+7+1)*31 = 465.

the information at weather stations and numerical weather prediction (NWP) data coupling to determine the weather-related LFU.

SERC gathers this weather information from FERC Form 714 Part 3, Schedule 2[8]. This source is by no means the only resource for weather related uncertainty, as there does exist data through metering at the ISO/RTO level. The ISO/RTO granular data opens up more ways to construct the LFU, similar to the benefits in the demand section above. The FERC data source requires that the Electric Utility Planning Area provide hourly demand levels in megawatts and the source starts at year 1993 for some regions. The format changes based on the year as per Table 1.1.

Table 1.1: FERC Data Source Format

Reporting Year	File Format	Notes on Use
1993 to 2004	.zip files organized by reporting year and NERC regions (legacy and current). Microsoft Windows compatible programs to read spreadsheet and text files, there exists a file that needs conversion in the archive, but many programs exist to convert to Microsoft products. Each entity has a separate format for each	Ensure that the data conversion you use for .wk1 files can be converted to Microsoft Excel. No viewer exists and must download to view the data. Conversions for analysis regarding multiple entities are needed to ensure the data gathered is uniform in the study.
2005	Similar to 1993 to 2004	Individual Entity filings can be viewed through the FERC eLibrary
2006 to present	All responding entities have the data and have the .zip archive to download. That archive contains .csv file formats	FERC Form Viewer is able to fully visualize the data prior to download. This year a unified format is applied across entities

It is suggested that the data be converted to a daily hour ending (1-24) matrix format. In order to perform that conversion, a few cleansing techniques can be utilized. Associated hourly trends and other whole filling algorithms will help to complete the database when holes or incompatible formats occur when adjusting time zones. To assist, FERC has placed a relational database viewer to assist with the collection of this data. See **Figure 1.3** for the database schema provided. Additional screening approaches to detect anomalies with the data that include outlier detection are also needed to ensure a good quality data set prior to utilization in the study.

[8] https://www.ferc.gov/docs-filing/forms/form-714/data.asp?csrt=18240670882965036364

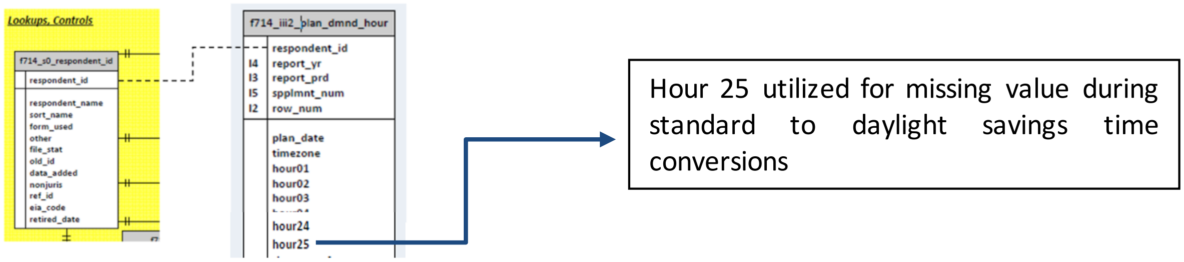


Figure 1.3: FERC Database Schema

In addition to just these hole filling requirements and other changes as required for outlier detection, additional screening approaches are need to reconstruct the data relationships. An example of what SERC has done to additionally adjust the FERC database forms can be found in **Figure 1.4**. As shown, the additional approaches can impose a slight difference between the NERC Long Term Reliability Assessment (LTRA) data and what is filed in the FERC database. For probabilistic studies, it is best to use the data in the LTRA (i.e. post additional screening) in order to calculate the weather related LFU.

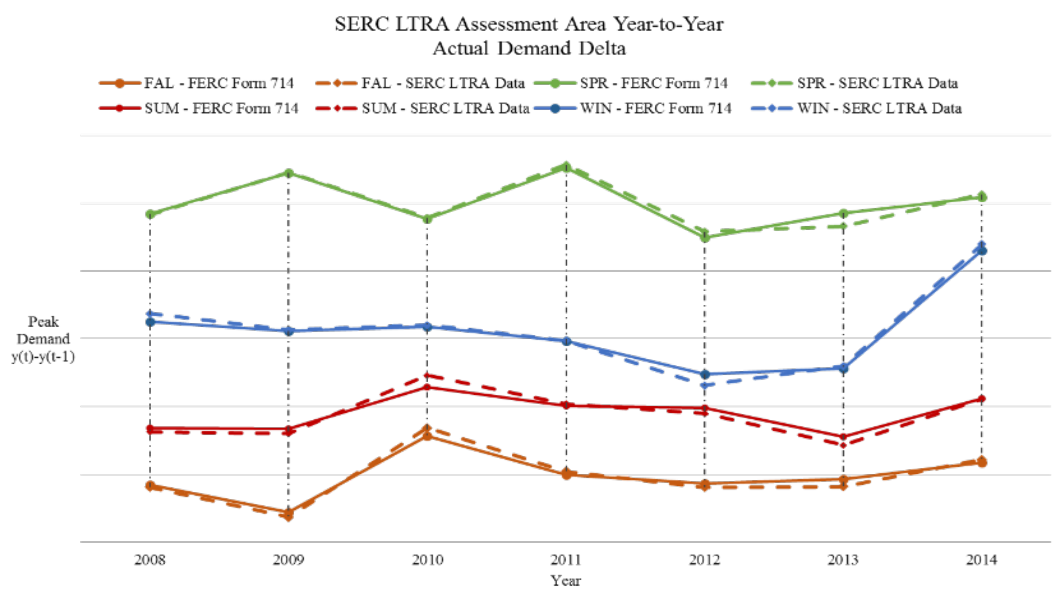


Figure 1.4: SERC Adjustment Example Utilizing FERC Databases

Complexities in Modeling Demand

While the basics of demand modeling in probabilistic studies is detailed above, multiple issues arise when allocating operational characteristics and other contractual obligations into the probabilistic study. Some of these complexities arise especially during the NERC Probabilistic Assessment process and are reflected in the following sections.

Modeling Multi-Area Systems

Entities should consider the correlation of peak demands with neighboring area systems in developing composite load shapes. These periods, perhaps due to heightened weather or economic conditions, represent high degrees of peak load correlations and represent the highest amount of coincident demands. The highest coincident peak demands represent a conservative assumption in the ability of the overall system to meet demand by reducing the ability or reliance of neighboring systems assistance in meeting peak loads. To capture this in the probabilistic study, load shapes from different Assessment Areas' geographic boundaries should have the same time frame as the study. Sometimes these regions change their boundaries; however, the goal is to stay consistent across the study in terms of data quality feeding the different geographic regions in the study. In cases where the boundaries of the probabilistic study cross different Assessment Area's geographic regions, data should be coordinated to capture the system coincident peak as a composite of the many geographic regions in the study.

Demand Response (DR)

For the probabilistic incorporation of demand response, the particular mechanics of each program or structure will dictate the utilization of the demand response. Primarily of concern is the amount of load relief the demand response provides at every stage, the number of times the resource can be called in a given period, and any other limitations on the duration or amount of relief the response. For regions where this is required to be registered, the above information can be found on the registration forms; however, not all regions are able to provide those registration forms. In these areas, the program can define many of the parameters; however, historical usage information can solidify the amount of load relief at each demand response tier. This historical usage however may be affected by more parameters than just the load relief as certain connections or disconnections affect the availability of the demand response to achieve the load relief. As these are quite complex, the PAWG recommends using a data source that captures operational conditions surrounding demand response in order to capture any cross correlations, or to calculate them otherwise.

For demand response that is registered, the amount of relief, number of times it can be called, and other duration limitations or restrictions are found in that registration forms to enter into their respective databases. For unregistered resources, resource planners are encouraged to use methods to predict their availability by analysis of past performance and heuristics going into the future to obtain these values. A quick overview of the data inputs for demand response are summarized in **Table 1.2**.

Table 1.2: Information Required for Demand Response (DR)

Information Required	Example Collection Source
Amount of load relief	Registration database that aggregates the load relief or informal survey to non-registered devices
Number of times in a given time period demand response can be called	State/Provincial level orders or similar utility contracts regarding Demand Response
Duration limitations	State/Provincial level orders or similar utility contracts regarding Demand Response
Tiers of response	State/Provincial level orders or similar utility contracts regarding Demand Response
Other restrictions	Utility specific directives, databases on controllable loads

In addition, there are market structures that contain different levels of this type of demand response. These are sometimes labeled as Emergency Response Service (ERS), but these are going to be varying by when they can be called and the response of the service. Supplemental collection of similar sources[9] should be utilized to capture these tiers of response.

Demand and Demand Response as a Resource

When demand response is modeled in the demand profiles themselves, adjustments to the demand profile will apply to the demand response. Conversely, when demand response is modeled as a resource, it is not included in the

[9] State or other regulatory bodies as well as other internal sources may manage these sources.

demand profiles and is not included in any of the alterations in the demand section. To further clarify the difference, when DR is modeled as a resource, adjustments from the weather or non-weather related LFU will be only on demand rather than both the DR and the demand. This can then be directly used in the study as all of the adjustments are on demand curve. When modeling DR as a resource, these techniques need to also be applied to the demand response modeled as a resource as such LFUs will impact the key model parameters in **Table 1.2**. The data source chosen to provide the LFU should be flexible to adjust for either modeling scenario. The key point for this separation is to ensure any adjustments to demand are adjusting the operational characteristic of the demand response or the demand, rather than both. If separating the demand response as a separate resource, then the collection of data may require more data than just the amount of load relief at any given time in the simulation and may require time-of-use or other operational profiles to determine in-simulation output of the demand response when called upon.

Distributed Energy Resources (DER)

DERs can be a multitude of differing resource types connected through the distribution system; however, many of the current installations are photovoltaic solar (Solar PV). Some probabilistic studies utilize simulated profiles as a load modifier in performing the load forecasts. In some areas, a DER forecast may be available, but these forecasts are generally at the state regulation level. As such, the forecasts may vary between Assessment Areas, and could even vary internally to the Assessment area if such boundaries cross state lines. Such data can be valuable to the planner when performing the probabilistic assessments, but should care needs to be taken such that the DER are not double counted in the demand portion of the study. That is, if a load modifier for simulated profiles are used; additional forecasts should not double count this modifier. See the section on Generation Availability in Behind the Meter Generation (found in Chapter 2) to see the setup for modeling DER as an explicit stochastic resource. The difference with current DER technology, however, is the high correlation to irradiance for their availability. With this high correlation, weather related data as demonstrated above could supply another marker into the DER's availability. These types of resources use a mix of demand techniques as seen above and parameters seen in Chapter 2, and as such similar data sources can be expected when modeling the DER in a probabilistic study. As there is no current database or source for availability of DER, a mix of operational data and weather data can be expected to model each state of the stochastic representation.

Data Validation & Cleansing

Once data are formatted across all reporting years, entities should consider performing data reviews and validations, as well as post-processing work if the data are large to ensure the underlying data in question is of sound quality. These validation and cleansing methods are not just relegated to demand data, and are summarized generally in Appendix A.

Demand Reconstruction under Boundary Changes

FERC 714 filings are housed in a central resource so an entity can import the same submitted demand data into the resource adequacy study. This, however, imposes an issue where an entity's boundary changes or is under study in a different boundary. These geographic changes will require some reconstruction of the demand in each area in order to maintain the same level of demand uncertainty across the entire study region. Two options generally exist, a time-series reconstruction or a comparison of the peak demand in each area creating a ratio. The former is more time intensive, but provides a greater level of accuracy for the added or reduced demand based on the geographic change. The latter option provides a quicker way to adjust the demand shape in the study, but assumes that the peak ratio is valid for all times in the year. This creates a less accurate depiction of the demand change.

Demand Data Requirements

The data requirements for use in resource adequacy studies revolve generally around the time granularity of the data. An hourly representation of demand levels is required for most studies, and associated databases may or may not have such hourly representations. In such instances, hole filling programs and other trend-based algorithms can fill the gaps associated with transferring the data into hourly format. This is crucial as some of the current metrics the

PAWG has in their previous reports, the metrics are in hourly format. The reader is reminded that many databases may not have the greatest quality of data; however, such data could be sufficient for their report or study. Such databases simply require the post processing methodologies as discussed in the SERC example in **Figure 1.4**.

Collection methods

There are varieties of both sources and mechanisms for which data can be acquired and utilized for conducting probabilistic assessments. The specific data needed can vary significantly depending on the type of assessment as well as the underlying characteristics of the system under study. Aspects potentially affecting the availability of data include status of local, state, federal regulatory framework, market construct and available operational data, underlying resource mix and trends information, and/or agreements or tariffs with other Registered Entities. For NERC Registered Entities conducting probabilistic assessments, data sources being utilized vary by jurisdiction and applicability to their respective systems. A summary table of the various types of collection sources for different types of entities is found in **Table 1.3**. It is anticipated that other data sources exist for this data, and the table is provided as a start for collecting the type of data.

Table 1.3: Data Collection Notes on Different Entities

Entity Category	Entity	Notes on Data Available
Federal, State, or Provincial level	US Energy Information Administration (EIA)	The EIA contains a lot of valuable information on various energy products, including: LNG export, generation capacity, and an hourly grid monitor. Care must be taken to gather the source of data, or to understand the assumptions associated with the reported charts, graphs, or other tools.
	National Renewable Energy Laboratory (NREL)	The data available contains maps, models, and tools used for energy analysis. Specific ones help with association of data and others are tools to feed probabilistic studies, such as weather data.
	US Census Bureau for US based regions and Statistics Canada for Canadian regions	The data here contain population and census data in particular geographic regions. Additionally, collects and publishes nationally commissioned data on such populations.
	Public Utilities Commissions	These entities can provide state, provincial, or local agency data specific to energy and resource type.
NERC Registered	Generator Owners or Generator Operators (GOs/Gops)	Generation entities can report their outage information to the NERC GADS, and in cases where more information is required, can assist in determining their generation availability. The latter is especially true for newer plants.
	Distribution Providers (DPs)	These entities provide their distribution system to serve end-use customers. These entities are able to provide information on their served demand
	Transmission Owners (Tos)	These entities are the owners of equipment for the long distance transmission of power, and may be able to provide outage information related to the equipment they own. For example: transmission lines and transformers

Table 1.3: Data Collection Notes on Different Entities		
Entity Category	**Entity**	**Notes on Data Available**
Operations/Market	ISO/RTO Capacity Markets	Each ISO/RTO provides an outlook on the anticipated socio-economic changes and some of them provide outputs usable in probabilistic studies

Chapter 2: Thermal Resources

A large majority of resources in the BPS are thermal resources that convert chemical energy into electrical energy by burning of a fuel. These resources can vary dramatically in construction; however, the focus on data collection for reliability studies is on modeling the availability of the generation and at what level that generation is. In general, a two state Markov model is the end goal for these types of resources so data collection will center on gathering enough information to fill the model. As other models exist, this section will detail the many sources of filling out any type of stochastic model.

Outage Data

Outages must be considered for all resources in conducting probabilistic assessments as outages have the ability to materially affect the availability of generators to meet the demand. NERC Registered Entities typically utilize a combination of data sources[10] to account for planned, forced, and maintenance outages along with their associated uncertainties. These typically include a combination of historical information, performance, and potential correlations to weather data. Some of the types of forms used for the information include generator availability[11] and outage rates (NERC GADS), such as the equivalent forced outage rate, FERC 714 hourly reported data, and market data. In addition, some selected entities utilize a combination of forecasted resource price data, powerflow studies or perform regression analyses for potential correlations with outside datasets.

Key Takeaway:
Building the outage rates of thermal resources requires forced, planned, maintenance, and other outage data. A single data source may not have all the types of outages.

For thermal resources, the majority of the outage data required to formulate the equivalent forced outage rate will require a data source including parameters for planned outages, maintenance frequency and length, and forced outages, which include repair and failure rates[12]. The parameters associated with the planned outages include the maintenance cycle and length, usually are related to the months of the year (i.e. two of the twelve months) and the length of days associated with that outage. There does exist cases where the planned outages can have durations across years, and such cases will need to assure that the durations are related to yearly outage metrics. In addition to these planned outage inputs, the parameters associated with the forced outages include full outage mean time to repair, full outage mean time to failure, and partial outage deratings for however many derate states there are. For partial outages, the critical component is hours for MW unavailable, no matter the derate type. The sum of the zone is the critical component, then grouping by event type, can be informative for other model or data validation considerations.

The data source for the forced outage rates can be fulfilled in the NERC GADS database; however, that data does not include reported planned outages and is a calendar-reporting database where multi-year events may have differing unique identifiers. To account for those differences, supplemental information is required to bridge the gaps. In an informal poll by PAWG membership at their meetings, many of the companies contain an internal data source that accounts for the planned outage data. Some of these functions are not in the planning departments, but rather in the operational departments. When using operational tools, it is important to remember that the data may need to be altered in order to account for errors occurred while logging the planned maintenance records. Additionally, a Canadian Electrical Association (CEA) reliability database can also provide the statistics regarding thermal outages

[10] These data sources may be quite large. For instance, ANL has over 650 million records of customer outage data sampled at about every 15 minutes.

[11] Depending on the generation model, EFOR versus EFORd will demonstrate if the plant was in demand when the outage occurred for use in determining the generation availability. The NERC Performance Analysis Subcommittee has identified that the NERC GADS does not have enough information to calculate the EFORd modeled outages using that data source only. As such, the resource planner needs additional operational data if using this in the model. [POSSIBLE LINK TO A PAPER]

[12] These sources for data are used to develop an estimate for the FOR of the unit. IEEE Std. 859-2018 describes the statistical modeling concerns surrounding the use of point estimates or averaging of results as well as the assumption of independent outages across the generation fleet.

that aren't related to event based performance sources, much like the NERC GADS. In each of these sources, cleansing of the data in order to align the information submitted to the database and aligning it with the records found in operations that take on these derates. This type of cleansing may require knowledge of the model[13] in order to align the transition rates with the submitted and forced conditions.

When utilizing the NERC GADS database, a few other peculiarities exist for thermal units, as the reporting for units may not be consistent across the database. For units with a high startup rate, taking startup outage out of EFOR is a more appropriate way to model the stochastic nature of the unit. Then the resource planner can utilize that reduced EFOR for those units. The startup failure rate may show up as a derate or as an outage rate. An additional consideration exists for NERC GADS. The database is set up for the immediate timeframe, meaning that using it as a data source for derates will only provide the reduction of MW from the current ambient conditions. For some thermal units, this is not an adequate indication of the starting point, as some units are highly sensitive to ambient temperature. For these units, additional data in the form of a temperature curve assists in developing their stochastic model.

For entities that do not use the GADS data, such as the IESO, they have an internal database that takes into account all outages (submitted, forced, and approved) on a per generator basis. Other entities also maintain an internal central database for this data. Generally, those entities utilize a set of samples from historical databases and submitted planned outages to forecast the generators outage data for the study. This outage data are similar to the planned outage databases discussed above. Similar conditions exist to ensure data accuracy with reporting of planned outages in this type of system as well as the forced outage data. For the IESO, the planned outages are modeled as a part of future planned outages, 10 Year Forms with projected outage schedules, and historical planned outage rates. By collecting the data in one source, IESO is able to model their thermal resources.

Perspectives on Predictive Outage Forecasting

Key Takeaway:
Predictive Outage schedulers provide methods to forecast outages in future years, where the planner conducts the probabilistic resource adequacy study.

Historical Generation Availability Data System (GADS) data collected by NERC is a common and standard data source for entities modeling conventional generation[14]. Operational schedulers can also be a source of this information, and the Control Room Operations Window (CROW) would be another valid data source for predictive outage forecasting. However, access to the information within this database can be challenging and unit specific information is not accessible to all entities[15] . An alternative way to obtain the data is by requesting it from resource entities directly. A specific example for requesting GADS data from resource entities, including the data request notice and data submission form, can be found in Appendix B. Since conventional generation outage trends may change over time, it is useful to predict outages in planning studies. An example of such is in ERCOT, where staff reviewed several predictive algorithms, such as the Prophet[16] tool developed by Facebook, to determine its usefulness in capturing changing trends. A predictive forecast approach based on Prophet[17] has been tested to forecast fleet-wide forced outages. For unit-specific outages used in probabilistic studies, the predictive approach may not be applicable. Based on the ERCOT's experiences with such data sources, the predictive approaches can help visualize the nature of the combined historical and planned outages to provide a way to more accurately collect the correct outage rates to apply to the study. To fuel a stochastic model, these predictive outage-forecasting tools should include mean time to failure, mean time to repair, mean time between failures, and other transitions between the stochastic states to be an effective data source.

[13] Such as the distinction between two-state and multi-state Markov models for thermal resources

[14] These databases log historic outage data to calculate their availability. There are conversations on the use or nonuse of historic data in predictive probabilistic studies found in IEEE Std. 762-2018 and IEEE Std. 859-2018.

[15] Only entities authorized to view unit specific data are allowed access to that data due to the sensitivities surrounding the data.

[16] A link to the tool can be found here

[17] Link for the Prophet tool can be found here

Data Considerations for Capacity Constraints

> **Key Takeaway:**
> Many of the capacity modifications are highly model dependent, indicating the need for varying data source requirements. Data collection should be considered on a case-by-case basis.

Outside of planned and forced generator outages, there are other factors that can also affect supply availability, which must be accounted for in reliability assessments. Factors such as emissions constraints, unit deratings, fuel availability and capacity constraints all limit the availability and ability for supply side resources to meet the demand and can have wide implications for reliability, especially in extenuating weather or stressed system conditions. Additionally, some future market conditions may impact the capacity or dispatch of a unit where such markets affect the operational characteristics of the thermal generation resource. Some of these constraints can be found in the source documents that dictate the market rules, or in the regulatory body that imposed the rules in the present or future market.

Emissions Constraints

Entities must account for the potential application of emissions if they plan to model these constraints in their resource adequacy studies. Some of these constraints are taken into account during economic dispatch of the units, while other models require explicit states modeled based upon the study conditions. Much of these constraints are regulated by different government agencies, and as such, they are generally unique in each area. In general, the assumption for emissions is that during blackout or resource inadequate periods the regulators will lift the constraint; however, these constraints can be adjusted by modeling the outage rates, capacity limits, and other water flow constraints in order to model the impact these policies have on specific generators. However, since the modeling varies, the amount of data required will vary as well. Resource planners are suggested to look to government agencies or emissions regulators in order to gather enough information to model the emissions constraints.

Fuel Availability Data

The NERC Electric-Gas Working Group (EGWG) has helped determine the interfaces and potential interdependencies that the electricity sector has with the gas pipelines and potential disruptions of those pipelines[18]. As it pertains to resource adequacy, the data required to model the impact of pipelines can be cumbersome and is not available in NERC GADS. The data source selected should consider mean time to failure and mean time to repair rates associated with those operating states. These general considerations are typically accounted for using Equivalent Forced Outage Duration (EFORd) in some regions, but others do account for this in the EFORd as that measure is typically reserved for mechanical outages. Similarly, the fuel availability statistics will need to account for the derate associated with lack of fuel. Due to these complexities, capturing this in a probabilistic study is very cumbersome and will require more than usual amounts of data to perform a study. A resource planner will require access to pipeline outages and other gas information systems in order to model the impact on a resource adequacy study. In some very restrictive areas for fuel availability, a resource planner can consider modeling this thermal resource as an energy limited resource with considering some aspects of other energy limited resources in Chapter 3. In particular, the available natural gas, in MBTU[19] per day, from a data source in these scarce periods is important to consider.

Capacity Modification on Ambient Conditions

> **Key Takeaway:**
> Thermal power curves allow the study to adjust the capacity based on the ambient temperature studied. Modeling ambient conditions also requires weather data close to the resource

To capture the capacity modifications due to differing ambient temperatures, some entities send a survey to their Generator Owners with capacities at specific temperature points. These points provide a curve and that particular curve is used to set the capacity derates under the ambient conditions; the source of those ambient temperatures is the same as the Weather Related LFU portion discussed in Chapter 1. The combination of these two provides a simplified method to model correlations between the weather and generator outputs for the

[18] Link to EGWG report here
[19] This is a common measurement in the natural gas industry to indicate 1,000 British Thermal Units (BTUs)

forecasted short-term; nevertheless, the source for these model considerations stays the same: a survey to generator owners to generate a thermal curve and the weather related LFU sources.

Other capacity modifications depending on the ambient conditions exist. Terms like High Sustainability Limit, which ERCOT defined as the real time maximum sustained energy production of a resource; Dependable Maximum Net Capacity, which is defined as the maximum power a resource can supply under specific conditions for a given time interval without exceeding thermal or other stress violations; and Seasonal Capacity, which is the capacity of a resource in a given season, come into play. These terms all try to describe the energy restrictions on ambient conditions and constraints that would hinder the modeled generator in the reliability study from producing its nameplate value. Should this be a major concern in the study, the data source[20] chosen should be equipped to handle the desired study conditions and gather enough data on the constraint to model it stochastically. At minimum, this means determining the mean values for transitioning between the states.

Generation Availability in BTM Generation

Data sources for behind the meter generation will be highly model dependent, but there are a few considerations for these generators, which typically do not report in surveys or other generator data sources. These types of resources sometimes can be found as a load modifier, but those resources can sometimes be sensitive to a market price of other dispatch signals, and are thus not related to the electrical characteristics at their Point of Interconnection (POI). To gather enough data on these types of resources, a case-by-case data structure will most likely be needed or a wide swath of assumptions to be made based on the available data to the resource planner. Two approaches exist for these generators. One is to net them against the load where they close geographically, which carries all the assumptions of demand modeling. The other is to model these as discrete stochastic resources, with a recommendation for a simple two state Markov model that can be developed off operational data superimposed on other time-synchronized measurements to determine the resource's full capacity. If modeling via the latter method, the same data types outlined in this Chapter are expected to be placed into the model, and as such similar data are to be collected. Collecting this type of data may be cumbersome for these types of generators, so heuristics developed off knowledge of these facilities can aid in determining when to collect the data to best model the resource.

[20] This may be a survey to the GO, as the IESO example above demonstrates

Chapter 3: Energy Limited Resources

Some of the common resource adequacy discussions are based around a discussion on the capacity of resources and the availability of those resources to meet the level of demand in a study. In the case of energy limited resources, such as hydro, wind and solar, capacity related discussions are only one facet of reliability planning. This chapter focuses on the different types of energy limited resources to describe how to collect data representative of them for use in a probabilistic study.

