BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c)	)	
Emergency Order: Midcontinent	)	Order No. 202-25-3
Independent System Operator	)	
(MISO)	)	
	)	

Exhibit to
Motion to Intervene and Request for Rehearing and Stay of
Public Interest Organizations

Filed June 18, 2025

Exhibit 28

2028/2029 MPSC Staff Capacity Demonstration Results

MICHIGAN PUBLIC SERVICE COMMISSION

Capacity Demonstration Results

Planning Year 2028/29

Case No. U-21775

May 12, 2025

MPSC Staff

LARA
LICENSING AND REGULATORY AFFAIRS

Contents

Executive Summary

All Michigan load serving entities (LSE)s required to file capacity demonstrations with the Michigan Public Service Commission (MPSC) for planning year 2028/29 pursuant to MCL 460.6w and the Commission Order in Case No. U-21775 have filed. Staff has audited the filings, contracts, and other materials and finds that all Michigan LSEs have satisfied the capacity demonstration requirements and have procured appropriate levels of resources for planning year 2028/29, except one agency representing municipalities which will be discussed further below.

Staff projects that the Midcontinent Independent System Operator, Inc. (MISO) Local Resource Zone (LRZ) 7, which consists of Michigan's lower peninsula excluding the southwest corner of the state located in Indiana Michigan Power Company's (I&M) service territory, will have sufficient resources to meet its planning reserve margin requirements and local clearing requirements (LCR) in all four seasons for the compliance year (2028/29).[1]. For MISO LRZ 1 and LRZ 2, the majority of which are in other states not subject to MCL 460.6w, Staff does not have sufficient detail to project the capacity positions of these zones. Staff projects that the I&M service territory in Michigan will have sufficient capacity to meet PJM's requirements for the prompt and compliance years.

The most recent OMS-MISO Survey results indicate that MISO will have an 11.8GW deficit to a 2.4 GW surplus by Summer 2028, depending on the amount of potential new capacity able to be added each year (the low projection assumes 2.3 GW/year and the high projection assumes 6.1 GW/year). Projections for other seasons of 2028/29 Planning Year are as follows: Fall ranges from .9 GW deficit to 14.3 GW surplus, Winter ranges from .4 to 15.6 GW surplus, and Spring ranges from 8.8GW deficit to 6.4GW surplus. In addition, projections for each subregion in Summer and Winter were published, showing the North/Central subregion ranging from a 10.4 GW deficit to 0.6 GW surplus in Summer 2028 and 0.3 to 11.3 GW surplus in Winter 2028/29[2] The MISO-OMS Survey no longer projects future capacity positions for individual LRZs, however the survey does show individual LRZ's potential to meet their LCR in each season of the prompt year. Both LRZ 1 and 2 show sufficient capacity to meet obligations in Planning Year 2025/26.

MISO's 2025/26 Planning Resource Auction (PRA) results indicated sufficient capacity at the regional, subregional, and zonal levels, with the summer price reflecting the highest risk and a tighter supply-demand balance. Systemwide surplus (above the target Planning Reserve Margin or PRM) offered into the auction dropped 43%

---

[1] This projection is based on the filed capacity demonstrations and information from MISO available at the time of this report and is dependent on several variables including but not limited to: load growth, delays in completion of planned resources, and changes to MISO's resource adequacy construct.

[2] 2024 OMS-MISO Survey Results, June 20, 2024.

compared to last summer, despite the lower target PRM (7.9% vs 9.0% last year). In terms of GW, the systemwide surplus capacity in the summer has reduced from ~6.5 GW in 2023, to 4.6 GW in 2024, to 2.6 GW this Planning Year.

MISO noted in its 2025 PRA Results[3] that new capacity additions did not keep pace with the capacity lost due to retirements/suspensions, decreased accreditation of certain resources, and fewer available external resources. MISO continues to reform its resource adequacy construct under the Reliability Imperative to address emerging risks due to fleet transition, new load additions, and retirements of dispatchable units.

[3] MISO 2025/26 PRA Auction Results

Background

On September 15, 2017, in Case No. U-18197, the Commission directed all Michigan LSEs to file capacity demonstrations annually pursuant to MCL 460.6w. This report outlines the results of the capacity demonstrations filed for planning year 2028/29 as directed by the Commission in Case No. U-21775 and represents the eighth annual capacity demonstration report. Prior year capacity demonstration reports can be found in the following dockets:

- 2021/22: Case No. U-18441
- 2022/23: Case No. U-20154
- 2023/24: Case No. U-20590
- 2024/25: Case No. U-20886
- 2025/26: Case No. U-21099
- 2026/27: Case No. U-21225
- 2027/28: Case No. U-21393

In Case No. U-21775, for the 2028/29 planning year, the Commission ordered[4] investor-owned utilities with one million or more customers[5] to file capacity demonstrations by February 24, 2025, investor-owned utilities with less than one million customers[6] by March 3, 2025, and alternative electric suppliers (AES),[7] cooperatives (co-ops), and municipal utilities on or before March 17, 2025.

The purpose of these demonstrations is to ensure that each electric utility owns or has contractual rights to capacity sufficient to meet its capacity obligations as set by the MISO, PJM, or the Commission, as required by MCL 460.6w.

Pre-Demonstration Process

As with previous years, Staff offered LSEs the opportunity to meet with Staff to discuss the capacity demonstration requirements and review relevant materials prior to the

[4] August 22, 2024 Order in Case No. U-21775.

[5] Consumers Energy Company, DTE Electric Company.

[6] Alpena Power Company, Indiana Michigan Power Company, Northern States Power Company-Wisconsin, Upper Michigan Energy Resources Corporation, and Upper Peninsula Power Company.

[7] AEP Energy Inc, American Rural Cooperative, BP Energy Retail Company, LLC, Calpine Energy Solutions LLC f/k/a Noble Americas Energy Solutions LLC, CMS ERM Michigan LLC, Constellation NewEnergy Inc, Dillon Power LLC, Direct Energy Business f/k/a NRG Energy Inc., Direct Energy Services LLC, Energy Harbor LLC, Energy International Power Marketing Corporation, Energy Services Providers Inc., ENGIE Power & Gas f/k/a Plymouth Rock Energy LLC, Interstate Gas Supply LLC, Just Energy Solutions Inc, MidAmerican Energy Services LLC, Nordic Energy Services LLC, Spartan Renewable Energy, Texas Retail Energy, LLC U.P. Power Marketing LLC, and Wolverine Power Marketing Cooperative Inc.

final filing deadlines. Several LSEs met with Staff remotely and clarified the process before filing reports in the docket. Staff found that the pre-filing consultations were helpful in resolving questions prior to filing. Staff will continue to offer pre-filing consultations each year to resolve potential issues prior to the filing deadlines.

Capacity Demonstration Filings

On or before February 24, 2025, capacity demonstrations were received from DTE Electric Company and Consumers Energy Company. On or before March 3, 2025, capacity demonstration filings were received from Alpena Power Company, Indiana Michigan Power Company, Northern States Power Company, Upper Michigan Energy Resources Corporation (UMERC), and Upper Peninsula Power Company (UPPCO). Many LSEs filed confidential information under seal as part of the electric utilities' filings. Staff reviewed this information and met with LSEs as needed.

On or before March 17, 2025, capacity demonstration filings were received from American Rural Cooperative, Bayfield Electric, Calpine Energy Solutions, LLC., City of Escanaba, City of Stephenson, City of Wakefield, Cloverland Electric Cooperative, CMS ERM, Constellation New Energy Inc., Croswell Light and Power, Daggett Electric Department, NRG Energy f/k/a Direct Energy Business, LLC, Energy Harbor, Michigan Public Power Agency, Michigan South Central Power Agency (MSCPA), Newberry Water and Light Board, Union City Electric Department, Wolverine Power Supply Cooperative, and WPPI Energy.

Several AESs filed letters in Case No. U-21775 indicating that they are currently not serving customers in Michigan.[8]

All LSEs, apart from MSCPA (see below), were able to procure the necessary capacity to demonstrate compliance for the current planning year in all four seasons. Two LSEs' filings indicated a shortage of capacity in the compliance year compared with projections of forecasted growth. MCL 460.6w requires all LSEs to demonstrate enough resources to cover *prompt* year obligations, and both entities met this requirement. After reviewing these filings, staff has determined that these entities have demonstrated sufficient capacity, and notes that both entities are in negotiations to acquire the appropriate amount of capacity needed to meet their forecasted growth.

Staff conducted an audit for each capacity demonstration filing received and requested additional information from the LSEs when necessary. Staff has reviewed all contracts included in capacity demonstrations from AESs as well as most of the contracts from co-ops, electric utilities, and municipalities. In addition to the required

[8] AEP Energy Inc., BP Energy Retail Company, LLC, Dillion Power LLC, Direct Energy Services LLC, Energy Services Providers, Inc., Interstate Gas Supply LLC, Just Energy, ENGIE Power and Gas, Energy International Power Marketing, MidAmerican Energy Services LLC, Nordic Energy Services LLC, Texas Retail Energy, LLC, and UP Power Marketing.

compliance year (PY 2028/29), most demonstrations included updates for the 2025/26 planning year through the 2028/29 planning year. [9] The order opening the docket in U-21775 directed all entities to file data for the prompt and interim years, as well as the compliance year. Most entities complied but some of the municipal and cooperative utilities continued to only provide information for the compliance year (PY 2028/29). For these entities, Staff was able to estimate the amount of capacity available for the prompt year and interim years by projecting the amount included for planning year 2028/29 backwards for three years.

Staff recommends the Commission continue to direct all LSEs to include updated prompt year and interim year capacity obligation and resource information in future filings. Staff uses this information to help track changes in load and resources and to project the zonal resource adequacy more closely in these years. In addition, Staff recommends the Commission direct LSEs to provide MECT screenshots of their load obligations (PRMR/PLC) to facilitate the Storage Target calculation used to comply with Public Act 235.[10]

At the time of this report MSCPA[11] did not have rights to sufficient capacity to meet its obligations. MSCPA is in the process of negotiating a bilateral contract to meet the deficiency with the intent to submit a revised capacity demonstration filing by the self-imposed deadline of September 1, 2025, showing that MSCPA has sufficient resources to meet its requirements. Staff meet with MSCPA on April 30, 2025 to discuss and to urge MSCPA to complete the process as soon as possible. Staff is prepared to review any future filings by MSCPA and file a memo to this docket updating the Commission on the issue following MSCPAs revised filing.

[9] The required demonstrations for planning years 2026/2027 and 2027/28 were made in the 2023 capacity demonstration (Case No. U-21225) and the 2024 capacity demonstration (Case No. U-21393).

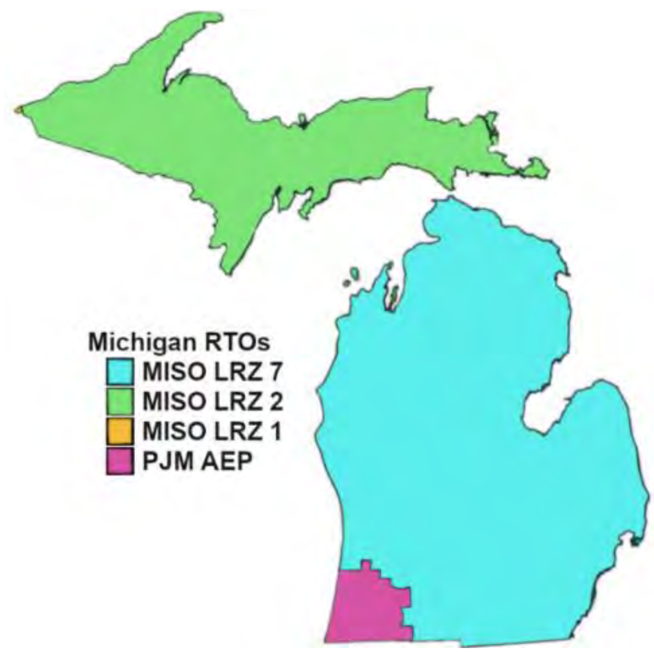
[10] See January 23, 2025 Order in Case No. U-21571

[11] MSCPA member municipal utilities include Clinton, Coldwater, Hillsdale, and Marshall.

Overview of Zonal Adequacy

Michigan contains load that spans two regional transmission operators (RTO)s: MISO and PJM. The majority of Michigan's load is located within MISO and is split between several LRZs. The exception is the Southwest corner of the Lower Peninsula which is located within the PJM RTO through I&M's service territory. PJM and MISO have different resource adequacy constructs and capacity obligations. The different RTO regions in Michigan are illustrated in Figure 1.

Figure 1: RTO Zonal Regions in Michigan



MISO Resource Adequacy

Michigan LSEs serve load in MISO Local Resource Zones 1, 2, and 7. MISO's capacity construct is for the upcoming year (prompt year) only. LSEs must demonstrate sufficient resources to meet their current prompt year requirement four years forward to comply with MCL 460.6w.

MISO establishes capacity obligations for all LSEs based on peak load forecasts and a planning reserve margin percentage (PRM) necessary to meet the North American Electric Reliability Corporation's (NERC) Loss of Load Expectation (LOLE) standard of 1 day in 10 years. LSEs within MISO can meet their capacity requirements either through a Fixed Resource Adequacy Plan (FRAP), self-schedule, Reliability Based Demand Curve (RBDC) opt-out (new this planning year, see more detail below), paying the capacity deficiency charge, or through the Planning Resource Auction (PRA). The PRA is a residual market for LSEs that choose not to utilize other participation options or do not have enough capacity resources, either owned or purchased bilaterally, to satisfy their capacity obligations, and thus need to purchase additional resources.

Within MISOs resource adequacy construct, the Planning Reserve Margin Requirement (PRMR) and the Local Clearing Requirement (LCR) must be satisfied to meet the LOLE standard. The Initial PRMR is determined through LOLE modeling based on the coincident MISO peak forecast and resources adjusted as necessary to meet the standard. PRMR resources are not location specific, i.e. they can come from outside an LSE's zone. Individual LSEs are responsible for their own share of the zone's PRMR. The ability to use imports to meet PRMR makes it likely all zones will meet this requirement. Failure to meet PRMR would only occur if there were not enough resources available within all of MISO's footprint or in the subregion (MISO North/Central or MISO South) given subregional transmission constraints

The LCR is the minimum capacity for a zone required to be located within the zone to meet the LOLE standard, while accounting for the LRZ's ability to import. The LCR is for the entire zone collectively, and not a requirement for individual LSEs; there is currently no LCR requirement applicable to individual LSEs in Michigan pursuant to MCL 460.6w. The LCR is determined by performing a LOLE analysis on each zone individually, to determine the Local Reliability Requirement (LRR), or the resources a zone would need to meet the loss-of-load standard if it were separated from MISO. Separately, MISO determines the import and export limits for each zone by performing a seasonal transfer analysis study. The study produces Zonal Import Ability (ZIA) and Zonal Export Ability (ZEA) values, which are then adjusted by the amount of controllable exports to non-MISO load to determine Capacity Import Limits (CIL) and Capacity Export Limits (CEL). The ZIA is an input to the LCR calculation, and the LCR, CEL, and CIL, and subregional constraints are inputs to the PRA clearing process.

In Planning Year 2023/24, MISO implemented a seasonal resource adequacy requirement for each summer, fall, winter and spring season and a seasonal accredited capacity (SAC) methodology for certain resources participating in MISO's

PRA to align with real time availability and planned outages. Staff reviewed these changes with participants in its 2022 and 2023 technical conferences as a part of the Commission's June 22, 2022 Order in U-21099, and results of these activities included requiring entities to file capacity demonstrations showing resources to meet obligations in all four seasons, modifications to the filing timeline, and adoption of ISO-neutral language into the process and requirements. Commencing PY 2024/25, the Commission's July 26, 2023 Order in U-21393 directed LSEs in MISO to demonstrate seasonal capacity obligations based on the MISO seasonal resource adequacy construct. LSEs are obligated to demonstrate enough capacity (owned or contracted) to meet that LSE's capacity obligation for each season. The specific capacity obligation for each season will be the LSE's prompt year (upcoming year) Initial Planning Reserve Margin Requirement for each respective season.

On June 27, 2024, the FERC accepted MISO's Reliability-Based Demand Curve (RBDC) tariff revision to incorporate sloped demand curves into the PRA. The vertical demand curve used in the PRA since the 2009/2010 Planning Year failed to properly value incremental capacity, did not facilitate efficient investment and retirement decisions necessary to maintain the resources needed to meet system reliability, and was inefficient at pricing capacity accurately.[12]

If a LRZ does not have sufficient resources to meet its seasonal requirements, the entire LRZ clears at the LRZ's seasonal Cost of New Entry (CONE) value. If a LRZ does not have sufficient resources to meet its seasonal requirements in more than one season, the PRA clearing price would be determined as described in section 69A.7.1 of Tariff Module E-1. CONE varies from zone to zone and changes from year to year but for reference, for 2025/26 CONE is $130,930/MW-year ($358.71/MW-day) in Zone 7.[13] The PRA clearing price being set at CONE would have economic ramifications and should provide a signal to entities with responsibilities regarding resource adequacy within the zone. However, it is important to note that MISO's resource adequacy construct is based on probabilistic determinations and failure to meet the requirements of the resource adequacy construct would not mean that the LRZ in question will experience a loss of load event. It simply means the probability of such a loss of load event would exceed the generally accepted criteria that govern the resource adequacy planning process.

Details on the Reliability-Based Demand Curve Tariff Revision

MISO introduced sloped demand curves in its resource adequacy construct through the implementation of RBDCs in the 2025 PRA. Specifically, MISO utilizes distinct sloped demand curves at both the systemwide and subregional levels. The systemwide RBDC addresses overall reliability needs across the entire system, while the subregional RBDCs capture additional reliability requirements specific to each subregion. As a result, for each season, MISO develops one systemwide RBDC and two

---

[12] Direct Testimony of Todd Ramey, FERC ER23-2977, p.8

[13] [MISO Cost of New Entry (CONE) and Net CONE Calculation for PY 2025/2026]

subregional RBDCs, one for each subregion aka Planning Area (MISO North/Central and MISO South). Ultimately, MISO seeks to develop and employ RBDCs at the LRZ level; however due to the complexity of developing another ten curves for each season, they have delayed this effort until a later date. Each sloped demand curve is developed using its respective Marginal Reliability Impact (MRI) Curve, expressed in MWh/UCAP MW-year, which provides information about the value of the reliability improvements brought about by additional capacity, and a Scaling Factor to support annual revenue prices driving toward annualized Net CONE when the system is at the reliability requirement in all four seasons. Net CONE, expressed in $/UCAP MW-year, is the net annualized cost to develop new capacity resources. For more information and detail on development of RBDCs, see the Reliability-Based Demand Curves Conceptual Design White Paper.[14]

The RBDCs fundamentally change the objective function of the PRA, from minimizing as-offered costs to minimizing the difference between supply offers and demand offers to maximize social surplus. The clearing quantities may vary from the initial PRMR, but the value of the reliability contribution of any additional MWs cleared must be greater than or equal to the cost of procuring those MWs. The PRA is conducted using an optimization to simultaneously complete the following tasks: (1) meet the supply demand balance both for MISO and for each of the two Planning Areas (MISO North/Central and MISO South); (2) meet the LCR for each LRZ; (3) efficiently use transmission transfer capability between LRZs; and (4) respect the Sub-Regional Power Balance Constraint. Step 1 of the auction clearing process solves an optimization problem to identify which type of RBDC produces a higher MW obligation for a given subregion, share-of-Systemwide or Subregional. Step 2 of the process solves the clearing and pricing problem based on the RBDC identified in step 1 and outputs both the resource clearing (Final PRMR) and the auction clearing price (ACP) for each LRZ and External Resource Zone. A final step verifies the solution found in step 2. The auction clearing price is determined by where the supply offer curve meets the applicable RBDC, and is equal to the marginal cost of capacity, the regional marginal cost of capacity, the marginal cost of financially binding LCR, CEL, and CIL for an LRZ, and the marginal cost of financially binding Subregional Export Constraints and Subregional Import Constraints. For more information on auction clearing under RBDC see Appendix M of MISO's Business Practice Manual 11.[15]

Within the RBDC proposal, MISO established the RBDC Opt-Out mechanism, which allows an LSE to opt out of the PRA if the Relevant Electric Retail Rate Authority (RERRA) does not deny the opt out plan. LSEs who choose the RBDC Opt-Out provision cannot include a partial opt-out, shall be locked-in for three consecutive years, and must include the RBDC Opt-Out Adder % in their obligation. The RBDC Opt-Out Adder % is based on a seasonal average of RBDC clearing for the prior three

[14] Reliability-Based Demand Curves Conceptual Design White Paper
[15] MISO BPM-011-r31 Appendix M

planning years, or a simulated PRA clearing if prior year RBDC-based PRA clearing is not available. In PY 2025/26, no LSEs chose to opt out in any LRZ in MISO.

Future Resource Adequacy Construct Changes

MISO has recently filed or is currently working on FERC filings to address issues and challenges related to demand side resources, including Demand Response Participation Rules Enhancements, Elimination of Dual Registration, DR and ER reforms (formerly known as LMR reforms). Also, MISO aims to implement enhanced resource adequacy risk modeling and a Direct Loss-of-Load (DLOL) accreditation methodology (FERC Docket ER24-1638-000 filed 3/28/2024) beginning in planning year 2028/29. MISO has committed to publishing indicative accreditation results based on the DLOL methodology prior to each Planning Resource Auction, starting with Planning Year 2025-2026[16]. These reforms will align PRMR with accreditation of all resource classes. MISO continues its work on the PRMR piece of the reforms, therefore indicative PRMR values under DLOL are not yet available. Several LSEs inquired whether DLOL accreditation methodology should be used in this case since the demonstration year aligns with the first year of DLOL implementation. Staff recommended and continues to recommend that demonstrating LSEs follow the prompt year MISO resource adequacy construct. The Commission should determine a timeline to implement MISO's DLOL accreditation changes into the state capacity demonstration process if it deems it necessary to implement prior to MISO tariff changes effective PY 2028-29.

The compliance year capacity obligations (PY 2028/29) that are demonstrated for in this case are based off an LSE's prompt year (PY 2025/26) requirement. Changes to load, resources, and MISO procedures in the upcoming years can lead to discrepancies between an LRZ having sufficient capacity to meet its four-year forward Michigan requirements and not having enough capacity to meet MISO's requirements when the prompt year arrives.

MISO – Local Resource Zone 7

Figure 2 shows historical annual MISO capacity requirements for LRZ 7. This data is taken from the respective annual MISO LOLE Study Reports.