Hydro Units

The vast majority of hydro generating facilities are considered as energy limited units since these facilities are dependent on the availability of water resource. The time constant for the availability of water may be longer than that of wind or solar. The effect of unit-forced unavailability is not significant on hydro generating system reliability; therefore, many resource planners incorporate this unavailability in estimates of energy limitations when conducting probabilistic analysis. Some of the input parameters for each hydro power plant are:

- Installed/in-service, Planned and retirement dates
- Monthly maximum and minimum output of each plant
- Monthly available energy from each plant
- Energy distribution (available energy to hydro unit)
- Forced Outage Rate (FOR) or EFORd

For hydro generating facilities, some entities may assume that the available water or fuel for each plant has little or no uncertainty, or that the water resource is in a drought condition. This is a conservative approach to ensure that sufficient resources will be available when needed. However, if the uncertainty is to be modeled, the data to incorporate that into the hydro facilities requires similar data to other weather-related energy limited resources.

Simulated Solar Generation

In a loss-of-load probabilistic study, it is important to cover all of the weather years of data for resources highly correlated to weather data (e.g. Solar PV). In order to do so, resoruce planners can simulate the expected behavior of the solar plant for use in their loss-of-load probabilistic studies, and many tools are available to augment or replace observed historical generation data for a particular resource or neighboring resources. One such tool is the Weather Research and Forecasting (WRF) model[21] used to generate the historical atmospheric variables such as wind speed, temperature and irradiance, which in turn simulate solar power production at each location in the model. The most important data points to produce a simulated solar profile are the types of arrays, soiling, shade, and control parameters associated with tracking the solar bodies. Some tools that utilize these parameters to then convert into AC capacity are the NREL SAM tool[22] or the Waterloo tool[23], with the former inputting parameters to produce the profile and the latter producing profiles off generic adjustments. The latter takes into account multi-order variables when producing the curves, but requires additional site-specific data that may not be available when conducting a resource adequacy study; however, it still remains an option for more specific profiles.

Key Takeaway:
Simulated profiles can be performed for both existing and planned solar PV sites. In either case, site-specific details help refine the fidelity of the profile. Some tools provide DC capacity and others AC capacity. For use in resource adequacy studies or assessments, an AC capacity will need to be calculated if the tool does not do so.

21 Information on this model is available here
22 Available here. See information on the PVWatts portion of the tool
23 Available here. JP NEEDS ASSISTANCE FINDING THIS ONE!

To walk through the process, ERCOT computed the atmospheric values and adjusted them using surface station data and input them into a proprietary PV model to produce the hourly power output profiles. Programs mentioned above would also provide a profile, but ERCOT utilized proprietary models to accomplish the goal, yet another option available to resource planners. More details about developing hourly solar power profiles can be found in the solar profile methodology report, available on ERCOT's Resource Adequacy webpage[24].

If utilizing site-specific information to inform profiles, data found in **Table 3.1** is useful in providing to a program or vender when gathering simulated solar profiles. Some of the information is expected to be assumed, as some can be site-specific and many of those parameters are not available at the time of study.

Table 3.1: Solar Profile Data Requirements

Category	Data Point	What to Gather
Static Plant Details	Installed Plant Capacity	DC MW Capacity
	Tracking System Type	Fixed, Single, or Dual Axis
	Tracking Origination	Azimuth, north-south, other
	Module Tilt	Horizontal, Tilt to Latitude, other
	Module Azimuth	Degrees off Azimuth
	Ground Cover Ratio	Ratio of array coverage by other arrays
DC to AC Conversation	DC to AC Ratio	Efficiency of DC to AC conversion in MW
Inverter Details	Inverter Capacity	Either 1) Inverter make and model, or 2) Number of Inverters and the inverter capacity
PV Module Details	Module Capacity	Either 1) Module make and model, or 2) Number of Modules per string and the module capacity

Key Takeaway:
Public resources exist to generate the simulated solar profile; however, non-public options exist for use as well.

Site-specific parameters are not required for these profiles; however, they provide a more granular approach to modeling the contributions of solar resources. In general, the solar profile is a time series of data on the total power production (in MW) at a solar facility. Two methods exist for this. One is to gather time-series irradiance data and convert it to MW by collecting efficiency of the solar facility to convert that irradiance into MW. This conversion acts as the solar profile for a particular resource and the NREL database for US entities contains many years of solar data for this purpose. Canadian regions can somewhat be covered by that database, but meteorological data from weather stations may be able to supplement this. The other method is to take historical generation samples from another solar generation facility, gather irradiance data as above, and then merge the two in order to capture some other uncertainties not related to irradiance. Some entities use a solar forecaster to accomplish this task, but many others do this merge of data inside their own company. This latter

[24] http://www.ercot.com/content/wcm/lists/114800/ERCOT_Solar_SiteScreenHrlyProfiles_Jan2017.pdf

method allows site-specific information that is not necessarily the information as detailed in **Table 3.1**, but captures the effects of that table.

Hydro, Wind and Solar Data

Hydroelectric, wind and solar resources are similar in that their production at a given point in time is governed by fuel availability. Hydroelectric resources have varying levels of control over their availability depending on the site; run-of-river generators are entirely dependent on river inflows, while generators with large reservoirs can have daily, weekly, seasonal or even annual storage. The goal of any data collection for modeling the capability of these resources is to find data that give the best representation of the capability of these resources over a period.

For all three resources, there are two basic types of data that can be collected: production data and fuel availability data. At a high level, production data captures the amount of electricity generated over a given period, while fuel availability data captures the amount of primary energy that could have been converted into electricity over a period. For all three resources, the collection of production data is the same, assuming full data availability. For many embedded generators, production data may not be available. Data that can be collected that captures the amount of primary energy that could have been converted into electricity for each resource type is outlined below.

When gathering data for these units, take care to ensure that the same historical time frame is used for the demand sampling. If a different historical year is excluded in the sampling for data in the solar resource, the cross correlation coefficients of the hydro, wind, or solar resource with the demand will impact the end probabilistic metrics in the study. Maintaining the same historical time period as the demand sampling will alleviate the concern over these cross correlations or any other dependency between the resource availability and demand. A good way to think about this is that in times of high irradiance, many air conditioning loads are likely to be active at a given time. If a TP samples irradiance outside of the same time boundaries as the load, the correlations in the shapes need to be described; otherwise, they may be misrepresented in the study.

Key Takeaway:
Energy limited resource data gathering should have the same timeframe as the demand collection in the resource adequacy study.

Solar Fuel Availability Data

For installed solar PV plants, the same irradiance data that created a solar profile can act as a fuel availability curve for that resource. There are various methods to collect irradiance data, with some sources detailed above. A cloud cover or satellite analysis might be necessary to fully determine how those impact the availability of the solar resource to contribute in the resource adequacy study. Some models ask for a temperature and wind speed aspect for solar availability, and any publically available data source or nearby weather station can have those measurements. In addition to Table 3.1, some models require the Global Horizontal Irradiance (GHI), Diffuse Horizontal Irradiance (DHI), or Direct Normal Irradiance (DNI) or some combination of the three in order to calculate the output of the solar facility. Regarding those values, some weather stations are not equipped to measure all of the values.

Wind Fuel Availability Data

Wind fuel availability is similarly build as the solar fuel availability. However, since wind speed is dependent upon the height of the measurement, the turbine height needs to be accounted for in the gathering of wind speed. The historical wind generation in that area is important to obtain in order to get the distribution of wind speeds and thus the generation of that facility. For operational plants, many have wind speed recorders that can be obtained in order to build the curve. NREL also maintains records for wind speeds between the years of 2012 and 2015; however, recent years are not recorded. NOAA can provide the wind speed for these and other years to supplement the data from NREL. If the operational plant does not record their data, close by weather stations are

Key Takeaway:
If historical generation records are unavailable for the resource, geographically close profiles are adequate. This includes weather stations.

also acceptable to get the data from. A power curve translates this wind speed curve into a total MW output of the wind facility in order to be used in the study. Other weather data may be required based on the sophistication of the wind model in the resource adequacy study.

For future looking resource adequacy studies, the assumption of geographically close data availability is not always a good assumption. One tactic is to collect g the capacity of the facility based on the projected design to assist in ascertaining the availability of the wind resource. The key parameters to procure are the design parameters and associate the parameters to an expected wind MW curve. Design factors to consider are turbine height, cut-in speed, cut-out speed, and other speed breakpoints as based upon the design. As an example, WECC samples historical wind generation from their nameplate and uses that profile at a different wind generation facility in order to supply the wind speed curves. Then any design constraints are applied to that profile to gain the total MW production curve from that resource. In general, for studies that are modeling future wind facilities, a profile of wind speeds from other facilities or meteorological stations along with design parameters from the resource developer can produce the expected MW profile of the wind facility. This process is very similar to the simulated solar PV section above.

In some instances, wind production reaches a point where transmission operators or generator owners must curtail the wind to meet plant or system condition constraints. In such instances, similar derating methods are required from the thermal resources. The conditions surrounding the derate should be recorded and the constraints modeled when using the wind resource in the resource adequacy study.

Hydroelectric Data

Similar to the wind data, representing energy-limited hydro facilities in the study could require a translation of their water supply into a total energy production. To do so, the resource planner will consider hydrologic or fluvial conditions such as water inflow, outflow, and head of the hydroelectric resource. If using flow data, a power curve is required to translate the water flow into a time series MW on that resource. For these types of facilities, many regulations dictate the amount of water stored or required to be flowing across the facility, so data on spilled water can supplement production data to give a better indication of the availability of the resource to produce electricity in the study. Additionally, only using production data underestimates the potential of the hydro resource. Offer data can supplement the production data to get the energy, operating reserve, or both to express the capability of the unit, as the total capacity of the unit is the current capacity of the resource is the operating reserve the unit is providing added to any current power production. Since hydro facilities have many moving parts, planned and forced outages are also a concern, albeit a lesser concern. Other outages for hydroelectric facilities can also include environmental or safety outages, which have a similar lesser concern in terms of modeling in the resource adequacy study. See Chapter 2 on Thermal resources to find databases that these facilities can report to on outages.

The end goal of data gathering for hydroelectric resources is to build a water year for the amount of water available for the plant to use in generation of electricity and to incorporate any environmental factors, operating restrictions, and generation availability that may limit production based on the sophistication of the model. Unlike other energy-limited resources, more attention can be made to the environmental factors that dictate the amount of flow out of the plant that will describe the availability of the resource. Additionally, if the hydro facility is a run-of-river facility, the inflow of the river and environmental constraints will likely dictate the availability of the plant. Some data sources for the data are Environment Canada, NOAA, and other national weather databases that measure hydrological quality.

Energy Storage Systems

As of this report, two major types of energy storage exist: battery energy storage systems (BESS) or pumped hydro storage. The inputs in **Table 3.2** are important to model energy storage systems. Not all parameters are exclusive to pumped energy storage systems or BESS, though many parameters cross over.

Table 3.2: Energy Storage System Profile Data Requirements		
Category	**Data Point**	**What to Gather**
Resource Characteristics	Maximum Generating Capacity	The maximum MW the facility can generate when discharging its energy
	Minimum Generating Capacity	The minimum MW the facility can generate when discharging its energy
	Maximum Charging Capacity	The maximum MW the facility can take on when charging its energy supply
	Minimum Charging Capacity	The minimum MW the facility can take on when charging its energy supply
	Dispatch Order	Position in the economically constrained dispatch[25]
	Storage Cycle Efficiency	Total Roundtrip efficiency on the charge or discharge cycles.
	Maximum Energy	Pumped Storage Reservoir or BESS maximum energy storage[26]
Outage and Maintenance Data	Historical Outage Data	Time series MW production and consumption for many historical years
	Maintenance Periods	Time windows where the resource is under outage for maintenance.
	Availability of the Unit	Failure and repair rates of the unit.[27]
Unit Availability during Ancillary Services*	Pumping Operation	Similar to the Outage and Maintenance Data
	Normal Operation	Similar to the Outage and Maintenance Data

*This type of data may be very difficult to obtain for battery energy storage systems as they may have many different ancillary services. An operational profile may be more informative.

Key Takeaway:
Understanding the energy storage device's operational characteristics allows for adequate modeling, and informs the data collection and databases required for the study.

Initial additions of energy storage systems to systems that are capacity constrained rather than energy constrained are generally capable of providing full capacity value with 4 to 6 hours of continuous operation relative to conventional resources. As an example, an energy storage resource can be charged during low load periods and dispatched during the few highest load hours of the day or by other dispatch patterns depending on how the resource is procured. However, when the penetration increases above 2 to 3 percent of system peak, rigorous modeling of all constraints and capabilities of energy storage systems is required. While the dispatch methodology is still the same, the frequency and duration of high loads becomes more binding on the capacity value that energy storage resources can provide since they are required to serve more of the load.

[25] This is important for Emergency Operating Procedures or other Ancillary Service capacities these storage systems supply. Market data may be required

[26] In pumped hydro cases, this maximum may be quite large.

[27] In BESS systems, this is highly crucial due to the construction of the battery pack. Other energy limited resources have resilient measures in place; however, BESS construction has either a "all or none" capacity.

It is also important to note that there are numerous possible interactions of the various energy storage specific inputs. For example, if the dispatch order of energy storage systems is not optimized for reliability, they may need significantly longer duration capability to provide full capacity value. In addition, if energy storage resources can be used to serve ancillary services, their reliability value can be substantial with even shorter duration capability.

Chapter 4: Emergency Operating Procedures

Emergency Operating Procedures (EOPs) are control actions or tools that system operators can utilize to modify generation or loads under stressed, abnormal or emergency system conditions. These conditions could be resource supply or reserve deficiencies, element contingencies under the course of BPS operations. EOPs should be properly accounted for and modeled into probabilistic reliability assessments to ensure that a realistic representation of system risk concerning resource adequacy are considered. These tools can be invoked or implemented to mitigate possible resource shortages or emergencies prior to the disconnection of load and the likelihoods of use and amount of relief can vary. The procedures and details of EOPs is widely dependent on a Regional, Area or entity basis and typically occurs under pre-established criteria.

Parameters

Modeling these types of resources can vary greatly by entity and data sources can vary accordingly. EOPs generally, however, will provide a means to relieve a constraint for a specific amount of time. Some types of EOP's that could be considered for studies include:

- Load Curtailments or Interruptible Load Programs;
- Operating Reserves;
- Use of import agreements with neighboring systems;
- Voltage Reduction;
- Special Resources;
- Demand Response;
- Public Appeals;
- Or, cyclic load shedding.

These types of procedures can have specific parameters that must be considered in modeling. These could include the number of times in a given time period the EOP/resource can be performed, duration and time period between calls, and the amount of relief on subsequent calls or fatigue factors. These constraints can be seasonally adjusted as well depending on the area as seasonal temperatures may prevent an EOP from being enacted on the demand side from a non-disturbed system. With regard to these procedures, state governments or programs may have the details on the limitations and can help to associate the exact parameters required to model that specific type of EOP.

Collection Methods

Key Takeaway:
Emergency Operations Procedures require less data gathering to model than the other topics discussed due to their fixed duration and frequency of calls.

Due to the rigidity for some EOPs, the duration and frequency are generally fixed indicating a lack of major data collection efforts being needed for a probabilistic study. In terms of data collection, some programs may require a customer to sign up with the utility for the program. As such, for those programs the repository that holds those records will be the source of data for the probabilistic study to determine how much load is relieved when the EOP is enacted. Relevant load relief data (in MW) for EOPs can be determined through several methods depending on the system; however, the majority are based on collection via source documentation or by historical availability.

The source documentation methods look at the establishing papers, legislation, or programs that dictate how EOPs will be called upon and use such information as data for study. For instance, some EOPs such as voltage reduction can be determined through the source documents of those schemes. Other EOPs' load relief data can be collected through the registration of resources and the availability requirements for these resources in an emergency. Even further, some EOPs are spelled out in the tariffs, and serve as a good data source for determining the amount of available capacity for load relief. Limitations on number of calls for these EOPs need be considered when collecting the data as well as looking at the assumptions surrounding the source documents to see if both still hold for the study in question. This type of data may not be found in the source documents and should be considered when collecting data for study.

Regarding historical availability methods, the resource planner can also actively collect data regarding how much relief occurred from historical calls to EOPs. Trends could be also reviewed from GADS or other measured data to develop reasonable assumptions for usages for a given EOP if the other methods cannot provide the data. Availability of these resources at the time of the emergency, such as the proportionality to peak loads should be considered when developing assumptions utilizing the availability databases.

Physical Testing or Audits for Voltage Reduction

If physical test are available to the planner, the resource planner can commission a voltage reduction test and utilize those results to determine the amount of relief that the EOP can provide in the probabilistic study. These tests may require other jurisdictional approval prior to conducting the test. Other types of tests may also exist to provide the estimated capacity relief other EOPs can provide and entities can look to either producing their own test or coordinating with other entities to produce a test.

Chapter 5: Transmission Representation

More and more attention has been given to consider transmission constraints in probabilistic resource adequacy assessment. There are many different parameters associated with transmission lines, and depending on the study, not all of those parameters may be useful in determining the interconnected system's reliability in a probabilistic representation. A majority of the data sources discussed in the other chapters are representative of the desire to determine if sufficient generation is available to meet demand. Similarly, there may be a desire to determine if sufficient transmission is available to meet demand.

Key Takeaway:
Data requirements depend on the types of transmission model used in the resource adequacy study. Some require additional line parameters, but others require only transfer limits

Interface Limit and Detailed Circuit Representation – Data Requirements

Typically, there are two different ways to represent transmission constraints: interface limit model and detailed circuit representation. In the interface limit model, the transmission is modeled as a "pipe" between two areas with specific constraints and properties. In the detailed circuit representation, the transmission is modeled using all transmission lines that may be seen in positive sequence load flow software into the reliability assessment realm. These types of representations can be useful depending on the type of study being done; however, their data sources may not always be the same.

Interface Limit Model

The transmission constraints between areas are modeled with interface transfer limits. Each interface is represented as a tie line with bidirectional transfer limits. Physically, each interface may consist of two or more transmission lines and the interface limits and equivalent admittances are typically determined based on thorough steady state and/or transient stability analyses. Most of the existing tools for resource adequacy assessment are able to simulate random forced outages on the interface between areas. The minimum data required for representing the interface limits depending on the purpose of assessment and the method employed for network flow analysis. **Table 5.1** shows the minimum data requirements for using the Interface Limit Model to incorporate transmission constraints in resource adequacy assessment. NERC TADS is a database that records the type of outages associated with transmission lines and provides enough information to formulate a forced outage rate for the transmission elements. Aggregation techniques will be required to associate the specific line data with how the transmission is modeled as the records in TADS may be more specific than the tie line representation. In order to find the bidirectional transfer limits, generally an Available Transfer Capacity (ATC) study can inform on the limiting conditions and the results of that study will provide a "source to sink" capacity between areas, which is very conducive to modeling these interfaces. If adding in the DC powerflow capabilities of load flow software, the equivalent reactance between the source and sink in that ATC study will need to be determined and provided. This may not always be provided in a single ATC study, so model reduction of the powerflow data collected for Interconnection-wide base cases created under NERC MOD-032[28] can aid in finding the equivalent reactance of the interface.

Table 5.1: Minimum Data Requirements (Interface Limit)

Network Flow Method	Import/Export Limit	Equivalent Reactance	FOR
Transportation Model	Yes	No	Maybe
DC Power Flow	Yes	Yes	Maybe

[28] NERC MOD-032 can be found here

Detailed Circuit Representation

Normally detailed transmission models are not required in resource adequacy assessment. If detailed circuits are modeled with generation facilities, the evaluation is often referred to as composite system reliability assessment and a vast number of input data are needed for such assessment. Composite system reliability assessment mainly involves the selection of possible system states for evaluation and the assessment of the consequences of these states. Two basic methodologies are used in the system state selection in composite system reliability assessment. These are analytical contingency enumeration approach and Monte Carlo simulation method. The system analysis in assessing the consequences of selected outage states is the same for both analytical and Monte Carlo simulation methods. AC or DC power flow is employed to determine if a particular state is a success or a failure in composite system reliability evaluations.

The detailed power flow data for composite system reliability assessment typically contains information on the system topology, equipment ratings and various potential operating conditions for example summer/winter, peak/light load, drought/wet water or export/import scenarios. These power flow data are maintained and updated by industry regularly. Outage statistics data such as the failure rate and average outage duration for all of the composite system facilities are required and available from NERC GADS and TADS systems for generation facilities and transmission facilities. Some system specific data such as remedial action schemes for example fast runback of HVDC, normal operating procedures, tapped transmission lines and common mode outage information may be needed. The general procedure and the minimum data requirements for composite generation and transmission reliability assessments are available in existing literature[29].

29

Billinton, R., 1969. Composite system reliability evaluation. IEEE Transactions on Power Apparatus and Systems, (4), pp.276-281.

Billinton, R. and Wenyuan, L., 1991, July. Composite system reliability assessment using a Monte Carlo approach. In 1991 Third International Conference on Probabilistic Methods Applied to Electric Power Systems (pp. 53-57). IET.

Ubeda, J.R. and Allan, R.N., 1992, March. Sequential simulation applied to composite system reliability evaluation. In IEE Proceedings C (Generation, Transmission and Distribution) (Vol. 139, No. 2, pp. 81-86). IET Digital Library.

Chapter 6: Concluding Remarks

Based on the current methods for setting up a probabilistic resource adequacy assessment, the PAWG identified a few commonalities that are of particular importance. While different studies may require additional data if they wish to study the impacts of a particular risk, for instance cyber-related attacks, the document provides different collection experiences and highlights the key points of resource adequacy studies. In particular, the PAWG identified a few common practices that should be emphasized. In general, the probabilistic studies require large quantities of data to add more complexity to the models in their assessments[30].

The Need for Data in Probabilistic Studies

In general, a resource planner's job is to predict and determine the level of risk for future years. They require a set of predictive models that they develop and maintain. In order to develop and maintain their models, they require access to a variety of different types of data that may not be generally made available. This particular point is crucial, as sometimes engineering judgement is able to fill where data is not available; however, judgement is not a substitute for high quality data sources that are representative of the equipment being modeled. This need for high quality data applies to all the different categories of data in the previous Chapters and is not relegated to demand, generation, transmission, etc. Additionally, the study objective may change the modeled parameters based on the engineering judgement of the resource planner. In any two given studies, certain resources or aspects of a resource may not be a necessary modeling requirement due to the study objective. The resource planner needs to determine the model complexity required for the loss-of-load probabilistic study and use the data sources appropriately to complete the model.

Common Key Points

The PAWG identified the following key points in data collection across many different portions of a probabilistic resource adequacy study:

- Collection of weather data and any portion of the resource adequacy study related to weather should have the samples taken in the same period. If samples are not able to coincide, a cross-correlation calculation can help reorient when the weather data sample was taken and when, for instance, the demand sample was taken.
- When utilizing GADS or other historical outage reporting data, the thermal resources future outage rate may not be indicative of this historic metric especially when the facility moves to different operational characteristics.
- Battery energy storage systems (BESS) can be modeled similarly to other energy-limited resources such as pumped hydro when performing a resource adequacy assessment, with an emphasis on understanding the operational characteristics of the BESS.
- Data collection for transmission systems in probabilistic resource adequacy assessments depends on how detailed of a transmission model is represented in the study. This is over and above the normal dependency that other portions of a probabilistic resource adequacy study.
- Planning Coordinators, Transmission Planners, and other modelers require access to detailed information in order to build and maintain their models for use in probabilistic studies.

Possible Future Work

As probabilistic resource adequacy studies develop and mature, the PAWG recommends that the ERO review this data collection document. By doing so, this document can be utilized along with other probabilistic resource adequacy

[30] This assumes that no assumptions will be made regarding the effect these new facets of the model have on the availability or performance of the element in the resource adequacy study.

documents to assist with entities developing new probabilistic requirements or improving previous ones. Additionally, the PAWG found the following recommendations:

- When utilizing Generation Availability Data System (GADS) or other historical outage reporting databases, the thermal resources future outage rate may not be adequately represented by use of this historic data, especially when the facility moves to different operational characteristics. A thorough review should be done before using historic outage data when representing future risk.
- Planning Coordinators, Transmission Planners, and other entities should work to gain access to data not otherwise made available that may affect the results of their resource adequacy studies or assumptions. Some entities do not have access to data sets to feed their models, and the need for more accurate studies may require access to data outside of those publically available. This is paramount as resource planners are not able to perform studies without well-developed models, which require a wide range of data.
- Careful understanding of data source assumptions and restrictions should be used when vetting a new or previous data source.

Appendix A: Overview of General Data Management

In general, data used for study should be complete, of high quality, and representative of the equipment under study. As with many other modeling issues, there are times when the data is not always complete, does not follow the guidelines for data submission in the database, or is not accessible without supplemental agreements. This appendix covers some of the general considerations for vetting the data for use in the probabilistic study.

Keeping Data Aligned

When the resource planner is merging many different sources of data or when dealing with large data sets, a few common procedures should be followed. Considering much of the data in probabilistic studies is based on a time series, or has a time dependence (such as weather years), many of the processes deal with this type of alignment. Some general data alignment techniques for entities to consider are listed below:

- Convert to a common time zone, including considerations for daylight savings time changes (if applicable).
- Utilize hourly trends to fill gaps in data, such as zeros and/or blank hourly values due to time zone conversions. These gaps should not be large in size, nor should they be frequent in the data source[31].
- Detect unit outliers in minimum and maximum daily, monthly, and annual peaks for possible data errors.
- Determine the per-unit relationships between hourly values and the daily peaks throughout the years in order to detect anomalies.
- Conduct benchmarking to similar data sets such as, but not limited to, entity reported actual summer and winter peak demands for use in Regional Reliability Assessments[32]

Common Sense Validation Checks

Additionally, there are a few other common sense check when preparing the data for use in a probabilistic study. This list is provided as an example, and other checks or metrics may exist for determining how trustworthy the data source is for providing information in a resource adequacy study. Examples of such checks are found in **Figure A.1**.

[31] For example, some data sets are not usable with more than five percent total data missing or when the largest gap of data is longer than12 hours. These values will change depending on the data. In general, a resource adequacy study can fill these gaps; however, these two metrics should be considered when vetting a data source.

[32] A common NERC approach for determining load forecast uncertainty uses the variance in year-over-year deltas of actual peak demand. For this reason, a good sanity check is to compare these deltas from FERC 714 for particular entity or area with that of another data set.

Peak Data

- Correctly filled out field
- Correct mangitude
- Correct units

Energy Data

- Correctly filled out field
- Correct mangitude
- Correct units

Load Growth

- Reason provided for growth exceeding +/- 1%

Resources

- Resource in the right Zone, Balancing Authority, and Organization
- Unit Type matches with fuel (e.g. PV unit with secondary battery incorrectly labeled as a gas turbine)
- No negative or zero capacities for nameplate or seasonal capacities
- Status Code, NERC Class Code, and WECC Class Code are consistent
- No duplicate resources

Reserves

- No blank or null values provided
- Data is consistent with other portions

Hourly Data (Demand, Hydro, Wind, Solar)

- Plotted data do not contain gaps
- Plotted data are consistent with request
- Plotted data demonstrate no abnormalities (e.g. jump discontinuities of large magnitude)

Transmission

- Line type should be overhead, underground, or submerged.
- Reactances are consistent with design (e.g. X/R ratio)
- Line information consistent in lines with many taps

Trasnformer

- Line type should be overhead, underground, or submerged.
- Reactances are consistent with design (e.g. X/R ratio)
- Line information consistent in lines with many taps

Figure A.1: Common Sense Checks for Data Validation

Data Retention for Future Studies

Due to the large set of data required to gather for modeling resources in a resource adequacy study, it is preferable to store much of the data for use in future studies. For instance, the transmission system representation, once built, does not need to request the same level of information at each time the model is updated; a notification of which elements, interfaces, or other equipment that have changes suffices. Additionally, outage data do not need to always be collected for the same period. The collection effort should be focused on the data that would supplement what has historically been collected. Because of these, a data maintainer should be used to ensure that the data are not lost, mutated, or in otherwise changed between studies. Additionally, some data are able to be used for different studies, further increasing the value of retaining large sets of data for probabilistic reliability studies.

Appendix B: Example GADS Data Request Example Forms

This Appendix serves as an example, data forms when requesting GADS data from other entities. ERCOT has graciously provided the following two forms in order to provide clarity on some of the information in the chapters.

GADS Data Request Notice

The following information is contained in ERCOT's GADS Data Request Notice and an example data, the form they send to other entities to request data that accompanies the notice. All content provided is to be used as an example for these requests and should be used only where appropriate.

NOTICE DATE: January 31, 2020

NOTICE TYPE: W-X013118-01 Operations

SHORT DESCRIPTION: Requested data for the Planning Reserve Study

INTENDED AUDIENCE: Resource entities

DAY AFFECTED: April 1, 2020

LONG DESCRIPTION: ERCOT is conducting a capacity planning reserve study in 2020 that is mandated by the Public Utility Commission of Texas, as well as a loss-of-load study for the North American Electric Reliability Corporation (NERC). In order to accurately model historical thermal unit availability for both studies, ERCOT is requesting that Resource Entities extract from the NERC Generating Availability Data System (GADS) certain unit-specific outage data for each of their thermal Generation Resources, and provide that data as instructed in the attached data submission form. ERCOT is requesting up to two Calendar Years (2018-2019) of GADS outage event and Equivalent Forced Outage Rate (EFOR) data for units that meet the following two criteria:

A. GADS data was submitted to NERC for Calendar Year 2018. (Wind unit outage data uploaded to the NERC GADS Wind system is not to be included in the submission.)
B. The thermal unit(s) are currently expected to be in operation, or could potentially be in operation, as of January 1, 2021.

The GADS data submissions are considered Protected Information under Nodal Protocols Section 1.3.1.1(q).

ACTION REQUIRED: Please return the attached data submission form and any accompanying data files, by April 1, 2020, via email to ClientServices@ercot.com.

CONTACT: If you have any questions, please contact your ERCOT Account Manager. You may also call the general ERCOT Client Services phone number at (512) 248-3900 or contact ERCOT Client Services via email at ClientServices@ercot.com.

If you are receiving email from a public ERCOT distribution list that you no longer wish to receive, please follow this link in order to unsubscribe from this list: http://lists.ercot.com.

GADS Data Submission Form

REPORTING INSTRUCTIONS:

1. An example GADS Data submission form ERCOT is required for all units that meet reference. Please use this as an example when improving or building similar GADS data requests. An important piece of the following two criteria:
    a. GADS "Conventional" data was form is the capability to categorize the submitted for Calendar Year 2018; wind data to each utility, unit, and solar units reported do not need to be included event in your data submission.
    b. The unit(s) are currently expected to be in operation as of January 1, 2021.
2. Data submittals are due no later than April 1, 2020.
3. In the shaded cells below, enter the contact order to feed the information for the preparer of into the data submission in case ERCOT staff has questions on the submitted GADS data probabilistic model.
4. The second and third tabs, named GADS_Unit Outage Details and GADS_EFOR, respectively, specify the GADS data elements to be reported for each thermal unit.
5. Provide the requested GADS data for Calendar Years 2018 and 2019, or for the subset of these years for which GADS data is available.
6. Resource Entities may submit the GADS data in separate files (one file for each tab) as long as the field names and ordering matches the two tabs. Although Excel files are preferred, text files (such as CSV) are acceptable.
7. This file, and any separate data files, should be sent in an email as attachments. The email address for the data submission is ClientServices@ercot.com.
8. This data submission is considered Protected Information under Nodal Protocols Section 1.3.1.1(q).
9. If the data file(s) is too large to be sent using email, a secure FTP file transfer will be arranged. Please send an email to ClientServices@ercot.com requesting a file transfer link.
10. Questions on the data form or submission process should be sent to ClientServices@ercot.com or your ERCOT Account Manager.

REPORTING INSTRUCTIONS:

1. Data submission is required for all units that meet the following two criteria:
   a. GADS "Conventional" data was submitted for Calendar Year 2018; wind and solar units reported do not need to be included in your data submission.
   b. The unit(s) are currently expected to be in operation as of January 1, 2021.
2. Data submittals are due no later than April 1, 2020.
3. In the shaded cells below, enter the contact information for the preparer of the data submission in case ERCOT staff has questions on the submitted GADS data.
4. The second and third tabs, named GADS_Unit Outage Details and GADS_EFOR, respectively, specify the GADS data elements to be reported for each thermal unit.
5. Provide the requested GADS data for Calendar Years 2018 and 2019, or for the subset of these years for which GADS data is available.
6. Resource Entities may submit the GADS data in separate files (one file for each tab) as long as the field names and ordering matches the two tabs. Although Excel files are preferred, text files (such as CSV) are acceptable.
7. This file, and any separate data files, should be sent in an email as attachments. The email address for the data submission is ClientServices@ercot.com.
8. This data submission is considered Protected Information under Nodal Protocols Section 1.3.1.1(q).**Respondent Contact Information:**
9. If the data file(s) is too large to be sent using email, a secure FTP file transfer will be arranged. Please send an email to ClientServices@ercot.com requesting a file transfer link. Contact Person:
10. Questions on the data form or submission process should be sent to ClientServices@ercot.com or your ERCOT Account Manager.

Title:
Telephone Number:
Resource Entity Name:
Email address:

Utility Code	Unit Code	Unit Name	Year	Event Type	Start of Event	End of Event	Net Available Capacity	Cause Code	Event Description

Utility Code	Unit Code	Unit Name	Year	Annual-EFOR	EFOR-Jan	EFOR-Feb	EFOR-Mar	EFOR-Apr	EFOR-May	EFOR-Jun	EFOR-Jul	EFOR-Aug	EFOR-Sep	EFOR-Oct	EFOR-Nov	EFOR-Dec

2020 Probabilistic Assessment | Regional Risk Scenario Sensitivity Case Report – Request for RSTC Reviewers

Summary

The draft report was prepared by the PAWG during the 2020 Probabilistic Assessment (ProbA) cycle with inputs from the six Regional Entities and 20 Assessment Areas. Assessment Areas developed tailored risk scenarios (e.g., ERCOT examined impacts of abnormally frequent low wind events) and assessed the effect that the scenarios would have on the probabilistic indices reported in the 2020 ProbA Base Case. This scenario analysis provides insights into area-specific reliability risk using probabilistic methods. Following review by RSTC members, PAWG and RAS will incorporate feedback and return the report to the RSTC for approval. RAS will review findings and consider them for addition to the 2021 Long-Term Reliability Assessment (LTRA).

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

2020 Probabilistic Assessment

Regional Risk Scenario Sensitivity Case

June 2021

DRAFT

RELIABILITY | RESILIENCE | SECURITY




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

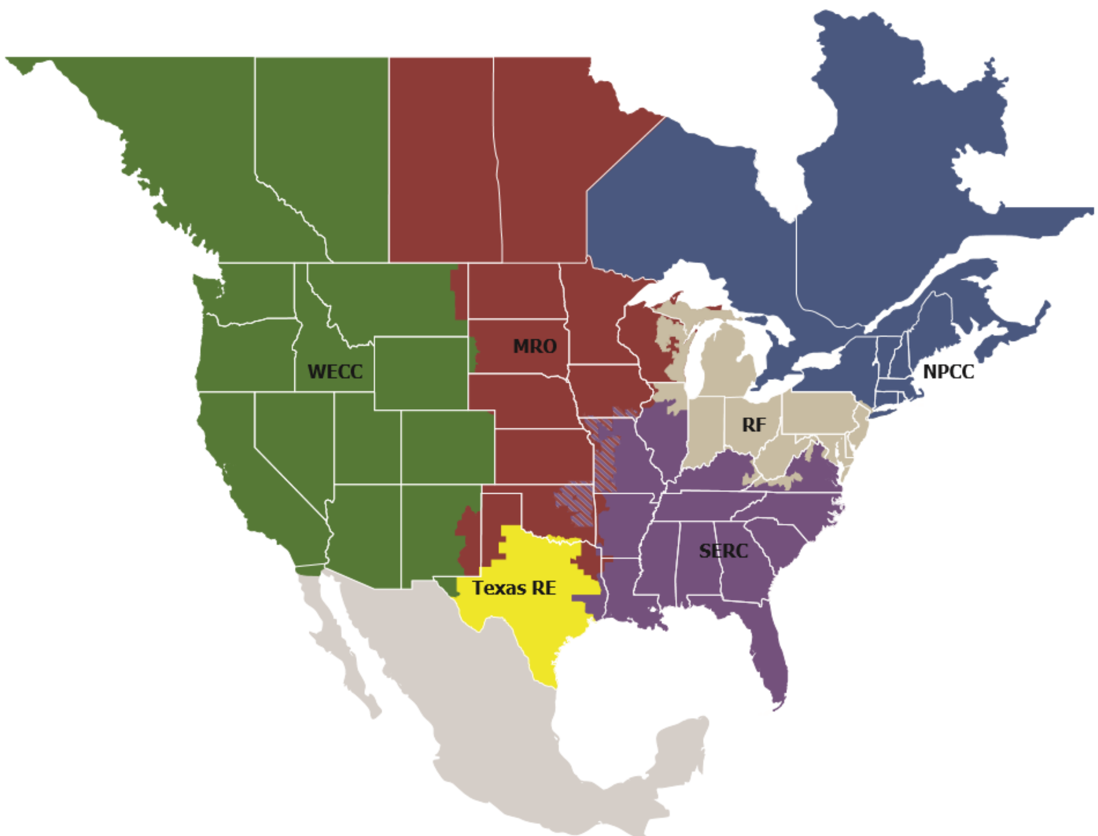
Table of Contents

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

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

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



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

NERC Regions and Assessment Areas

FRCC – Florida Reliability Coordinating Council

FRCC

MRO – Midwest Reliability Organization

MRO-SaskPower
MRO-Manitoba Hydro
MISO

NPCC – Northeast Power Coordinating Council

NPCC-New England
NPCC-Maritimes
NPCC-New York
NPCC-Ontario
NPCC-Québec

RF – ReliabilityFirst

PJM

SERC – SERC Reliability Corporation

SERC-East
SERC-North
SERC-Southeast
SERC-FP

SPP RE – Southwest Power Pool Regional Entity

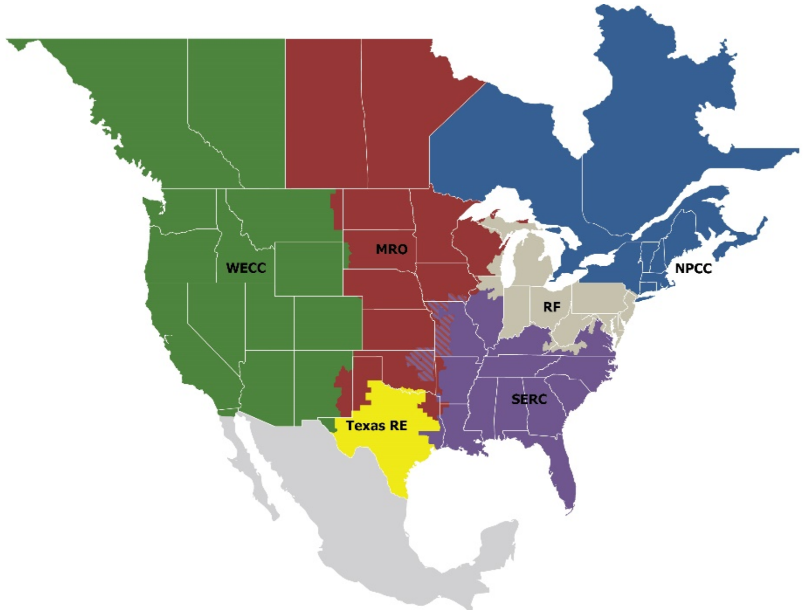
SPP

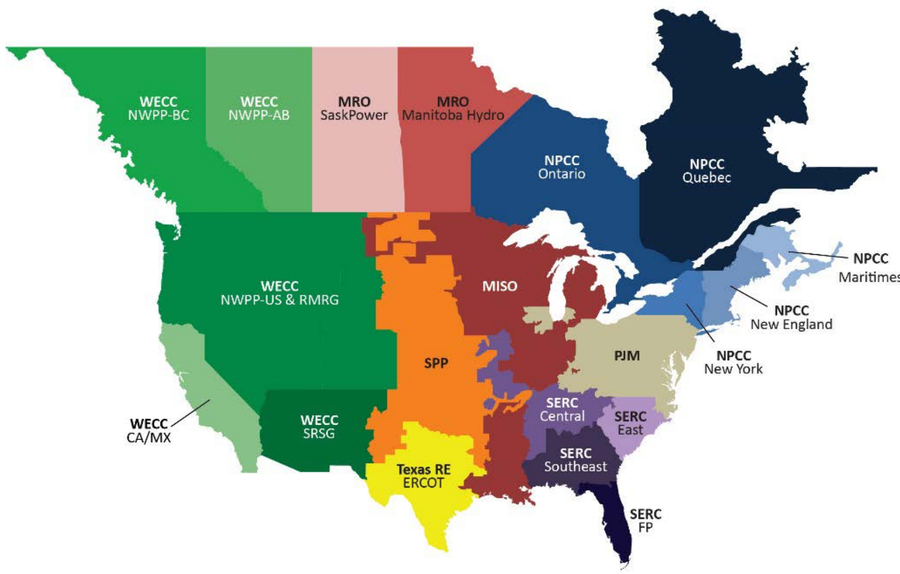
Texas RE – Texas Reliability Entity

Texas RE-ERCOT

WECC – Western Electricity Coordinating Council

WECC-BC
WECC-AB
WECC-RMRG
WECC-CA/MX
WECC-SRSG
WECC-NWPP-US





Executive Summary

Sensitivity results were varied across the study and dependent on their underlying assumptions. In some Assessment Areas such as Manitoba Hydro, SaskPower, PJM and certain Areas of NPCC, the study demonstrated that the risks were not significant, did not impact the probabilistic indices, or could be mitigated using preventive planning and operating measures. Other Assessment Areas noted potential risks if the chosen scenario were to materialize under the sensitivity assumptions. SPP determined LOLH and EUE increases in their scenario, mostly occurring on or around the peak hour. SERC also noted low to moderate increases in their Loss of Load (LOL) indices from the Base Case associated with maintenance outages, noting an emphasis and need to adequately plan outage windows accordingly. WECC found that in many regions across the Western Interconnection, the advanced retirement of coal units either dramatically increases or negligibly increases the LOLH or EUE. Results were also dependent on the amount of available external assistance between Assessment Areas and the penetration of coal resources in their respective portfolios. High level results of the Regional Risk Scenarios performed by Assessment Area can be found in Table ES.1

NERC has increasingly used probabilistic assessments as the industry plans resource mixes more dependent on variable energy resources and as conventional forms of generation are steadily replaced. With various resource portfolios and distinct plans to meet electricity reliability requirements across the Bulk Electric System (BES) and Bulk Power System (BPS), the NERC PAWG encouraged regional flexibility in the 2020 ProbA Sensitivity Case by developing a Regional Risk Scenarios model. This model allowed system planners to more closely study area-specific reliability risks and their uncertainties by using probabilistic methods. It is important to recognize that the BES (and by extension the BPS), across the six NERC Regions and Assessment Areas, is diverse in terms of planning and operations processes, as well as their associated risks. The assessment utilized a comprehensive and peer-review process for each Assessment Area's respective methods, assumptions, and results.

The Sensitivity Case scenarios include the following:

- MISO (MRO) – Increased demand response as a percentage of the overall resource mix
- Manitoba Hydro (MRO) – Variations in low water conditions with external assistance limitations
- SaskPower (MRO) – Impact of low hydro conditions on its system reliability
- SPP (MRO) – Low wind resource output with an increase in conventional generation forced outages
- NPCC – Planned/expected future capacity or resources may not materialize
- PJM (RF) – Planned/expected future capacity or resources may not materialize
- SERC – Impact of planned maintenance outage on system risk
- ERCOT (TRE) – Impacts of a difference in the realized frequency of high load and low wind output events
- WECC - Impacts to resource adequacy associated with potential coal-fired generation retirements.

Regions were requested to compare the purported risk factor results in the Probabilistic Assessment (ProbA) Sensitivity Case to the ProbA Base Case results from the 2020 NERC LTRA. These comparisons between the Base and Sensitivity Cases, combined with the trending results compared from the 2018 ProbA (found in the 2018 LTRA), provide a complete analysis to better understand underlying uncertainties and benchmark system risks. At regional discretion, the scenarios intentionally stressed the assumptions to study their associated impacts on the probabilistic indices. Although mitigation efforts were not the intended focus of the study, some regions provided rationale on expected methods to mitigate against that chosen risk.

Table ES.1: Summary of Regional Risk Scenario for Each Assessment Area[1]				
Assessment Area	2022		2024	
	Expected Energy Unserved [MWh/yr.]	Loss of Load Hours [hrs./yr.]	Expected Energy Unserved [MWh/yr.]	Loss of Load Hours [hrs./yr.]
MRO				
MISO[2]	N/A	N/A	27.69	0.24
Manitoba Hydro	45.13	1.79	0.05	0.06
SaskPower	319.20	3.50	59.70	0.60
SPP	N/A	N/A	72.60	0.11
NPCC				
New England	5.30	0.01	88.10	0.14
Maritimes	4.16	0.08	6.72	0.13
New York	0.68	0.00	13.90	0.05
Ontario	0.09	0.00	79.96	0.14
Québec	0.00	0.00	0.00	0.00
RF				
PJM	0.00	0.00	0.33	0.00
SERC[3]				
Central	N/A	N/A	12.20	0.02
East	N/A	N/A	517.40	0.57
Southeast	N/A	N/A	7.50	0.01
Florida Peninsula	N/A	N/A	513.30	0.52
Texas RE				
ERCOT[4]	N/A	N/A	64.72	0.05
WECC				
BC	0.00	0.00	0.00	0.00
AB	0.00	0.00	0.00	0.00
CA/MX[5]	1,005,716	32.00	2,402,976	71.00
SRSG	212	14.00	437	22.00
NWPP-US	14,681	Less than 1	274,091	6.00

With an increasing amount of uncertainty expected on the BPS with regional resource transitions, the PAWG recommends further increasing the use of probabilistic methods and scenarios to adequately study the reliability risks and to determine the sensitivity of those risks for various scenarios. The PAWG also recommends increasing the coordination between industry operations and planning personnel to develop enhanced and more complex scenario assumptions for reliability assessments. These collaborations and studies could better inform, strengthen and reinforce the fundamental BPS planning and operations processes to meet future reliability needs.

[1] An "N/A" is denoted where the Assessment Area chose not to perform the Risk Scenario for the optional study year.
[2] MISO's scenario has many different amounts of Demand Response entered in 2024. This table uses the maximum Demand Response added in their scenario.
[3] SERC performed an extensive stressing of their system to start at a higher LOLE than from the Base Case and performed many different multiplications of their capacity on maintenance. This table uses the maximum reported EUE and LOLH at the extreme scenario. Readers are extremely encouraged to read SERC's Chapter to understand these numbers.
[4] ERCOT's scenario contained many different load draws. The one that produced the highest EUE and LOLH are presented in this table.
[5] See the Western Assessment in Appendix E for detailed information on this scenario run as well as Chapter 9 for a detailed meaning of the results.

Introduction

The primary function of the NERC Probabilistic Assessment Working Group (PAWG) is to advance and support probabilistic resource adequacy efforts of the ERO Enterprise in assessing the reliability of the North American Bulk Power System. The group's origins and ongoing activities stem from work initiated by the Probabilistic Assessment Improvement Task Force (PAITF)[6] with the Probabilistic Assessment Improvement Plan.[7] Specifically, the group researches, identifies and details probabilistic enhancements applied to resource adequacy. The group's long-term focus addresses relevant aspects of the ERO Enterprise Long-Term Strategy[8] and the Reliability Issues Steering Committee (RISC) report[9] in conjunction with the NERC Reliability Assessment Subcommittee (RAS).

NERC regularly utilizes reliability assessments to objectively evaluate the reliability of the North American Bulk Power System (BPS). On a biennial basis, the NERC PAWG performs a Probabilistic Assessment (ProbA) to supplement the annual NERC Long Term Reliability Assessment (LTRA) analysis. The ProbA calculates monthly Expected Unserved Energy (EUE) and Loss of Load Hours (LOLH)[10] indices for years 2 (Y2) and 4 (Y4) of the 10-year LTRA outlook (2022 and 2024 for the 2020 LTRA[11], respectively) and contains two studies: a Base Case and a Sensitivity Case. The two differ in that the Base Case contains assumptions for under normal, anticipated operating conditions, and study results were each peer-reviewed by the NERC PAWG, NERC RAS and NERC Reliability and Security Technical Committee (RSTC) to ensure comparisons made in the LTRA can be made across entities. Complete details and underlying assumptions of the 2020 ProbA Base Case analysis were included in the published 2020 LTRA in December 2020. The Sensitivity Case provides NERC a way to characterize more "what-ifs" in terms of the probabilistic methods used in each region that can provide a much different result depending on. For the 2020 ProbA Sensitivity Case, the PAWG developed a Regional Risk Scenarios approach specific to each assessment area. Each region and assessment area has varied resource portfolios which differentiates changing reliability drivers between assessment areas. The assessment areas identified and studied respective risk factors to drive deeper understandings of the reliability implications across all hours (instead of the peak hour) using probabilistic methods. The PAWG believes this approach to be of higher value than standardizing a Sensitivity Case study to capture the varied and complex reliability risks across the BPS. Y2 and Y4 indices were reported for the Base Case study. For the Sensitivity Case, assessment areas were required to perform the analysis on Y4 and Y2 was optional.

Chapters in this assessment are primarily divided by the Regional Risk Scenario chosen for the 2020 ProbA. While Regional Risk Scenarios represent an analysis into potential reliability risk factors, there is no guarantee or indication these scenarios indicative future occurrences. These results are used to inform system planners and operators about potential emerging reliability risk. The PAWG intends to utilize study results for use in future probabilistic resource adequacy studies (such as trending applications) to develop further guidance for future work activities. Where prominent, key points and takeaways are called out.

---

[6] Probabilistic Assessment Improvement Task Force (PAITF)

[7] Probabilistic Assessment Improvement Plan

[8] See Focus Areas 1 and 4: ERO Enterprise Long-Term Strategy

[9] See Risk 1: Reliability Issues Steering Committee (RISC)

[10] NERC PAWG Probabilistic Adequacy and Measures Report

[11] NERC_LTRA_2020.pdf

Chapter 1: MRO - MISO

MISO is a summer peaking system that spans 15 states and consists of 36 Local Balancing Areas which are grouped into 10 Local Resource Zones (LRZs). For the 2020 NERC Probabilistic Assessment, MISO utilized a multi-area modeling technique for the 10 LRZs internal to the MISO footprint. Firm external imports as well as non-firm imports were also modeled within the cases.

Key Assessment Takeaway

MISO found that as the percent of Demand Response resources increased in their system, their Reliability Indices could double or triple. This is due to the need to call on Demand Response more and earlier in the year, leaving them unavailable for future calls in the year.

Risk Scenario Description

For the 2020 Probabilistic Assessment Risk Scenario, MISO performed a sensitivity analysis that examined the effects of increasing Demand Response (DR) resources as a percentage of the overall resource mix. Over the past several years the amount of DR in MISO has been steadily increasing. For DR to qualify as a capacity resource in MISO, it must be available for a minimum of 5 calls per year and 4 hours per day. These minimum dispatch requirements make up much of the DR that currently participates in MISO's capacity market.

MISO conducts a Loss of Load Expectation (LOLE) study annually to determine the amount reserves required to meet the 1-day-in-10-years LOLE standard. In this study, each individual DR resource in MISO is modeled with their registered dispatch limits. There are cases in that analysis where all the available dispatches for DR would be used and load shed occurred as a result. This discovery prompted a desire to further investigate the effect that dispatch limited DR has on reliability hence this risk scenario. See Appendix E for where to find the report.

To perform this analysis, MISO began from the 2024 base case ProbA scenario. DR was then added to the resource mix in increments of 1,000 MW evenly distributed among the 10 LRZs while simultaneously removing 1,000 MW of generation. Doing this allowed MISO to examine how the risk changes from the base case as DR makes up an increasing amount of reserves.