[16] Planning Year 2025-2026 Indicative Direct Loss of Load (DLOL) Results

Figure 2: Annual MISO LOLE Report Data LRZ 7

Planning Year	Source	LRR[17]	CIL[18]	LCR (ZRCs)[19]
2013/14	MISO 2013 LOLE Report	25,305	4,576	20,729
2014/15	MISO 2014 LOLE Report	24,815	3,884	20,931
2015/16	MISO 2015 LOLE Report	24,710	3,813	20,897
2016/17	MISO 2016 LOLE Report	24,715	3,813	21,309
2017/18	MISO 2017 LOLE Report	24,654	3,320	21,334
2018/19	MISO 2018 LOLE Report	24,545	3,785	20,760
2019/20	MISO 2019 LOLE Report	24,845	3,211	21,634
2020/21	MISO 2020 LOLE Report	25,370	3,200	22,170
2021/22	MISO 2021 LOLE Report	25,054	4,888	20,166
2022/23	MISO 2022 LOLE Report	24,115	3,749	20,366
2023/24[20]	MISO 2023 LOLE Report	24,428	5,087	19,341
2024/25	MISO 2024 LOLE Report	24,558	4,500	19,271
2025/26	MISO 2025 LOLE Report	23,250	3,569	19,681

These numbers typically change slightly between the LOLE Study and the PRA, primarily due to updated load forecasting used in the PRA but can be used to see how the capacity requirements have changed over time. Changes in these requirements can have economic and reliability impacts and will continue to be monitored.

In its seasonal construct, MISO includes an LRR, ZIA, and PRMR for each zone for each season. The current year MISO requirements are shown in comparison with Planning Year 2024-25 requirements in Appendix B.

The difference between a zone's PRMR and its LCR is sometimes referred to as Effective Capacity Import Limit (ECIL). The ECIL is not a MISO defined term and is not representative of a physical import limitation. To meet the loss of load standard and avoid the auction clearing price being set at CONE, a zone must have enough resources located within the zone to meet its LCR even if the LCR exceeds the PRMR. Note the year-over-year decrease in CIL in PY 2025/26. This decrease is driven by generation and transmission changes in LRZ 7 Local Balancing Authorities (LBAs), their neighboring LBAs, and the LBAs adjacent to

[17] **Local Reliability Requirement**. Representative of the resources required for LRZ 7 to meet the LOLE standard when modeled as an island (no imports). MISO Loss of Load Expectation Study Report, Table 2-1 through 2-4.
[18] **Capacity Import Limit**. Representative of the ability of an LRZ to import capacity from areas outside of that LRZ. MISO Loss of Load Expectation Study Report, Tables ES-3 through ES-6.
[19] **Local Clearing Requirement**. Representative of the minimum resources that must be located within a specific zone for that zone to meet the reliability standard. Calculated as shown in Table 1.1 of MISO Loss of Load Expectation Study Report.
[20] Values for summer season starting Planning Year 2023/24. Other seasons shown in Appendix C.

these neighbors. Historically, Michigan utilities have assumed a CIL of approximately 3200 MW for input in capacity expansion modeling conducted during the development of Integrated Resource Plans and other planning exercises.

Figure 3 shows a comparison of LRZ 7 aggregated resources demonstrated, plus known undemonstrated resources likely to still be available, for each season in the 2028/29 planning year and MISO's resource adequacy requirement for PY 2025/26. Appendix C contains seasonal capacity position tables for the prompt, interim, and demonstration years. These numbers represent Staff's current projection based on the capacity demonstration filings and MISO publications at the time of this report although the information is subject to change for all forward years. Unless otherwise noted, resources and resource requirements in this report are in Unforced Capacity (UCAP) Megawatts (MW), equal to Zonal Resource Credits (ZRCs).

Figure 3: U-21775 Results – PY 2028/29 LRZ 7 Capacity Position (ZRCs)

Line #		Summer	Autumn	Winter	Spring
1	Planning Reserve Margin Requirements (PRMR)	21,228	20,494	16,124	19,853
2	Local Reliability Requirement (LRR)	23,250	23,312	20,262	21,619
3	Capacity Import Limit (CIL)	3,569	5,115	4,762	5,166
4	Zonal Import Ability (ZIA)	3,569	5,115	4,762	5,166
5	Local Clearing Requirement (LCR) (L1-L4)	19,681	18,197	15,500	16,453
6	Total Owned	17,981	16,378	14,542	16,263
7	Total PPA Contracts	4,321	4,086	2,981	4,175
8	Total ZRC Contracts	610	573	309	543
9	Total Qualified Demand Response	1,502	845	793	879
10	Total Resources (sum of L6 through L9)	24,415	21,883	18,624	21,860
11	LCR Demonstrated Position (L10-L5)	4,734	3,686	3,124	5,406
12	PRMR Demonstrated Position (L10-L1)	3,187	1,389	2,501	2,006
13	Net Undemonstrated Capacity	241	264	538	323
14	Anticipated LCR Position (L11+L13)	4975	3950	3662	5729
15	Anticipated PRMR Position (L12+L13)	3428	1653	3039	2329

(1) PY 2025 PRMR from PRA Data and held constant at prompt year value.

(2) PY 2025 LRR from PRA Data and held constant at prompt year value (LRR=LCR+ZIA).

(3) PY 2025 CIL from PRA Data and held constant at prompt year value.

(4) PY 2025 LCR from PRA Data and held constant at prompt year value.

(5-9) Zone 7 resources included in capacity demonstrations sorted by resource type.

(10) LCR position based on demonstrated resources only.

(11) PRMR position based on demonstrated resources only.

(12) Net Undemonstrated Zone 7 Capacity is Staff's attempt to reconcile the capacity demonstration resources with the MISO PRA. There are resources located in Zone 7 that Staff anticipates will be in the PRA that were not included in any capacity demonstration as well as a small number of resources included in the capacity demonstration that are no longer available due to recent events.

(13) LCR Position after accounting for undemonstrated Zone 7 Capacity.

(14) PRMR position after accounting for undemonstrated Zone 7 capacity. A negative value means the Zone will need to import resource to meet its requirement. A positive value means the Zone may import resources based on economics but will not need to meet its PRMR.

Prompt Year (PY 2025/26) and Compliance Year (PY 2028/29)

For the prompt year (PY 2025/26), based on the PRA Results posted April 28, 2025,[21] LRZ 7's summer Initial PRMR is 21,228 ZRCs and the LCR is 19,681 ZRCs. The total LRZ 7 resources offered in the PRA for the summer season in the prompt year is 20,884 ZRCs, which exceeds the anticipated LCR by 2,203 ZRCs, however falls short of the zone's portion of PRMR. The zone relied on 785.5 ZRCs of external resources to meet its resource adequacy requirement target. Other seasons' data is shown in Appendix C.

All resources offered into the North/Central subregion were cleared, and the final PRMRs as determined through auction clearing were greater than the initial targets (Initial PRMRs) in all seasons. In other words, the auction cleared above seasonal reliability targets, representing additional reliability value at cost-competitive prices. The "effective" PRMs are calculated from the Final PRMRs (determined by auction clearing):

2025 PRA Results	Initial PRM	Final Cleared PRM
Summer	7.9%	9.8%
Fall	14.9%	17.5%
Winter	18.4%	24.5%
Spring	25.3%	26.8%

Based on the resources included in the capacity demonstration filings for PY 2028/29 Staff projects LRZ 7 to have a surplus of resources compared to the projected LCR in all four seasons, as shown in Figure 4. It is important to note that these projections are subject to change. A few examples of things that could change include load forecasts, resource availability and performance, and MISO policies and practices.

MISO has previously provided projections of both PRMR and LRR into the compliance year from the prompt year. These calculations were not available to Staff at the time of its report. In absence of projected PRMR/LRR values, Staff has assumed these values remain constant for the purposes of this comparison.

Interim Years (PY 2026/27 & PY 2027/28)

Appendix C also includes data and projections for each season in the interim years, PY 2026/27 & PY 2027/28. This information is derived using the same methodology as described for the compliance year. Comparing those projected requirements to the demonstrated and undemonstrated resources in LRZ 7, results in a capacity surplus for both years compared to the projected LCRs. This information is based on the best information currently available to Staff, but includes several assumptions and, again, is subject to change. Similar to the

[21] 2025 MISO PRA Results, accessed May 2, 2025

compliance year, likely changes include new forecasts, unknown resource additions or subtractions, changes in generator performance, increased or decreased zonal import ability, seasonal variability, and/or changes to MISO requirements. It is also worth noting that the capacity margin looks to be tight in 2026/27 across all four seasons with the tightest capacity position in the Fall season.

MISO – Local Resource Zone 2

MISO's LRZ 2 encompasses almost the entire upper peninsula of Michigan as well as northern and eastern Wisconsin. MISO LRZ 2 has seasonal CILs of 4,370 MWs in Summer, 6,537 MWs in Fall, 6,522 MWs in Winter, and 6,439 MWs in Spring.[22] MISO does not define MW capacity imports or export limits between states within the boundaries of the same MISO LRZ. Considering LRZ 2 includes LSEs from Wisconsin (not subject to MCL 460.6w), the data available to Staff for LRZ 2 from capacity demonstration filings is not comprehensive enough to project a zonal capacity position as Staff did in its analysis of LRZ 7. Nevertheless, all Michigan LSEs serving load within MISO LRZ 2 demonstrated sufficient resources to meet their requirements.

The 2025 MISO PRA results indicate an installed capacity surplus in the 2025/26 planning year for LRZ 2.[23]

MISO – Local Resource Zone 1

A very small fraction of Michigan's upper peninsula load is located in LRZ 1. Northern States Power, Bayfield Electric Cooperative, and the City of Wakefield municipal utility have less than 37 MW combined in MISO LRZ 1. All LSEs in LRZ 1 demonstrated sufficient capacity to meet their obligations for PY 2028/29. The 2025/26 MISO PRA results show sufficient capacity for each season in the 2025/26 planning year, relying on a small amount of imports to meet their resource adequacy target in Winter and Spring. [24]

---

[22] Id

[23] Id

[24] Id

PJM Resource Adequacy

A few LSEs in Michigan serve load within the PJM RTO. These LSEs are still subject to the requirements of MCL 460.6w requiring sufficient capacity for four years forward in planning year 2028/29. PJM LSEs demonstrate sufficiency by providing evidence that the LSE complies with its PJM obligations.

LSEs in the PJM service territory must meet capacity obligations either through participation in PJM's Reliability Pricing Model (RPM) Base Residual Auction (BRA) or through PJM's Fixed Resource Requirement (FRR) plan. The FRR plan is an alternative to the RPM, where an LSE must demonstrate to PJM that it has enough resources to cover its projected load plus an additional reserve requirement. Both the RPM and the FRR resources are subject to monetary penalties if they fail to maintain PJM's reliability standard. PJM's resource adequacy construct is based on annual requirements.

The largest LSE in PJM is Indiana Michigan Power Company (I&M).[25] I&M elects to file an FRR plan each year. I&M's most recent capacity demonstration indicates that the company plans to continue with the PJM FRR plan barring any major FERC-ordered changes. Staff reviewed I&M's filing and finds that they have sufficient resources to meet its obligations at PJM.

In addition to I&M's capacity demonstration, Staff also reviewed information of cooperative and municipal utility obligations in the Michigan portion of PJM's territory for planning year 2028/29. The results are displayed in the table below.

Figure 4: PJM Capacity Demonstration Summary

Item	PY 2025/26	PY 2026/27	PY 2027/28	PY 2028/29
Utility Total Planning Resources, MW	3825	4462	4695	4359
Other PJM Resources, MW	295.2	336.8	350.8	321.8
Total PJM Resources, MW	4120.2	4798.8	5045.8	4680.8

Staff expects that the LSEs in the Michigan portion of PJM will continue to meet the PJM capacity obligations based on information included in individual capacity demonstrations. If PJM LSEs were to encounter an unanticipated shortfall in the immediate future, Staff expects that it would be accommodated through the procurement of reserve resources by market purchases. As market conditions may change over time, Staff will continue to monitor the resource adequacy of the PJM

[25] Indiana Michigan Power Company is an electric operating company of American Electric Power Company, Inc. (AEP). I&M is a wholly owned subsidiary of AEP and is operated as a single utility in the American Electric Power System (AEP System).

region and the capacity plans of Michigan LSEs located within the PJM territory. As reaffirmed in the Company's most recent IRP, filed in Case No U-21189,[26] Staff does not anticipate I&M to have any issues meeting capacity obligations.

The Commission order in Case No. U-16090 set I&M's customer choice cap amount to zero, and was subsequently reset to ten percent on February 1, 2019, pursuant to the Commission order and MCL 460.10a(1)(c). On February 1, 2019, I&M began enrolling customers in its choice program and is now fully subscribed at the cap. Currently I&M is responsible for the capacity of its choice load in its FRR plan under the PJM RAA. If suppliers were to choose to self-supply capacity, then that capacity would also need to be included in I&M's FRR plan.

The North American Electric Reliability Corporations 2024 Long-Term Reliability Assessment categorizes PJM as having elevated risk level post 2026, with resource additions not keeping up with generator retirements and demand growth, and winter season replacing summer as the higher-risk period due to generator performance and fuel supply issues.[27]

The PJM Base Residual Auction (BRA) schedule has experienced delays awaiting FERC action on capacity auction related issues. The following timeline shows the published BRA schedule of auctions every six months until they can get back to the original schedule (every May, three years in advance of the delivery year):

- July 2025 2026/27 BRA
- December 2025 2027/28 BRA
- June 2026 2028/29 BRA
- December 2026 2029/30 BRA

Commencing in Planning Year 2025/26, PJM has introduced a more robust risk model while simultaneously implementing the Effective Load Carry Capability (ELCC) methodology for all assets. These changes are expected to result in lower accreditation amounts for demand-side resources and lower load obligations for every entity.

LSE Capacity Demonstration Results (PY 2028/2029)

Staff appreciates the time and effort made by all Michigan LSEs to comply with the provisions of MCL 460.6w, as well as to comply with the questions, audits, contract reviews, and requests for additional information throughout this process. The LSE capacity demonstration results are reported for planning year 2028/2029 because, following the initial capacity demonstration which covered four years, only the fourth year forward is required for compliance. As previously described in its September 15, 2017 order in Case No. U-18197, the Commission requested a table be included in this

---

[26] MPSC Case No. U-21189, Direct Testimony of Stephan F. Baker, p. 7, February 28, 2022.
[27] NERC 2024 Long-Term Reliability Assessment

report that identifies the capacity by type for each individual electric provider without revealing the identity of any specific electric provider. The requested table with a breakdown for each electric provider that filed a capacity demonstration is included as Appendix A. In addition to the breakdown by individual supplier, Staff reports the following aggregate results in Figure 5 below.

Figure 5: Resource Breakdown (%) by Supplier Type Planning Year 2028/29 - Summer

Supplier Type	Owned	DR	Contract – PPA	Contract - ZRC	Auction
Muni/Co-Op Aggregate	58.5%	0.3%	29.3%	8.9%	3.0%
AES Aggregate	0.7%	0.2%	2.1%	96.5%	0.5%
Utility Aggregate	71.8%	5.3%	16.1%	1.8%	5.0%

Demand Response

As part of its analysis, Staff reviewed the LSEs' demand response (DR) programs as an optional source of capacity. When used by a LSE, a reduction in demand through DR programs offsets a portion of their capacity needs. LSEs can utilize interruptible DR during critical peak times to quickly respond to bulk electric system needs which can delay future capital investment in new generation. Behavioral DR programs allow the utility to lower its peak demand forecast, thus mitigating the need for an equal of amount supply side resources.

Demand response played a prominent role in LSEs' integrated resource plan filings, where DR is required to be considered along with traditional supply side resources for meeting capacity needs. MCL 460.6t directs Staff to complete a statewide study of DR potential in Michigan every five years, and the most current Michigan Demand Response Potential Study was issued on September 24, 2021.[28] In addition, the Commission approved Michigan Integrated Resource Planning Parameters on November 21, 2017 in Case No. U-18418 that include provisions regarding including DR options in future integrated resource plans and Staff is currently working to update those parameters.

The DR levels assumed in both Consumers Energy's and DTE Electric's current integrated resource plans[29] are reflected in their capacity demonstration filing. Staff will continue to monitor these plans and the use of DR in Michigan for the foreseeable future.

[28] Michigan Demand Response Statewide Potential Study (2021-2040), Guidehouse, September 24, 2021.

[29] DTE's current IRP filed and approved in MPSC Case No. U-21193.
CE's current IRP filed in MPSC Case No. U-21090.

Demand Response Aggregation

Pursuant to the September 15, 2017 Order in Case No. U-18369, the Commission affirmed that AESs may offer DR programs to their customers through a curtailment service provider (CSP) or third-party aggregator. The Commission made this determination in the context of finding that it will continue to review DR programs offered by AESs as part of the capacity demonstration process.

As the Relevant Electric Retail Regulatory Authority (RERRA), the Commission is aware of aggregation of approximately 85 ZRCs of DR offered into the 2025 MISO capacity market. Staff continues to work with CSPs, ARCs and MISO to ensure that aggregated DR's load modifications are accounted for when dispatched on MISO's coincident peak and continues to monitor the discussions taking place regarding FERC Order 2222.

ZRC Contracts

Staff recommended that forward ZRC contracts be used for capacity demonstration purposes to specify delivery of the ZRCs in the MISO Module E Capacity Tracking (MECT) tool prior to the applicable PRA auction. This year's demonstration shows an increase in the percentage of ZRC contracts utilized this year by the utilities, municipal utilities and cooperatives compared to last year.

An important thing to note is that ZRCs are defined in MISO's tariff and are created in the prompt year when UCAP for supply-side and demand-side resources are converted into ZRCs in the MISO MECT. ZRCs for any year further out than the prompt year are projected and don't become ZRCs until the prompt year. ZRCs are fungible products that can be sold or transferred, and in some cases, sold more than once. The characteristics of ZRCs allow for them to be easily traded and tracked within the MISO MECT. MISO has a view into the source and transfers of those ZRCs that occur prior to the PRA in the prompt year, and those ZRC transfers are audited by Staff as a secondary check on the ZRC contracts utilized in the capacity demonstrations.

At this point in time, the overall amount of ZRC contracts included in capacity demonstration filings do not impact Staff's ability to continue to make forward resource adequacy projections on a zonal basis. Staff will continue to monitor and audit ZRC contracts and ZRC transfers within the MECT going forward.

AES Load Switching

Staff requested that any AES who experienced load switching during this time provide a signed affidavit confirming the increase or reduction in their load compared to the PLC data provided by the utility with their capacity demonstration that contained the amount of load switching for each planning year. Each supplier contracting for additional customer load provided a copy of its affidavit confirming this transaction to the supplier that was losing the load to be accounted for in both suppliers' demonstrations. The load switching process was made more complex with the change to a seasonal construct.

Staff continues to see an increase in the amount of load switching among entities. To better organize and facilitate the filing process, Staff recommends that filing entities who include load switching information in their filing include it within the Contracted Resources on the spreadsheet templates provided for the capacity demonstration for the demonstration years as well as the interim years. Staff also recommends that both the losing and the gaining suppliers have copies of the load switching affidavits in each of their filings, so Staff is able to easily cross check that the load is being accounted for.

Capacity Retirements and Additions

NERC's 2024 Long Term Reliability Assessment shows added resource capacity on the Bulk Power System (BPS) falling short of industry projections the year prior[30], illustrating an over-projection of natural gas, solar PV, and wind resources and giving evidence to project delays. The Lawrence Berkeley National Laboratory published results of an interconnection queue study in April 2024 assessing that only 19% of the projects (and just 14% of capacity) that submitted interconnection requests from 2000 to 2018 reached commercial operations by the end of 2023.[31] In recognition of the interconnection backlog risk, some RTOs have taken steps to address these issues, including PJM's Reliability Resource Initiative, MISO's work to reduce queue cycle times through automation, and MISO's Expedited Resource Addition Study (ERAS) process which is currently awaiting FERC approval.

The state of Michigan continues to follow national trends showing a tightening capacity position due to the scheduled retirements outpacing the buildout of replacement capacity. Staff had the opportunity to meet with several LSEs to discuss their filings and many expressed concerns about the dwindling amount of capacity available in the compliance year, especially season-specific contracts and bilateral contracts in general. Various factors could cause delays for new additions, including broad economic factors such as supply chain constraints, labor shortages, high component prices, etc., as well as delays associated with obtaining permitting, regulatory approval, or interconnection queue delays. The issue may be further exacerbated should demand increase faster than expected due to unanticipated loads such as data centers, as well as electrification of the building and transportation sectors. Staff has noted a significant number of planned resources used as demonstrated capacity in this case and recent previous cases that have not come to fruition in the demonstration year as planned, with estimates in the range of 900-1000MW/year removed from the list of planned resources due to delays or cancellations. There are many instances of

[30] NERC 2024 LTRA, p.24.
[31] Queued Up: 2024 Edition, Lawrence Berkely National Laboratory, April 2024.

this occurring with IRP-identified resources, consequently Staff met with both large investor-owned utilities to discuss this issue in depth and determine what actions can be taken to overcome the delays. One of these utilities indicated they are in the process of quantifying project delays and terminations, and early estimates showed an average delay of ~1.5 years past Commercial Operation Date (COD) and a project failure rate greater than 25%.

A portion of the capacity from the Palisades Nuclear Power Plant was included as demonstrated capacity starting in Spring 2026. The remainder of the capacity from Palisades is being contracted by an LSE in Indiana. However, all the capacity from Palisades would provide resource adequacy benefits to MISO LRZ 7 and be counted towards meeting the LCR for LRZ 7. Re-opening of this plant is conditional on approval from the Nuclear Regulatory Commission (NRC).

Conclusion and Recommendations

All Michigan LSEs required to file capacity demonstrations with the Michigan Public Service Commission for planning year 2028/29 pursuant to MCL 460.6w and the August 22, 2024 Commission Order in Case No. U-21775 have filed. Staff has audited the filings, contracts and other materials and finds that all Michigan LSEs have satisfied the capacity demonstration requirements and have procured appropriate levels of resources for planning year 2028/29, with the exception of one agency representing municipalities, as previously described.

Staff appreciates the cooperation of all Michigan LSEs with respect to this process and the willingness to provide data and answer questions necessary for Staff to complete its review.