Base Case Results

MISO's Base Case results, reproduced here, show a small amount of EUE and LOLH which is consistent with past ProbA results. Since MISO is a summer peaking system, most of the risk occurs during the summer months (June – Sept) as expected. However, there are cases where off-peak risk occurs due to certain zones being import limited during periods of high planned outages.

Base Case Summary of Results		
Reserve Margin (RM) %		
	2022	**2024**
Anticipated	**21.6%**	**17.6%**
Reference	**18.0%**	**18.0%**
ProbA Forecast Operable	**17.9%**	**17.8%**
Annual Probabilistic Indices		
	2022	**2024**
EUE (MWh)	**27.3**	**14.3**
EUE (ppm)	**0.038**	**0.020**
LOLH (hours/year)	**0.196**	**0.085**

Risk Scenario Results

Currently, DR makes up roughly 4.9% of the total resource mix in MISO. This percentage is reflected in the Base Case results and served as a starting point for the Risk Scenario study. From that starting point, an additional 5,000 MW of DR was added to the system in increments of 1,000 MW at a time which nearly doubled the amount of DR as a percentage of total resources. The percentage of DR to the overall resource mix can be found in Table 1.1.

Table 1.1: Demand Response Percentage of Overall Resource Mix	
Demand Response Added [MW]	**Percent of Overall Resource Mix [%]**
Base Case	4.9
1,000	5.5
2,000	6.1
3,000	6.8
4,000	7.4
5,000	8.1

EUE and LOLH values were recorded for each iteration of increasing DR. As shown in the chart below, when DR increases as a percentage of total resources, EUE and LOLH also increase. By the time an additional 5,000 MW of DR was added, the EUE had nearly doubled and LOLH nearly tripled when compared to the Base Case. The increased risk is driven by the dispatch limits of DR. As previously mentioned, most DR in MISO is only available for 5 calls per year and 4 hours per day. As DR begins to make up more of the resources on the system, these resources exhaust their dispatch limits sooner and become unavailable for the remainder of the year.

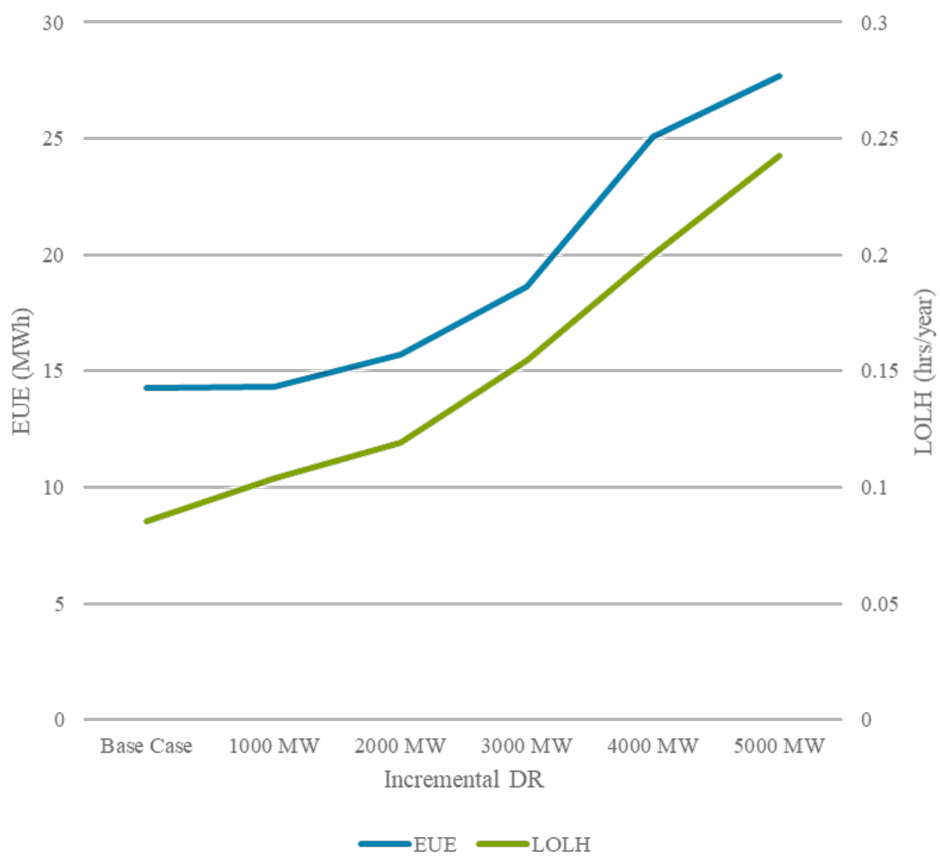


Figure 1.1 MISO Regional Risk Scenario EUE and LOLH

Chapter 2: MRO – Manitoba Hydro

Key Assessment Takeaway

Manitoba Hydro's reliance on hydro facilities can be susceptible to low water conditions for a given year. This is mitigated by proper management of reservoirs.

Manitoba Hydro (MH) system has approximately 6,878.9 MW (nameplate) of total generation. The system is characterized by around 4,350 MW of remote hydraulic generation located in northern Manitoba and connected to the concentration of load in southern Manitoba via the Nelson River HVdc transmission system. MH also has about 1,858.4 MW of hydraulic generation distributed throughout the province. In addition, 258.5 MW of wind generation and 412 MW thermal generation are distributed in the southern part of the province. The MH system is interconnected to the transmission systems in the Canadian provinces of Saskatchewan and Ontario and the US states of North Dakota and Minnesota.

The 2020 NERC Probabilistic Assessment for the MH system was conducted using the Multi-Area Reliability Simulation (MARS) program developed by the General Electric Company (GE). The reliability indices of the annual Loss of Load Hours (LOLH) and the Expected Unserved Energy (EUE) for 2022 and 2024 were calculated by considering different types of generating units (thermal, hydro and wind), firm capacity contractual sales and purchases, non-firm external assistances, interface transmission constraints, peak load, load variations, load forecast uncertainty and demand side management programs. The data used in the MARS simulation model are consistent with the information reported in the 2020 LTRA submittals from MH to NERC.

Risk Scenario Description

There are a number of influencing factors associated with Manitoba Hydro's resource adequacy performance such as the water resource conditions, energy exchanges with neighboring jurisdictions, forecast load level, uncertainties in load forecast, demand responses, energy efficiency and conservation programs, wind penetration and generation fleet availability.

The vast majority of MH's generating facilities are use-limited or energy-limited hydro units. The annual energy output of these facilities is mostly dependent on the availability of the water resource. In the 2020 Assessment, MH has examined the impact of the most significant factor over the long run - variations in water conditions as detailed in the following:

1. Analyze the system as is to establish base reliability indices (Base case)
2. Variations in water conditions: model a 10-percentile low water condition and report the indices

All hydro units are modeled as Type 2 energy limited units in MARS. The MARS input parameters for each hydro power plant are installed/in-service and retirement dates, monthly maximum and minimum output of each plant and monthly available energy from each plant. Each energy limited hydro unit is scheduled on a monthly basis. The first step is to dispatch the unit's minimum rating for all of the hours in the month. The remaining capacity and energy are then scheduled as needed as a load modifier during the Monte Carlo simulation.

Base Case Results

Base Case Summary of Results		
Reserve Margin (RM) %		
	2022	**2024**
Anticipated	**16.6%**	**16.0%**
Reference	**12%**	**12%**
ProbA Forecast Operable	**20%**	**20%**
Annual Probabilistic Indices		

	2022	2024
EUE (MWh)	**2.7077**	**3.3831**
EUE (ppm)	**0.1072**	**0.1329**
LOLH (hours/year)	**0.0033**	**0.0039**

The base case LOLH values calculated for the reporting year of 2022 and 2024 are virtually zero. Non-zero EUE are obtained but these values are small. These results are mainly due to the larger forecast reserve margin and the increase in the transfer capability between Manitoba and US due to the addition of the new 500 kV tie line between Manitoba and Minnesota. The base case LOLH and EUE values calculated in this assessment for the reporting year of 2022 increase a bit from those zero values obtained in 2018 assessment for the reporting year of 2022. This is expected as result of modeling improvement and changes in assumptions. The most significant model improvement for 2020 Probabilistic Assessment is that Manitoba Hydro modeled seven (7) different load shapes using actual historical data to capture the uncertainties associated with load profiles and peak load forecast. In 2018 assessment, a typical year load profile was used to model the annual load curve shape.

Risk Scenario Results

Scenario Case Summary of Results

	2022	2024
EUE (MWh)	**45.13**	**56.38**
EUE (ppm)	**1.7870**	**2.2150**
LOLH (hours/year)	**0.0544**	**0.0643**

Hydro flow condition is the most significant parameter that characterizes Manitoba Hydro’s system resource adequacy. In the 2020 assessment Manitoba Hydro has examined variations in water conditions in the scenario analysis. Scenario analysis results show that LOLH and EUE values increase for both 2022 and 2024 when an extreme drought scenario is modeled. Water flow conditions of 10 percentile or lower tend to increase the loss of load hours and expected unserved energy. As a small winter peaking system on the northern edge of a large summer peaking system (MISO), there generally assistance available, particularly in off peak hours, to provide energy to supplement hydro generation in low flow conditions in winter. Management of energy in reservoir storage in accordance with good utility practice provides risk mitigation under low water flow conditions.

Chapter 3: MRO – SaskPower

Saskatchewan is a province of Canada and comprises a geographic area of approximately 652,000 square kilometers (251,739 square miles) with approximately 1.2 million people. Peak demand is experienced in the winter. The Saskatchewan Power Corporation (SaskPower) is the Planning Coordinator and Reliability Coordinator for the province of Saskatchewan. SaskPower is the principal supplier of electricity in the province and responsible for serving over 540,000 customer accounts. SaskPower is a provincial crown corporation and, under provincial legislation, is responsible for the reliability oversight of the Saskatchewan bulk electric system and its interconnections

Key Assessment Takeaway

SaskPower's lower quartile hydro scenario provided an increase in the Reliability Indices, as expected, but did not rise significantly. Such increases can be mitigated by reliance on emergency procedures, if required.

Risk Scenario Description

SaskPower analyzed the impact of low hydro conditions on its system reliability. The low hydro forecast is based on 25 percentile hydro flow conditions. Hydro units constitute approximately 20 percent of Saskatchewan's net installed generation capacity and it hasn't experienced significantly low hydro conditions since 2001. The region consists of three main rivers systems and one river system experiencing low flow conditions doesn't necessarily indicate that the other systems would experience the same conditions. Although, there is low probability of low flow conditions experienced by all the river systems in the same year, the sensitivity scenario tests the system's resiliency when having less energy to dispatch hydro units, and subsequently limited peak load shaving capability. Furthermore, this risk scenario has become more relevant since the Saskatchewan government announced in July 2020 that it intends to pursue a $4 billion irrigation project at Lake Diefenbaker which could significantly impact the future water flows available for hydro generation by SaskPower.

The methodology used to derive the various hydro conditions is based on the historical hydrological records in the basin. Before using these historical hydrological records to any flow scenarios, adjustments were applied to these records, which includes historical and present upstream water uses, adjustment to the current level of development, and naturalized flow records if necessary. The long-term forecasts typically use low (lower quartile), best (median) and high estimate (upper quartile) flows based on the current level of development adjusted historical records. Hydro units are modelled as Type 2 energy limited units in MARS. The median quartile hydro conditions in the base case were replaced with lower quartile hydro conditions for the sensitivity scenario.

Base Case Results

Saskatchewan has planned for adequate resources to meet anticipated load and reserve requirements for the assessment period. The major contribution to the Loss of Load Hours (LOLH) and Expected Unserved Energy (EUE) is in the off-peak periods due to maintenances scheduled for some of the largest units.

Base Case Summary of Results		
Reserve Margin (RM) %		
	2022	**2024**
Anticipated	**34.2%**	**30.0%**
Reference	**11%**	**11%**
Prob A Forecast Operable	**30%**	**25.7%**
Annual Probabilistic Indices		
	2022	**2024**
EUE (MWh)	**80.4**	**26.4**
EUE (ppm)	**3.34**	**1.07**
LOLH (hours/year)	**0.96**	**0.28**

SaskPower did further analysis changing some of the fixed unit maintenances in year 2022 and let the model schedule it automatically. With changing the unit maintenances, EUE reduced by more than 50 percent. Most of the maintenances are scheduled during off-peak periods and can be rescheduled to mitigate short–term reliability issues when identified.

Since the 2018 Probabilistic Assessment, the reported forecast reserve margin for 2022 has increased, mainly due to reductions in the load forecast.

Risk Scenario Results

Modelling Hydro units using Lower Quartile Hydro Conditions result in higher loss of load values as compared to the base case. It is to be expected but this increase in the LOLH and EUE is not anticipated to cause any reliability issues. Since the difference in LOLH and EUE values between the Base Case and Sensitivity Case is quite low, its affects can be mitigated using emergency assistance if needed.

Sensitivity Case summary of Results

	2022	**2024**
EUE (MWh)	**319.2**	**59.7**
EUE (ppm)	**13.2**	**2.4**
LOLH (hours/year)	**3.5**	**0.6**

Chapter 4: MRO - SPP

Southwest Power Pool (SPP) Planning Coordinator footprint covers 546,000 square miles and encompasses all or parts of Arkansas, Iowa, Kansas, Louisiana, Minnesota, Missouri, Montana, Nebraska, New Mexico, North Dakota, Oklahoma, South Dakota, Texas, and Wyoming. The SPP Assessment Area is reported based on the Planning Coordinator footprint, which touches parts of the Midwest Reliability Organization Regional Entity, and the WECC Regional Entity. The SPP assessment area footprint has approximately 61,000 miles of transmission lines, 756 generating plants, and 4,811 transmission-class substations, and it serves a population of more than 18 million.

SPP assessment area has over 90,000 MW (name plate) of total generation, which includes over 28,000 MW of nameplate wind generation. SPP is also a summer peaking assessment area at approximately 51,000 MW of summer peak demand.

Key Assessment Takeaway

Southwest Power Pool demonstrated that many low probability events overlaid can impact their Reliability Indices. A significant increase in forced outage rates, coupled with a low wind output, on a hot summer day can created the conditions for increased risk to EUE and LOLH. This scenario immensely stressed the conditions studied under the Base Case, with over 99% of the potential risk identified occurring during summer peak hours. and demonstrated a high margin between the scenario studied and the Base Case.

Risk Scenario Description

SPP has seen an increase in installed wind and slight increase in forced outage rates over the past few years. Therefore, SPP chose a low wind output scenario paired with an increase in conventional forced generation outages as the 2020 ProbA Regional Risk Scenario. The historical weather year with the lowest capacity factor output on summer peak hours between years 2012 to 2019 was used to model a low wind scenario. When determining the lowest performing wind year, only peak hours (12 PM to 8 PM) during months June, July, and August were analyzed to derive the average capacity factor by year. Through this analysis, 2012 wind year was modeled with each historical load year (2012 to 2019) in the risk scenario. The weighted forced outage rate of the Base Case study was approximately 12.5%. The weighted forced outage rate for all conventional resources were increased proportionally and applied to each resource to achieve an SPP weighted forced outage rate of 15%. The regional risk scenario was performed on year 2024 to reflect additional generation retirements and projected installed wind capacity.

Base Case Results

No loss of load events were indicated for the Base Case study due to a surplus of capacity in the SPP Assessment Area. Reserve margins are well above 20% in both study years and no major impacts were observed related to resource retirements. In addition, the 2018 Probabilistic Assessment Base Case results for 2022 were the same for the 2020 Base Case results, i.e. zero loss of load.

Base Case Summary of Results		
Reserve Margin (RM) %		
	2022	**2024**
Anticipated	27.6%	26.8%
Reference	15.8%	15.8%
ProbA Forecast Operable	13.6%	13.3%
Annual Probabilistic Indices		
	2022	**2024**
EUE (MWh)	**0.00**	**0.00**
EUE (ppm)	**0.00**	**0.00**
LOLH (hours/year)	**0.00**	**0.00**

Scenario Case Summary of Results		
	2022	**2024**
EUE (MWh)	**--**	**72.6**
EUE (ppm)	**--**	**2.44**
LOLH (hours/year)	**--**	**0.113**

Risk Scenario Results

The results of the risk scenario showed an increase of potential loss of load, which reflects the low probability of increased summer forced outages paired with a low output wind year across the summer peak periods. Scenario analysis results show that LOLH and EUE values increase for 2024 when compared to the base case results. The modeling of the lowest wind output year paired with all load years showed the most impact in contributing approximately 80% to the increase of EUE and LOLH. Over 99% of the EUE and LOLH events occurred during the summer season. All risk was identified on peak load hours.

Chapter 5: NPCC

The Northeast Power Coordinating Council (NPCC) divides their region into five different areas and provides a report out of each region. The following pages contain the results for each sub region of NPCC. For each of the Risk Scenario results sections, a more detailed report covering the modeling assumptions and results can be found in Appendix E. Note that the metrics estimated are consistent with NPCC's Resource Adequacy – Design Criteria[12].

Key Assessment Takeaway

NPCC's multiple different assessment areas generally pursued the same risk scenario, with the sole exception of Ontario as such a scenario did not differ much from their Base Case assumptions. NPCC demonstrated that with the removal of Tier 1 resources and transmission projects, their Reliability Indices did not rise significantly for each Assessment Area. Such rises also occurred in similar times for each Assessment Area, emphasizing the risks found in the Base Case For Ontario, their different scenario also accentuated the same concerns from the Base Case results.

NPCC - Maritimes

The Maritimes assessment area is a winter peaking NPCC sub-region with a single Reliability Coordinator and two Balancing Authority Areas. It is comprised of the Canadian provinces of New Brunswick (NB), Nova Scotia (NS), and Prince Edward Island (PEI), and the northern portion of Maine (NM), which is radially connected to NB. The area covers 58,000 square miles with a total population of 1.9 million people. There is no regulatory requirement for a single authority to produce a forecast for the whole Maritimes Area. Demand for the Maritimes Area is determined to be the non-coincident sum of the peak loads forecasted by the individual sub-areas.

Risk Scenario Description

Tier 1 resources were removed in other NPCC areas, the low levels of Tier 1 resources in the Maritimes Area would not be an adequate test for severe conditions. For this reason, the Area assumed the winter wind capacity is de-rated by half (1224 MW to 612 MW) for every hour in December, January and February to simulate widespread icing conditions and that only 50% (from 532 MW to 266 MW) of natural gas capacity is available due to winter curtailments of natural gas supplies. Dual fuel units are assumed to revert to oil.

The Area has a diverse resource mix, and this scenario tests the reliability impacts associated with the most likely and therefore realistic shortages. Other scenarios did not meet the degree of severity and likelihood. This scenario was chosen now to allow a direct comparison between the NERC and NPCC probabilistic analyses as the same severe scenario was used for both.

The results of this risk scenario are valuable to resource planners since they demonstrate a high level of reliability by meeting the NPCC loss of load expectancy (LOLE) target of not more than 0.1 days per year of exposure to load loss despite the severity of the scenario. Note that the required maximum LOLE for loss of load due to resource deficiencies is less than 0.1 days per year. This would equate to a value of 2.4 hours for the loss of load hours (LOLH) measured in the ProbA analysis. Hence, since the LOLH value for both the base case and risk scenarios are less than this value, the NPCC target is met for both study years.

Base Case Results

The base case reserve margin for 2022 was 21%, slightly higher than the Area's target of 20%. In the short term, unexpected delays in the development of Advanced Metering Infrastructure in New Brunswick which led to conservative short term increases in load forecasts, on peak sales of firm capacity to neighboring jurisdictions, and

[12] i.e., they are calculated following all possible allowable "load relief from available operating procedures". For more information see Directory #1 (npcc.org)

retirement of small thermal generators in PEI and NM has reduced the base case planning reserve margins to levels slightly below the target levels of 20% in 2024.

For the two studied years, this gave rise to non-zero values of EUE and LOLH with pronounced weighting during the months of December, January, and February, however the values are low being in the order of single digits or fractions of MWh and hours. The results for 2022 are 0.575 MWh and 0.010 hours respectively. The results are slightly worse for 2024 at 1.125 MWh and 0.023 hours respectively. Expressed in terms of Parts per Million MWh of Net energy for load, the EUE values are 0.021 and 0.039 for the years 2022 and 2024.

Risk Scenario Results

As expected, with the additional loss of half of the Area's wind and natural gas resources over and above the normal probability for loss of system resources, the risk scenarios reduce both the planning reserve margins to levels below the Area's target of 20%. Forecast ranges for planning reserves are 17% and 15% for the two study years of 2022 and 2024.

For the two studied years, this gave rise to non-zero values of EUE and LOLH again with pronounced weighting during the months of December, January, and February and again the values are still low being in the order of single digits or fractions of MWh and hours. The results for 2022 are 4.161 MWh and 0.077 hours respectively. The results are slightly worse for 2024 at 6.718 MWh and 0.128 hours respectively. Expressed in terms of Parts per Million MWh of Net energy for load, the EUE values are 0.149 and 0.236 for the years 2022 and 2024.

NPCC - New England

ISO New England (ISO-NE) Inc. is a regional transmission organization that serves the six New England states of Connecticut, Maine, Massachusetts, New Hampshire, Rhode Island, and Vermont. It is responsible for the reliable day-to-day operation of New England's bulk power generation and transmission system, administers the area's wholesale electricity markets, and manages the comprehensive planning of the regional bulk power system (BPS). The New England BPS serves approximately 14.5 million people over 68,000 square miles.

Risk Scenario Description

Currently, in the probabilistic reliability analysis, the seasonal capacity ratings of the wind and solar resources are represented by a single value applicable to every hour of the day. The single value of the seasonal rating is based on the resource's seasonal claimed capability that are established using its historical median net real power output during the reliability hours (hours ending 14:00 through 18:00 for the summer period, and 18:00 through 19:00 for the winter period). As the system evolves with higher Behind-the-Meter solar penetration, the daily peaks may occur in the hours outside of the established reliability-hours window. The reduction in the wind and solar resources' rating is meant to identify the impact on system reliability if the current rating methodology overstates the capacity value of these resources in the future with the peaks occurring in different hours. The removal of the Tie 1 future resources is to take a conservative approach and identify the reliability consequences to the New England system if the in-service of these future resources is delayed.

Base Case Results

For year 2022, the 2018 study estimated an annual LOLH of 0.007 hours/year and a corresponding EUE of 2.713 MWh. In this year's study, the LOLH and the EUE slightly increased to 0.008 hours/year, and 3.292 MWh, respectively.

For year 2024, results show that the LOLH and the EUE values will increase to 0.095 hours/year, and a corresponding EUE of 58.618 MWh. The increase in LOLH and EUE is mainly attributed to the expected retirement of Mystic 8 and 9 (~1,400 MW) in the Boston area.

Risk Scenario Results

As expected, assuming less capacity contribution from the wind and solar resources and the delay of Tier 1 new resources will increase the LOLH and the EUE of the system. The LOLH and the EUE values are estimated to increase to 0.011 hours/year, and 5.3 MWh for 2022, respectively and to 0.135 hours/year, and 88.1 MWh for 2024, respectively.

NPCC - New York

The NYISO is responsible for operating New York's BPS, administering wholesale electricity markets, and conducting system planning. The NYISO is the only Balancing Authority within the state of New York. The transmission grid of New York State encompasses approximately 11,000 miles of transmission lines, 760 power generation units, and serves the electricity needs of 19.5 million people. New York experienced its all-time peak demand of 33,956 MW in the summer of 2013.

Risk Scenario Description

This scenario evaluates the reliability of the system under the assumption that no major Tier 1 generation (see Table 5.1) or transmission (see Table 5.2) projects come to fruition within the ProbA study period. Below is a list of the major Tier 1 proposed transmission and generation projects that were removed from the Base Case.

Table 5.1: Tier 1 Generation Projects for NPCC – New York

Unit Name	Name Plate [MW]	Zone	2020 RNA COD
Ball Hill Wind	100	A	12/2022
Baron Winds	238.4	C	12/2021
Cassadaga Wind	126.5	A	12/2021
Eight Point Wind Energy Center	101.8	B	12/2021
Calverton Solar Energy Center	22.9	K	12/2021
Roaring Brook Wind	79.7	E	12/2021

Table 5.2: Tier 1 Transmission Projects for NPCC – New York

Queue #	Project Name	Zone	CRIS Request	SP MW	Interconnection Status	2020 RNA COD (In-Service Date)
Proposed Transmission Additions, other than Local Transmission Owner Plans (LTPs)						
Q545A	Empire State Line	Regulated Transmission Solutions	N/A	N/A	Completed TIP Facility Study (Western NY PPTPP)	5/2022
556	Segment A Double Circuit	Regulated Transmission Solutions	N/A	N/A	TIP Facility Study in progress (AC PPTPP)	12/2023
543	Segment B Knickerbocker-Pleasant Valley 345 kV	Regulated Transmission Solutions	N/A	N/A	TIP Facility Study in progress (AC PPTPP)	12/2023

SDU	Leeds-Hurley SDU	System Deliverability Upgrades (SDU)	n/a	n/a	SDU triggered for construction in CY11	Summer 2021
CRIS Request						
430	Cedar Rapids Transmission Upgrade	D	80	80	CY17	10/2021

This scenario provides an indication of the potential reliability risks related to projects relied upon in the NYISO's 2020–2021 Reliability Planning Process not materializing.

Base Case Results

The MARS planning model was developed by NPCC with input from each Area (Ontario, New York, New England, Hydro Quebec, and Maritimes). The New York Loss of Load Hours (LOLH) for 2022 and 2024 are 0.003 and 0.029 (hours/year), respectively, with corresponding Expect Unserved Energy (EUE) values of 0.594 and 6.837 (MWh). These values trend higher than the past ProbA results. The trend is mainly due to the decrease in the forecasted Prospective Reserve Margin and Operable Reserve Margins.[13] The New York area is summer-peaking and the LOLH and EUE risk occurs primarily during the summer months.

Risk Scenario Results

As expected, if no major Tier 1 transmission and generation projects are assumed to come in-service within ProbA Study Period, the LOLH and EUE results are observed to be higher than ProbA Base Case. The LOLH for 2022 and 2024 are 0.003 and 0.045 (hours/year), respectively, with corresponding EUE values of 0.681 and 13.904 (MWh).

NPCC - Ontario

The IESO is the Planning Coordinator, Resource Planner and Balancing Authority for Ontario, as defined by the North American Electric Reliability Corporation. As detailed in Section 8 of the Ontario Resource and Transmission Assessment Criteria (ORTAC), the IESO follows the Northeast Power Coordinating Council resource adequacy criterion. ORTAC Section 8.2 states that the IESO will not consider emergency operating procedures for long-term capacity planning. The IESO also currently does not consider assistance over interconnections with neighboring Planning Coordinator Areas as contributing to resource adequacy needs in the Annual Planning Outlook resource adequacy assessments.

Risk Scenario Description

Ontario currently has 18 nuclear units, six of which are expected to retire by 2024/2025. As of today, one unit has been refurbished with nine more units being refurbished over the next decade. Given the size of each unit, there is a significant risk to resource adequacy if the return of units is delayed due to unforeseen circumstances, the reason for the IESO to pick refurbishment project delays for risk scenario. The demand forecast was increased by 5% for Ontario risk scenario to reflect possible rapid economic recovery from COVID-19 impacts.

Removing Tier 1 resources would not have been an appropriate scenario to test the system because those resources amounted to only 360 MW.

Base Case Results

The previous ProbA estimated an annual LOLH of 0.0 hours/year and EUE of 0.0 MWh for the year 2022. The median peak demand forecast for 2022 has increased by 2.5% compared to the 2018 forecast. The current forecasts are LOLH

[13] As defined by NERC for the Long-Term Reliability Assessments (LTRA) and Probabilistic Assessment (Prob A) application.

of 0.0 hours/year and EUE of 0.049 MWh for the year 2022. No difference in the estimated LOLH and a marginal difference in EUE are observed between the two assessments.

Risk Scenario Results

The ProbA estimated an annual LOLH of 0.0013 hours/year and EUE of 0.0925 MWh for the year 2022. For the year 2024, the estimated annual LOLH was 0.1408 hours/year and EUE was 79.9585 MWh, as expected.

The results emphasize the resource adequacy needs that Ontario faces in the mid to long-term. The IESO is transitioning to the use of competitive mechanisms with stakeholder inputs to meet Ontario’s adequacy needs.

NPCC - Québec

The Québec assessment area (Province of Québec) is a winter-peaking NPCC subregion that covers 595,391 square miles with a population of eight and a half million. Québec is one of the four NERC Interconnections in North America with ties to Ontario, New York, New England, and the Maritimes. These ties consist of either HVDC ties, radial generation, or load to and from neighboring systems.

Risk Scenario Description

In this scenario, it is assumed that Tier 1 resources be removed to test the reliability impacts associated with the most likely and therefore realistic shortages. Other scenarios are less likely compare to this scenario.

Base Case Results

The base case reserve margin for 2022 was 13.2%, which is higher than the Area’s reference reserve margin of 10%. In the short term, increase in load forecasts, on peak sales of firm capacity to neighboring jurisdictions reduced the base case planning reserve margins to levels slightly below the reference reserve margin of 10% in 2024.

For the two studied years, the results are zero for EUE and LOLH. Expressed in terms of Parts per Million MWh of Net energy for load, the EUE values are zero for the years 2022 and 2024.

Risk Scenario Results

As expected, after removing all Tier-1 resources, the risk scenarios reduce both the planning reserve margins to levels below the Area’s target of 10%. Forecast ranges for planning reserves are 13.0% and 8.9% for the two study years of 2022 and 2024. For the two studied years, the EUE and LOLH remain close to zero.

Chapter 6: RF - PJM

PJM is a regional transmission organization that coordinates the movement of wholesale electricity in all or parts of 13 states and the District of Columbia. It is part of the Eastern Interconnection and serves approximately 65 million people over 369,000 square miles.

Key Assessment Takeaway

PJM decided to remove all Tier 1 resources as part of their scenario. They demonstrate no significant rise in Reliability Indices based on these removals.

Risk Scenario Description

The risk scenario considers the removal of all Tier 1 units from the simulation. This scenario serves as a proxy for potential withdrawals or delays of queue projects in the PJM Interconnection Queue. Furthermore, it provides with an opportunity to analyze the impact of a higher RTO-wide forced outage rate on reliability metrics due to the fact that, in general, Tier 1 units are expected to have lower forced outage rates than existing units. This is because most Tier 1 units are combined cycle units. This scenario provides value to resource adequacy planners due to the fact that it considers reserve margins that are much lower than current reserve margins at PJM.

Base Case Results

The Base Case results in LOLH and EUE equal to zero for both 2022 and 2024 due to large Forecast Planning Reserve Margins (36.6% and 40.1%, respectively). These reserve margins are significantly above the reference values of 14.5% and 14.4%.

The LOLH and EUE in the 2020 study are identical to the values reported in the 2018 study. There are no differences in the EUE and LOLH results because in both studies the Forecast Planning Reserve Margin values are well above the reference values. Furthermore, the Forecast Planning Reserve Margin for 2022 in the 2020 study has actually increased compared to the value in the 2018 study due to a slightly higher amount (~300 MW) of Forecast Capacity Resources and a lower (~3,000 MW) Net Internal Demand value.

Base Case Summary of Results			
Reserve Margin (RM) %			
	2022*	**2022**	**2024**
Anticipated	**33.5%**	**36.6%**	**40.1%**
Reference	**15.8%**	**14.5%**	**14.4%**
ProbA Forecast Operable	**22.5%**	**25.6%**	**29.0%**
Annual Probabilistic Indices			
	2022*	**2022**	**2024**
EUE (MWh)	**0.000**	**0.000**	**0.000**
EUE (ppm)	**0.000**	**0.000**	**0.000**
LOLH (hours/year)	**0.000**	**0.000**	**0.000**
2022*: results from the 2018 ProbA			

Risk Scenario Results

The regional risk scenario yields LOLH and EUE values that are practically zero for both 2022 and 2024 (the EUE value of 0.33 MWh in 2024 is, for all intents and purposes, a negligible value).

These results are also caused by Forecast Planning Reserve Margins, even after excluding Tier 1 resources, which are well above the reference values (i.e., 25.9% vs a reference value of 14.5% in 2022 and 24.1% vs a reference value of 14.4% in 2024).

Risk Scenario Summary of Results		
Reserve Margin (RM) %		
	2022	**2024**
Anticipated	**25.9%**	**24.1%**
Reference	**14.5%**	**14.4%**
ProbA Forecast Operable	**15.3%**	**13.6%**
Annual Probabilistic Indices		
	2022	**2024**
EUE (MWh)	**0.000**	**0.330**
EUE (ppm)	**0.000**	**0.000**
LOLH (hours/year)	**0.000**	**0.000**

Note that PJM's anticipated reserve margins in the Base Case and the Risk Scenario are largely driven by past and expected outcomes of PJM's capacity market, the Reliability Pricing Model, which by design allows for the possibility of procuring reserve margin levels above the reference levels[14].

[14] Sections 3.1 – 3.4 in PJM Manual 18 available at https://www.pjm.com/~/media/documents/manuals/m18.ashx

Chapter 7: SERC

SERC covers approximately 308,900 square miles and serves a population estimated at 39.4 million. The regional entity includes four NERC assessment areas: SERC-East, SERC-Central, SERC-Southeast, and SERC-Florida Peninsula.

In addition to seeing loss of load risk during peak load summer months, SERC is also experiencing tighter operating conditions during non-summer months. One factor that has contributed to this trend is the amount of thermal generation resources taking planned maintenance outages during the shoulder months. While the LTRA projects reserves for summer, winter, and annual assessments, it may not highlight risk, if any, during spring and fall.

> **Key Assessment Takeaway**
>
> SERC's increase of maintenance outages on their Base Case did not demonstrate a significant increase of Reliability Indices. In response, SERC then altered their cases to ensure each of the regions started at a LOLE of 0.1. This change allowed SERC to determine their Reliability Indices produce an exponential relationship to the increase of maximum capacity undergoing maintenance. This is able to be mitigated by proper coordination of planned outages.

SERC has not experienced any reliability events directly related to planned maintenance outages. However, reports on events in neighboring regions highlight the importance of evaluating this risk for SERC. A FERC and NERC staff report on the 2018 cold weather event[15] identified that planned outages contributed to system reliability risk in the South-Central United States. Additionally, MISO declared Maximum Generation Events in January and May of 2019 which supports MISO's finding that the combination of high planned outages, reduced capacity availability, and volatile load has increased the risk of capacity shortages during non-summer months.[16]

Risk Scenario Description

To investigate the impact of planned maintenance outages on system risk, SERC conducted a sensitivity study in the 2020 Probabilistic Assessment that increased the amount of planned maintenance outages on the SERC system for year 2024. This sensitivity study helps resource adequacy planners understand how planned maintenance outages can impact the distribution of loss of load risk across all times of the year and it improves the ability to plan maintenance outage schedules that minimize loss of load risk.

SERC incrementally increased the planned maintenance rates for thermal resources to test the reliability of the SERC system under a scenario with higher levels of planned maintenance outages. Given that the base case metrics are very small for many of SERC's sub-regional areas, known as metric reporting areas (MRAs), we performed a two-part sensitivity study. One, starting with the base report and the other starting at each MRA's PRM resource level, where the starting point reserves were adjusted for each MRA to reach the LOLE target of 0.1 days/year. In both instances, the base case planned outage rates were multiplied by factors of 1.5, 2 and 2.5.

Base Case Results

The 2020 Probabilistic Assessment Base Case results show that each of the MRAs are projected to have reserves and access to imports from neighboring areas that are well more than that needed to meet the 0.1 days/year LOLE target. In the 2020 study year, the planning reserve margins (PRM) results are 21.8% for 2022 and 18.9% for 2024. These projections are higher than the SERC 2018 Probabilistic Assessment study. The increase in PRM could be attributed to several modeling changes in the 2020 study, particularly the integration of Florida Peninsula, a rapidly changing capacity mix, and updates to transfer capacities. The snippets of the 2020 LTRA tables for the base case results for all SERC MRAs are found below.

[15] FERC and NERC Release Report on January 2018 Extreme Cold Weather Event

[16] Resource Availability and Need, Evaluation Whitepaper September 2018 and MISO January 2019 Max Gen Event Overview and May 2019 Max Gen Event Overview

SERC-Central: Base Case Summary of Results			
Reserve Margin (RM) %			
	2022*	2022	2024
Anticipated	24.9%	26.4%	27.0%
Reference	14.4%	15.0%	15.0%
ProbA Forecast Operable	17.7%	17.9%	18.4%
Annual Probabilistic Indices			
	2022*	2022	2024
EUE (MWh)	0.000	0.001	0.001
EUE (ppm)	0.000	0.000	0.000
LOLH (hours/year)	0.000	0.000	0.000

SERC-East: Base Case Summary of Results			
Reserve Margin (RM) %			
	2022*	2022	2024
Anticipated	24.9%	22.8%	23.9%
Reference	14.4%	15.0%	15.0%
ProbA Forecast Operable	18.0%	14.9%	15.9%
Annual Probabilistic Indices			
	2022*	2022	2024
EUE (MWh)	0.000	0.717	5.262
EUE (ppm)	0.000	0.003	0.024
LOLH (hours/year)	0.000	0.001	0.009

SERC- Southeast: Base Case Summary of Results			
Reserve Margin (RM) %			
	2022*	2022	2024
Anticipated	32.4%	35.8%	39.1%
Reference	14.4%	15.0%	15.0%
ProbA Forecast Operabl	24.7%	26.9%	30.2%
Annual Probabilistic Indices			
	2022*	2022	2024
EUE (MWh)	0.00	0.009	0.028
EUE (ppm)	0.00	0.000	0.000
LOLH (hours/year)	0.00	0.000	0.000

SERC-Florida Peninsula: Base Case Summary of Results			
Reserve Margin (RM) %			
	2022*	2022	2024
Anticipated	N/A	21.6%	22.8%
Reference	N/A	15.0%	15.0%
ProbA Forecast Operable	N/A	10.2%	11.4%
Annual Probabilistic Indices			
	2022*	2022	2024
EUE (MWh)	N/A	22.66	2.262
EUE (ppm)	N/A	0.096	0.009
LOLH (hours/year)	N/A	0.035	0.004

Risk Scenario Results

When using the maintenance multiplier of 1x, maintenance outages are primarily scheduled in March-May and September-November for SERC-C, SERC-SE, and SERC-E. In SERC-FP, maintenance outages are scheduled throughout the year, except for summer. Increasing the multiplier beyond 1.5x causes maintenance outages to begin to be scheduled in the peak load summer months. Figure 7.1 shows how the multipliers impact the maximum capacity undergoing maintenance during the simulation.

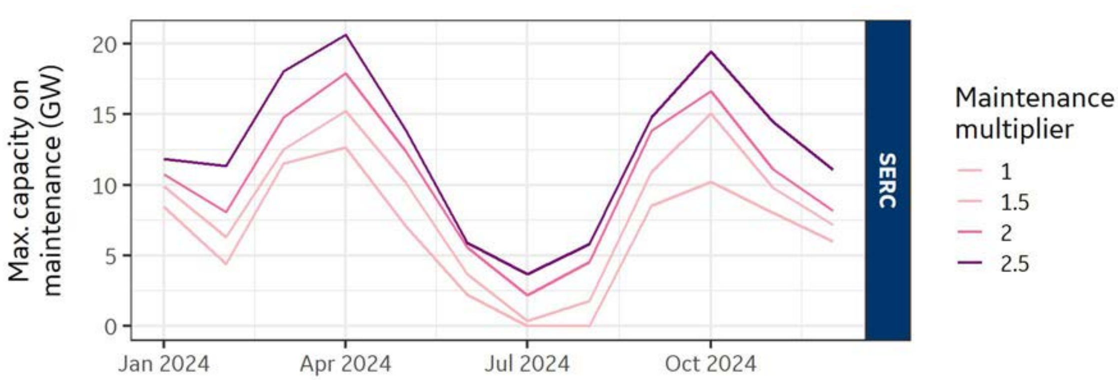


Figure 7.1 Maximum simultaneous capacity on maintenance outage for all of SERC

The reliability metrics for the base case are summarized in Table 7.1. The MRAs that had a measurable amount of LOLE in the base case (SERC-E and SERC-FP) see an increase in their observed metrics as the maintenance multiplier is increased. However, this increase in LOLE is somewhat moderate. For instance, in the case with double the maintenance rates, both SERC-E and SERC-FP have a LOLE below 0.1 days/year.

Table 7.1: Reliability Indices for Increased Maintenance for Base Case, Year 2024

MRA	Maintenance Multiplier	LOLE (days/yr.)	LOLH (hrs./yr)	EUE (MWh/yr.)	EUE (MPM)
SERC-C	1	0.000	0.000	0.0	0.000
	1.5	0.000	0.000	0.0	0.000
	2	0.001	0.002	1.1	0.005
	2.5	0.008	0.017	12.2	0.055
SERC-SE	1	0.000	0.000	0.0	0.000
	1.5	0.000	0.000	0.0	0.000
	2	0.001	0.001	0.4	0.002
	2.5	0.008	0.013	7.5	0.030
SERC-E	1	0.004	0.009	5.3	0.024
	1.5	0.012	0.019	12.3	0.056
	2	0.085	0.136	107.8	0.490
	2.5	0.277	0.574	517.4	2.349
SERC-FP	1	0.003	0.004	2.3	0.009
	1.5	0.018	0.024	19.1	0.079
	2	0.099	0.147	141.4	0.583
	2.5	0.320	0.518	513.3	2.114
SERC	1	0.006	0.013	7.6	0.006
	1.5	0.029	0.043	31.5	0.023
	2	0.183	0.284	250.8	0.186
	2.5	0.588	1.087	1,050.4	0.778

Given that the base case metrics are very small for many of the MRAs, SERC performed a second set of simulations to better understand the impact of higher maintenance outages in all MRAs. Instead of starting with the base case scenario, the starting point was the final step in the Probabilistic Assessment's interconnected PRM simulation, where every MRA in the model experiences a LOLE of 0.1 days/year. This provides a starting point with observable loss of load statistics for all the areas. Table 7.2 show that as the maintenance multiplier increases in the PRM case, all the MRAs experience an exponential increase of LOLE and other metrics. The increase is similar across all MRAs with the exception that SERC-FP experiences a larger-than-average increase in LOLE. Figure 7.2 also highlights this same exponential increases under this second simulation.

Table 7.2: Reliability Indices for Increased Maintenance for Planning Reserve Margin Case, Year 2024

MRA	Maintenance Multiplier	LOLE (days/yr.)	LOLH (hrs./yr)	EUE (MWh/yr.)	EUE (MPM)
SERC-C	1	0.100	0.263	255.8	1.166
	1.5	0.156	0.379	402.4	1.835
	2	0.594	1.517	2,139.7	9.757
	2.5	1.772	4.863	6,560.1	29.916
SERC-SE	1	0.099	0.233	280.9	1.113

	1.5	0.136	0.296	349.6	1.386
	2	0.521	1.131	1,418.4	5.623
	2.5	1.800	4.442	6,079.4	24,098
SERC-E	1	0.100	0.256	275.5	1.251
	1.5	0.142	0.331	343.8	1.561
	2	0.554	1.204	1,208.4	5.486
	2.5	1.799	4.634	5,218.9	23.691
SERC-FP	1	0.100	0.203	160.0	0.659
	1.5	0.261	0.440	394.7	1.626
	2	0.805	1.474	1,573.9	6.482
	2.5	2.321	4.810	5,484.6	22.588
SERC	1	0.307	0.767	1,527.0	1.131
	1.5	0.561	1.197	2,177.4	1.613
	2	1.908	4.485	8,815.7	6.532
	2.5	6.523	18.373	35,211.9	26.091

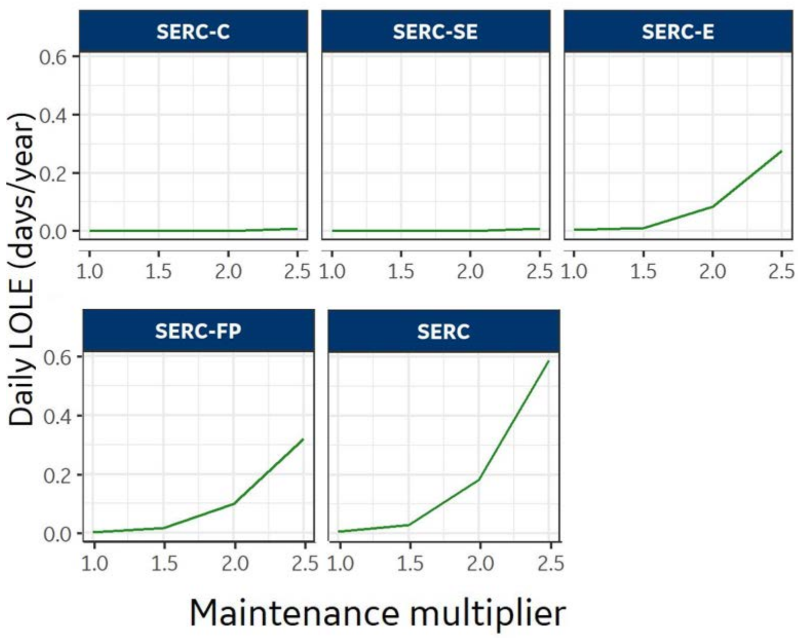


Figure 7.2 Loss of Load Statistics by Maintenance Multiplier per MRA

Figure 7.3 shows that under the 1x multiplier case, the majority of MRAs have the largest accumulation of LOLE in the summer. SERC-FP is the exception, with nearly 20% of the LOLE occurring during the winter. As the maintenance multiplier increases, most MRAs experience less LOLE in the summer and more LOLE in the spring and fall. SERC-FP is again the exception, with the majority of the LOLE moving to the winter and a smaller portion of LOLE moving to the fall.

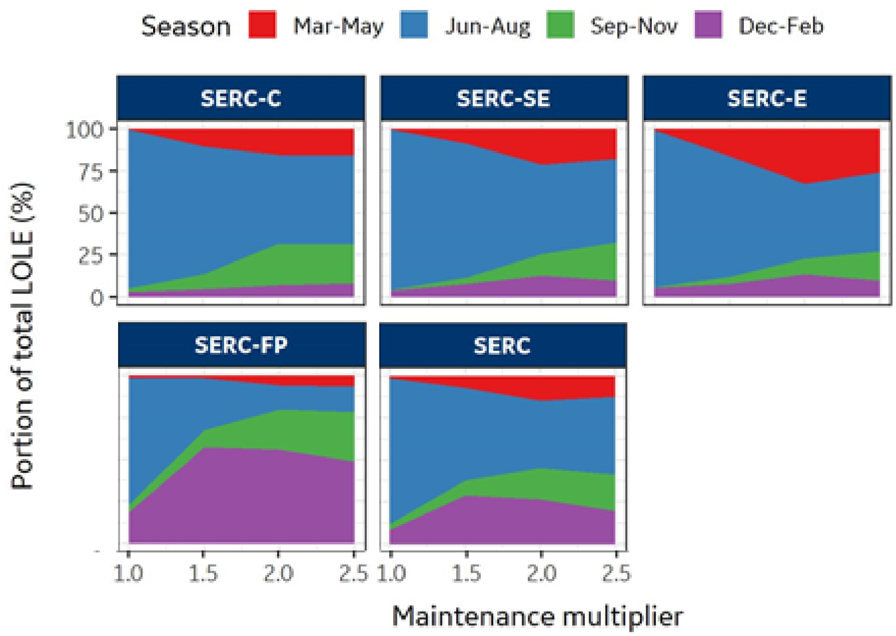


Figure 7.3 Seasonal LOLE Distribution for PRM Cases with Increased Maintenance

Risk and Recommendations

The sensitivity scenarios indicate that the risk in year 2024 associated with increased planned maintenance outages is low to moderate. For instance, the MRAs with the highest increase in LOLE, SERC-E and SERC-FP were still below 0.1 LOLE with double the maintenance rates. The small increase in LOLE for the SERC MRAs resulting from increased planned maintenance outages can be partially attributable to the fact that the SERC MRAs in 2024 are projected to have reserves and access to imports from neighboring areas that is well in excess of that needed to meet the 0.1 days/year LOLE target.

The results of this sensitivity study highlight the need for planned outage coordinators to develop unique maintenance schedules that align with expected local weather and system conditions. For this reason, the optimal time periods for scheduling maintenance outages vary across the SERC MRAs.

It is worth noting that the model assumes an optimized outage schedule based on foresight of average weather conditions. The GE MARS software schedules planned outages with a “packing” algorithm that schedules maintenance in the weeks with highest margins. A further comparison between the maintenance schedule developed by GE MARS and historical maintenance schedules could be insightful in understanding the findings of this sensitivity study. A link to the redacted copy of the SERC 2020 Probabilistic Assessment report can be found in Appendix E

Chapter 8: Texas RE – ERCOT

The Electric Reliability Council of Texas (ERCOT) region encompasses about 75 percent of the land area in Texas. The grid delivers approximately 90 percent of the electricity used by more than 26 million consumers in Texas.

Key Assessment Takeaway

ERCOT demonstrates that by resampling their wind profiles with their load profile to emphasize low to moderate amounts of wind has a significant effect on their net load peaks, and as a result increase their Reliability Indices. This increase is similar to those that alter their system such that a LOLE of 1 day in 10 years is expected. This indicates that the ERCOT system increases in Reliability Indices for their scenario, while significant in comparisons to the Base Case, are not significant in comparison to industry accepted standards.

Risk Scenario Description

The total installed wind capacity in ERCOT is around 25 GW, and additional 13 GW of new wind is expected to come online in the next three to four years. Furthermore, the two EEA events in 2019 summer were primarily due to low output from wind resources. In addition, simulated loss of load events in ERCOT are largely driven by high load, low wind output conditions. These conditions occur with relative rarity such that a relatively small change in their frequency could have significant impact on the expected reliability of the ERCOT system. The risk scenario for ERCOT was designed to stress test the impact of a difference in the realized frequency of high load and low wind events from that in the synthetic profiles used for the base case simulations.

To construct the alternate wind profiles which reflect a higher likelihood of low wind output, a filter was performed for days in the simulated base case which had any firm loss of load. An alternate wind profile for each day was randomly selected from the wind profiles from this set of days. This re-shuffling of load and wind profiles was performed 100 times. The sampled sets of profiles which represent the most extreme and 10th most extreme sets of net load profiles were selected to be simulated for 2024. The criteria for most extreme was based on the set with the highest average net loads in the top 40 net load days.

Base Case Results

The Base Case study results in minimal reliability events.

As compared to the 2018 ProbA Study, the reserve margin has increased substantially primarily due to increase in solar resources. More than 12GW of additional solar installed capacity is expected in 2022 now than was forecast when the 2018 ProbA Study was published. Compared to the results from the 2018 ProbA Study, LOLH decreased from 0.87 to 0.00 for the first study year. The results are driven by an increase in the Anticipated Reserve Margin, resulting from growth in planned solar and wind capacity.

Base Case Summary of Results		
Reserve Margin (RM) %		
	2022	**2024**
Anticipated	**19.1%**	**15.5%**
Reference	**13.8%**	**13.8%**
ProbA Forecast Operable	**13.7%**	**10.3%**
Annual Probabilistic Indices		
	2022	**2024**
EUE (MWh)	**.05**	**12.86**
EUE (ppm)	**0.00**	**0.03**
LOLH (hours/year)	**0.00**	**0.01**

Risk Scenario Results

Resampling the wind profiles on peak load days increased the average net load peak for the top 40 net load days by 235 MW for the 10th most extreme scenario and 525 MW for the most extreme scenario. A snapshot of the top 40 daily net load peaks for each of the scenarios is shown below in Figure 8.1. In the most extreme days in the risk scenarios, the daily net load peak is over 1,000 MW higher than in the base case.