A summary of recommendations included in this report is below:

1. Staff recommends the Commission continue to direct all LSEs to include updated prompt year and interim year capacity obligation and resource information in future filings.
2. Staff recommends the Commission direct all LSEs to provide MECT screenshot of their prompt load obligations (PRMR/PLC) to facilitate the Storage Target calculation used to comply with Public Act 235.
3. The Commission should determine a timeline to implement MISO's DLOL accreditation changes into the state capacity demonstration process if it deems it necessary to implement prior to MISO tariff changes effective PY 2028-29.
4. Staff recommends that filing entities who include load switching information in their filing include it within the Contracted Resources on the spreadsheet templates provided for the capacity demonstration for the demonstration years as well as the interim years. Staff also recommends that both the losing and the gaining suppliers have copies of the load switching affidavits in each of their filings, so Staff is able to cross check that the load is being accounted for.

Appendix A

Planning Year 2028/29 Resource Breakdown (%) by Individual Supplier[32]

LSE	Owned	DR	Contract - PPA	Contract - ZRC	Auction
Supplier 1	30%	0%	63%	0%	7%
Supplier 2	0%	24%	0%	76%	0%
Supplier 3	0%	0%	100%	0%	0%
Supplier 4	0%	0%	0%	100%	0%
Supplier 5	61%	8%	30%	0%	0%
Supplier 6	55%	0%	21%	18%	6%
Supplier 7	0%	0%	0%	100%	0%
Supplier 8	49%	51%	0%	0%	0%
Supplier 9	0%	0%	0%	100%	0%
Supplier 10	0%	0%	0%	100%	0%
Supplier 11	0%	0%	0%	100%	0%
Supplier 12	9%	9%	81%	0%	0%
Supplier 13	0%	0%	100%	0%	0%
Supplier 14	0%	0%	100%	0%	0%
Supplier 15	49%	4%	6%	1%	41%
Supplier 16	0%	0%	100%	0%	0%
Supplier 17	0%	0%	0%	100%	0%
Supplier 18	87%	6%	6%	0%	0%
Supplier 19	67%	0%	35%	-2%	0%
Supplier 20	51%	8%	41%	0%	0%
Supplier 21	44%	25%	32%	0%	0%
Supplier 22	73%	0%	21%	6%	0%
Supplier 23	100%	0%	0%	0%	0%
Supplier 24	0%	0%	0%	100%	0%

[32] Suppliers (municipal and cooperative electric utilities) that combined their capacity resources are shown as one supplier in the above figure. The total number of suppliers may vary from year to year based on changes to which suppliers combine their capacity demonstrations as well as new suppliers or suppliers no longer serving load in Michigan.

Appendix B

LRZ 7 Local Clearing Requirement								
	A	B	C=A+B	D	E=C*D	F	G	H=E-F-G
	Zonal Coincident Peak Forecast (ZCPF)	Transmission Losses	LRZ Peak Demand	LRR UCAP/LRZ Peak Demand from LOLE	Local Reliability Requirement (LRR)	Zonal Import Ability (ZIA)	Controllable Exports	**Local Clearing Requirement (LCR)**
Summer								
2025	19791.9	638.8	20430.7	1.138	23250.1	3569	0	19681.1
2024	19867.5	606.7	20474.2	1.161	23770.5	4490	10	19270.5
Δ (MW)			-43.5		-520.4	-921		410.6
Δ (%)			-0.2%		-2.2%	-20.5%		2.1%
Fall								
2025	17957.3	617.6	18574.9	1.255	23311.5	5115	0	18196.5
2024	17752.9	434.2	18187.1	1.311	23843.3	4390	10	19443.3
Δ (MW)			387.8		-531.8	725		-1246.8
Δ (%)			2.1%		-2.2%	16.5%		-6.4%
Winter								
2025-26	13626.6	376.2	14002.8	1.447	20262.1	4762	0	15500.1
2024-25	13542	305	13847	1.607	22252.1	4656	10	17586.1
Δ (MW)			155.8		-1990.1	106		-2086.1
Δ (%)			1.1%		-8.9%	2.3%		-11.9%
Spring								
2026	15983.2	407.5	16390.7	1.319	21619.3	5166	0	16453.3
2025	15702	376	16078	1.322	21255.1	4883	10	16362.1
Δ (MW)			312.7		364.2	283		91.2
Δ (%)			1.9%		1.7%	5.8%		0.6%

Appendix C

U-21775 Results - LRZ 7 Summer Capacity Position (ZRCs)					
Line #	Summer Values	PY 2025	PY 2026	PY 2027	PY 2028
1	Planning Reserve Margin Requirements (PRMR)	21228	21228	21228	21228
2	Local Reliability Requirement (LRR)	23250	23250	23250	23250
3	Zonal Import Ability (ZIA)	3569	3569	3569	3569
4	Local Clearing Requirement (LCR)	19681	19681	19681	19681
5	Total Owned	15782	16271	17086	17981
6	Total PPA Contracts	3015	3336	4284	4321
7	Total ZRC Contracts	829	507	800	610
8	Total Qualified Demand Response	1208	1308	1463	1502
9	Total Resources (Line 5 + Line 6 + Line 7 + Line 8)	20834	21422	23633	24415
10	LCR Demonstrated Position (Line 9 - Line 4)	1153	1741	3952	4734
11	PRMR Demonstrated Capacity Position (Line 9 - Line 1)	-394	194	2405	3187
12	Net Undemonstrated Zone 7 Capacity	-18	347	-112	241
13	Anticipated LCR Position (Line 10 + Line 12)	1135	2088	3840	4975
14	Anticipated PRMR Capacity Position (Line 11 + Line 12)	(412)	541	2293	3428
(1) PY 2025 PRMR from PRA Data and held constant at prompt year value.					
(3) PY 2025 ZIA from PRA Data and held constant at prompt year value.					
(4) PY 2025 LCR from PRA Data and held constant at prompt year value.					
(5-9) Zone 7 resources included in capacity demonstrations sorted by resource type.					
(10) LCR position based on demonstrated resources only.					
(11) PRMR position based on demonstrated resources only.					
(12) Net Undemonstrated Zone 7 Capacity is Staff's attempt to reconcile the capacity demonstration resources with the MISO PRA. There are resources located in Zone 7 that Staff anticipates will be in the PRA that were not included in any capacity demonstration as well as a small number of resources included in the capacity demonstration that are no longer available due to recent events.					
(13) LCR Position after accounting for undemonstrated Zone 7 Capacity.					
(14) PRMR position after accounting for undemonstrated Zone 7 capacity. A negative value means the Zone will need to import resource to meet its requirement. A positive value means the Zone may import resources based on economics but will not need to meet its PRMR.					

U-21775 Results - LRZ 7 Autumn Capacity Position (ZRCs)					
Line #		PY 2025	PY 2026	PY 2027	PY 2028
1	Planning Reserve Margin Requirements (PRMR)	20494	20494	20494	20494
2	Local Reliability Requirement (LRR)	23312	23312	23312	23312
3	Zonal Import Ability (ZIA)	5115	5115	5115	5115
4	Local Clearing Requirement (LCR)	18197	18197	18197	18197
5	Total Owned	14996	15318	16797	16378
6	Total PPA Contracts	2802	3113	4083	4086
7	Total ZRC Contracts	936	569	759	573
8	Total Qualified Demand Response	793	780	816	845
9	Total Resources (Line 5 + Line 6 + Line 7 + Line 8)	19526	19780	22458	21883
10	LCR Demonstrated Position (Line 9 - Line 4)	1330	1583	4261	3686
11	PRMR Demonstrated Capacity Position (Line 9 - Line 1)	-968	-556	1964	1389
12	Net Undemonstrated Zone 7 Capacity	-130	263	-70	264
13	Anticipated LCR Position (Line 10 + Line 12)	1200	1846	4191	3950
14	Anticipated PRMR Capacity Position (Line 11 + Line 12)	(1097)	(452)	1893	1653
(1) PY 2025 PRMR from PRA Data and held constant at prompt year value.					
(3) PY 2025 ZIA from PRA Data and held constant at prompt year value.					
(4) PY 2025 LCR from PRA Data and held constant at prompt year value.					
(5-9) Zone 7 resources included in capacity demonstrations sorted by resource type.					
(10) LCR position based on demonstrated resources only.					
(11) PRMR position based on demonstrated resources only.					
(12) Net Undemonstrated Zone 7 Capacity is Staff's attempt to reconcile the capacity demonstration resources with the MISO PRA. There are resources located in Zone 7 that Staff anticipates will be in the PRA that were not included in any capacity demonstration as well as a small number of resources included in the capacity demonstration that are no longer available due to recent events.					
(13) LCR Position after accounting for undemonstrated Zone 7 Capacity.					
(14) PRMR position after accounting for undemonstrated Zone 7 capacity. A negative value means the Zone will need to import resource to meet its requirement. A positive value means the Zone may import resources based on economics but will not need to meet its PRMR.					

U-21775 Results - LRZ 7 Winter Capacity Position (ZRCs)					
Line #		PY 2025	PY 2026	PY 2027	PY 2028
1	Planning Reserve Margin Requirements (PRMR)	16124	16124	16124	16124
2	Local Reliability Requirement (LRR)	20262	20262	20262	20262
3	Zonal Import Ability (ZIA)	4762	4762	4762	4762
4	Local Clearing Requirement (LCR)	15500	15500	15500	15500
5	Total Owned	15568	15313	15954	14542
6	Total PPA Contracts	2307	2521	3177	2981
7	Total ZRC Contracts	857	510	630	309
8	Total Qualified Demand Response	730	738	769	793
9	Total Resources (Line 5 + Line 6 + Line 7 + Line 8)	19461	19082	20530	18624
10	LCR Demonstrated Position (Line 9 - Line 4)	3961	3582	5029	3124
11	PRMR Demonstrated Capacity Position (Line 9 - Line 1)	3338	2958	4406	2501
12	Net Undemonstrated Zone 7 Capacity	-65	306	90	538
13	Anticipated LCR Position (Line 10 + Line 12)	3896	3887	5120	3662
14	Anticipated PRMR Capacity Position (Line 11 + Line 12)	3272	3264	4496	3039
(1) PY 2025 PRMR from PRA Data and held constant at prompt year value.					
(3) PY 2025 ZIA from PRA Data and held constant at prompt year value.					
(4) PY 2025 LCR from PRA Data and held constant at prompt year value.					
(5-9) Zone 7 resources included in capacity demonstrations sorted by resource type.					
(10) LCR position based on demonstrated resources only.					
(11) PRMR position based on demonstrated resources only.					
(12) Net Undemonstrated Zone 7 Capacity is Staff's attempt to reconcile the capacity demonstration resources with the MISO PRA. There are resources located in Zone 7 that Staff anticipates will be in the PRA that were not included in any capacity demonstration as well as a small number of resources included in the capacity demonstration that are no longer available due to recent events.					
(13) LCR Position after accounting for undemonstrated Zone 7 Capacity.					
(14) PRMR position after accounting for undemonstrated Zone 7 capacity. A negative value means the Zone will need to import resource to meet its requirement. A positive value means the Zone may import resources based on economics but will not need to meet its PRMR.					

U-21775 Results - LRZ 7 Spring Capacity Position (ZRCs)					
Line #		PY 2025	PY 2026	PY 2027	PY 2028
1	Planning Reserve Margin Requirements (PRMR)	19853	19853	19853	19853
2	Local Reliability Requirement (LRR)	21619	21619	21619	21619
3	Zonal Import Ability (ZIA)	5166	5166	5166	5166
4	Local Clearing Requirement (LCR)	16453	16453	16453	16453
5	Total Owned	14609	15739	16992	16263
6	Total PPA Contracts	2861	3711	4213	4175
7	Total ZRC Contracts	931	584	771	543
8	Total Qualified Demand Response	802	802	847	879
9	Total Resources (Line 5 + Line 6 + Line 7 + Line 8)	19203	20837	22823	21860
10	LCR Demonstrated Position (Line 9 - Line 4)	2749	4383	6369	5406
11	PRMR Demonstrated Capacity Position (Line 9 - Line 1)	-651	983	2969	2006
12	Net Undemonstrated Zone 7 Capacity	-99	282	-50	323
13	Anticipated LCR Position (Line 10 + Line 12)	2650	4665	6319	5729
14	Anticipated PRMR Capacity Position (Line 11 + Line 12)	(750)	1265	2919	2329
(1) PY 2025 PRMR from PRA Data and held constant at prompt year value.					
(3) PY 2025 ZIA from PRA Data and held constant at prompt year value.					
(4) PY 2025 LCR from PRA Data and held constant at prompt year value.					
(5-9) Zone 7 resources included in capacity demonstrations sorted by resource type.					
(10) LCR position based on demonstrated resources only.					
(11) PRMR position based on demonstrated resources only.					
(12) Net Undemonstrated Zone 7 Capacity is Staff's attempt to reconcile the capacity demonstration resources with the MISO PRA. There are resources located in Zone 7 that Staff anticipates will be in the PRA that were not included in any capacity demonstration as well as a small number of resources included in the capacity demonstration that are no longer available due to recent events.					
(13) LCR Position after accounting for undemonstrated Zone 7 Capacity.					
(14) PRMR position after accounting for undemonstrated Zone 7 capacity. A negative value means the Zone will need to import resource to meet its requirement. A positive value means the Zone may import resources based on economics but will not need to meet its PRMR.					

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Midcontinent Independent System Operator (MISO)	)	Order No. 202-25-3

Exhibit to
Motion to Intervene and Request for Rehearing and Stay of
Public Interest Organizations

Filed June 18, 2025

Exhibit 29

2024 Consumers ELG Annual Report

Consumers Energy
Count on Us®

December 16, 2024 Electronically Submitted via MiEnviro

Ms. Bonnie Broadwater
Michigan Department of Environment, Great Lakes, and Energy
Water Resources Division
350 Ottawa Avenue NW, Unit 10
Grand Rapids, MI 49503-2316

RE: NOTICE OF PLANNED PARTICIPATION
ANNUAL PROGRESS REPORT PURSUANT TO 40 CFR 423.19(g)(3)
CONSUMERS ENERGY COMPANY, JH CAMPBELL COMPLEX NPDES PERMIT NO. MI0001422, STEAM ELECTRIC EFFLUENT LIMITATION GUIDELINES

Dear Ms. Broadwater,

Consumers Energy Company (Consumers) submitted a Notice of Planned Participation (NOPP) for the JH Campbell (Campbell) Complex, NPDES Permit No. MI0001422 on October 11, 2021, seeking to qualify as an electric generating unit that will achieve permanent cessation of coal combustion by December 31, 2028. According to 40 CFR 423.19 (g)(3) annual progress reports shall be submitted detailing the progress made to achieve the cessation of coal use. Consumers is submitting the following information to support the requirements for Campbell Units 1, 2, & 3 that will achieve permanent cessation of coal combustion by December 31, 2028.

Pursuant to 40 CFR 423.19 (g)(4), an annual progress report shall detail the completion of any interim milestones listed in the NOPP since the previous progress report, provide a narrative discussion of any completed, missed, or delayed milestones, and provide updated milestones. An updated timeline, to reflect the requirements of 40 CFR 423.19(f)(4), is included in Attachment A. A copy of the official retirement filing as required under 40 CFR 423.19(f)(4)(ii), is included in Attachment B.

If you have any questions or need additional information, please do not hesitate to contact Rachel Proctor at (517) 788-1429 or by email at Rachel.proctor@cmsenergy.com.

I certify under penalty of law that this document and all attachments were prepared under my direction or supervision in accordance with a system designed to assure that qualified personnel properly gather and evaluate the information submitted. Based on my inquiry of the person or persons who manage the system, or those persons directly responsible for gathering the information, the information submitted is, to the best of my knowledge and belief, true,

Consumers Energy
Count on Us®

accurate, and complete. I am aware that there are significant penalties for submitting false information, including the possibility of fine and imprisonment for knowing violations.

Sincerely,

Nathan J. Hoffman
Consumers Energy
Executive Director of Fossil Generation

Electronically Distributed

CC: Ms. Rachel Proctor, Consumers Energy Company
Ms. Kristin Melcher, Consumers Energy Company, Campbell

Attachment A
Permanent Cessation Timeline Update

ACTIVITY – INTERIM MILESTONE	PROJECTED DATE OF COMPLETION	STATUS	NOTES
NOPP Submittal	10/13/2021	COMPLETE	
Expected Integrated Resource Plan (IRP) Approval by the MPSC	6/27/2022	COMPLETE	12/16/2022: The IRP was approved on June 23, 2022. A copy of the most recent integrated resource plan for which the applicable state agency approved the retirement of the unit subject to the Effluent Limitation Guidelines (ELGs), pursuant to 40 CFR 423.19(f)(2), was included as **Attachment B** in the 2022 Annual Progress Report.
Expected MISO Study Results	3/11/2022	COMPLETE	12/15/2023: MISO approved the suspension of Campbell Units 1, 2, & 3 effective June 1, 2025, on March 11, 2022
Cold & Dark[1] Outage Specifications Finalized	~~4/22/2024~~ 7/18/2024	COMPLETE	12/16/2022: Cold and Dark outage specifications are delayed; however, the delay in these final specifications will not impact Campbell Units 1, 2, and 3 retirement schedule, which are still expected to retire in 2025 consistent with the NOPP. The delay is due to the difference between the initial conceptual schedule and the refined project schedule.

ACTIVITY – INTERIM MILESTONE	PROJECTED DATE OF COMPLETION	STATUS	NOTES
Cold & Dark Contract Award	~~1/26/2025~~ 12/19/2024	ON SCHEDULE	12/16/2022: Change in date is due to the difference between the initial conceptual schedule and the refined project schedule.
MPSC[2] and MISO[3] approved Unit 1, 2, & 3 Retirement; Cold & Dark Outage Start	~~5/31/2025~~ 6/1/2025	ON SCHEDULE	12/10/2024: Suspension of Campbell Units 1,2 & 3, effective June 1, 2025. See **Attachment B.** 10/11/2021: 5/31/2025 is the expected date that JH Campbell Units 1, 2, and 3 will no longer generate electricity
Cold & Dark Outage Complete	~~9/6/2025~~ ~~8/31/2025~~ 10/31/2025	ON SCHEDULE	12/14/2023: The change in date will not impact Campbell Units 1, 2, and 3 retirement schedule. 10/11/2021: JH Campbell Units 1, 2, and 3 will be deenergized and ready for AD&D. The change in date is due to the difference between the initial conceptual schedule and the refined project schedule.

Notes:

(1) "Cold & Dark" refers to a period of time where preparations are put in place for Abatement, Decommissioning & Demolition (AD&D).

(2) MPSC is the Michigan Public Service Commission

(3) MISO is the Midcontinent Independent System Operator

Attachment B
Official Filing Pursuant to §423.19(g)(4)(ii)

Consumers Energy
Count on Us®

A CMS Energy Company

Timothy J. Sparks, P.E.
Vice President Electric Grid Integration

VIA Electronic Mail

December 14,2021

Andrew Witmeier
Director of Resource Utilization
Midcontinent Independent System Operator, Inc.
720 City Center Drive
Carmel, IN 46032

Re: Suspension of Campbell Units 1, 2 & 3

Dear Mr. Witmeier:

Consumers Energy Company ("Company") hereby provides notice to the Midcontinent Independent System Operator, Inc. ("MISO") that it intends to suspend Campbell Units 1, 2 and 3 effective June 1, 2025. Attached is the notice of such intent in accordance with Section 38.2.7 and Attachment Y of MISO's Open Access Transmission, Energy and Operating Reserve Markets Tariff ("Tariff").

Campbell Unit 3 is jointly owned by the Company (93.3%), CPNode CONS.CAMPBELL3, Michigan Public Power Agency (4.8%), CPNode CONS.CA3.MPPA, and Wolverine Power Supply Cooperative (1.9%), CPNode CONS.CA3_WPSC. The Company attests that, pursuant to the relevant Operating Agreements, it is authorized to submit this Attachment Y notice on behalf of all Campbell Unit 3 owners.

In the event you have any questions regarding this matter, please contact Kathy Wetzel at (517) 788-2039.

Regards,

Timothy J. Sparks
Vice President Electric Grid Integration
Consumers Energy Company
1945 W. Parnall Rd.
Jackson, MI 49201

Cc: Kathy Wetzel
Thomas Clark

ATTACHMENT Y

Notification of Generation Resource/SCU/Pseudo-tied Out Generator

Change of Status,

Including Notification of Rescission

This is a notification of change of status of a Generation Resource, Synchronous Condenser Unit ("SCU"), or Pseudo-tied out Generator in accordance with Section 38.2.7.a of the Tariff. An electronic copy of the completed form will be accepted by the Transmission Provider, however, a form will not be considered complete until the original form containing an original signature, including all attachments, is received by the Transmission Provider at the following address: MISO, Attention: Director of Transmission Planning; 720 City Center Drive, Carmel, IN 46032.

The Transmission Provider may request additional information as reasonably necessary to support operations under the Tariff.

Owner of the Generation Resource, SCU or Pseudo-tied out Generator:
Consumers Energy Company (see attached letter re: Campbell Unit 3)

Name of Market Participant: Consumers Energy Company - NERC ID: CETR

Owner's state of organization or incorporation Michigan

Generation Resource/SCU/Pseudo-tied Out Generator [plant and unit number(s)] Campbell Units 1, 2 & 3

Source/Identification of Generation Interconnection Service [name of agreement, parties, date, date filed and docket number, and any other information to identify an agreement] CAMPBELL UNITS 1+2: UMBRELLA GIA BETWEEN CONSUMERS, METC+MISO FERC DOCKET ER21-999. CAMPBELL UNIT 3: FERC DOCKET ER06-1441 FOR MISO SERVICE AGREEMENT NO. 1755

Pursuant to the terms of the MISO Tariff, Owner hereby certifies that it will

[X] Suspend for economic reasons operation of all or a portion of the Generation Resource/SCU/Pseudo-tied out Generator commencing on 1st [day] of June [month] of 2025 [year]

[ ] Rescind the current notice to SuspendThe facility is further described as follows:

Location: West Olive, Michigan

Unit Name	CPNode (if applicable)	Nameplate Capacity(MW)	Change in Capacity(MW)
Campbell Unit 1	CONS.CAMPBELL1	260	260
Campbell Unit 2	CONS.CAMPBELL2	360	360
Campbell Unit 3	CONS.CAMPBELL3	844	844

Owner understands and agrees that this notification is provided in accordance with Section 38.2.7 of the Transmission Provider's Tariff and will not be made public by the Transmission Provider except as provided for under Section 38.2.7 of the Tariff.

The undersigned certifies that he or she is an officer of the owner of the Generation Resource/SCU/Pseudo-tied out Generator, that he or she is authorized to execute and submit this notification, and that the statements contained herein are true and correct.

Signature

Name: TIMOTHY J SPARKS

Title: VP ELECTRIC GRID INTEGRATION

Date:

Contact Information

Email: TIMOTHY.SPARKS@CMSENERGY.COM

Phone: 517 788 1053

Andrew Witmeier
Director, Resource Utilization
317-249-5585
awitmeier@misoenergy.org

VIA OVERNIGHT DELIVERY

March 11, 2022

Timothy J. Sparks
Vice President, Electric Grid Integration
Consumers Energy Company
1945 W. Parnall Rd.
Jackson, MI 49201

Subject: **Approval of Campbell Units 1,2 &3 Attachment Y Suspension Notice**

Dear Mr. Sparks,

On December 14, 2021, Consumers Energy Company submitted an Attachment Y Notice to MISO for the suspension of Campbell Units 1,2 & 3, effective June 1, 2025. After being reviewed for power system reliability impacts as provided for under Section 38.2.7 of MISO's Open Access Transmission, Energy, and Operating Reserve Markets Tariff ("Tariff"), the suspension of Campbell Units 1,2 & 3 would not result in violations of applicable reliability criteria. Therefore, Campbell Units 1,2 & 3 may suspend without the need for the generators to be designated as a System Support Resource ("SSR") units as defined in the Tariff.

As there were no reliability criteria violations, MISO will continue to preserve the confidentiality of the Attachment Y Notice.

Please do not hesitate to contact me if you have any questions regarding this matter.

Respectfully,

Andrew Witmeier
Director, Resource Utilization

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c)	)	
Emergency Order: Midcontinent	)	Order No. 202-25-3
Independent System Operator	)	
(MISO)	)	
	)	

Exhibit to
Motion to Intervene and Request for Rehearing and Stay of
Public Interest Organizations

Filed June 18, 2025

Exhibit 30

DOE Rehearing Procedures

U.S. DEPARTMENT of ENERGY

DOE 202(c) Order Rehearing Procedures

DOE may revise these procedures through advance written notification to the parties and posting here.

Intervention. Any person seeking to intervene to become a party must file a written motion to intervene by emailing AskCR@hq.doe.gov. A motion to intervene must state the movant's interest in sufficient factual detail to demonstrate that the movant has or represents an interest which may be directly and substantially affected by the outcome of the proceeding. A motion to intervene must be filed within 30 days after the issuance of a section 202(c) order, which includes an original order or a renewal order. No grant of late intervention is permitted unless DOE finds good cause. The grant of party status will be expressly stated by DOE order within thirty days of filing. A motion to intervene may be combined with a motion for rehearing, answer, or other motion.

Rehearing. Pursuant to 16 U.S. Code § 825*l*, any party applying for rehearing must file a written motion for rehearing by emailing AskCR@hq.doe.gov within 30 days after the issuance of a section 202(c) order. The motion for rehearing must set forth specifically the ground or grounds upon which such motion is based and must contain a clear and concise statement of the facts and law which support the motion and the specific relief or ruling requested. Any grounds not specifically identified in such motion shall be waived. All motions for rehearing will be addressed in a consolidated proceeding and order on rehearing. Unless DOE acts upon the motion for rehearing within 30 days of filing, such motion may be deemed to have been denied.

Answers. Any party may file an answer to another party's motion by emailing AskCR@hq.doe.gov within 7 days after the motion is filed. An answer must contain a clear and concise statement of any disputed factual allegations and any law upon which the answer relies. An answer to an answer is not permitted.

Timing and Service. DOE will use best efforts to post filings here within 24 hours of receipt. Such posting constitutes service to all parties. Filing or posting due dates that fall on a federal holiday or weekend shall be extended to the next business day. Documents received after 4:30 p.m. Eastern Time are deemed filed on the next business day.

Confidentiality. DOE strongly encourages that all filings be limited to information suitable for public release. If procedures to maintain confidentiality are requested, DOE will provide them as needed at the discretion of DOE.

Committed to Restoring America's Energy Dominance.

Quick Links

Leadership & Offices

Mission

Contact Us

Careers

Resources

Budget & Performance

Directives, Delegations, & Requirements

Freedom of Information Act (FOIA)

Inspector General

Privacy Program

Federal Government

USA.gov

The White House

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Midcontinent Independent System Operator (MISO)	)))))	Order No. 202-25-3

Exhibit to
Motion to Intervene and Request for Rehearing and Stay of
Public Interest Organizations

Filed June 18, 2025

Exhibit 31

MISO 2025–26 Auction Results

Planning Resource Auction
Results for Planning Year 2025-26

April 2025

CORRECTIONS
Reposted 05/29/25

Slides Updated: 7, 11, 18-20, 23, 32-34

MISO met the planning year 2025/26 resource adequacy requirements, but pressure persists with reduced capacity surplus across the region and is reflected through improved price signals in this year's auction

Summer
$666.50
—
Fall
$91.60 (North/Central)
$74.09 (South)
—
Winter
$33.20
—
Spring
$69.88
—
Annualized
$217 (North/Central)
$212 (South)

- MISO's Reliability-Based Demand Curve (RBDC) improves price signals, reflecting the increased value of accredited capacity beyond the seasonal Planning Reserve Margin (PRM) target
  - For example, the auction cleared 1.9% above the 7.9% summer PRM target
- Summer price reflects the lowest available surplus capacity
  - Fall price varied slightly due to transfer limitations between the North and South
- Consistent with past years, most Load Service Entities (LSEs) self-supplied or secured capacity in advance and are hedged with respect to auction prices
- Surplus above the target PRM dropped 43% compared to last summer, despite the slightly lower PRM target (7.9% vs. 9.0% last year)
  - New capacity additions did not keep pace with reduced accreditation, suspensions/retirements and slightly reduced imports
- The results reinforce the need to increase capacity, as demand is expected to grow with new large load additions

Auction outcomes are consistent with the design intent of the Reliability-Based Demand Curve (RBDC), and MISO and its members can expect more stable and predictable capacity pricing, especially in surplus situations

In the 2025 PRA, the RBDC…

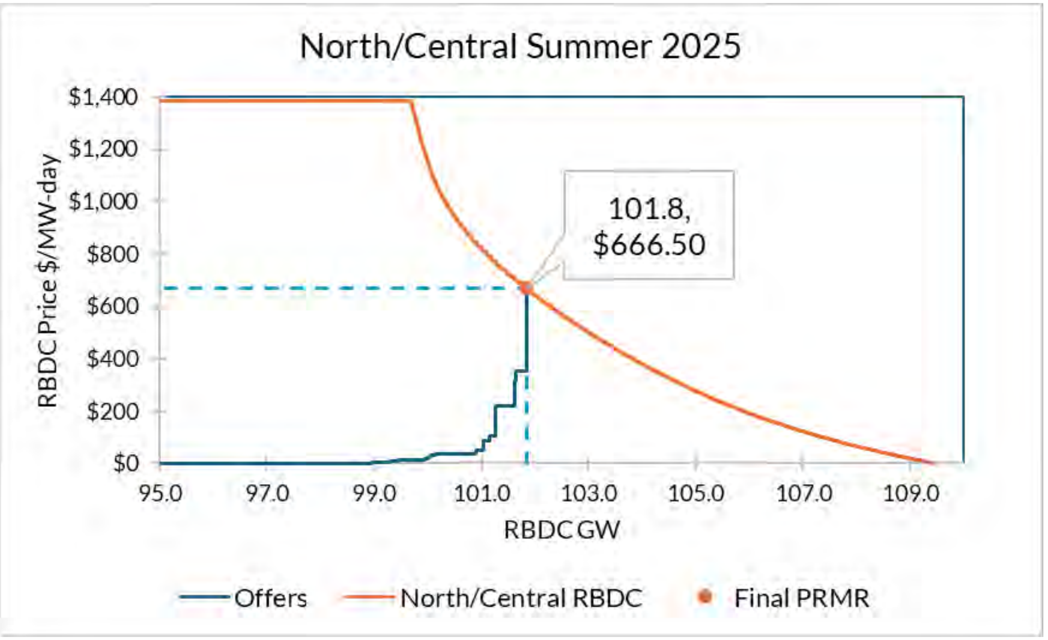
- Delivers competitive prices aligned with seasonal risks and tightening surplus
  - Prioritizes summer availability, the system's highest-risk season (based on 1-in-10 LOLE)
- Values incremental capacity above and below the LOLE target based on its reliability
  - Clears capacity above target Planning Reserve Margin based on its reliability value in each season
- Stabilizes prices in non-summer seasons, avoiding extreme volatility

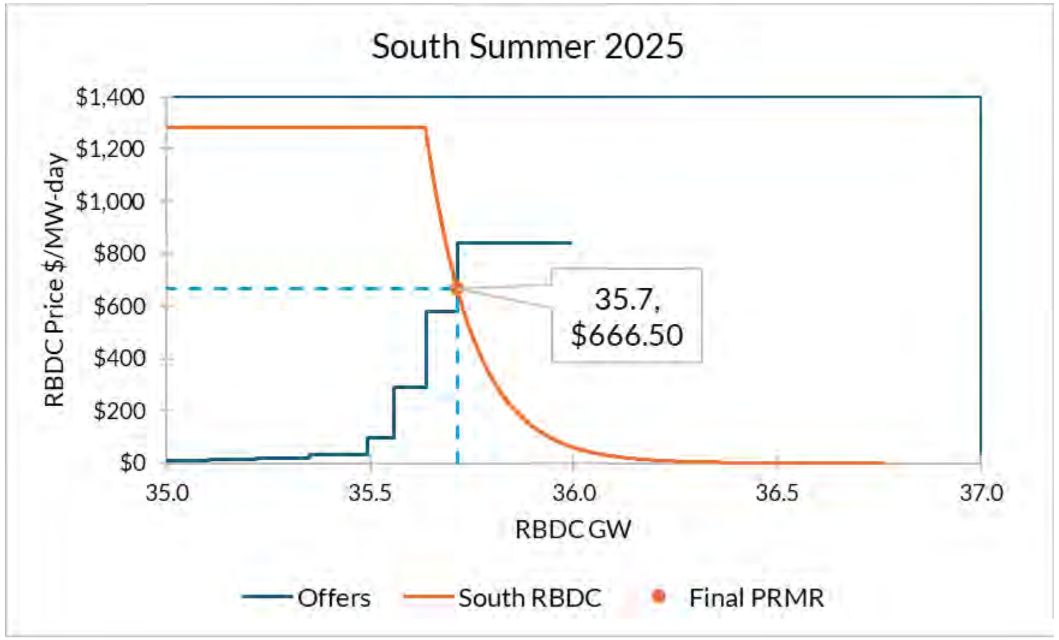
Why it Matters

- Sends clear and stable investment signals across the system, including to external resources
- Provides transparent value for capacity that exceeds the Planning Reserve Margin target
- Reflects subregional capacity needs and clears accordingly across all seasons

LOLE: Loss of Load Expectation

Auction pricing outcomes with the Reliability-Based Demand Curve (RBDC) better reflect value of capacity and resource adequacy risk across seasons





- Summer clearing of $666.50 reflects highest reliability risk and reducing surplus capacity year-over-year
  - Surplus capacity in the summer has reduced from approximately 6.5 GW in 2023, to 4.6 GW in 2024, to 2.6 GW in 2025
- Incremental capacity cleared beyond the target Planning Reserve Margin based on the value it adds to reliability (e.g., North/Central "effective" summer margin at 10.1% and South at 8.7% vs. target 7.9%)
  - A small quantity of capacity, that was offered at a price higher than the reliability value indicated through the demand curve, did not clear

LOLE: Loss of Load Expectation

MISO's Reliability-Based Demand Curve (RBDC) improves price signals, reflecting the increased value of accredited capacity beyond seasonal reliability targets

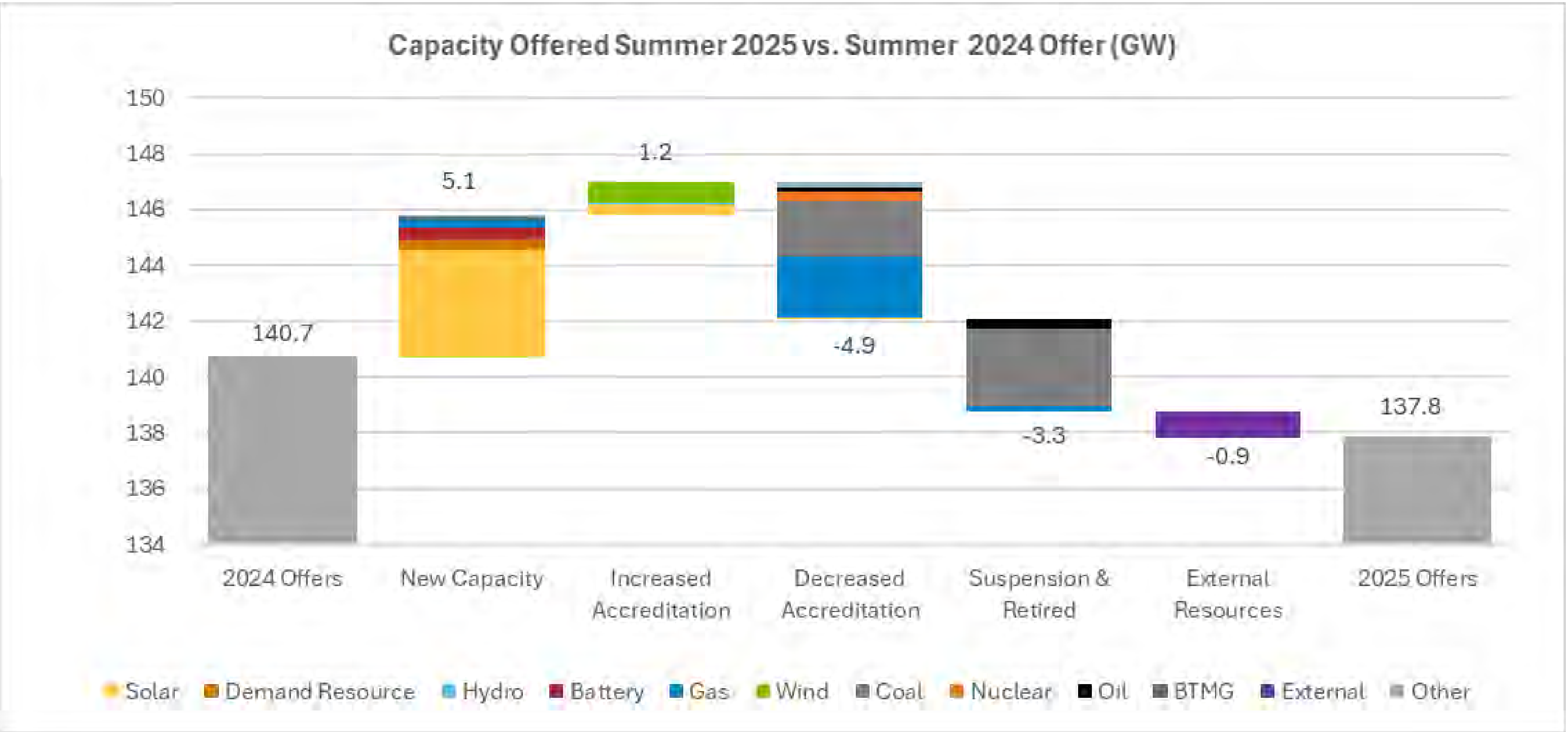
- Under RBDC, each season has an initial reliability target (PRM%)
- Auction cleared above seasonal final reliability target, representing additional reliability value at cost-competitive prices

	2025 Planning Resource Auction Initial Target vs. Final Cleared	Additional Reliability	Auction Clearing Price
Summer	Initial, 7.90% Cleared, 9.80%	+1.9%	$666.50
Fall	Initial, 14.90% Cleared, 17.50%	+2.6%	$91.60 N/C $74.09 S
Winter	Initial, 18.40% Cleared, 24.50%	+6.1%	$33.20
Spring	Initial, 25.30% Cleared, 26.80%	+1.5%	$69.88

Annualized
$217 (North/Central)
$212 (South)

PRM: Planning Reserve Margin

New capacity additions did not keep pace with decreased accreditation, suspensions/ retirements and external resources



BTMG: Behind the Meter Generation | Capacity indicated is offered accredited value

MISO has taken action on many Reliability Imperative initiatives to address resource adequacy challenges, but there's more to be done

Ongoing Challenges

- Accelerating demand for electricity
- Rapid pace of generation retirements continue
- Loss of accredited capacity and reliability attributes
- Majority of new resources with variable, intermittent output and high weather correlation
- Delays of new resource additions
- More frequent extreme weather

Completed Initiatives

- ✓ Implemented Reliability-Based Demand Curve in 2025 PRA
- ✓ Non-emergency resource accreditation *(effective PY 2028/29)*
- ✓ Generation interconnection queue cap
- ✓ Improved generator interconnection queue process (*New application portal coming June 2025)*
- ✓ Approved over $30 billion in new transmission lines

Initiatives In Progress

- ❑ Implement Direct Loss of Load (DLOL)-based accreditation
- ❑ Enhance resource adequacy risk modeling
- ❑ Reduce queue cycle times through automation
- ❑ Implement interim Expedited Resource Addition Study (ERAS) process *(June 2025)*
- ❑ Demand Response and Emergency Resource reforms
- ❑ Enhance allocation of resource adequacy requirements

Next Steps

April 28

2025 PRA Results Posted

May 21

Zonal deliverability benefits available at the May RASC
—
MISO publishes cleared Load Modifying Resources to Operations tools

May 28

Posting of PRA masked offer data per Module E-1 69 A.7.4

June 1

2025 PRA prices go into affect
—
New Planning Year starts

Appendix

Table of Contents

Acronyms

ACP: Auction Clearing Price

ARC: Aggregator of Retail Customers

BTMG: Behind the Meter Generator

CIL: Capacity Import Limit

CEL: Capacity Export Limit

CONE: Cost of New Entry

CPF: Coincident Peak Forecast

DLOL: Direct Loss-of-Load

DR: Demand Resource

ELCC: Effective Load Carrying Capability

EE: Energy Efficiency

ER: External Resource

ERAS: Expedited Resource Addition Study

ERZ: External Resource Zones

FRAP: Fixed Resource Adequacy Plan

ICAP: Installed Capacity

IMM: Independent Market Monitor

LBA: Load Balancing Authority

LCR: Local Clearing Requirement

LOLE: Loss of Load Expectation

LMR: Load Modifying Resource

LRR: Local Reliability Requirement

LRZ: Local Resource Zone

LSE: Load Serving Entity

OMS: Organization of MISO States

PO: Planned Outage

PRA: Planning Resource Auction

PRM: Planning Reserve Margin

PRMR: Planning Reserve Margin Requirement

RASC: Resource Adequacy Sub-Committee

RBDC: Reliability-Based Demand Curve

SAC: Seasonal Accredited Capacity

SREC: Sub-Regional Export Constraint

SRIC: Sub-Regional Import Constraint

SRPBC: Sub-Regional Power Balance Constraint

SS: Self Schedule

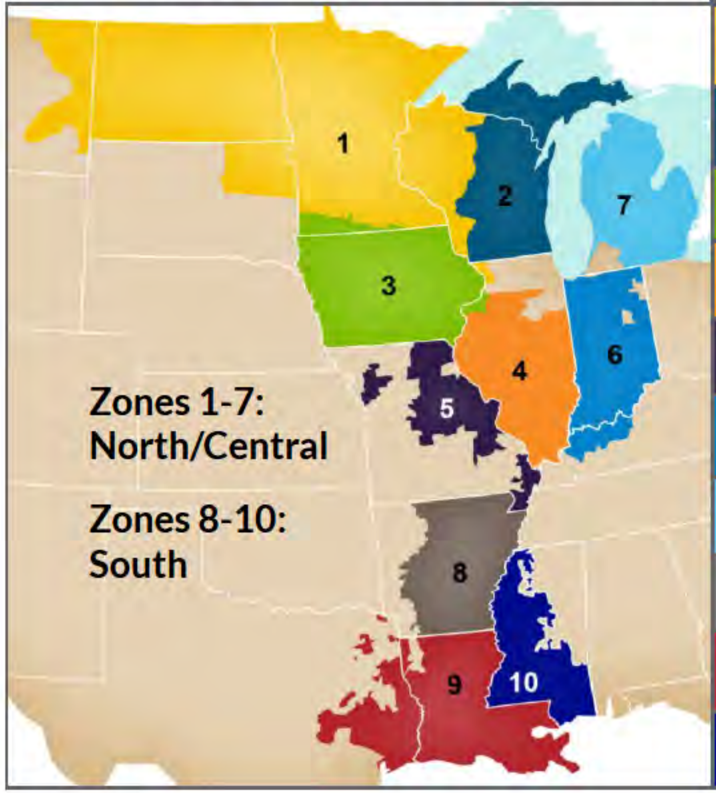
UCAP: Unforced Capacity

ZIA: Zonal Import Ability

ZRC: Zonal Resource Credit

The 2025 PRA demonstrated sufficient capacity at the regional, subregional and zonal levels, with the summer price reflecting the highest risk and a tighter supply-demand balance