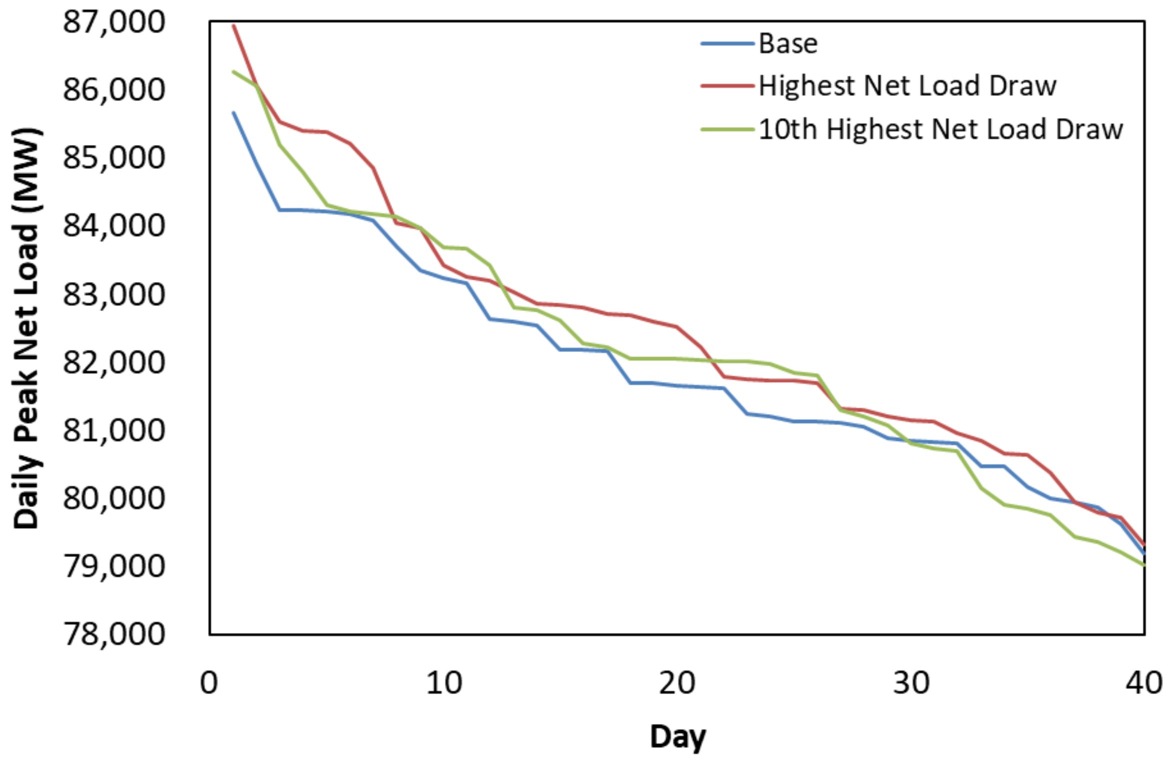


Figure 8.1 ERCOT's Load profiles for Various Assumptions.

The increase in net load corresponds to a degradation of reliability when the risk scenarios are simulated. While the assumption that daily wind profiles from peak load days are fungible is not realistic, it likely provides an upper bound for the impact of wind profile uncertainty on average reliability metrics. The scenario results are compared to those found in the Base Case in Table 8.1 and highlight this upper boundary.

Table 8.1: Scenario Case Reliability Index Comparison

Reliability Index	Base Case	10th Highest Net Load Draw	Highest Net Load Dra~~t~~w
EUE [MWh]	12.86	31.0	64.72
LOLH [hrs./yr.]	0.01	0.03	0.05

Since reliability metrics in the base case are quite low, the risk scenario impact appears quite large. EUE and LOLH in the highest net load draw scenario increase by a factor of approximately 5. However, simulating the risk scenarios at a lower reserve margin which is more consistent with industry standard reliability expectations (0.1 LOLE) suggests a smaller impact. In this case LOLH increases from .24 to .49 for the highest net load draw scenario.

Chapter 9: WECC

The Western Interconnection serves a population of over 80 million people. The interconnection spans 1.8 million square miles in all or part of 14 states, the Canadian provinces of British Columbia and Alberta, and the northern part of Baja California in Mexico. Due to the unique geography, demography, and history, the Western Interconnection is distinct in many ways from the other North American interconnections.

Risk Scenario Description

The Western Electricity Coordinating Council (WECC) Regional Risk Scenario examines the impacts to resource adequacy associated with potential coal-fired generation retirements. The generation resources included in this scenario started with the LTRA resources and removed additional coal-fired generation resources that are expected to retire but do not yet have an approved decommission plan.

Key Assessment Takeaway

WECC, like NPCC, performs a simulation for multiple different Assessment Areas. These areas all were subject to a reduction of coal-fired generation and demonstrated varying results. In some areas, this scenario greatly impacted their Reliability Indices and in others, no significant increase was observed from the Base Case results. WECC determined that the impact of a reduction of coal-fired generation on the Reliability Indices depends heavily on the current penetration of coal-fired generation in the Assessment Area, as well as the Assessment Area's ability to take on external assistance under higher demand. Such a result is not indicative for more or less coal, but that the impact of faster retirements than expected has a varying impact on the Reliability Indices in each Assessment Area.

Coal-fired generation is a key baseload component of the Western Interconnection's resource mix but is also one of the most controversial. With the retirement or planned retirement of considerable amounts of coal-fired generation, and an increase in variable energy resources, the need to ensure sufficient capacity to reliably meet electricity demand at any given hour within the Western Interconnection is becoming more significant. This scenario specifically analyzes the reliability impacts of retiring coal plants beyond those that are being retired in the LTRA; this assessment includes coal retirements based on the best information provided by stakeholders or are mandated by state polices. This scenario also provides insights into where additional risk may occur with fewer baseload resources and examines the effects of these potential retirements to help mitigate reliability risks to the Bulk Power System (BPS).

WECC's Reliability Risk Priorities focus on four reliability concerns: Resource Adequacy and Performance, Changing Resource Mix, Distribution System and Customer Load Impacts on the BPS, and Extreme Natural Events. It would be appropriate to study any of these topics, but Resource Adequacy incorporates elements of each priority and serves as the basis for additional studies in each of these priorities. If more information is desired, please see Appendix E for the link to WECC's Western Assessment that contains more details.

Coal-fired generation has historically been a major energy resource in the Western Interconnection. However, as the generation resource mix in the Western Interconnection transitions from thermal based resources to variable generation resources, coal-fired generation will continue to be retired. This study examines the impacts to resource adequacy and planning reserve margins associated with aggressive coal-fired generation retirements.

It is anticipated that coal-fired generation retirements will continue, both in response to governmental directives and for economic reasons. For the most part these baseload resources are being replaced by high variable generation such as wind and solar. Resource adequacy planners need to understand the variability associated with wind and solar generation and incorporate probabilistic studies in the resource adequacy planning process. This assessment is focused on examining the risks to resource adequacy associated with not having enough resources to meet demand following aggressive coal-fired generation retirements.

The chart (below in Figure 9.1) shows the amount of possible coal retirements over the next ten years that were not reported in the LTRA or Prob-A base case. The years 2022 and 2024 are highlighted as the years reported in the scenario. Accumulated coal-fired capacity retirements that were included in the ProbA scenario total over 2,300 MW.

Figure 9.1: WECC's Possible Coal Retirement Capacity by Year[17]

WECC - California – Mexico (CAMX)

The CAMX subregion is a summer peaking subregion that consists of most of the state of California and a portion of Baja California, Mexico. The CAMX subregion has two distinct peak periods, one in southern California and one in northern California, which benefits the subregion as there are resources available in one area when the other is experiencing their demand peak.

Demand

The CAMX subregion is expected to peak in late August at approximately 53,400 MW for both 2022 and 2024. Overall, the CAMX subregion should expect an 100% ramp, or 26,700 MW, from the lowest to the highest demand hour of the peak demand day in 2022. In 2022, there is a 5% possibility the subregion could peak as high as 66,000 MW, which equates to a 24% load forecast uncertainty and could peak as high as 65,000 MW in 2024.

Resource Availability

The expected availability of resources on the peak hour in 2022 is 50,400 MW. Under low resource availability conditions, the CAMX subregion may only have 44,300 MW available to meet a 53,400 MW expected peak. The expected availability of resources on the peak hour in 2024 is 54,400 MW. Under low resource availability conditions, the CAMX subregion may only have 46,400 MW available to meet a 53,400 MW expected peak. Although there is only a 5% probability of this occurring, a large amount of external assistance would be needed to meet demand under low-availability conditions.

Variability is highly dependent on the resource type. Although baseload resources account for roughly 45,000 MW of availability, the low availability end of the spectrum would only see a loss of 4,000 MW, or less than 10%. Whereas,

[17] For further information regarding this study please see WECC's Western Assessment of Resource Adequacy report, see Appendix E.

solar resources total 6,500 MW, which on a low availability end of the spectrum for resource availability, could expect to lose 5,500 MW or nearly 90% of this resource.

For this scenario, there were no new coal retirements included in this subregion. However, coal retirements that occurred in the other subregions did have an impact in the amount of energy available to transfer to CAMX.

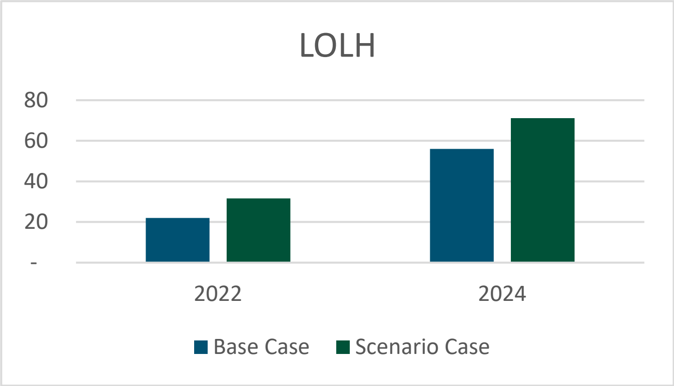
Planning Reserve Margin

Given the growing variability, a 15% margin for the CAMX area is close to the median level of reserve margin needed to maintain reliability; it should not be considered the maximum for all hours. The highest reserve margin needed is expected to be around 40%. Therefore, it is important to look at reserve margins in terms of MWs. The highest reserve margin needed equates to approximately 11,000 MW or 20% of the expected peak demand.

Risk Scenario Results

Annual Demand at Risk

In 2022, for the scenario, the CAMX subregion could experience as many as 32 hours where the one day in ten years threshold of resource adequacy is not maintained, and up to 71 by 2024. For the base case the results were 22 and 56 hours respectively. Given the CAMX subregion will need to rely heavily on external assistance to maintain resource adequacy, the impacts to demand at risk of the scenario came from retirements in other subregions as no coal was retired in CAMX.

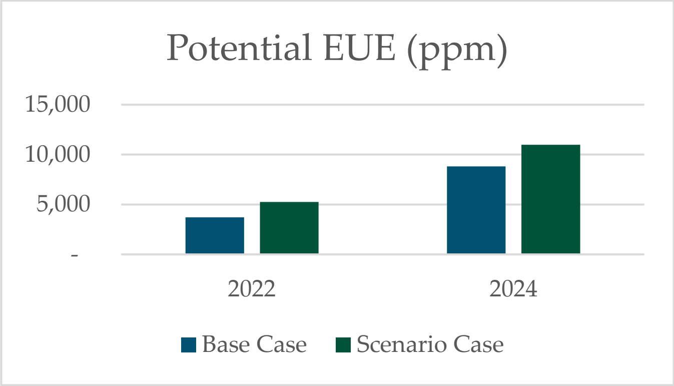


Hours at Risk

A system wide high demand scenario would eliminate much of the external assistance available for CAMX causing this to be exacerbated, and a low availability scenario would lead to a highly constrained external assistance scenario throughout the system. Even under expected conditions, the CAMX subregion is expected to have many hours where the one day in ten years threshold of reliability is not maintained through the inclusion of new resources and/or external assistance.

Energy at Risk

In 2022, about 5,200 per million MWh of energy is at risk in the scenario case and grows to nearly 11,000 per million MWh by 2024. In the base case, the results were 3,700 and 8,800 per million MWh respectively. For the 32 hours of potential demand at risk in the scenario results, this would equate to approximately 162 per million MWh on average in 2022. For the 71 hours of potential demand at risk in the scenario results, this would equate to approximately 155 per million MWh on average in 2024.



WECC - Southwest Reserve Sharing Group (SRSG)

The SRSG subregion is a summer peaking area that consists of the entire states of Arizona and New Mexico and a portion of the states Texas and California.

Demand

The SRSG subregion is expected to peak in mid-July at approximately 26,100 MW in 2022 and 26,900 MW in 2024. Overall, the SRSG subregion should expect an 93% ramp, or 12,600 MW, from the lowest to the highest demand hour of the peak demand day in 2022. In 2022, there is a 5% possibility the subregion could peak as high as 29,600 MW, which equates to a 13% load forecast uncertainty, and could peak as high as 30,600 MW in 2024.

Resource Availability

The expected availability of resources on the peak hour in 2022 is 29,600 MW. Under low resource availability conditions, the SRSG subregion may only have 24,100 MW available to meet a 26,100 MW expected peak. The expected availability of resources on the peak hour in 2024 is 29,200 MW. Under low resource availability conditions, the SRSG subregion may only have 24,200 MW available to meet a 26,900 MW expected peak. Although there is only a 5% probability of this occurring, a large amount of external assistance would be needed to meet demand under low-availability conditions.

Variability is highly dependent on the resource type. Although baseload resources account for roughly 25,000 MW of availability, the low availability end of the spectrum would only see a loss of 3,100 MW. Whereas, solar resources total 1,400 MW of availability, but on a low availability end of the spectrum for resource availability, they could expect to lose 600 MW or nearly half of this resource.

For this scenario, there were approximately 400 MW of additional coal retirements included in this subregion.

Planning Reserve Margin

Given the growing variability, a 16% margin for the SRSG subregion is close to the median level of reserve margin needed to maintain reliability; it should not be considered the maximum for all hours. The highest reserve margin needed is expected to be around 27%. Therefore, it is important to look at reserve margins in terms of MWs. The highest reserve margin needed equates to approximately 3,500 MW or 13% of the expected peak demand. As more variable resources are added to the system, both on the demand side through roof-top resources and the resource side through generation plants, a larger reserve margin is needed to account for variability in the system.

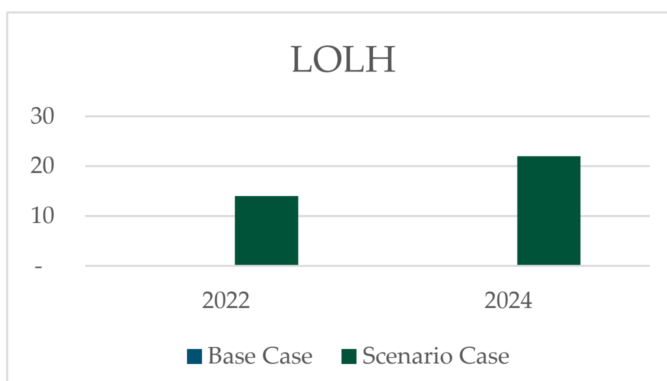
Risk Scenario Results

Annual Demand at Risk

In 2022, for the scenario, the SRSG subregion could experience as many as 14 hours where the one day in ten years threshold of resource adequacy is not maintained, and up to 22 by 2024. For the base case the results were less than an hour in both years. The impacts of the scenario came from the 400 MW coal retirement as well as impacts from external assistance in other subregions.

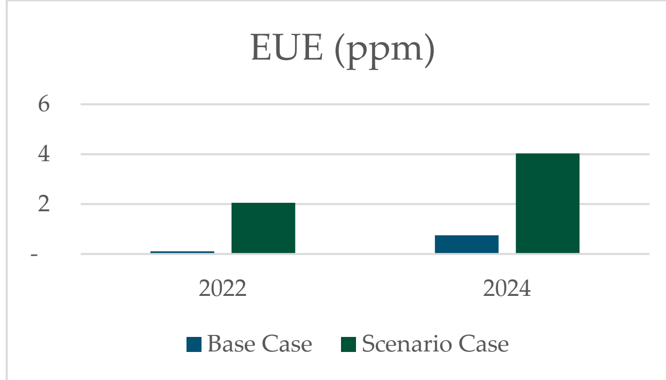
Hours at Risk

A system wide high demand scenario would eliminate much of the external assistance available for SRSG causing this to be exacerbated, and a low availability scenario would lead to a highly constrained external assistance scenario throughout the system. Even under expected conditions, the SRSG subregion is expected to have many hours where the one day in ten years threshold of reliability is not maintained through the inclusion of new resources and/or external assistance.



Energy at Risk

In 2022, about 2 per million MWh of energy is at risk in the scenario case and grows to nearly 4 per million MWh by 2024. In the base case, the results were less than 1 per million MWh for both years.



WECC - Northwest Power Pool – United States (NWPP-US)

The Northwest Power Pool – US subregion consists of the northern US and central portions of the Western Interconnection. This subregion is both summer and winter peaking depending on location. The area covers all the states of Washington, Oregon, Idaho, Nevada, Utah, Colorado, and Wyoming as well as portions of the states of Montana, California, South Dakota, and Nebraska.

Demand

The NWPP-US subregion is expected to peak in late-July at approximately 65,000 MW in 2022 and 66,100 MW in 2024. Overall, the NWPP-US subregion should expect an 81% ramp, or 29,100 MW, from the lowest to the highest demand hour of the peak demand day in 2022. In 2022, there is a 5% possibility the subregion could peak as high as 73,700 MW, which equates to a 13% load forecast uncertainty, and could peak as high as 75,500 MW in 2024.

Resource Availability

The expected availability of resources on the peak hour in 2022 and 2024 is 81,300 MW. Under low resource availability conditions, the NWPP-US subregion may only have 58,700 MW available to meet a 65,000 MW expected peak. Although there is only a 5% probability of this occurring, a large amount of external assistance would be needed to meet demand under low-availability conditions.

Variability is highly dependent on the resource type. Although baseload resources account for roughly 50,200 MW of availability, the low availability end of the spectrum would only see a loss of 8,800 MW. Whereas, solar resources total 3,600 MW of availability, but on a low availability end of the spectrum for resource availability, they could expect to lose 2,000 MW or over half of this resource.

For this scenario, there were approximately 1,100 MW of additional coal retirements included in this subregion.

Planning Reserve Margin

Given the growing variability, a 15-21% margin for the NWPP-US subregion is close to the median level of reserve margin needed to maintain reliability, it should not be considered the maximum for all hours. The highest reserve margin needed is expected to be around 42%. Therefore, it is important to look at reserve margins in terms of MWs. The highest reserve margin needed equates to approximately 18,200 MW or 28% of the expected peak demand. As more variable resources are added to the system, both on the demand side through roof-top resources and the resource side through generation plants, a larger reserve margin is needed to account for variability in the system.

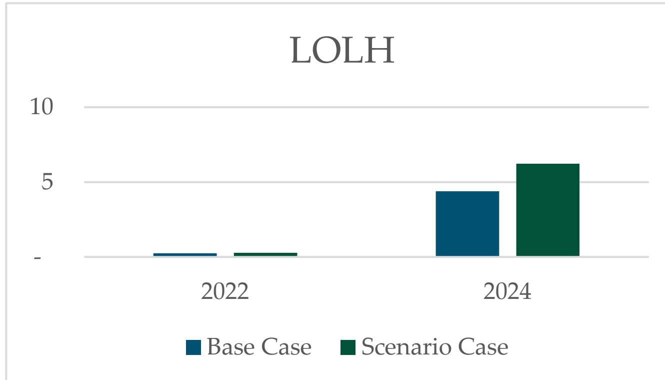
Risk Scenario Results

Annual Demand at Risk

In 2022, for the scenario, the NWPP-US subregion could experience less than one hour where the one day in ten years threshold of resource adequacy is not maintained and just over 6 hours by 2024. For the base case the results were less than an hour in 2022 and 4 hours in 2024. The impacts of the scenario came from the 1,100 MW coal retirement as well as impacts from external assistance in other subregions.

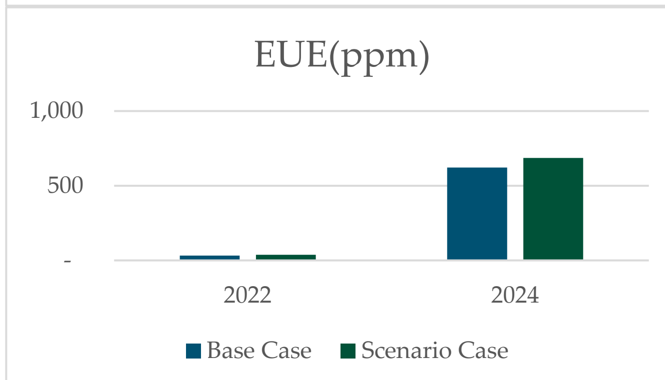
Hours at Risk

A system wide high demand scenario would eliminate much of the external assistance available for NWPP-US causing this to be exacerbated, and a low availability scenario would lead to a highly constrained external assistance scenario throughout the system. Even under expected conditions, the NWPP-US subregion is expected to have many hours where the one day in ten years threshold of reliability is not maintained through the inclusion of new resources and/or external assistance.



Energy at Risk

In 2022, about 37 per million MWh of energy is at risk in the scenario case and grows to nearly 685 per million MWh by 2024. In the base case, the results were 32 and 621 per million MWh respectively. For the 6 hours of potential demand at risk in the scenario results, this would equate to approximately 110 per million MWh on average in 2024.



WECC – Alberta & British Columbia (WECC-AB) & (WECC-BC)

The WECC-AB subregion covers the Alberta province of Canada while the WECC-BC subregion covers the British Columbia province. Both subregions are winter peaking.

Demand

The WECC-AB subregion is expected to peak in early-February at approximately 9,200 MW in 2022 and 2024. Overall, the WECC-AB subregion should expect an 30% ramp, or 2,100 MW, from the lowest to the highest demand hour of the peak demand day. In 2022, there is a 5% possibility the subregion could peak as high as 9,500 MW, which equates to a 3% load forecast uncertainty.

The WECC-BC subregion is expected to peak in mid-January at approximately 9,300 MW in 2022 and 9,600 MW in 2024. Overall, the WECC-BC subregion should expect a 49% ramp, or 3,000 MW, from the lowest to the highest demand hour of the peak demand day. In 2022, there is a 5% possibility the subregion could peak as high as 10,000 MW, which equates to an 11% load forecast uncertainty.

Resource Availability

In the WEC-AB subregion the expected availability of resources on the peak hour in 2022 is 13,300 MW and 11,000 MW in 2024. Under low resource availability conditions, the WECC-AB subregion may only have 12,000 MW available to meet a 9,200 MW expected peak. Although there is only a 5% probability of this occurring, a large amount of external assistance would be needed to meet demand under low-availability conditions.

Variability is highly dependent on the resource type. Although baseload resources account for roughly 12,300 MW of availability, the low availability end of the spectrum would only see a loss of 500 MW. Whereas, wind resources total 700 MW of availability, but on a low availability end of the spectrum for resource availability, they could expect to lose all this resource.

In the WECC-BC subregion the expected availability of resources on the peak hour in 2022 and 2024 is 12,900 MW. Under low resource availability conditions, the WECC-BC subregion may only have 10,600 MW available to meet a 9,300 MW expected peak. Although there is only a 5% probability of this occurring, a large amount of external assistance would be needed to meet demand under low-availability conditions.

Variability is highly dependent on the resource type. Although baseload resources account for roughly 1,000 MW of availability, the low availability end of the spectrum would only see a loss of 100 MW or 10%. Whereas, hydro resources total 11,800 MW of availability, but on a low availability end of the spectrum for resource availability, they could expect to lose 2,100 MW of this resource or about 20%.
For this scenario, there were approximately 800 MW of additional coal retirements included in the WECC–AB subregion, zero in WECC-BC.

Planning Reserve Margin

Given the growing variability, a 15% margin for the WECC-AB subregion is close to the median level of reserve margin needed to maintain reliability; it should not be considered the maximum needed for all hours. The highest reserve margin needed is expected to be around 22%. Therefore, it is important to look at reserve margins in terms of MWs. The highest reserve margin needed equates to approximately 1,700 MW or 19% of the expected peak demand.

Given the growing variability, a 15% margin for the WECC-BC subregion is close to the median level of reserve margin needed to maintain reliability; it should not be considered the maximum for all hours. The highest reserve margin needed is expected to be around 42%. Therefore, it is important to look at reserve margins in terms of MWs. The highest reserve margin needed equates to approximately 2,800 MW or 31% of the expected peak demand.

As more variable resources are added to the system, both on the demand side through roof-top resources and the resource side through generation plants, a larger reserve margin is needed to account for variability in the system.

Risk Scenario Results

For the scenario of both Canada subregions showed no expected LOLH or EUE. For the Canada subregions, the coal resource portion of the generation portfolio is small, and removal of these resources had little to no impact on the resource adequacy of these subregions.

Appendix A: Assessment Preparation, Design, and Data Concepts

The North American Electric Reliability Corporation
Atlanta
3353 Peachtree Road NE, Suite 600 – North Tower
Atlanta, GA 30326
404-446-2560

Washington, D.C.
1325 G Street NW, Suite 600
Washington, DC 20005
202-400-3000

Assessment Data Questions

Please direct all data inquiries to NERC staff (assessments@nerc.net). References to the data and/or findings of the assessment are welcome with appropriate attribution of the source to the *2020 NERC Probabilistic Assessment*[18]. However, extensive reproduction of tables and/or charts will require permission from NERC Staff and PAWG Members:

NERC Probabilistic Assessment Working Group (PAWG) Members

Name:	Organization:	Name:	Organization:
Andreas Klaube	Chair; NPCC	Julie Jin	ERCOT
Alex Crawford	Vice Chair; Southwest Power Pool, Inc.	Peter Warnken	ERCOT
John Skeath	North American Electric Reliability, Corp.	Sennoun Abdelhakim	Hydro-Québec
Salva Andiappan	Midwest Reliability Organization	Lewis De La Rosa	TRE
Guarav Maingi	SaskPower	David Richardson	Independent Electricity System Operator
Bagen Bagen	Manitoba Hydro	Vithy Vithyananthan	Independent Electricity System Operator
Darius Monson	Midcontinent Independent System Operator	Anna Lafoyiannis	Independent Electricity System Operator
Phil Fedora	NPCC	Richard Becker	SERC Reliability Corporation
Peter Wong	ISO New England, Inc.	Anaisha Jaykumar	SERC Reliability Corporation
Manasa Kotha	ISO New England, Inc.	Wyatt Ellertson	Entergy
Laura Popa	New York ISO	Patricio Rocha-Garrido	PJM Interconnection, L.L.C.
Sadhana Shrestha	New York ISO	Jason Quevada	PJM Interconnection, L.L.C.
Mike Welch	New York ISO	Tim FryFogle	ReliabilityFirst
Benjamin O'Rourke	New York ISO	William Lamanna	North American Electric Reliability, Corp.