MISO Resource Adequacy Zones



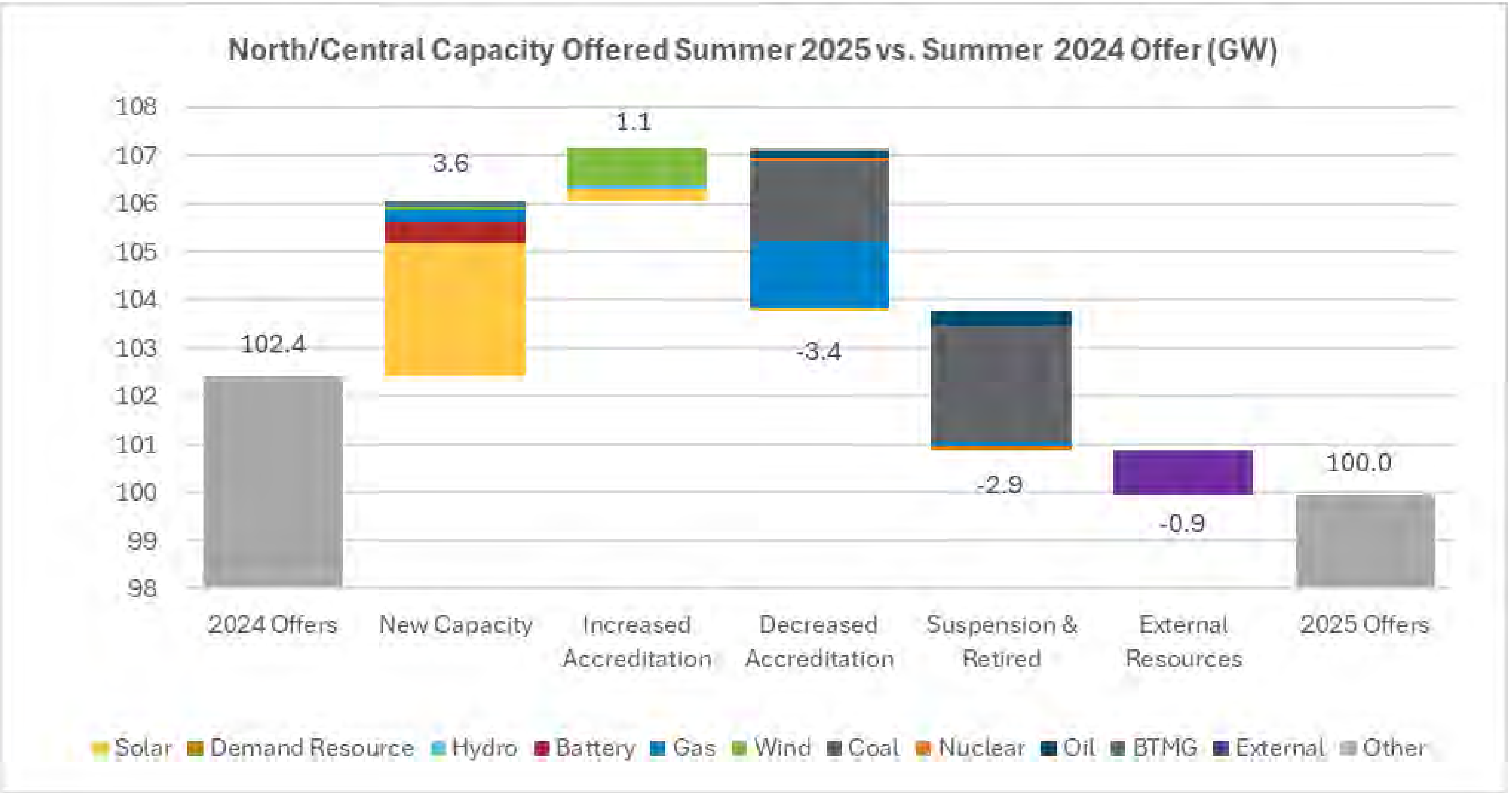
2025 PRA Results

<table>
<tr><th></th><th colspan="4">Price/MW-Day</th></tr>
<tr><th></th><th>Summer</th><th>Fall</th><th>Winter</th><th>Spring</th></tr>
<tr><td>1</td><td rowspan="10">$666.50</td><td rowspan="7">$91.60</td><td rowspan="10">$33.20</td><td rowspan="10">$69.88</td></tr>
<tr><td>2</td></tr>
<tr><td>3</td></tr>
<tr><td>4</td></tr>
<tr><td>5</td></tr>
<tr><td>6</td></tr>
<tr><td>7</td></tr>
<tr><td>8</td><td rowspan="3">$74.09</td></tr>
<tr><td>9</td></tr>
<tr><td>10</td></tr>
</table>

Annualized
$217 (North/Central)
$212 (South)

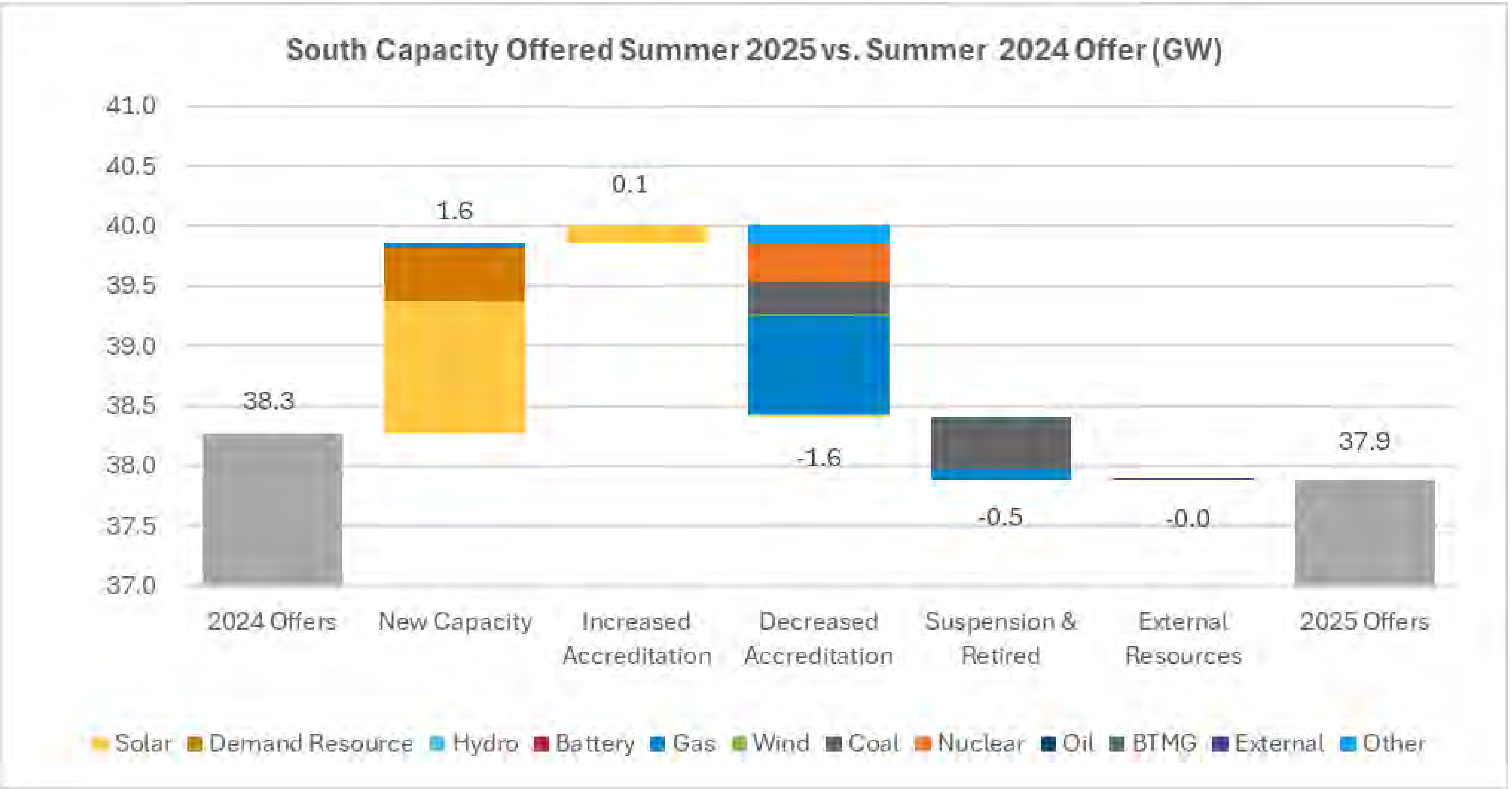
05/29/2025: MISO Planning Resource Auction for Planning Year 2025/26 Results Posting

For North/Central, new capacity additions were insufficient to offset the negative impacts of decreased accreditation, suspensions/retirements and external resources



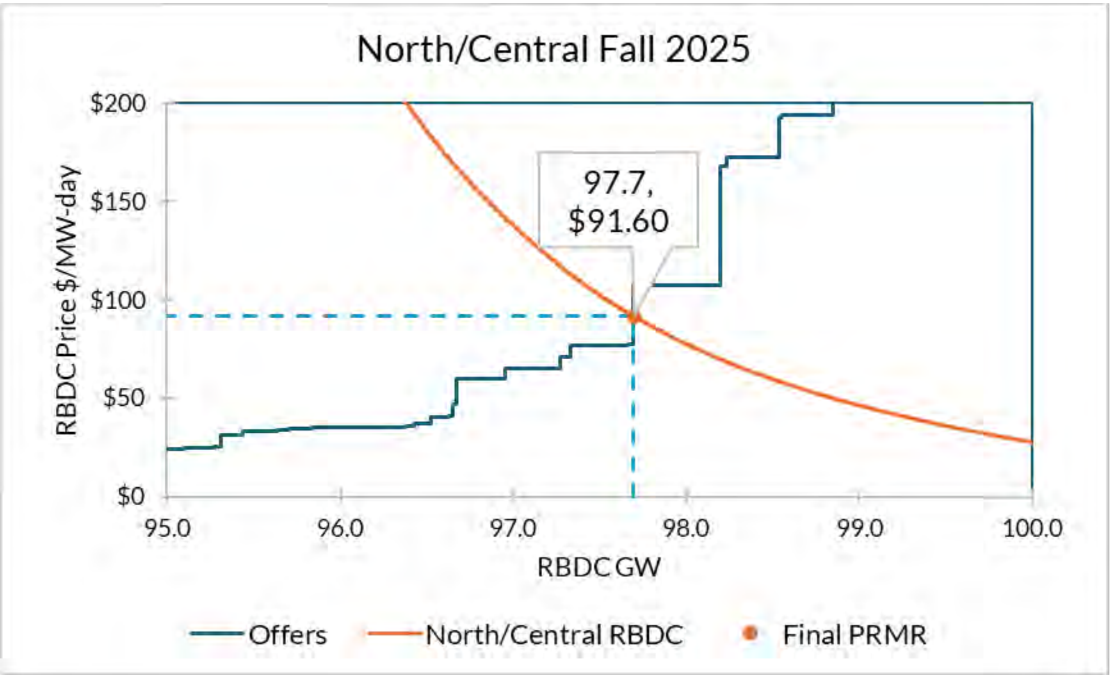
BTMG: Behind the Meter Generation | Capacity indicated is offered accredited value

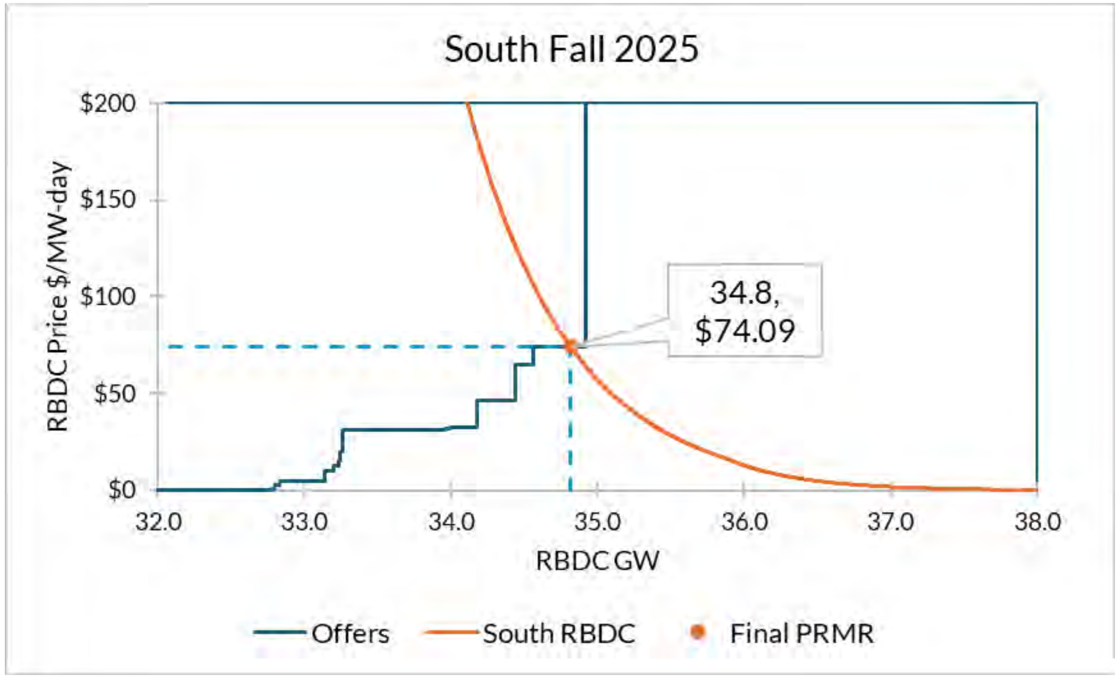
For the South, new capacity additions nearly offset the negative impacts of decreased accreditation, suspensions/retirements



BTMG: Behind the Meter Generation | Capacity indicated is offered accredited value

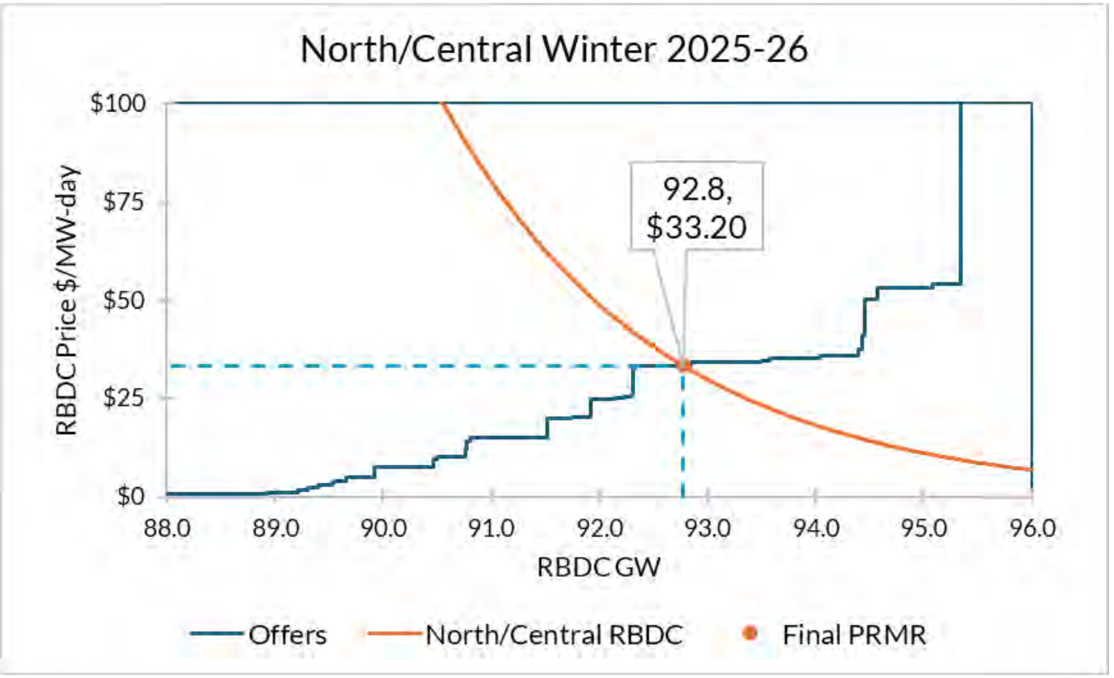
Fall 2025 Reliability-Based Demand Curve, Offer Curves and Auction Clearing Prices

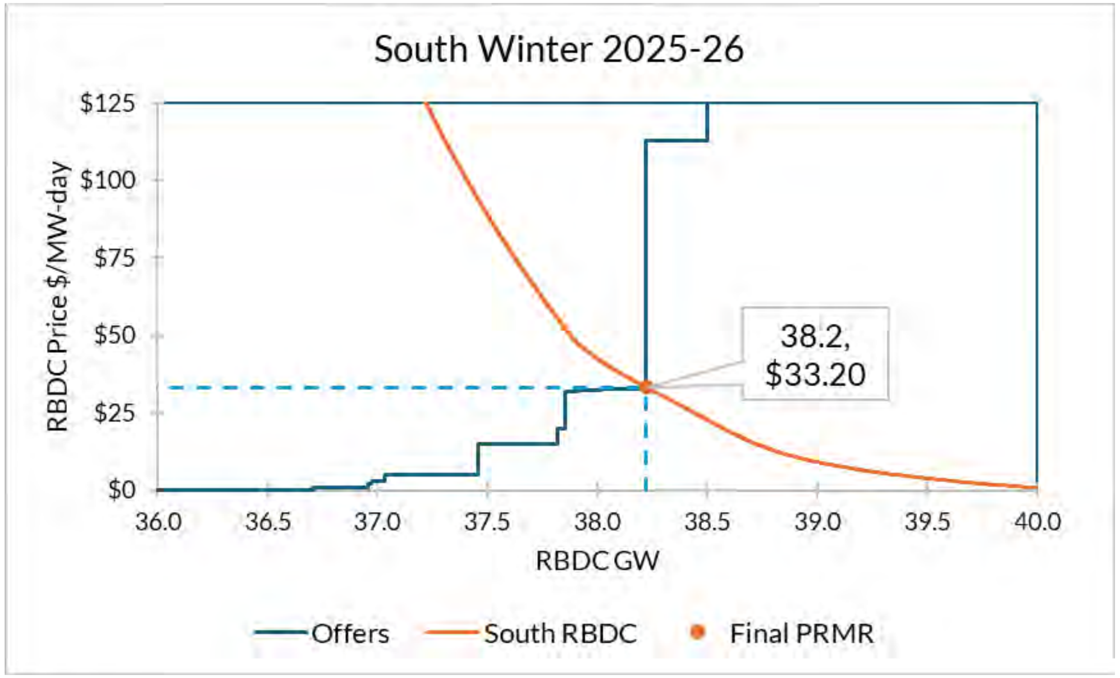




- Subregional RBDCs are determining clearing for both subregions
- Subregional Power Balance Constraint (SRPBC), South to North, is binding resulting in price separation between North/Central and South subregions in Fall season
    - ACP for North subregion is $91.60, and $74.09 South subregion
    - A marginal resource in the South sets the price in that subregion
- In fall season, “effective” margin for North/Central subregion is at 18.4% and 15.2 % for South subregion vs. target of 14.9%

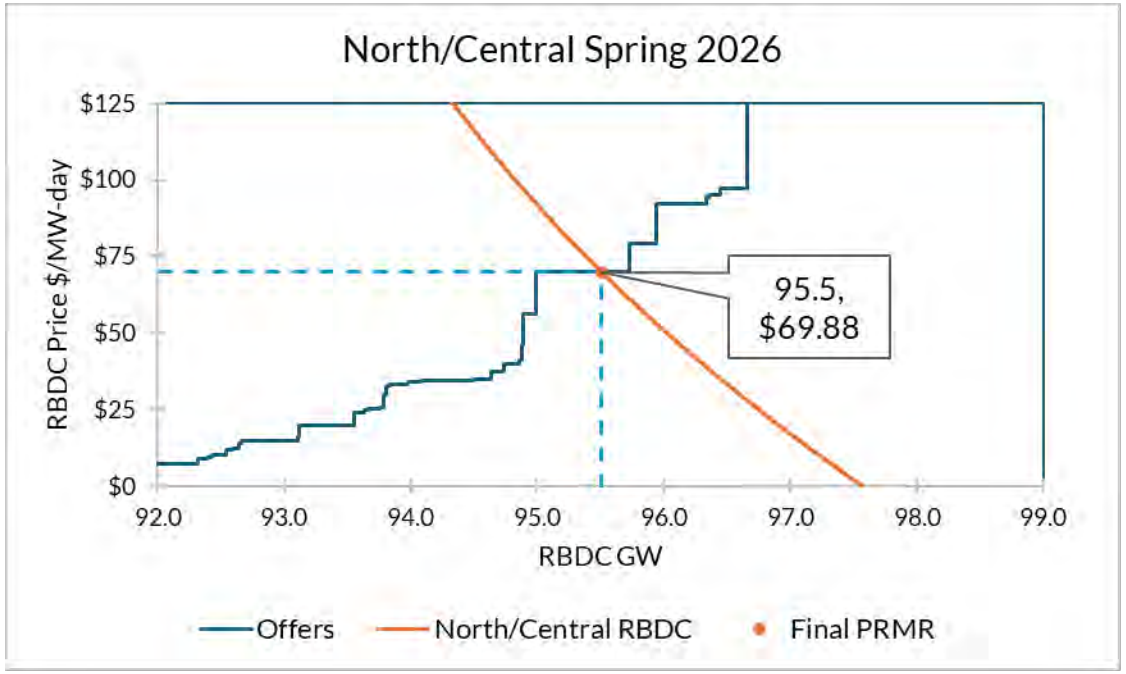
Winter 2025/26 Reliability-Based Demand Curve, Offer Curves and Auction Clearing Prices

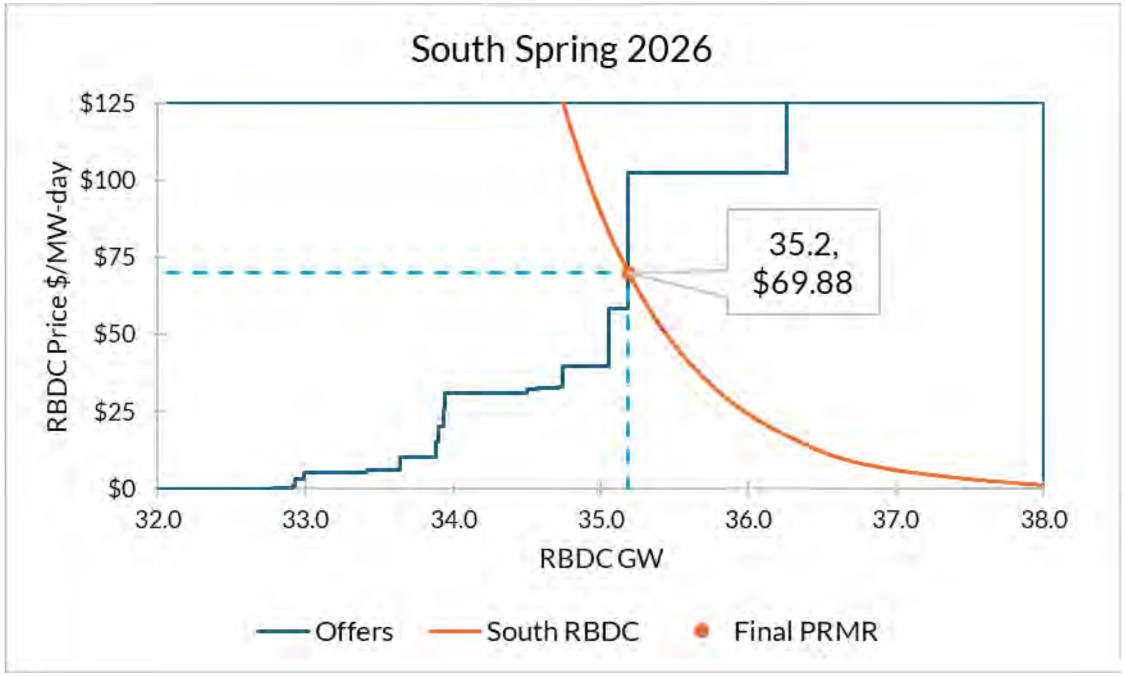




- Subregional RBDCs are determining clearing for both subregions
- No price separation between North/Central and South subregions in winter
  - ACP for both subregions is $33.20
  - Multiple marginal resources, cleared *pro rata*, sets the price
- In winter, "effective" margin for North/Central subregion is at 23.3% and $27.3% for South subregion vs. target of 18.4%

Spring 2026 Reliability-Based Demand Curve, Offer Curves and Auction Clearing





- Subregional RBDCs are determining clearing for both subregions
- No price separation between North/Central and South subregions in spring
  - ACP for both subregions is $69.88
  - A marginal resource sets the price
- In spring, “effective” margin for North/Central subregion is at 27.5% and 25% for South subregion vs. target of 25.3%

Summary 2025 PRA Results by Zone

	Z1	Z2	Z3	Z4	Z5	Z6	Z7	Z8	Z9	Z10	ERZ	North	South	System
Initial PRMR	18,459.4	13,190.2	10,889.2	9,237.6	8,281.3	18,484.8	21,228.0	8,487.8	21,812.2	5,142.9	N/A	99,770.5	35,442.9	135,213.4
Final PRMR	18,843.5	13,464.4	11,116.0	9,430.10	8,453.5	18,868.9	21,669.2	8,552.6	21,978.8	5,182.3	N/A	101,845.6	35,713.7	137,559.3
Offer Submitted (Including FRAP)	19,732.4	14,569.7	11,321.4	9,328.1	6,737.9	16,123.6	20,883.9	11,517.3	20,498.6	5,543.3	1580.1	99,952.6	37,883.7	137,836.3
FRAP	4,619.2	10,252.6	456.9	789.4	0.0	1,080.7	541.3	494.9	157.5	1,507.7	46.8	17,779.2	2,167.8	19,947.0
RBDC Opt-Out	-	-	-	-	-	-	-	-	-	-	-	0.0	0.0	0.0
Self Scheduled (SS)	4,985.3	3,344.1	10,450.2	7,677.2	6,647.8	11,080.3	20,305.5	10,260.6	17,870.6	3,831.3	1,358.8	65,567.6	32,244,1	97,811.7
Non-SS Offer Cleared	10,127.9	973.0	414.3	861.5	90.1	3,962.6	37.1	761.8	2,193.5	204.3	174.5	16,605.8	3,194.8	19,800.6
Committed (Offer Cleared + FRAP)	19,732.4	14,569.7	11,321.4	9,328.1	6,737.9	16,123.6	20,883.9	11,517.3	20,221.6	5,543.3	1,580.1	99,952.6	37,606.7	137,559.3
LCR	15,696.9	9,719.3	8,049.3	2,577.8	6,071.1	13,051.7	19,681.4	8,487.0	19,615.0	2,523.8	-	N/A	N/A	N/A
CIL	6,025	4,370	5,555	8,525	4,117	8,651	3,569	2,568	4,361	4,474	-	N/A	N/A	N/A
ZIA	6,023	4,370	5,460	7,757	4,117	8,366	3,569	2,358	4,361	4,474	-	N/A	N/A	N/A
Import	0.0	0.0	0.0	101.7	1,715.5	2,745.5	785.5	0.0	1,757.1	0.0	-	1,893.0	0.0	1,580.1
CEL	3,991	4,614	4,618	4,584	3,939	6,881	5,726	6,299	4,286	2,097	-	N/A	N/A	N/A
Export	888.8	1105.2	205.5	0.0	0.0	0.0	0.0	2964.7	0.0	360.9	1,580.1	0.0	1,893.0	-
ACP ($/MW-Day)	666.50	666.50	666.50	666.50	666.50	666.50	666.50	666.50	666.50	666.50	666.50			N/A

Values displayed in MW SAC; ERZ: External Resource Zones *Final PRMR values provided at Zonal level given lack of RBDC Opt-Out.*

Fall 2025 PRA Results by Zone

	Z1	Z2	Z3	Z4	Z5	Z6	Z7	Z8	Z9	Z10	ERZ	North	South	System
Initial PRMR	17,290.4	12,086.4	10,179.1	8,950.4	7,898.3	17,939.5	20,493.9	8,019.3	21,578.1	5,142.6	N/A	94,838.0	34,740.0	129,578.0
Final PRMR	17,811.9	12,450.7	10,486.0	9,220.4	8,136.0	18,480.2	21,111.9	8,037.4	21,627.1	5,154.2	N/A	97,697.1	34,818.7	132,515.8
Offer Submitted (Including FRAP)	18,893.1	14,291.7	13,615.9	8,887.5	6,839.6	15,518.1	19,517.6	11,000.8	21,112.5	5,516.6	1,582.1	98,835.3	37,940.2	136,775.5
FRAP	4,233.2	9,259.1	582.7	773.3	0.0	983.1	533.1	459.4	153.4	1,518.3	44.6	16,402.6	2,137.6	18,540.2
RBDC Opt-Out	-	-	-	-	-	-	-	-	-	-	-	0.0	0.0	0.0
Self Scheduled (SS)	4,646.8	3,423.5	10,580.4	7,036.0	6,706.5	10,590.4	16,911.4	9,029.4	17,788.1	3,286.3	1,208.0	60,831.1	30,375.7	91,206.8
Non-SS Offer Cleared	9,019.0	834.8	2,452.8	1,078.2	133.1	3,728.7	1,089.1	1,512.0	2,406.6	254.9	259.6	18,563.3	4,205.5	22,768.8
Committed (Offer Cleared + FRAP)	17,899.0	13,517.4	13,615.9	8,887.5	6,839.6	15,302.2	18,533.6	11,000.8	20,348.1	5,059.5	1,512.2	95,797.1	36,718.7	132,515.8
LCR	14,691.0	6,591.1	6,331.4	2,588.7	4,857.2	11,725.4	18,196.1	5,006.3	18,963.6	2,577.6	-	N/A	N/A	N/A
CIL	5,740	6,537	7,797	7,773	4,679	8,952	5,115	5,839	4,741	4,508	-	N/A	N/A	N/A
ZIA	5,688	6,537	7,704	7,013	4,679	8,672	5,115	5,675	4,741	4,508	-	N/A	N/A	N/A
Import	0.0	0.0	0.0	332.8	1,296.8	3,178.0	2,578.2	0.0	1,278.9	94.7	-	1,900.0	0.0	1,512.2
CEL	6,115	4,259	5,831	4,309	5,816	5,191	5,168	4,055	4,173	3,164	-	N/A	N/A	N/A
Export	87.2	1,066.8	3,129.9	0.0	0.0	0.0	0.0	2,963.3	0.0	0.0	1,512.2	0.0	1,900.0	-
ACP ($/MW-Day)	91.60	91.60	91.60	91.60	91.60	91.60	91.60	74.09	74.09	74.10	83.24-91.60			N/A

Values displayed in MW SAC; ERZ: External Resource Zones

Final PRMR values provided at Zonal level given lack of RBDC Opt-Out.

Winter 2025/26 PRA Results by Zone

	Z1	Z2	Z3	Z4	Z5	Z6	Z7	Z8	Z9	Z10	ERZ	North	South	System
Initial PRMR	17,823.8	10,789.8	9,889.1	8,549.5	7,954.8	17,939.1	16,123.6	8,545.6	21,864.3	5,136.1	N/A	89,069.7	35,546.0	124,615.7
Final PRMR	18,565.8	11,238.7	10,300.9	8,905.1	8,285.9	18,685.7	16,794.7	9,189.0	23,511.0	5,522.7	N/A	92,776.8	38,222.7	130,999.5
Offer Submitted (Including FRAP)	19,750.7	13,217.2	12,059.1	7,547.1	6,339.9	14,679.5	19,957.3	10,751.9	22,273.0	5,939.7	1,746.5	94,964.8	39,297.1	134,261.9
FRAP	4,683.9	8,342.7	479.4	513.4	0.0	1,176.6	566.3	441.6	130.9	1,822.6	16.1	15,771.2	2,402.3	18,173.5
RBDC Opt-Out	-	-	-	-	-	-	-	-	-	-	-	0.0	0.0	0.0
Self Scheduled (SS)	5,835.8	3,156.0	10,468.3	6,685.7	6,188.7	9,146.2	18,640.6	10,018.6	18,579.3	4,046.0	1,550.8	61,380.9	32,935.1	94,316.0
Non-SS Offer Cleared	7,977.9	1,062.6	1,044.5	271.5	99.9	4,008.7	397.0	291.7	3,105.5	71.1	179.6	15,007.6	3,502.4	18,510.0
Committed (Offer Cleared + FRAP)	18,497.6	12,561.3	11,992.2	7,470.6	6,288.6	14,331.5	19,603.9	10,751.9	21,815.7	5,939.7	1,746.5	92,159.7	38,839.8	130,999.5
LCR	13,462.0	5,951.6	8,008.4	1,371.4	3,644.7	11,074.8	15,500.2	8,014.7	20,593.7	3,534.1	-	N/A	N/A	N/A
CIL	6,177	6,522	5,877	7,232	4,922	7,927	4,762	3,613	4,418	3,458	-	N/A	N/A	N/A
ZIA	5,575	6,435	5,785	6,457	4,922	7,690	4,762	3,432	4,418	3,458	-	N/A	N/A	N/A
Import	68.0	0.0	0.0	1,434.8	1,997.3	4,354.1	0.0	0.0	1,695.2	0.0	-	617.1	0.0	1,746.5
CEL	2,991	4,706	7,388	4,756	4,814	1,674	5,712	3,602	3,618	2,028	-	N/A	N/A	N/A
Export	0.0	1,322.6	1,691.5	0.0	0.0	0.0	2,809.2	1,562.8	0.0	416.9	1,746.5	0.0	617.1	0.0
ACP ($/MW-Day)	33.20	33.20	33.20	33.20	33.20	33.20	33.20	33.20	33.20	33.20	33.20			N/A

Values displayed in MW SAC; ERZ: External Resource Zones *Final PRMR values provided at Zonal level given lack of RBDC Opt-Out.*

Spring 2026 PRA Results by Zone

	Z1	Z2	Z3	Z4	Z5	Z6	Z7	Z8	Z9	Z10	ERZ	North	South	System
Initial PRMR	17,866.7	12,149.2	10,152.2	8,304.0	7,707.9	17,858.6	19,853.2	7,977.8	22,139.8	5,167.9	N/A	93,891.8	35,285.5	129,177.3
Final PRMR	18,174.5	12,358.6	10,327.0	8,447.2	7,841.0	18,166.7	20,195.5	7,955.2	22,076.1	5,157.7	N/A	95,510.5	35,189.0	130,699.5
Offer Submitted (Including FRAP)	18,662.6	14,525.3	12,333.3	9,178.5	6,118.7	15,824.7	19,451.0	11,495.2	21,064.7	5,864.0	1,542.6	97,313.7	38,746.9	136,060.6
FRAP	4,560.6	9,393.4	529.5	629.6	0.0	1,212.4	512.5	475.3	142.1	1,464.3	45.9	16,877.1	2,088.5	18,965.6
RBDC Opt-Out	-	-	-	-	-	-	-	-	-	-	-	0.0	0.0	0.0
Self Scheduled (SS)	4,600.8	3,602.8	10,816.2	7,415.0	5,968.5	9,967.6	17,621.9	8,476.0	16,778.9	4,073.9	1,260.8	60,972.6	29,609.8	90,582.4
Non-SS Offer Cleared	8,578.5	1,069.5	589.6	1,133.9	150.2	4,001.0	719.2	1,470.2	2,947.5	325.8	166.1	16,372.9	4,778.6	21,151.5
Committed (Offer Cleared + FRAP)	17,739.9	14,065.7	11,935.3	9,178.5	6,118.7	15,181.0	18,853.6	10,421.5	19,868.5	5,864.0	1,472.8	94,222.5	36,477.0	130,699.5
LCR	12,239.1	6,737.5	5,014.7	1,823.8	4,700.3	10,377.1	16,453.6	4,243.1	19,790.5	3,178.8	-	N/A	N/A	N/A
CIL	6,598	6,439	7,829	8,142	4,453	9,457	5,166	6,289	4,855	4,365	-	N/A	N/A	N/A
ZIA	6,396	6,439	7,726	7,373	4,453	9,176	5,166	6,085	4,855	4,365	-	N/A	N/A	N/A
Import	434.5	0.0	0.0	0.0	1,722.2	2,985.6	1,341.9	0.0	2,210.8	0.0	-	1,288.0	0.0	1,472.8
CEL	5,083	6,119	5,936	5,111	5,797	6,425	5,499	3,520	4,146	3,072	-	N/A	N/A	N/A
Export	0.0	1,707.2	1,608.0	731.2	0.0	0.0	0.0	2,465.6	0.0	710.3	1,472.8	0.0	1,288.0	-
ACP ($/MW-Day)	69.88	69.88	69.88	69.88	69.88	69.88	69.88	69.88	69.88	69.88	69.88			N/A

Values displayed in MW SAC; ERZ: External Resource Zones *Final PRMR values provided at Zonal level given lack of RBDC Opt-Out.*

Summer Supply Offered and Cleared Comparison Trend

	Offered (ZRC)			Cleared (ZRC)		
Planning Resource	Summer 2023	Summer 2024	Summer 2025	Summer 2023	Summer 2024	Summer 2025
Generation	122,375.6	123,395.6	121,015.6	116,989.7	119,479.2	120,738.6
External Resources	4,514.6	4,430.4	3,505.9	4,072.5	4,309.8	3,505.9
Behind the Meter Generation	4,175.2	4,180.2	4,282.8	4,129.4	4,143.5	4,282.8
Demand Resources	8,303.5	8,660.2	9,004.4	7,694.6	8,109.4	9,004.4
Energy Efficiency	5.0	22.5	27.6	5.0	22.5	27.6
Total	**139,373.9**	**140,688.9**	**137,836.3**	**132,891.2**	**136,064.4**	**137,559.3**

ZRC: Zonal Resource Credit

Fall Supply Offered and Cleared Comparison Trend

	Offered (ZRC)			Cleared (ZRC)		
Planning Resource	**Fall 2023**	**Fall 2024**	**Fall 2025**	**Fall 2023**	**Fall 2024**	**Fall 2025**
Generation	121,403.5	119,745.3	122,283.4	111,713.8	111,791.5	118,309.5
External Resources	4,095.4	4,366.8	2,833.5	3,979.6	3,990.2	2,763.6
Behind the Meter Generation	3,874.2	3,877.9	3,646.8	3,842.8	3,789.7	3,646.8
Demand Resources	6,999.2	6,866.1	7,983.7	6,254.4	5,957.5	7,767.8
Energy Efficiency	4.9	22.5	28.1	4.8	22.5	28.1
Total	**136,377.2**	**134,878.6**	**136,775.5**	**125,795.4**	**125,551.4**	**132,515.8**

ZRC: Zonal Resource Credit

Winter Supply Offered and Cleared Comparison Trend

	Offered (ZRC)			Cleared (ZRC)		
Planning Resource	**Winter 2023-2024**	**Winter 2024-2025**	**Winter 2025-2026**	**Winter 2023-2024**	**Winter 2024-2025**	**Winter 2025-2026**
Generation	124,632.7	133,457.4	120,225.1	114,886.6	118,253.8	117,392.0
External Resources	3,937.1	3,973.0	2,808.7	3,334.6	3,313.3	2,793.7
Behind the Meter Generation	3,257.8	3,111.5	3,082.9	3,173.9	2,957.3	3,082.6
Demand Resources	7,644.4	7,866.4	8,112.3	6,702.4	6,822.7	7,698.3
Energy Efficiency	6.7	29.7	32.9	6.7	29.7	32.9
Total	**139,478.7**	**148,438.0**	**134,261.9**	**128,104.2**	**131,376.8**	**130,999.5**

ZRC: Zonal Resource Credit

Spring Supply Offered and Cleared Comparison Trend

	Offered (ZRC)			Cleared (ZRC)		
Planning Resource	**Spring 2024**	**Spring 2025**	**Spring 2026**	**Spring 2024**	**Spring 2025**	**Spring 2026**
Generation	119,254.7	121,303.8	120,780.6	110,195.8	113,091.4	115,724.7
External Resources	3,794.1	3,481.8	2,640.1	3,409.1	3,406.5	2,570.3
Behind the Meter Generation	4,096.4	4,201.6	4,133.5	4,058.9	4,180.5	4,133.5
Demand Resources	7,282.9	7602.9	8,475.9	6,720.0	7,087.2	8,240.5
Energy Efficiency	5.3	25.0	30.5	5.3	25.0	30.5
Total	**134,433.4**	**136,615.1**	**136,060.6**	**124,389.1**	**127,790.6**	**130,699.5**

ZRC: Zonal Resource Credit

2025 PRA pricing compared with Independent Market Monitor (IMM) Conduct Threshold and Cost of New Entry (CONE)

PY	Zone 1	Zone 2	Zone 3	Zone 4	Zone 5	Zone 6	Zone 7	Zone 8	Zone 9	Zone 10	ERZs	System CONE (Seasonal)	North/Central CONE (Seasonal)	South CONE (Seasonal)
Summer 2025	$666.50											$1,353.84	$1,384.36	$1,282.61
Fall 2025	$91.60							$74.09			$83.24-$91.60	$1,368.71	$1,399.58	$1,296.70
Winter 2025-26	$33.20											$1,383.92	$1,415.13	$1,311.11
Spring 2026	$69.88											$1,353.84	$1,384.36	$1,282.61
Cost of New Entry (Annual)	$127,720	$125,090	$121,220	$126,040	$136,170	$124,360	$130,930	$118,960	$117,710	$117,330	$136,170			
IMM Conduct Threshold*	$34.99	$34.27	$33.21	$34.53	$37.31	$34.07	$35.87	$32.59	$32.25	$32.15	-			

- *Zonal Auction Clearing Prices (ACP) shown in $/MW-day*

**Zonal Resource Credit (ZRC) offers that impact pricing should generally stay below the IMM Conduct Threshold and applies to all seasons.*

ERZ: External Resource Zones

Historical Summer Auction Clearing Price Comparison

<table>
<tr><th>PY</th><th>Zone 1</th><th>Zone 2</th><th>Zone 3</th><th>Zone 4</th><th>Zone 5</th><th>Zone 6</th><th>Zone 7</th><th>Zone 8</th><th>Zone 9</th><th>Zone 10</th><th>ERZs</th></tr>
<tr><td>2015-2016</td><td colspan="3">$3.48</td><td>$150.00</td><td colspan="3">$3.48</td><td colspan="2">$3.29</td><td>N/A</td><td>N/A</td></tr>
<tr><td>2016-2017</td><td>$19.72</td><td colspan="6">$72.00</td><td colspan="3">$2.99</td><td>N/A</td></tr>
<tr><td>2017-2018</td><td colspan="10">$1.50</td><td>N/A</td></tr>
<tr><td>2018-2019</td><td>$1.00</td><td colspan="9">$10.00</td><td>N/A</td></tr>
<tr><td>2019-2020</td><td colspan="6">$2.99</td><td>$24.30</td><td colspan="4">$2.99</td></tr>
<tr><td>2020-2021</td><td colspan="6">$5.00</td><td>$257.53</td><td>$4.75</td><td>$6.88</td><td>$4.75</td><td>$4.89-$5.00</td></tr>
<tr><td>2021-2022</td><td colspan="7">$5.00</td><td colspan="3">$0.01</td><td>$2.78-$5.00</td></tr>
<tr><td>2022-2023</td><td colspan="7">$236.66</td><td colspan="3">$2.88</td><td>$2.88-236.66</td></tr>
<tr><td>Summer 2023</td><td colspan="11">$10.00</td></tr>
<tr><td>Summer 2024</td><td colspan="11">$30.00</td></tr>
<tr><td>Summer 2025</td><td colspan="11">$666.50</td></tr>
</table>

- Auction Clearing Prices shown in $/MW-Day

ERZ: External Resource Zones

Fall Auction Clearing Price Comparison

<table>
<tr><th>PY</th><th>Zone 1</th><th>Zone 2</th><th>Zone 3</th><th>Zone 4</th><th>Zone 5</th><th>Zone 6</th><th>Zone 7</th><th>Zone 8</th><th>Zone 9</th><th>Zone 10</th><th>ERZs</th></tr>
<tr><td>Fall 2023</td><td colspan="8">$15.00</td><td>$59.21</td><td colspan="2">$15.00</td></tr>
<tr><td>Fall 2024</td><td colspan="4">$15.00</td><td>$719.81</td><td colspan="6">$15.00</td></tr>
<tr><td>Fall 2025</td><td colspan="7">$91.60</td><td colspan="3">$74.09</td><td>$83.24-$91.60</td></tr>
</table>

- Auction Clearing Prices shown in $/MW-Day
- Price separation present in Fall 2025 between the North and South subregions since the Sub-Regional Import Constraint (SRIC) / Sub-Regional Export Constraint (SREC) bound

ERZ: External Resource Zones

Winter Auction Clearing Price Comparison

<table>
<tr><th>PY</th><th>Zone 1</th><th>Zone 2</th><th>Zone 3</th><th>Zone 4</th><th>Zone 5</th><th>Zone 6</th><th>Zone 7</th><th>Zone 8</th><th>Zone 9</th><th>Zone 10</th><th>ERZs</th></tr>
<tr><td>Winter 2023-24</td><td colspan="8">$2.00</td><td>$18.88</td><td colspan="2">$2.00</td></tr>
<tr><td>Winter 2024-25</td><td colspan="11">$0.75</td></tr>
<tr><td>Winter 2025-26</td><td colspan="11">$33.20</td></tr>
</table>

- Auction Clearing Prices shown in $/MW-Day

ERZ: External Resource Zones

Spring Auction Clearing Price Comparison

<table>
<tr><th>PY</th><th>Zone 1</th><th>Zone 2</th><th>Zone 3</th><th>Zone 4</th><th>Zone 5</th><th>Zone 6</th><th>Zone 7</th><th>Zone 8</th><th>Zone 9</th><th>Zone 10</th><th>ERZs</th></tr>
<tr><td>Spring 2024</td><td colspan="11">$10.00</td></tr>
<tr><td>Spring 2025</td><td colspan="4">$34.10</td><td>$719.81</td><td colspan="6">$34.10</td></tr>
<tr><td>Spring 2026</td><td colspan="11">$69.88</td></tr>
</table>