[18] NERC_LTRA_2020.pdf

Appendix B: Description of Study Method in the ProbA

Descriptions and assumptions of each Region's probabilistic model are detailed in the sections below. Where a region is not listed, information was not provided at time of publication, but may be provided through contact via information listed in Appendix A.

MRO - MISO

General description

MISO utilized the Strategic Energy Risk Valuation Model (SERVM) to perform the 2020 ProbA base case and scenario. 30 historic weather years were modeled with 5 different economic uncertainty multipliers and 125 outage draws resulting in 18,750 unique load/outage scenarios being analyzed. In SERVM the MISO system was represented as a transportation model with each of MISO's 10 Local Resource Zones (LRZ's) modeled with their respective load forecasts and resource mixes. The LRZ's were able to import and export energy with each other within the model and the results of the study were aggregated up to the MISO level.

Demand & LFU

To account for load uncertainty due to weather, MISO modeled 30 unique load shapes based on historic weather patterns. These load shapes were developed using a neural-net software to create functional relationships between demand and weather using the most recent 5 years of actual demand and weather data within MISO. These neural-net relationships were then applied to the most recent 30 years of weather data to create 30 synthetic load shapes based on historic weather. Finally, the average of these 30 load shapes was scaled to the 50-50 forecasts from MISO's Load Serving Entities (LSE's).

To capture economic uncertainty in peak demand forecasts, MISO modeled each of the 30 load shapes with 5 different scalars (-2%, -1%, 0%, 1%, 2%). This resulted in 150 unique load scenarios (30 load shapes X 5 uncertainty scalars) being modeled.

Thermal Resources

All thermal resources in MISO were modeled as 2-state units i.e. either dispatched to full installed capacity or offline. Units with at least 1 year of operating history were modeled with their actual EFORd based on GADS data (up to 5 historic years). Units with insufficient operating history to determine an EFORd were assigned the class average EFORd.

Wind & Solar

Wind units were modeled with monthly ELCC values which can be found in MISO's 2021-22 PY LOLE Study Report. Solar resources were modeled at 50% of installed capacity. Both wind and solar were treated as a net-load reduction within the model.

Hydroelectric

Hydro units in MISO were modeled as a resource with an EFORd except for run of river units. These were modeled at their individual capacity credit which is determined by the resources historic performance during peak hours.

Demand-side resources

Demand Response was modeled as dispatchable call limited resources. These resources were only dispatched when needed during emergency conditions to avoid shedding load. Energy Efficiency resources were modeled as load modifiers which were netted from the load within the model.

Transmission

Capacity Import Limits (CIL) and Capacity Export Limits (CEL) were modeled for each of the 10 LRZ's. If a LRZ was expected to be unable to meet its peak demand, then that zone would import capacity up to its CIL provided there was sufficient exports available from other zones.

MRO - SaskPower

General description

Saskatchewan utilizes the Multi-Area Reliability Simulation (MARS) program for reliability planning. The software performs the Monte Carlo simulation by stepping through the time chronologically and calculates the standard reliability indices of daily and hourly Loss of Load Expectation (LOLE) and Expected Unserved Energy (EUE).
Detailed representation of the utility system, such as load forecast, expansion sequence, unit characteristics, maintenance, and outages are included in the model. The model simultaneously considers many types of randomly occurring events such as forced outages of generating units. Based on the deterministic calculations within this assessment, Saskatchewan's anticipated reserve margin is 34.2 % and 30.0 %, for years 2022 and 2024 respectively. EUE calculated for base case is 80.4 MWh and 26.4 MWh for the years 2022 and 2024, respectively. LOLH follows a similar pattern to EUE.

Demand & LFU

This reliability study is based on the 50:50 load forecast that includes data such as annual peak, annual target energy, and load profiles. The model distributes the annual energy into hourly data based on the load shape. Saskatchewan develops energy and peak demand forecasts based on provincial econometric model forecasted industrial load data, and weather normalization model.

The forecasts also take into consideration of the Saskatchewan economic forecast, historic energy sales, customer forecasts, weather normalized sales, and system losses. Load Forecast Uncertainty is explicitly modeled utilizing a seven-step normal distribution with a standard deviation of ± 3%, 5% and 10%.

Thermal Resources

Natural gas units are typically modeled as a two-state unit so that gas unit is either available to be dispatched up to full load or is on a full forced outage with zero generation. Coal facilities are typically modeled as a three-state unit. Coal unit can be at a full load, a derated forced outage or a full forced outage state. Forecast derated hours are based on the percentage of the time the unit was derated out of all hours, excluding planned outages, based on the 5-year historical average. Generally, we use UFOP when forecasting reliability for the gas turbine units and FOR/DAFOR for the Steam units.

Wind & Solar

For reliability planning purposes, Saskatchewan plans for 10 percent of wind nameplate capacity to be available to meet summer peak and 20 percent of wind nameplate capacity to be available to meet winter peak demand. Two methods were utilized to carry out the analysis for determining wind capacity credit. First method approximates the Effective Load Carrying Capability (ELCC) of the wind turbines by determining the wind capacity during peak load hours of each month by looking at historical wind generation in those hours. A period of 4 consecutive hours was selected and the actual wind generation in those 4 hours was used to determine the ELCC of the wind turbines. The median capacity value of wind generation in those 4 hours of each day of the month is calculated and is converted to a percent capacity by dividing that number by the maximum capacity of the wind turbine. Another method to estimate the ELCC was also utilized by looking at the top 1%, 5%, 10% and 30% of load hours in each month. Using these methods, we then looked at the lowest averages in each of the winter and summer months to come up with the wind capacity credit value.

Currently, Saskatchewan has low penetration level of Solar resources and most of it is Distributed Energy Resource (DER), which is netted off the load forecast.

Hydroelectric

Hydro generation is modeled as energy limited resource and the annual hydro energy is calculated based on the historical data that has been accumulated over the last 30 plus years. Hydro units are described by specifying maximum rating, minimum rating, and monthly available energy. The first step is to dispatch the minimum rating for all the hours in the month. Remaining capacity and energy are then scheduled to reduce the peak loads as much as possible.

Demand-side resources

Controllable and Dispatchable Demand Response Program*:* Demand Response is modelled as an Emergency Operating Procedure by assigning a fixed capacity value (60 MW) and thus configured as a negative margin state for which MARS evaluates the required metrics. An Emergency Operating Procedure is initiated when the reserve conditions on a system approach critical level.

Energy provided from Energy Efficiency (EE) and Conservation programs is netted off the load forecast.

Transmission

No transmission facility data is used in this assessment as the model assumes that all firm capacity resources are deliverable within the assessment area. Separate transmission planning assessments indicate that transmission capability is expected to be adequate to supply firm customer demand and planned transmission service for generation sources.

MRO - SPP

General description

Southwest Power Pool (SPP) Planning Coordinator footprint covers 546,000 square miles and encompasses all or parts of Arkansas, Iowa, Kansas, Louisiana, Minnesota, Missouri, Montana, Nebraska, New Mexico, North Dakota, Oklahoma, South Dakota, Texas, and Wyoming. The SPP assessment area footprint has approximately 61,000 miles of transmission lines, 756 generating plants, and 4,811 transmission-class substations, and it serves a population of more than 18 million. SPP assessment area has over 90,000 MW (name plate) of total generation, which includes over 28,000 MW of nameplate wind generation. SPP is also a summer peaking assessment area at approximately 51,000 MW of summer peak demand.

Demand & LFU

Eight years (2012-2019) of historical hourly load data were individually modeled to produce 8,760 hourly load profiles for each zone in the SPP Assessment Area. In order to not overestimate the peak demand, the forecasted peak demand for 2022 and 2024 were assigned to the load shape from 2014 (the median year of the eight historical years). The other seven years were also scaled to a forecasted peak demand calculated by distributing the variance between the peaks of the non-median years to the median year.
Microsoft Excel was used to regress the daily peak values against temperatures, economics, and previous daily peak loads observed at key weather stations throughout the SPP footprint to derive the load forecast uncertainty components. The load multipliers were determined from a uniform distribution and assigned seven discrete steps with the applicable probability occurrence weighting. All seven of the load forecast uncertainty steps were modeled at or above the 50/50 peak forecast.

Thermal Resources

SPP modeled seasonal maximum net capabilities reported in the LTRA for thermal resources. Physical and economic parameters were modeled to reflect physical attributes and capabilities of the resources. Full and partial forced outages from NERC GADS data in the SPP footprint were applied on a resource basis.

Wind & Solar

SPP included wind and solar resources currently installed, under construction, or that have a signed interconnection agreement. Wind and solar resources were modeled in SERVM with an hourly generation profile assigned to each individual resource. Hourly generation is based upon historical profiles correlating with the yearly load shapes (2012 to 2019). Any resources that did not have historical shapes were supplemented by the nearest resource.

Hydroelectric

Hydro generation was modeled as energy limited resources while considering monthly hydro energy limitations calculated using historical data from 2012 to 2019. Hydro resources also considered historical daily max energies and the software dispatched by the resources as needed to maintain reliability.

Demand-side resources

Controllable and dispatchable demand response programs were modelled as equivalent thermal units with high fuel costs so that those units would be dispatched last to reflect demand-response operating scenarios to prevent loss of load events.

Transmission

The SPP transmission system was represented as "pipes" between six zones modeled in the SPP Assessment Area. A First Contingency Incremental Transfer Capability analysis was performed outside of the SERVM software which determined transfer limits modeled between zones. All resources and loads in their respective zone were modeled as a "copper sheet" system.

NPCC- Maritimes

General description

The Maritimes assessment area is winter peaking and part of NPCC with a single RC and two BA areas. It is comprised of the Canadian provinces of New Brunswick, Nova Scotia, Prince Edward Island, and the northern portion of Maine, which is radially connected to NB. The area covers 58,000 square miles with a total population of 1.9 million.

Demand & LFU

Maritimes area demand is the maximum of the hourly sums of the individual sub-area load forecasts. Except for the Northern Maine subarea that uses a simple scaling factor, all other sub-areas use a combination of some or all of efficiency trend analysis, anticipated weather conditions, econometric modeling, and end-use modeling to develop their load forecasts. Annual peak demand in the Maritimes area varies by +9% of forecasted Maritimes area demand based upon the 90/10 percentage points of LFU distributions.

Thermal Resources

Maritimes area uses seasonal dependable maximum net capability to establish combustion turbine capacity for resource adequacy. During summer, these values are derated accordingly.

Wind

The Maritimes area provides an hourly historical wind profile for each of its four sub-areas based on actual wind shapes for the 2012–2018 period. The wind in any hour is a probabilistic amount determined by selecting a random wind and load shape from the historic years. Each sub-area's actual MW wind output was normalized by the total installed capacity in the sub-area during that calendar year. These profiles, when multiplied by current sub-area total installed wind capacities, yield an annual wind forecast for each sub-area. The sum of these four sub-area forecasts represents the Maritimes area's hourly wind forecast.

Solar

Solar capacity in the Maritimes area is BTM and netted against load forecasts. It does not currently count as capacity.

Hydroelectric

Hydro capacity in the Maritimes area is predominantly run of the river, but enough storage is available for full rated capability during daily peak load periods.

Demand-side resources

Plans to develop up to 120 MW by 2029/2030 of controllable direct load control programs by using smart grid technology to selectively interrupt space and/ or water heater systems in residential and commercial facilities are underway, but no specific annual demand and energy saving targets currently exist. During this 10-year LTRA assessment period in the Maritimes area, annual amounts for summer peak demand reductions associated with EE and conservation programs rise from 20 MW to 196 MW while the annual amounts for winter peak demand reductions rise from 93 MW to 465 MW.

Transmission

Construction of a 475 MW +/-200 kV HVDC undersea cable link (the Maritime Link) between Newfoundland and Labrador and Nova Scotia was completed in late 2017; this cable, in conjunction with the construction of the Muskrat Falls hydro development in Labrador, is expected to facilitate the unconfirmed retirement of a 150 MW (nameplate) coal-fired unit in Nova Scotia in 2021. This unit will only be retired once a similarly sized replacement firm capacity contract from Muskrat Falls is in operation so that the overall resource adequacy is unaffected by these changes. The Maritime Link could also potentially provide a source for imports from Nova Scotia into New Brunswick that would reduce transmission loading in the southeastern New Brunswick area.

Other

The current amount of DERs in the Maritimes area is currently insignificant at about 29 MW in winter. During this LTRA period, additions of solar (mainly rooftop) resources in Nova Scotia are expected to increase this value to about 184 MW. The capacity contribution of rooftop solar during the peak is zero as system winter peaks occur during darkness. As more installations are phased in, operational challenges, like ramping and light load conditions, will be considered and mitigation techniques investigated.

NPCC- New England

General description

ISO New England (ISO-NE) Inc. is a regional transmission organization that serves the six New England states of Connecticut, Maine, Massachusetts, New Hampshire, Rhode Island, and Vermont. It is responsible for the reliable day-to-day operation of New England’s bulk power generation and transmission system, administers the area’s wholesale electricity markets, and manages the comprehensive planning process for the regional BPS. The New England BPS serves approximately 14.5 million people over 68,000 square miles.

Demand & LFU

ISO-NE develops an independent demand forecast for its BA area by using historical hourly demand data from individual member utilities. This data is used to develop the regional hourly peak demand and energy forecasts. ISO-NE then develops a forecast of both state and system hourly peak and energy demands. The regional peak and state demand forecast are considered coincident. This demand forecast is the gross demand forecast that is then decreased to a net forecast by subtracting the impacts of EE measures and BTM PV. Annual peak demand in the New England area varies by +11% of forecasted New England area demand based upon the 90/10% points of LFU distributions.

Thermal Resources

The seasonal claimed capability as established through claimed capability audit is used to rate the sustainable maximum capacity of nonintermittent thermal resources. The seasonal claimed capability for intermittent thermal resources is based on their historical median net real power output during ISO-NE defined seasonal reliability hours.

Wind

New England models wind resources use the seasonal claimed capability that is based on their historical median net real power output during seasonal reliability hours.

Solar

Most of the solar resource development in New England consists of the state-sponsored distributed BTM PV resources that do not participate in the wholesale electricity markets but reduce the real-time system load observed by ISO-NE system operators. These resources are modeled as load modifiers on an hourly basis based on the 2002 historical hourly weather profile.

Hydroelectric

New England uses the seasonal claimed capability to represent hydroelectric resources. The seasonal claimed capability for intermittent hydro-electric resources is based on their historical median net real power output during seasonal reliability hours.

Demand-side resources

On June 1, 2018, ISO-NE integrated price-responsive DR into the energy and reserve markets. Currently, approximately 584 MW of DR participates in these markets and is dispatchable (i.e., treated like generators). Regional DR will increase to 592 MW by 2023 and this value is assumed constant/available thru the remainder of the assessment period.

Transmission

The area has constructed several major reliability-based transmission projects within the past few years to strengthen the regional BPS. While several major projects are nearing completion, two significant projects remain under construction: Greater Boston and Southeastern Massachusetts and Rhode Island (SEMA/RI). The majority of the Greater Boston project will be in-service by December 2021 while the addition of a 115 kV line between Sudbury and Hudson is expected to be in service by December 2023. The SEMA/RI project is in the early stages of construction. Additional future reliability concerns have been identified in Boston and are being addressed through a development request-for-proposal.

Other

New England has 174 MW (1,379 MW nameplate) of wind generation and 787 MW (2,164 MW nameplate) of BTM PV. Approximately 12,400 MW (nameplate) of wind generation projects have requested generation interconnection studies. BTM PV is forecast to grow to 1,062 MW (4,306 MW nameplate) by 2029. The BTM PV peak load reduction values are calculated as a percentage of ac nameplate. The percentages include the effect of diminishing PV production at the time of the system peak as increasing PV penetrations shift the timing of peaks later in the day, decreasing from 34.3% of nameplate in 2020 to about 23.8% in 2029.

NPCC- New York

General description

The NYISO is responsible for operating New York's BPS, administering wholesale electricity markets, and conducting system planning. The NYISO is the only BA within the state of New York. The transmission grid of New York State encompasses approximately 11,000 miles of transmission lines, 760 power generation units, and serves the electricity needs of 19.5 million people. New York experienced its all-time peak demand of 33,956 MW in the summer of 2013.

Demand & LFU

The energy and peak load forecasts are based upon end-use models that incorporate forecasts of economic drivers and end-use technology efficiency and saturation trends. The impacts of EE and technology trends are largely incorporated directly in the forecast model with additional adjustments for policy-driven EE impacts made where needed. The impacts of DERs, EVs, other electrification, energy storage, and BTM solar PV are made exogenous to the model. At the system level, annual peak demand forecasts range from 6% above the baseline for the ninetieth percentile forecast to 8% below the baseline for the tenth percentile forecast. These peak forecast variations due to weather are reflected in the LFU distributions applied to the load shapes within the MARS model.

Thermal Resources

Installed capacity values for thermal units are based on the minimum of seasonal dependable maximum net capability test results and the capacity resource interconnection service MW values. Generator availability is derived from the most recent calendar five-year period forced outage data. Units are modeled using a multi-state representation that represents an EFORd.

Wind
New York provides 8,760 hours of historical wind profiles for each year of the most recent five-year calendar period for each wind plant based on production data. Wind seasonality is captured by randomly selecting an annual wind shape for each wind unit in each draw. Each wind shape is equally weighted.

Solar
New York provides 8,760 hours of historical solar MW profiles for each year of the most recent five-year calendar period for each solar plant based on production data. Solar seasonality is captured by randomly selecting an annual solar shape for each solar unit in each draw. Each solar shape is equally weighted.

Hydroelectric
Large New York hydro units are modeled as thermal units with a corresponding multistate representation that represents an EFORd. For run-of-river units, New York provides 8,760 hours of historical unit profiles for each year of the most recent five-year calendar period for each facility based on production data. Run-of-river unit seasonality is captured by randomly selecting an annual shape for each run-of-river unit in each draw. Each shape is equally weighted.

Demand-side resources
The NYISO's planning process accounts for DR resources that participate in the NYISO's reliability-based DR programs based on the enrolled MW derated by historical performance.

Transmission
The 2020–2021 reliability planning process includes proposed transmission projects and transmission owner local transmission plans that have met the RPP inclusion rules. The NYISO Board of Directors selected projects under two public policy transmission planning processes: the first for Western New York and the second for Central New York and the Hudson Valley, which is known as the ac transmission need. When completed, these projects will add more transfer capability in Western New York and between Upstate and Downstate New York.

Other
The NYISO is currently implementing a 3–5-year plan to integrate DERs, including DR resources, into its energy, capacity, and ancillary services markets. The NYISO published a DER roadmap document in February 2017 that outlined NYISO's vision for DER market integration. The FERC approved the NYISO's proposed tariff changes in January 2020. The NYISO is currently identifying the related software and procedure changes and is targeting implementation in Q4 2021.

NPCC- Ontario
General description
The IESO is the BA for the province of Ontario. The province of Ontario covers more than one million square kilometers (415,000 square miles) and has a population of more than 14 million people. Ontario is interconnected electrically with Québec, MRO-Manitoba, states in MISO (Minnesota and Michigan), and NPCC–New York.

Demand & LFU
Each zone has an hourly load from the demand forecast, as well as a monthly load forecast uncertainty (LFU) distribution. The LFU is derived by simulating the effect of many years of historical weather on forecasted loads. Monthly distributions of simulated demand peaks are generated at a zonal level and then adjusted to match the equivalent distribution at the provincial level.

The adjusted LFU distributions are used to create a seven-step approximation of the actual distribution. When generating reliability indices, the MARS model assesses all seven steps of the LFU distribution, weighted by probability. Annual peak demand in the Ontario Area varies by +11% of forecasted Ontario area demand based upon the 90/10% points of LFU distributions.

Thermal Resources

The capacity values and planned outage schedules for thermal units are based on information submitted by market participants. The available capacity states and state transition rates for each existing thermal unit are derived based on analysis of a rolling five-year history of actual forced outage data. For existing units with insufficient historical data, and for new units, capacity states and state transition rate data of existing units with similar size and technical characteristics are applied.

Wind

Historical hourly load profiles are used to model wind generation. Wind generation is aggregated by zone. For the Monte Carlo analysis, the model randomly selects a different yearly simulated profile during each iteration.

Solar

Historical hourly profiles are used to model solar generation. Solar generation is aggregated by zone. In the Monte Carlo analysis, in each iteration the model randomly shuffles the order of the days within each month for solar production.

Hydroelectric

Hydroelectric generation is modelled using three inputs: a run-of-river component, which simulates the range of historical water availability, a maximum dispatchable capacity, and a dispatchable energy. Input values are calculated using a combination of historic hourly maximum offer data and historic hourly production data, aggregated on a zonal level. The three inputs work together to simulate the range of historical water conditions that have been experienced since market opening in 2002.

Demand-side resources

The IESO models two demand-side resources as a supply resource: demand response (DR) and dispatchable loads (DL). Both measures are modelled on an as-needed basis in MARS and will only be used when all other supply-side resources are insufficient to meet demand. DR and DL capacity is aggregated by IESO zone.

Transmission

The IESO-controlled grid is modelled using 10 electrical zones with connecting transmission interfaces. Transmission transfer capabilities are developed according to NERC standard requirements; the methodology for developing transmission transfer capabilities is described in the IESO's "Transfer Capability Assessment Methodology: For Transmission Planning Studies.

NPCC- Quebec

General description

The Québec assessment area (province of Québec) is winter-peaking and part of NPCC. It covers 595,391 square miles with a population of 8.5 million. Québec is one of the four NERC Interconnections in North America with ties to Ontario, New York, New England, and the Maritimes. These ties consist of either HVDC ties, radial generation, or load to and from neighboring systems.

Demand & LFU

The requirements are obtained by adding transmission and distribution losses to the sales forecasts. The monthly peak demand is then calculated by applying load factors to each end-use and/or sector sale. The sum of these monthly end-use sector peak demands is the total monthly peak demand. The Quebec area demand forecast average annual growth is 0.8% during the 10-year period. Annual peak demand in the Quebec area varies by +9% of forecasted Ontario area demand based upon the 90/10% points of load forecast LFU distributions.

Thermal Resources
For thermal units, maximum capacity in the Québec area is defined as the net output a unit can sustain over a two-consecutive hour period.

Wind
In Quebec, wind capacity credit is set for the wintertime as the system is winter peaking. Capacity credit of wind generation is based on a historical simulated data adjusted with actual data of all wind plants in service in 2015. For the summer period, wind power generation is derated by 100%.

Solar
In Québec, BTM generation (solar and wind) is estimated at approximately 10 MW and doesn't affect the load monitored from a network perspective.

Hydroelectric
In Québec, hydro resources maximum capacity is set equal to the power that each plant can generate at its maximum rating during two full hours while expected on-peak capacity is set equal to maximum capacity minus scheduled maintenance outages and restrictions.

Demand-side resources
The Québec area has various types of DR resources specifically designed for peak shaving during winter operating periods. The first type of DR resource is the interruptible load program that is mainly designed for large industrial customers; it has an impact of 1,730 MW on Winter 2020–2021 peak demand. The area is also expanding its existing interruptible load program for commercial buildings, which will have an impact of 310 MW in 2020–2021, 150 MW for Winter 2021–2022, and then growing to 300 MW by 2026–2027. Another similar program for residential customers is under development and should gradually rise from 57 MW for Winter 2020–2021 to 621 MW for Winter 2030–2031.

Transmission
The Romaine River Hydro Complex Integration project is presently underway; its total capacity will be 1,550 MW. Romaine-2 (640 MW) has been commissioned in 2014, Romaine-1 (270 MW) in 2015, and Romaine-3 (395 MW) in 2017. Romaine-4 (245 MW) was planned be in service in 2020, but its commissioning is delayed to 2022. A new 735 kV line extending some 250 km (155 miles) between Micoua substation in the Côte-Nord area and Saguenay substation in Saguenay–Lac–Saint-Jean is now under construction phase and is planned to be in service in 2022. The project also includes adding equipment to both substations and expanding Saguenay substation.

Other
Total installed BTM capacity (solar PV) is expected to increase to more than 500 MW in 2031. Solar PV is accounted for in the load forecast. Nevertheless, since Quebec is a winter-peaking area, DERs on-peak contribution ranges from 1 MW for Winter 2020–2021 to 10 MW for Winter 2030–2031. No potential operational impacts of DERs are expected in the Quebec area, considering the low DER penetration in the area.

SERC
General description
SERC covers approximately 308,900 square miles and serves a population estimated at 39.4 million. SERC utilizes General Electric (GE) Multi-area Reliability Simulation (MARS) software an 8,760 hourly load, generation, and transmission sequential Monte Carlo simulation model consisting of fifteen interconnected areas, four of which are SERC's NERC Assessment Areas (SERC-E, SERC-C, SERC-SE, and SERC-FP). All assumptions and methods are described below and apply to the assessment areas.

Demand & LFU

For this study, annual load shapes for the seven years between 2007 and 2013 were used to develop the Base Case load model. Each of the hourly load profiles developed from the historical loads were then adjusted to model the seasonal peaks and annual energies reported in the 2020 SERC LTRA filings. Except for SERC-FP, all assessment areas are winter peaking. This study accounted for LFU in two ways. The first was to utilize seven different load shapes, representing seven years of historical weather patterns from 2007 through 2013. The second way is through multipliers on the projected seasonal peak load and the probability of occurrence for each load level. Annual peak demand varies by the following load forecast uncertainty, SERC-C: 4.75%, SERC-E: 3.95%, SERC-SE-6.11%, SERC-FP: 4.04%.