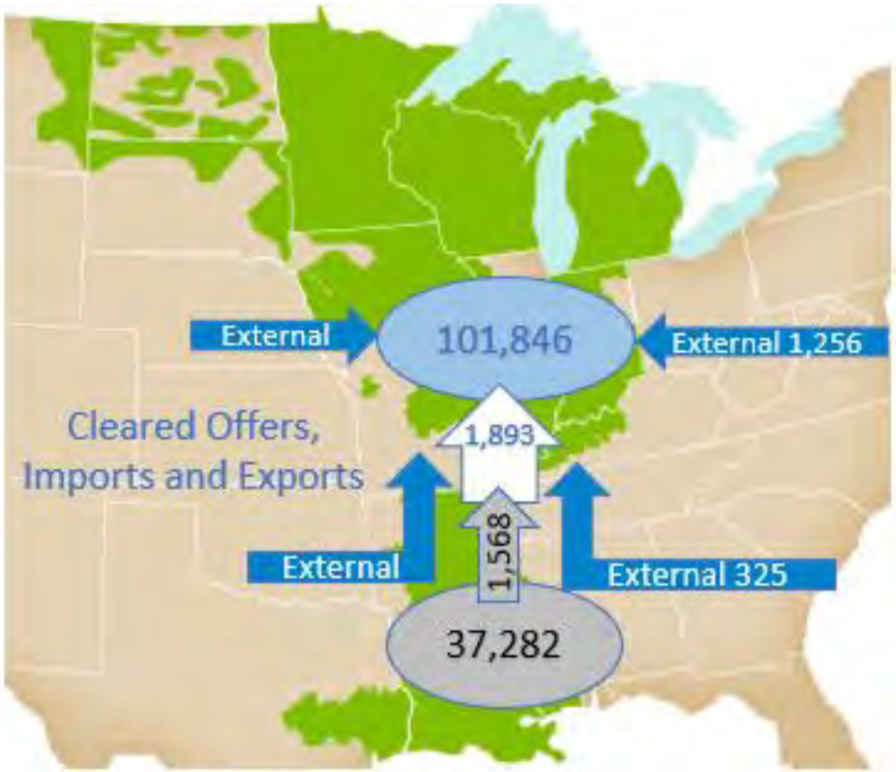
- Auction Clearing Prices shown in $/MW-Day

ERZ: External Resource Zones

Summer 2025 Capacity

Offered Capacity & Final PRMR (MW)

Cleared Capacity, Imports & Exports (MW)



PRMR: Planning Reserve Margin Requirement
Offers includes Fixed Resource Adequacy Plan (FRAP), Self-scheduled and price sensitive offers

05/29/2025: MISO Planning Resource Auction for Planning Year 2025/26 Results Posting

Fall 2025 Capacity

Offered Capacity & Final PRMR (MW)

Cleared Capacity, Imports & Exports (MW)

PRMR: Planning Reserve Margin Requirement
Offers includes Fixed Resource Adequacy Plan (FRAP), Self-scheduled and price sensitive offers
05/29/2025: MISO Planning Resource Auction for Planning Year 2025/26 Results Posting

Winter 2025/26 Capacity

Offered Capacity & Final PRMR (MW)

Cleared Capacity, Imports & Exports (MW)

PRMR: Planning Reserve Margin Requirement
Offers includes Fixed Resource Adequacy Plan (FRAP), Self-scheduled and price sensitive offers
05/29/2025: MISO Planning Resource Auction for Planning Year 2025/26 Results Posting

Spring 2026 Capacity

Offered Capacity & Final PRMR (MW)

Cleared Capacity, Imports & Exports (MW)

PRMR: Planning Reserve Margin Requirement
Offers includes Fixed Resource Adequacy Plan (FRAP), Self-scheduled and price sensitive offers
05/29/2025: MISO Planning Resource Auction for Planning Year 2025/26 Results Posting

The 2025 auction resulted in a surplus compared to the PRMR target, in contrast to the 2024 OMS-MISO Survey projection of a shortfall

Summer 2025 auction outcomes vs. 2024 OMS-MISO Survey projection for 2025

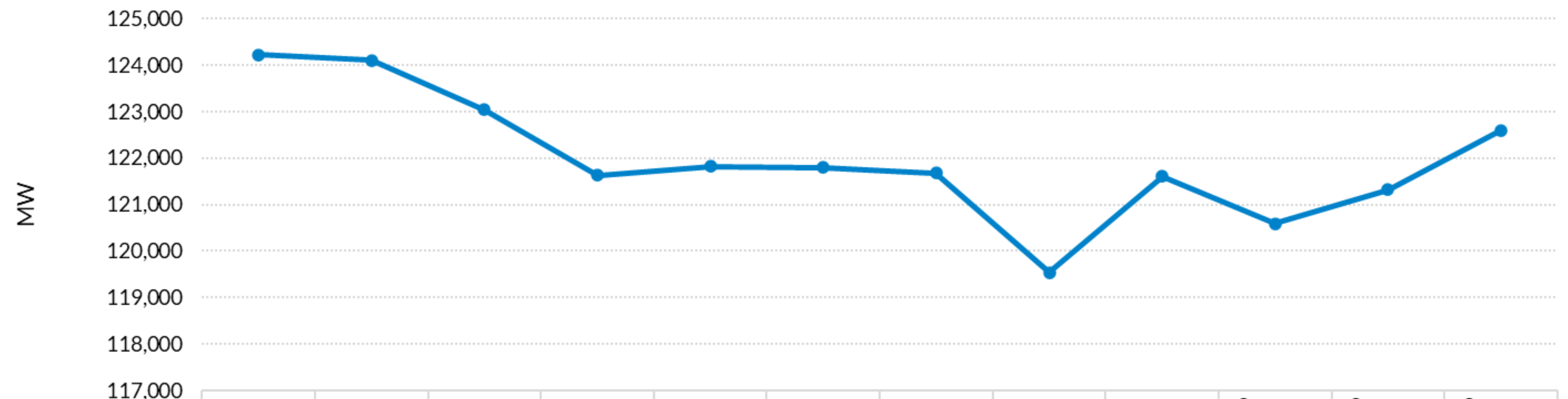
- Resource offers in the auction were comparable to “High Certainty” values projected in the OMS-MISO Survey
- Incremental accreditation reductions in the auction were offset by incremental increases in new resource additions
- Notably, initial PRMR was lower (5.5 GW) than projected in the OMS-MISO Survey

2024 OMS-MISO Survey Projection vs. 2025 PRA Actual PRMR Surplus (MW)

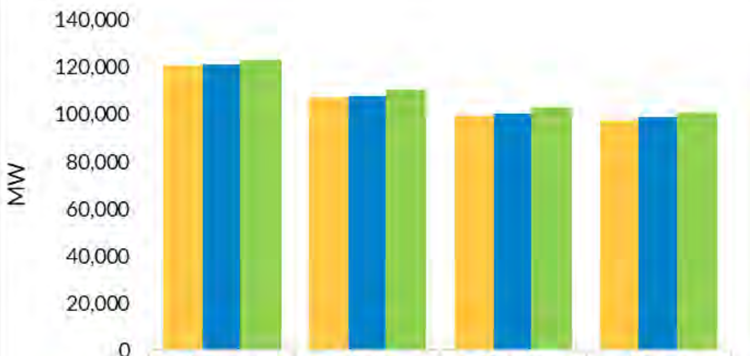
PRA Shortfall/Surplus relative to Initial PRMR *PRMR: Planning Reserve Margin Requirement*

Coincident Peak Forecast

Year over year the Summer CPF (+1.3 GW), PRM (-1.1%) and Final PRMR (+1.5 GW) are higher.



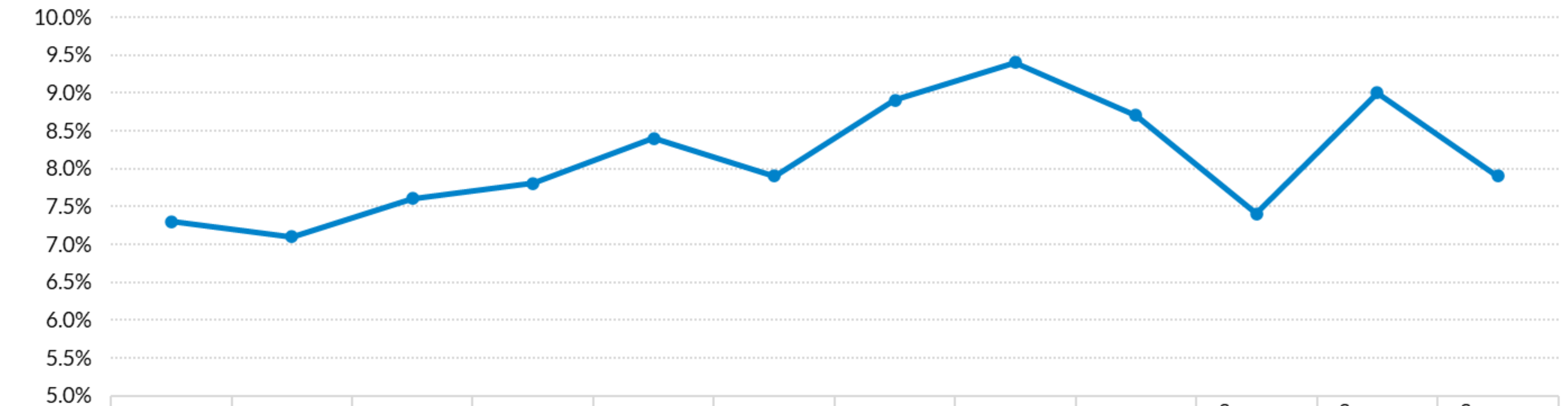
	2014	2015	2016	2017	2018	2019	2020	2021	2022	Summer 2023	Summer 2024	Summer 2025
Summer CPF	124,212.2	124,097.3	123,035.8	121,631.2	121,815.6	121,791.4	121,679.8	119,532.0	121,608.5	120,586.8	121,314.1	122,596.6



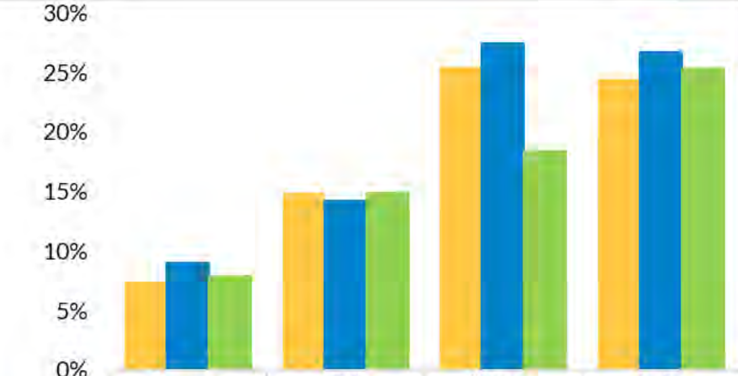
	Summer	Fall	Winter	Spring
2023-24	120,586.8	106,973.8	99,188.0	97,537.6
2024-25	121,314.1	107,701.4	100,114.6	98,697.8
2025-26	122,596.6	109,850.0	102,624.0	100,225.2

PRMR: Planning Reserve Margin Requirement

Planning Reserve Margin (%)

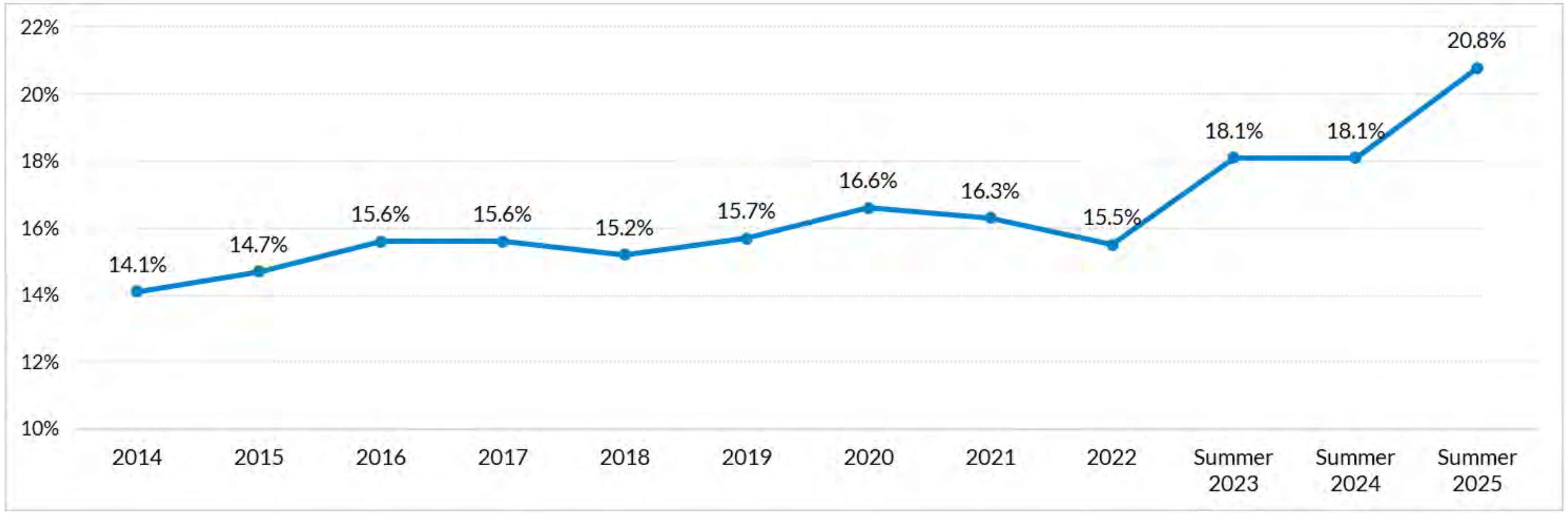


	2014	2015	2016	2017	2018	2019	2020	2021	2022	Summer 2023	Summer 2024	Summer 2025
PRM	7.3%	7.1%	7.6%	7.8%	8.4%	7.9%	8.9%	9.4%	8.7%	7.4%	9.0%	7.9%



	Summer	Fall	Winter	Spring
2023-24	7.4%	14.9%	25.5%	24.5%
2024-25	9.0%	14.2%	27.4%	26.7%
2025-26	7.9%	14.9%	18.4%	25.3%

Wind Effective Load Carrying Capacity (%)

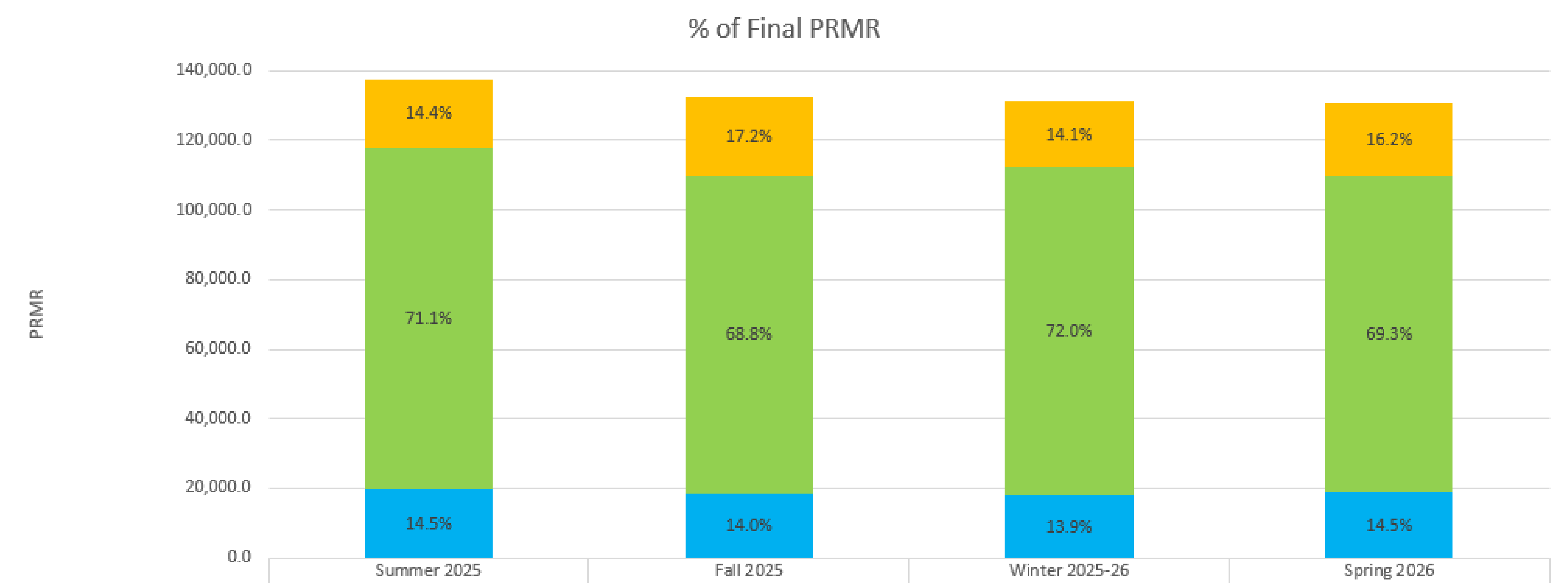


	Summer	Fall	Winter	Spring
2023-24	18.1%	23.1%	40.3%	23.0%
2024-25	18.1%	15.6%	53.1%	18.0%
2025-26	20.8%	30.7%	29.0%	25.3%

- No change to wind or solar accreditation methodology from previous years.
- Methodology applied on a seasonal basis.
- Wind ELCC and new solar capacity is established in the LOLE Study
- New solar class average
  - Summer, fall, spring 50%
  - Winter 5%

ELCC: Effective Load Carrying Capability LOLE: Loss of Load Expectation

2025/26 Seasonal Resource Adequacy Requirements are fulfilled similarly across all four seasons

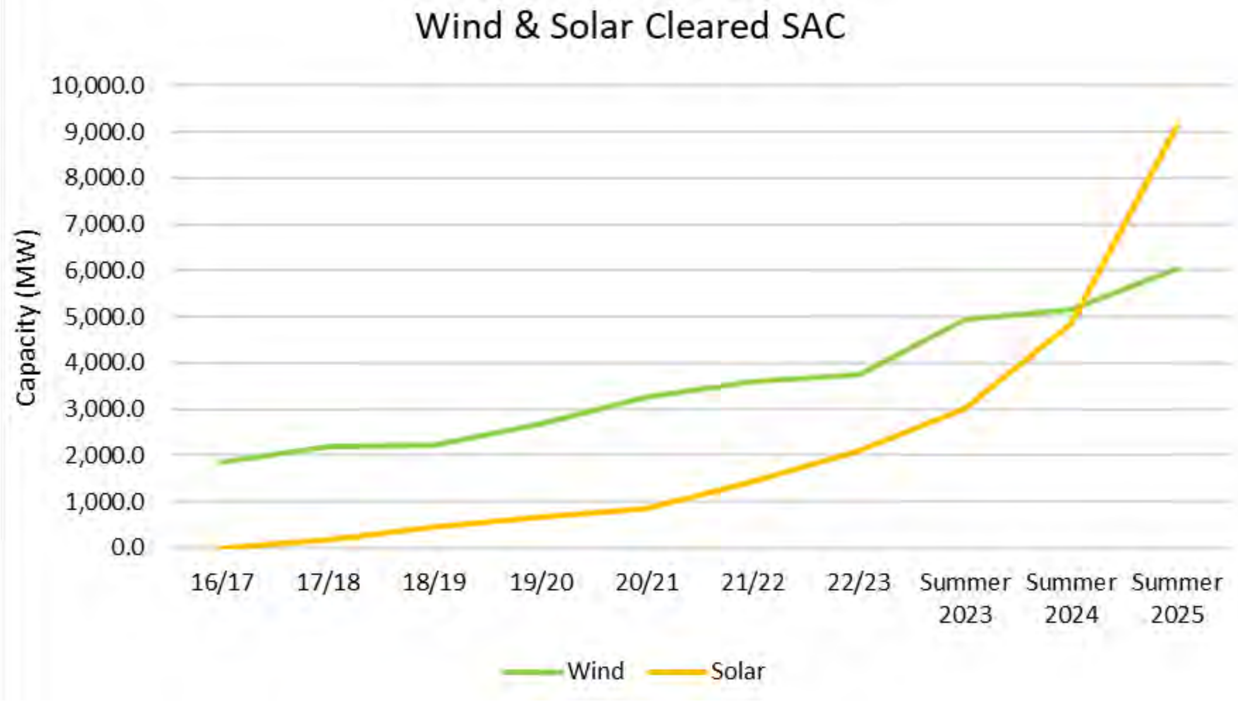


	Summer 2025	Fall 2025	Winter 2025-26	Spring 2026
Cleared Non-Self Scheduled	19,800.6	22,768.8	18,510.0	21,151.5
Self Scheduled	97,811.7	91,206.8	94,316.0	90,582.4
FRAP	19,947.0	18,540.2	18,173.5	18,965.6

PRMR: Planning Reserve Margin Requirement

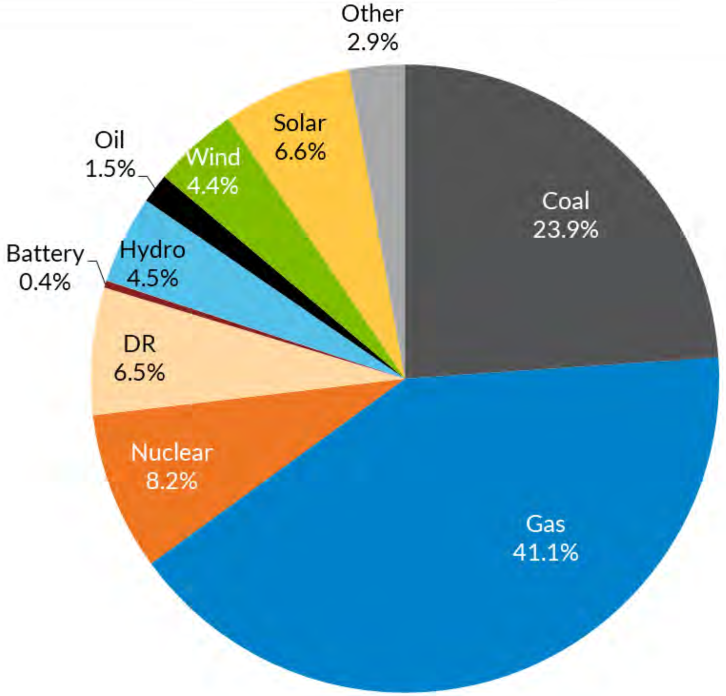
Although conventional generation still comprises most of the capacity, wind and solar continue to grow

- 9.1 GW of solar cleared this year's auction, an increase of 88% from Planning Year 2024/25 (4.9 GW)
- 6 GW of wind cleared this year, an increase of 17% compared to last year (5.2 GW)