Thermal Resources

The three categories modeled in this study were thermal, energy-limited, and hourly resources. Most of the generating units were modeled as thermal units, for which the program assumes that the unit is always available to provide capacity unless it is on planned or forced outage. All the thermal units were modeled with two capacity states, either available or on forced outage.

The data for the individual units modeled in the SERC assessment areas was taken from the 2020 LTRA filings.

Wind & Solar

Wind and solar profiles for the units in the SERC footprint were represented using hourly generation time series. To represent the 2007-2013 meteorology, corresponding to the historical hourly load profiles, simulated production profiles were used. These profiles were extracted from available datasets from the National Renewable Energy Laboratory (NREL).

Five distinct sites were chosen for each assessment area, to represent existing wind farm locations. Similarly, five locations per SERC MRA were selected to create the solar profiles. Each site data was converted to power and aggregated to produce a typical solar shape per assessment area. To improve the robustness of the results, the study team used a 7-day sliding window method in the selection of wind and solar data.

Hydroelectric

MARS schedules the dispatch of hydro units in two steps. The minimum rating of each unit is set to 20% of the nameplate capacity, which represents the run-of-river portion of the unit and is dispatched across all hours of the month. Any remaining capacity and energy are then scheduled on an hourly basis as needed to serve any load that cannot be met by the thermal generation on the system. For hydro units, which are modeled as energy limited resources, their capacity factors (the ratio of the energy output to the maximum possible if operated at full output for all of the hours in the period) are an indication of their contribution to meeting load. Energy limited resources have a zero forced-outage rate.

The hydro unit data was extracted from the ABB Velocity Suite database and then adjusted to match the seasonal ratings of the units from the 2020 LTRA data. The monthly energy available is the average over the last 10 years of generation for each plant.

Demand-side resources

Demand-side resources are incorporated as an Energy Limited Resource with an annual energy megawatt hour limitation. These resources will be second in priority to thermal and variable generation to serve load. Demand response is modeled for all SERC assessment areas. For externals areas, these resources are modeled as emergency operating procedures, using the values from their LTRA submissions.

Transmission

The transmission system between interconnected areas is modeled through transfer limits on the interfaces between pairs of area. First Contingency Incremental Transfer Capability Values for interface limits are modeled for the system. The assumption within areas is a copper sheet system (full capacity deliverability).

Texas-RE-ERCOT

General description

The Electric Reliability Council of Texas (ERCOT) region encompasses about 75 percent of the land area in Texas. The grid delivers approximately 90 percent of the electricity used by more than 26 million consumers in Texas. The probabilistic assessment using Strategic Energy Risk Valuation Model (SERVM) captured the uncertainty of weather, economic growth, unit availability, and external assistance from neighboring regions as stochastic variables. The model performed 10,000 hourly simulations for each study year to calculate physical reliability metrics. The 10,000 hourly simulations were derived from 40 weather years, 5 load forecast multipliers, and 50 Monte Carlo unit outage draws.

Demand & LFU

ERCOT developed a 50/50 peak load forecast which represented the average peak load from 40 synthetic load profiles, each representing the expected load in a future year given the weather patterns from each of the last 40 years of history. Annual peak demand in ERCOT varied by +2.1% based upon the 90^{th} percentile distribution. Each synthetic weather year was given equal probability of occurring. Five load forecast uncertainty multipliers were applied to each of the 40 synthetic weather years. The multipliers, which range from -4% to +4%, captured economic load growth uncertainty.

Thermal Resources

Conventional generators were modeled in detail with maximum capacities, minimum capacities, heat rate curves, startup times, minimum up and down times, and ramp rates. The winter and summer capacity ratings were based on ERCOT's LTRA Report. SERVM's Monte Carlo forced outage logic incorporated full and partial outages based on historical operations.

Wind & Solar

Wind and solar resources were modeled as capacity resources with 40 historical weather years consisting of hourly profiles which coincide with the load and hydro years. The assumed peak capacity contributions for reserve margin accounting were 63% for coastal wind, 29% for panhandle wind, 16% for other wind, and 76% for solar. The actual reliability contributions were based on the hourly modeled profiles.

Hydroelectric

Dispatch heuristics for hydro resources were developed from eight years of hourly data provided by ERCOT, applied to 40 years of monthly data from FERC 923 and ERCOT, and modeled with different parameters for each month, including total energy output, daily maximum and minimum outputs, and monthly maximum output. A separate energy-limited hydro resource was modeled to represent additional capability during emergency conditions.

Demand-Side Resources

Interruptible load and demand response resources were captured as resources with specific price thresholds at which each resource is dispatched. These resources were also modeled with call limits and Energy Emergency Alert (EEA) level.

Transmission

SERVM is a state-of-the-art reliability and hourly production cost simulation tool that performs an hourly chronological economic commitment and dispatch for multiple zones using a transportation/pipeline representation. ERCOT was modeled as a single region with ties to SPP, Entergy, and Mexico to reflect historical import/export activity and potential assistance. 1,220 MW of high voltage direct current interties were included in this study.

WECC

General description

The Multiple Area Variable Resource Integration Convolution (MAVRIC) model was developed to capture many of the functions needed in the Western Interconnection for probabilistic modeling. The Western Interconnection has many transmission connections between demand and supply points, with energy transfers being a large part of the interconnection operation. A model was needed that could factor in dynamic imports from neighboring areas. The Western Interconnection has a large geographical footprint, with winter-peaking and summer-peaking load-serving areas, and a large amount of hydro capacity that experiences large springtime variability. The ability to study all hours of the year on a timely run-time basis was essential for the probabilistic modeling of the interconnection. Additionally, the large portfolio penetration of Variable Energy Resources (VER), and the different generation patterns depending on the geographical location of these resources, called for correlation capability in scenario planning. MAVRIC is a convolution model that calculates resource adequacy through Loss-of-Load Probabilities (LOLP) on each of the stand-alone (without transmission) load-serving areas. The model then calculates the LOLP through balancing the system with transmission to a probabilistic LOLP. Finally, MAVRIC can supply hourly demand, VER output, and baseload generation profiles that can be used in production cost and scenario planning models. Figure B.1 provides the high level logic diagram of the processes MAVRIC performs.

There are many ways to perform probabilistic studies, each with its strengths and weaknesses. The tool used to perform the calculations depends on the system and the desired output that is being analyzed. The MAVRIC model was developed to enhance the probabilistic capabilities at WECC. It allows WECC to perform independent reliability assessments of the Western Interconnection, a system that is geographically diverse and dependent on transfer capabilities. Using convolution techniques and Monte-Carlo simulations, and with the ability to use transfers dynamically, the tool models the overall resource adequacy of the Western Interconnection while maintaining adequate run-time and computing capabilities.

Demand & LFU

Probability distributions for the demand variability are determined by aligning historical hourly demand data to each of the Balancing Authorities in the database. The first Sundays of each historical year are aligned so that weekends and weekdays are consistent. Each hour is then compared against a rolling seven-week average for the same hour of the same weekday. This establishes the difference between the historical hour and the average. MAVRIC uses each of these percentages to calculate a percentile probability for a given hour based on the variability of the three weeks before and three weeks after the given hour for each of the historical years. The output is a series of hourly percentile profiles with different probabilities of occurring.

Thermal Resources

The distributions of the baseload resources, nuclear, coal-fired, gas-fired, and in some cases, biofuel and geothermal resources is determined by using the historical rate of unexpected failure and the time to return to service from the NERC Generation Availability Data System (GADS). Generator operators submit data that summarizes expected and unexpected outages that occur to their generating units. The annual frequency and recovery time for the unexpected outages is used to calculate the availability probability distributions for baseload resources. Through Monte-Carlo random sampling, MAVRIC performs 1,000 iterations for each resource, calculating the available capacity on an hourly basis for all hours of a given year. The model randomly applies outages to units throughout the year adhering to the annual frequency of outage rates for those units. Once a unit is made unavailable, the mean time to recovery is adhered to, meaning for a certain period of hours after the unexpected failure, that unit remains unavailable. The total available baseload capacity for each load serving area for each hour, is then computed and stored as a sample in a database. After 1,000 iterations, the data points of availability for each hour are used to generate availability probability distributions. The output of this process is consistent with the VER distributions, in that a series of hourly percentile profiles with different probabilities of occurring is produced.

Wind & Solar / Hydroelectric

Determining the availability probability distributions for the VERs (water, wind, and solar-fueled resources), is conducted like the demand calculations but with two notable differences. The first, and most significant, difference is the time frame used in calculating the VER availability probability distributions. For VER fuel sources, the day of the week does not influence variability, as weather is variable weekday or weekends. Therefore, the need to use the data from the same day of the week is not necessary. This allows the VER distributions to be condensed to a rolling seven-day window using the same hour for each of the seven days of the scenario. The other difference is that the historical generation data is compared against the available capacity to determine the historical capacity factor for that hour to be used in the percentile probability calculation. The output of this process is a series of hourly percentile profiles with different probabilities of occurring.

Demand-side resources

A significant portion of the controllable Demand Response/Demand-Side Management (DR/DSM) programs within the Western Interconnection are associated with large industrial facilities, air conditioner cycling programs, and water pumping – both canal and underground potable water and for irrigation. These programs are created by Load Serving Entities (LSEs) who are responsible for their administration and execution when needed. In some areas, the programs are market driven (CAISO and AESO) and can be called upon for economic considerations. However, most areas in the Western Interconnection are not parties to organized markets and DSM programs are approved by local authorities and used only for the benefit of the approved LSE. DSM programs in the Western Interconnection often have limitations such as limited number of times they can be called on and some can only be activated during a declared local emergency. Entities within WECC are not forecasting significant increases in controllable demand response.

Transmission

MAVRIC goes through a step-by-step balancing logic where excess energy, energy above an area's planning reserve margin to maintain the resource adequacy threshold, can be used to satisfy another area's resource adequacy shortfalls. This is dependent on the neighboring areas having excess energy as well as there being enough transfer capability between the two areas allowing the excess energy to flow to the deficit area. MAVRIC analyzes first order transfers, external assistance from an immediate neighbor, and second order transfers, external assistance from an immediate neighbor's immediate neighbors, in all cases checking for sufficient transfer capacity. After balancing all areas in the system for a given hour, MAVRIC then moves to the next hour and balances the system where needed. The end result is an analysis of the entire system reflecting the ability of all load-serving areas to maintain a resource adequacy planning reserve margin equal to or less than the threshold. Analysis is then done on any areas where the threshold margin cannot be maintained even after external assistance from excess load-serving areas.

Other

Planning Reserve Margins - For each hour the demand and availability distributions are compared to one another to determine the amount of "overlap" in the upper tail of the demand distribution with the lower tail of the generation availability distribution. The amount of overlap and the probabilities associated with each percentile of the distributions represents the LOLP. This would be the accumulative probability associated with the overlap. If the probability is greater than the selected threshold, then there is a resource adequacy shortfall in that area for that hour. A resource adequacy threshold planning reserve margin can be determined to identify the planning reserve margin needed to maintain a level of LOLP at or less than the threshold.

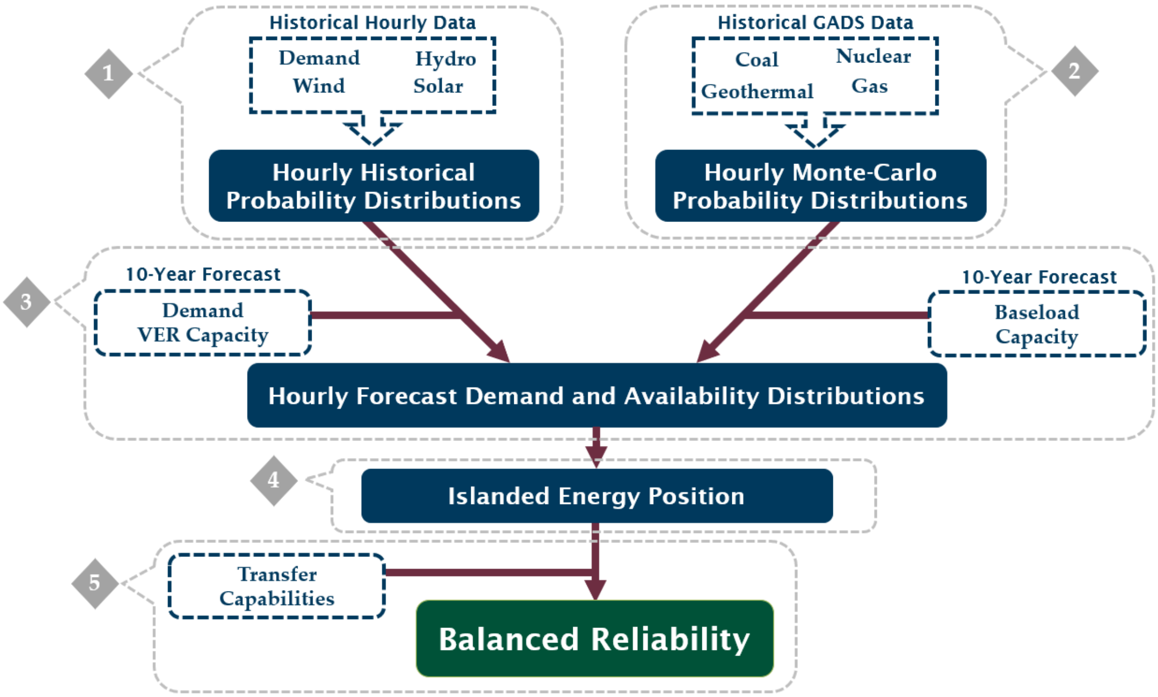


Figure B.1: MAVRIC Process Flowchart

Appendix C: Summary of Inputs and Assumptions in the ProbA

		NPCC	PJM	SERC	MISO	Manitoba	Sask.	SPP	ERCOT	WECC
Model Used	**Name**	GE MARS	GE MARS	GE MARS	GE-MARS	GE MARS	GE MARS	SERVM	SERVM	MAVRIC
	Model Type	Monte Carlo	Monte Carlo	Monte Carlo	Monte Carlo	Monte Carlo	Monte Carlo	Monte Carlo	Monte Carlo	Convolution
	# Trials	1,000*7	1,000*7	1,000*10*7	50000 * 7	10000	20000 x 7	28,000	50 x 40 x 5	N/A
	Total Run Time	2 hours * 72 CPUs	2 hours * 40 CPUs	50 min * 720 CPUs	3 Hours	35 min	0.5 hours	30 hours/Study Year; 35 processors	7 hours; 25 cores	N/A
Load	**Internal Load Shape**	Typ. Yr. S-2002; W-2004	Typ. Yr. S-2002; W-2004	07 yrs.; 2007-2013; Risk-based weighted load shapes	Typical Year 2005 for North/Central; 2006 for South	Typical year 2002	Peak (2008)	8 historical years (2012 to 2019)	40 weather years 1980 to 2019	2004-2014
	External Load Shape	Typ. Yr. S-2002; W-2004	Typ. Yr. S-2002; W-2004	2007-2013 using ProbA data sheets & PJM model	N/A	Typical year 2002	None	No External Areas represented	40 weather years 1980 to 2019	N/A
	Adjustment to Forecast	Monthly Peak & Energy	Monthly Peak	Seasonal Peaks	Monthly Peaks	Monthly Peak & Energy	Monthly Peaks and Energy	Annual Peak	Annual Peak	N/A

Load Forecast Uncertainty	**Modeling**	7-step Discrete Distribution	7-step Discrete Distribution. Monthly	Weather: 7 years	7 discrete steps normally distributed capturing weather and economic uncertainty	7-step Discrete Normal Distribution, weather	Normal Distribution	7 discrete steps all steps at or above a 50/50 forecast	40 weather years x 5 load forecast uncertainty multipliers = 200 load scenarios	3%-97% probability distribution
	90th %ile (% above 50/50 peak)	Varies by Area; asymmetrical	2022-6%; 2024-6%	7.56% at 90%ile (1.28 Standard Deviation)	5.11%	2018-3.9% 2020-5.2%	2020-2.6%; 2018-2.6%	+5% at 99%ile	+2.1% at 90%ile	Varies by Region
	Uncertainties Considered	weather, economic, forecast	Weather, Forecast	Weather Forecast	Weather and Economic	Weather, economic, forecast	Weather, Economic	Weather, economic, forecast	Weather, Economic Forecast Error	Weather and Economic Variability
Behind-the-Meter	**Percentage of Peak Load at Peak**	Unknown	2022-1.9%; 2024-2.6%; Solar only	Minimal; ~1%	N/A	N/A	0	Minimal; Less than 1%	Resource	N/A
	Thermal Generation	Resource	Netted From Load	Within the load	Resource	N/A	N/A	Mix; Resource and Netted from Load	Resource	N/A
	Variable Generation	Resource	Netted From Load	Within the load	Resource	N/A	N/A	Netted from Load	Resource	N/A

	Demand Management	Resource	Netted From Load	Within the load	Resource	NA	N/A	Netted from Load	Resource	N/A
Demand-Side Management	**Modeling**	Dispatchable resource, Operating procedure (varies by area)	Operating procedure	Operating Procedure	Energy-Limited Resource	Load Modifier	DSM adjusted Load Forecast	Dispatchable Resource	Dispatchable Resource	N/A
	Load shape / Derates /FOR	N/A	N/A	Flat Seasonal	Count and Duration Limited	Reduction in Peak	None	None	Operation Count Limited	N/A
	Correlation to load	When modeled as EOP (varies by area)	Not modeled	Not Modeled	not explicitly modeled	NA	None	Not Modeled	Dispatched based on shadow price	N/A
Variable Generation - Wind	**Modeling**	Resource, Fixed resource	Resource	Load Modifier	Load Modifier	Resource	Load Modifier	Resource	Resource	Energy Limited Resource
	Load shape / Derates /FOR	Hourly shape, Monthly	Modeled at Capacity Value	Monthly	Modeled at capacity credit value	NA	Weekly	Hourly Shape	Hourly Shape for 40 years matching load profile	Hourly Shape
	Correlation to load	Consistent with load, Not modeled	Not Modeled	Flat	Not Modeled	Consistent with load	Not Modeled	Consistent with load	Match load	N/A
	Capacity Value	0% to 35% (varies by area)	13%	~11%	By wind farm. MISO System Capacity Credit is 15.6%	20% winter and 16% summer	20% Win 10% Sum	Ranges from 10% to 30% for Summer Peak depending on historical year and resource location	63% for coastal wind, 29% for panhandle wind, and 16% for other wind	Varies by Region
Variable Generation - Solar	**Modeling**	Resource	Resource	Load Modifier	Load Modifier	None	None	Resource	Resource with hourly profiles	Energy Limited Resource
	Load shape / Derates /FOR	Hourly shape, Monthly	Modeled at Capacity Value	Monthly	Modeled at capacity credit value	NA	N/A	Hourly Shape	Hourly for 40 years matching load profile	Hourly Shape

	Correlation to load	Consistent with load, Not modeled	Not Modeled	Flat	Not Modeled	NA	N/A	Consistent with load	Yes, same weather	N/A
	Capacity Value	Not specified	0% Winter; 38% Summer	94%	MISO System Capacity Credit is 50%	NA	N/A	Ranges from 80% to 100% for Summer Peak depending on historical year	76% for Summer Peak	Varies by Region
Hydro - Electric Generation	**Modeling**	Energy Limited Res., Dispatched after Thermal	Resource	Energy Limited Resource, Dispatched after Thermal to reduce LOLE	Resource unless Run-Of-River. Run-of-River submit 3 years of historical data at peak	Energy Limited Resource	Energy Limited Resource, Peak Shaving	Energy Limited Peak Shaving Component	Energy Limited Peak Shaving Component and Emergency Component	Energy Limited Resource
	Energy Limits	Average	N/A	Average 10 years monthly output	Summer Months, Peak Hours 14 - 17 HE	Different below average water conditions including extreme drought	Median	8 years of historical hydro conditions were modeled 2012-2019	40 years of historical hydro conditions were modeled for 1980-2019	Hourly Shape
	Capacity Derates	Monthly	Monthly	Monthly	At Firm Capacity	Monthly	Monthly	Monthly	Monthly values	N/A
	Planned Outages	Model schedule, Within Capacity Derates	Model scheduled	Model scheduled	Model Scheduled	Not modeled	First five years are scheduled maintenance. Remaining is scheduled by program.	Model scheduled	Netted out based on modeling actual monthly hydro energies	Varies by Region
	Forced Outages	Monte Carlo, Not modeled (varies by area)	Monte Carlo	Not Modeled	Monte Carlo, Run-of-River has none	N/A	Not Modeled	Within Capacity Derates	N/A	N/A
Thermal Generation	**Modeling**	MC; 2 state - some areas up to 7-state	MC; 2-state	MC; 2-state	MC; 2-state	MC 2-state	MC up to 5 state	MC; Up to n-state	MC; 50 iterations of annual simulations with unique forced outage draws performed for each weather year and load forecast error	2-State 3%-97% Probability Distribution

	Energy Limits	None	None	None	None explicitly	None	None	None	None	None
	Capacity Derates	Monthly	Monthly	Monthly	Monthly	Monthly	Monthly, Monthly derates inputted into the model	Weekly	Used a summer capacity and a winter capacity value for each unit	Seasonal
	Planned Outages	By model, External Input	By Model	By Model	By Model	By Model	By Model & Manual Input	By Model	By Model calibrated to total historical planned outages	By Model
	Forced Outages	EFORd	5 yr. EEFORd	EFORd	5 yr. unit specific EFORd	EFORd	5-year historical average	5-year EFOR GADS Data	5-year EFOR GADS Data; Historical Events Modeled Discretely	Historical 12-year EFOR
Firm Capacity Transfers	**Modeling**	Explicitly Modeled	Explicitly Modeled	Explicitly Modeled	Imports treated as Resource; Exports derated from monthly unit capacities	Imports treated as resource; Exports added as load	Import treated as load modifier	Explicitly Modeled	Not Modeled. All firm resources are modeled inside the ERCOT zone.	Explicitly Modeled
	Hourly Shape Issues	None	None	N/A	None	Weekly capacities	Hourly Load modification for a typical week.	None	N/A	N/A
	Capacity Adjustments - Transmission Limitations	None	None	N/A	None	None	N/A	N/A	N/A	N/A

	Transmission Limit Impact of Firm Transfers	Impact derived within model	Endogenously modeled	Limits adjusted	None	Accounted for in interface limits	N/A	N/A	N/A	N/A
	Forced Outages	N/A	No	No	5 yr. unit specific EFORd	No	No	No	N/A	N/A
Internal Representation	**Assessment Areas**	5	1	7	1	1	1	1	1	6
	Total Nodes	56	5	7	10	1	1	6	1	49
	Node Definition	Determined by potentially limiting transmission interfaces	Market-Defined Regions	Assessment Areas = Nodes	Local Resource Zone	N/A	N/A	Determined by potentially limiting transmission interfaces	N/A	Balancing Authority
	Transmission Flow Modeling in ProbA Model	Transportation/Pipeline	Transportation/Pipeline	AC/DC in PSSE, Transportation/ Pipeline in MARS	Transfer Analysis Import/Export Limit for each Local Resource Zone	Transportation/ Pipeline	N/A	Transportation/Pipe and Bubble; Transmission Limits modeled between nodes	N/A	Transportation/Pipeline
	Transmission Limit Ratings	NY and Maritimes - short-term emergency; all other – normal	Short-term Emergency	normal and short-term emergency ratings	N/A	Normal	N/A	Long-Term Emergency	N/A	Normal
	Transmission Uncertainty	Selected Lines	No	No	No	No	N/A	No	N/A	No
External	**# Connected Areas**	3	4	4	7	1	3	5	3	0
	# External Areas in Study	8	4	4	7	1	0	0	SPP; MISO LRZ 8,9,10; Mexico	0

	Total External Nodes	8	59	4	1	1	N/A	N/A	3	0
	Modeling	Detailed	Detailed and At planning reserve margin	Detailed	Less Detailed	Detailed at their Planning Reserve Margin	N/A	No external assistance above firm contracts and transmission service reservation	Detailed at their Planning Reserve Margin	0
Other Demands	**Operating Reserve**	Yes	Yes	No	No	Not Considered	Yes	Yes	Yes, regulation, spin and non-spin reserve requirements modeled. Firm load shed to maintain 1150 MW of operating reserves.	No
Operating Procedures (pre-LOL)	**Forgo Operating Reserve**	OR to 0 in all Areas except Québec and New England.	Fully	Partially or Fully, depending on input from Assessment Area	N/A	N/A	Fully	Fully	Partially	Fully
	Other	DR, public appeals, voltage reductions	DR, 30-min reserves, voltage reduction, 10-min reserves, public appeals	CPP; DCLM;	None	None	Demand Response, Emergency	None	DR and Emergency Thermal Generation from Conventional Generators	None

Appendix D: ProbA Data Forms

The forms used for the 2020 Probabilistic Assessment can be found on the NERC PAWG webpage, located at the following link:
https://www.nerc.com/comm/PC/Pages/Probabilistic-Assessment-Working-Group-(PAWG).aspx

Appendix E – Additional Assessments by Regions or Assessment Areas

This informational Appendix serves as a list of references for more detailed information on assessments or assessment methods used by Regional Entities or Assessment Areas.

NERC Webpage:
www.nerc.com
The NERC webpage contains valuable information regarding its mission. For information on its assessments, please see the Reliability Assessment and Performance Analysis page. It also contains valuable information regarding the statistics for assessing BES reliability.

NPCC:
https://www.npcc.org/content/docs/public/library/resource-adequacy/2020/2020-12-01-nerc-ras-probabilistic-assessment-npcc-region.pdf
NPCC publishes a report that contains a more detailed look at the multi-area assessment used to fuel the NERC Probabilistic Assessment and this year's regional risk scenarios.

SERC:
serc1.org.
SERC publishes many different assessments that can be found in the link to their main webpage above. Please use the contact information in Appendix A for any questions.

WECC:
WECC's WARA Part 1.
WECC performed a separate assessment that contains more details on how the possible coal retirements in their region were selected and can affect their system's reliability.

WECC is also working on developing a portion of their webpage to provide educational materials on how they perform their probabilistic assessments and will work as a great educational material upon its completion.

MISO:
https://cdn.misoenergy.org/PY%202021%2022%20LOLE%20Study%20Report489442.pdf
MISO performs a Loss of Load Expectation study on an annual basis as part of their Resource Adequacy construct.