Winter final PRMR is 6.6 GW (4.8%) lower than the summer with fewer solar resources to meet final PRMR in the winter versus the summer

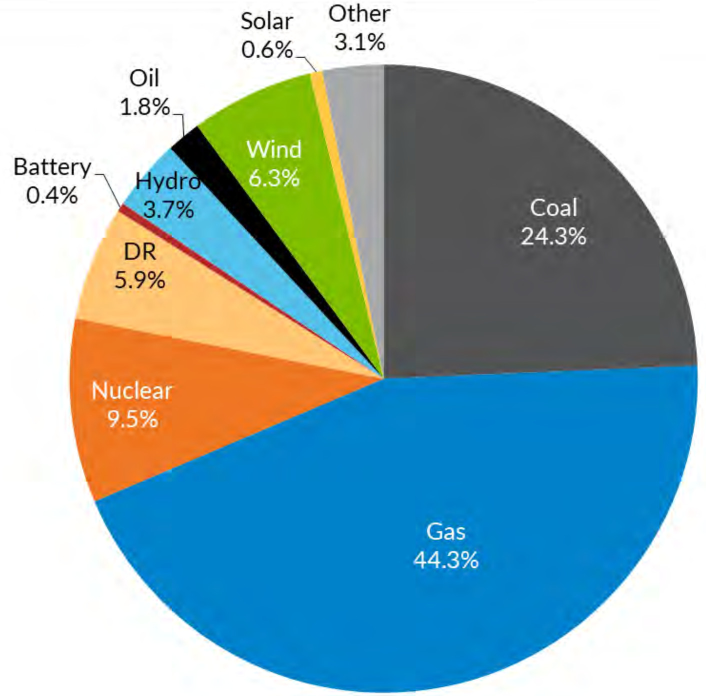
Summer 2025



MISO-wide

Cleared ZRC	Summer 2025	Winter 2025/26	Difference
Coal	32,909.6	31,887.2	1,022.4
Gas	56,470.0	57,990.5	-1,520.5
Nuclear	11,232.1	12,416.7	-1,184.6
DR	9,004.4	7,698.3	1,306.1
Battery	499.2	588.5	-89.3
EE	27.6	32.9	-5.3
Hydro	6,231.3	4,823.7	1,407.6
Oil	2,088.8	2,315.7	-226.9
Wind	6,039.1	8,282.9	-2,243.8
Solar	9,122.8	847.3	8,275.5
Misc	3,934.4	4,115.8	-181.4
PRMR	137,559.3	130,999.5	6,559.8

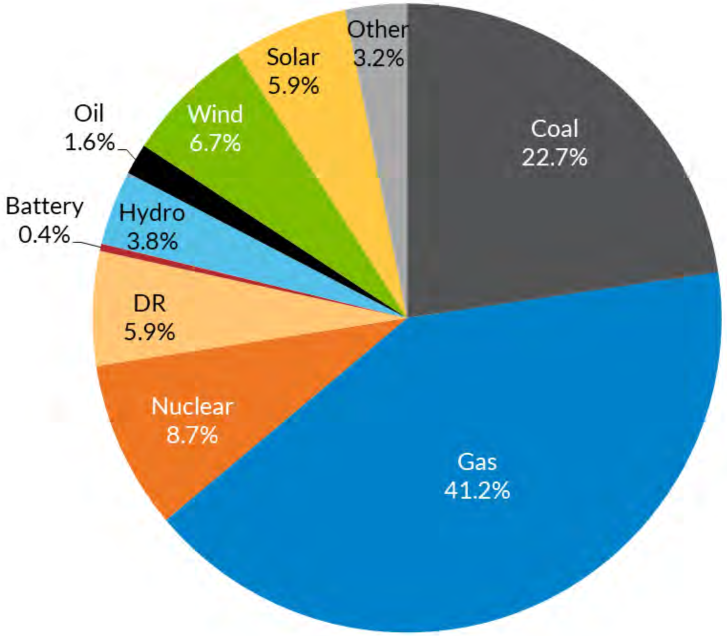
Winter 2025/26



PRMR: Planning Reserve Margin Requirement

Fall 2025 and Spring 2026 - Cleared ZRCs and Final PRMR

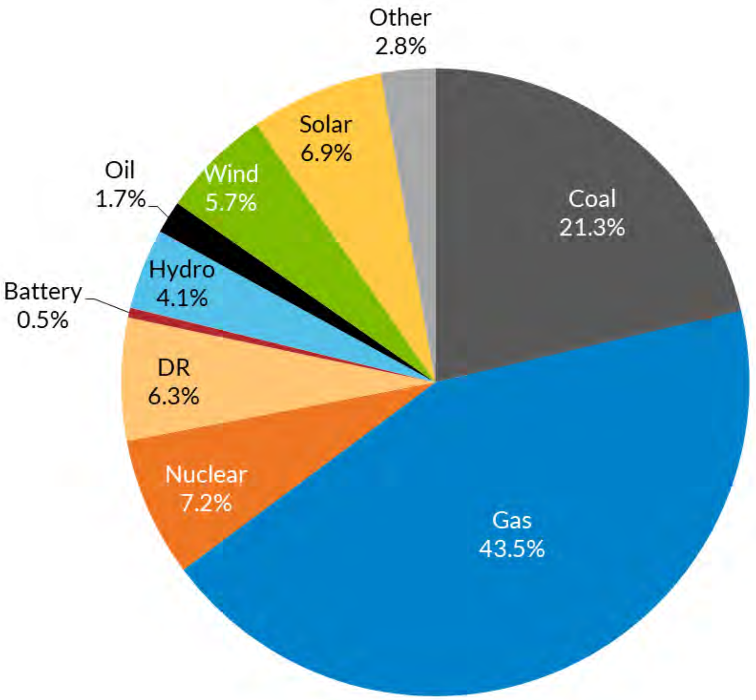
Fall 2025



MISO-Wide

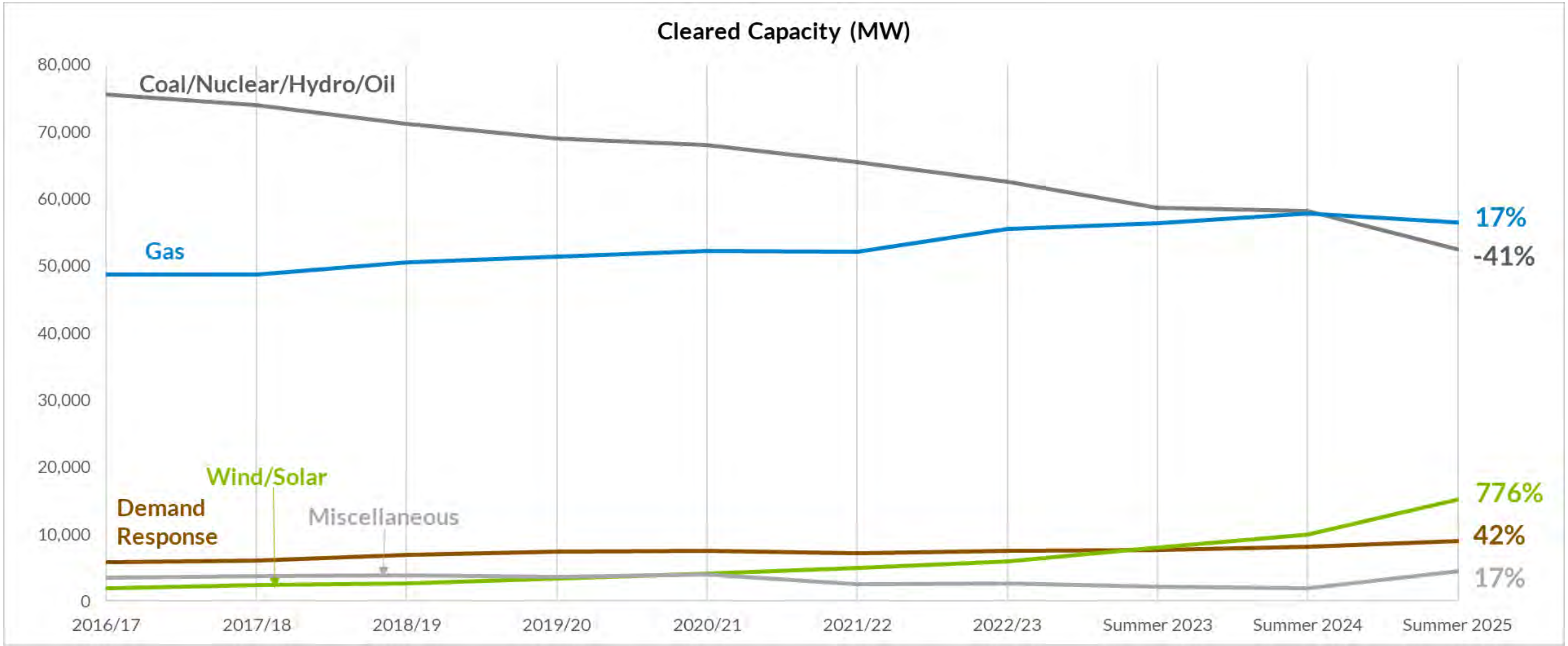
Cleared ZRC	Fall 2025	Spring 2026
Coal	30,038.9	27,886.8
Gas	54,636.4	56,820.7
Nuclear	11,482.1	9,405.4
DR	7,767.8	8,240.5
Battery	497.9	663.3
EE	28.1	30.5
Hydro	5,047.4	5,415.8
Oil	2,123.8	2,190.4
Wind	8,864.8	7,438.0
Solar	7,843.8	8,975.1
Misc	4,184.8	3,633.0
PRMR	132,515.8	130,699.5

Spring 2026

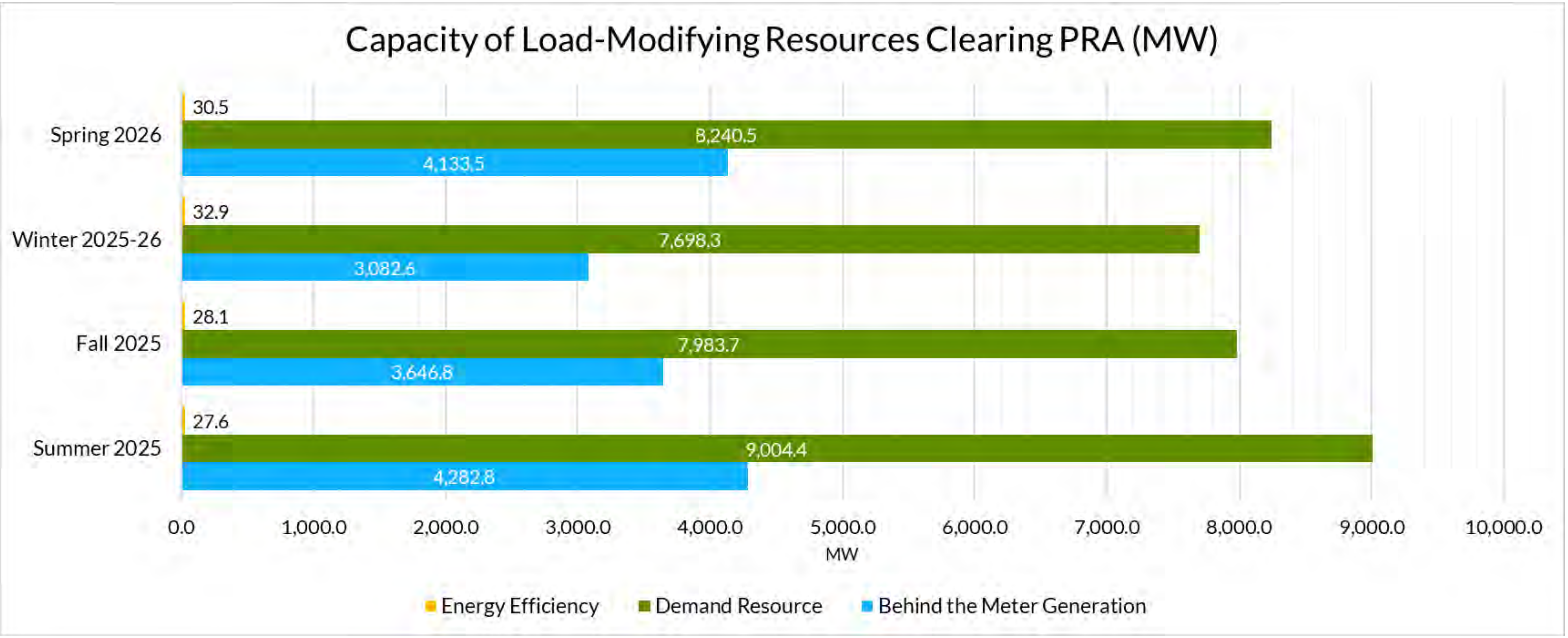


PRMR: Planning Reserve Margin Requirement

The planning resource mix shows the continuation of a multi-year trend towards less coal/nuclear/hydro/oil and increased gas and non-conventional resources



2025/26 Seasonally Cleared Load Modifying Resources Comparison



Visit MISO's Help Center
for more information
https://help.misoenergy.org/

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Midcontinent Independent System Operator (MISO)	)))))	Order No. 202-25-3

Exhibit to
Motion to Intervene and Request for Rehearing and Stay of
Public Interest Organizations

Filed June 18, 2025

Exhibit 32

MISO Emergency Declarations

Maximum Generation Emergency Declarations

through June 2024

(Updated 08/30/2024)

Contents

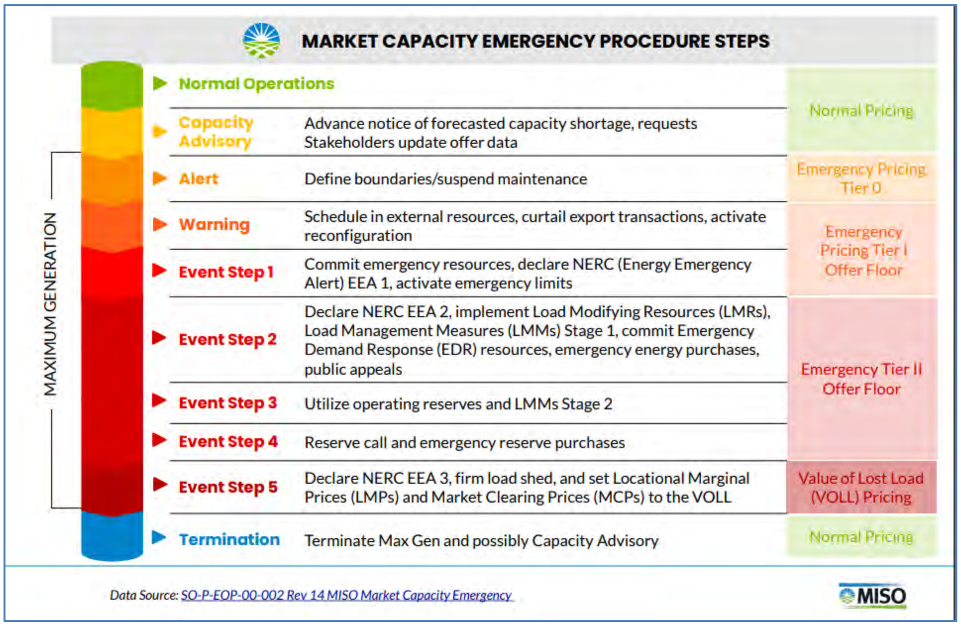


Table 4: Maximum Generation Emergency Overview

Level	MISO Major Actions	Stakeholder Major Actions
Declaration	Send MCS Declaration message	Prepare to implement this procedure and follow internal procedures for emergency conditions
	Declare Conservative System Operations	Follow instructions per Conservative System Operations procedure and declaration
Alert	Identity available Module E Resources	MPs communicate available Module E Resources
	Identify non-firm Export Schedules	MPs update energy interchange transaction E-tags of Capacity Resources
	Implement Emergency Pricing - Tier 0	LBA/TOP provide potential exclusion of constrained pockets within the declaration area
	Raise transfer capability or make constraint stranded generation available	TOPs coordinate with MISO RC to identify potential reconfiguration options
	Request MPs/LBAs ensure accuracy of LMM/LMR availability and Self Scheduled values	LBAs/MPs ensure accuracy of LMM/LMR availability and Self Scheduled values in MCS/DSRI Tools
	Send LBAs LMM survey	Affected GOPs communicate capacity limited facilities to MISO and update limits and offers
Warning	Implement Emergency pricing - Tier 1	
	Suspend CTS	
	Determine EDR availability and MW amounts	MPs update EDR availability and MW amounts
	Obtain updated MW amounts of relief available via Load Management Form in MCS	LBAs update LMM availability via Load Management Form in the MCS
	Review LMR availability using MCS-LMR tool	MPs ensure LMR availability data is correct in the DSRI Tool
	Schedule available Module E Resources into declaration area	As directed by MISO, MPs schedule available Module E Resources into the declaration area
	Curtail Export Schedules as required	
	Instruct TOPs to implement reconfiguration options	As directed by MISO RC, MPs implement reconfiguration options

Maximum Generation Emergency Declarations

through June 2024

(Updated 08/30/2024)

Page 37 of 37

Table 4: Maximum Generation Emergency Overview

Level	MISO Major Actions	Stakeholder Major Actions
Event Step 1a	Commit AME resources	As directed by MISO, LBAs/GOPs/MPs start AME Resources
Event Step 1b/EEA1	Declare EEA1	MPs review Offers and ensure all available Emergency ranges and Resources are offered
	Activate Emergency Maximum Limits	
Event Step 2a/EEA2	Declare EEA2	
	Implement Emergency pricing - Tier 2	
	Instruct Load to be reduced via LMMs - Stage 1 and LMRs	As directed by MISO, LBAs reduce load via LMM - Stage 1
	Implement LMRs	MPs implement LMRs via DSRI Tool
Event Step 2b	Commit EDR Resources	As directed by MISO, MPs commit EDRs
Event Step 2c	Implement Emergency energy purchases	LBAs issue public appeals to reduce demand per internal procedures and OE-417 filings
	Instruct LBAs to issue Public Appeals	
		LBAs in defined Event area shall prepare to shed Load
Event Step 3a	Notify affected GOPs with Generator de-rates to request waivers	Affected GOPs dispatch de-rated Generators with waivers from government regulations
	Implement spinning and supplemental reserves	
Event Step 3b	Elevate identified Priority 6-NN tags	
	Instruct Load to be reduced via LMMs - Stage 2	Affected LBAs reduce load via LMM - Stage 2
Event Step 4a	Implement Reserve Call from CRSG	MPs review Offers and ensure all available Emergency ranges and Resources are offered
Event Step 4b	Implement Emergency energy purchases from neighboring BAs (Operating Reserves)	
Event Step 5/EEA3	Declare EEA3	
	Issue Emergency Operating Instruction to shed load	LBAs shed load per MISO and confirm action via MCS Firm Load Shed Tool
	Set LMPs and MCPs to the VOLL	LBAs review OE-417 filing requirements

- **Maximum Generation (Max Gen) Capacity Advisory** - Provides advanced notice of forecasted capacity shortage and will request stakeholder update data.
- **Max Gen Alert** - Provides an early alert that system conditions may require the use of MISO's generation Emergency procedures.
- **Max Gen Warning** - MISO foresees or is experiencing conditions where all available economic Resources are committed to meet Load, firm transactions, and reserve requirements, and is concerned about sustaining required Operating Reserves.
- **Max Gen Event** - MISO's forecasted or real-time energy demand and Operating Reserve Requirements within the MBAA (or sub-area due to a transmission constraint) can NOT be satisfied with Economic Maximum Limits of all available Resources; MISO issues a Max Gen Event due to a shortage of economic Resources

2009

- 01/13/2009 18:00 – 20:30 EST – West Region Maximum Generation Emergency **ALERT** The reason for the Alert is cold temperatures and generation loss.

2010

- 08/11/2010 14:00 – 20:00 EST – Sub-Area Maximum Generation Emergency **ALERT** Declared for the subarea of FE-Northeast Ohio due to generation loss and forced outages.

2011

- 06/08/2011 12:00-19:00 EST –MISO RC declared a Maximum Generation Emergency **Alert** for the following entities: Central Region Market area(s) of: AMIL, AMMO, AMRN, BREC, CIN, CWLD, CWLP, HE, IPL, SIGE, SIPC and East Region Market area(s) of: ALTE, MECS, MGE, NIPS, UPPC, WEC, WPS and West Region Market area(s) of: ALTW, DPC, MEC, MPW due to Above Normal Temps.
    - This Alert does not include the following LBA's: GRE, NSP, SMP, MP, OTP, MDU, which are all in the Minnesota and the Dakotas area. Temperatures have dropped considerably from yesterday in this area.
- 07/18/2011 14:00-15:00 EST - Market Footprint Maximum Generation Emergency ALERT The reason for the **Alert** is because of Above Normal Temps and Higher than Forecasted Load.
- 07/21/2011 13:00 EST – 17:30 EST: The MISO Reliability Coordinator (RC) is declaring a Maximum Generation Emergency **Alert** for the following entities: Market Footprint. The reason for the alert is Above Normal Temps.
- 07/21/2011 15:00-17:30 EST - Market Footprint Maximum Generation Emergency **WARNING** The reason for the Warning is because of Forced Generation Outages, Above Normal Temps, Higher than Forecasted Load.
- 07/21/2011 12:00-15:00 EST - Market Footprint Maximum Generation Emergency **EVENT (Step 1)** The reason for the Event is because of Forced Generation

2012

- 06/28/2012 14:00-19:00 EST - Market Footprint Maximum Generation Emergency **ALERT** The reason for the Alert is because of Forced Generation Outages, Above Normal Temps.
- 06/29/2012 14:00-15:30 EST - Market Footprint Maximum Generation Emergency **ALERT** The reason for the Alert is because of Forced Generation Outages, Above Normal Temps.
- 07/02/2012 14:00-20:00 EST - Market Footprint Maximum Generation Emergency **ALERT** The reason for the Alert is because of Forced Generation Outages, Above Normal Temps.
- 07/05/2012 14:00 – 17:45 EST: The MISO Reliability Coordinator (RC) is declaring a Maximum Generation Emergency **Alert** for the following entities: Market Footprint. The reason for the alert is Forced Generation Outages, Above Normal Temps. 07/05/2012 14:00-17:45 EST - Market Footprint Maximum Generation Emergency **WARNING** The reason for the Alert is because of Forced Generation Outages, Above Normal Temps.
- 07/06/2012 12:00-12:30 EST - Market Footprint Maximum Generation Emergency **ALERT** The reason for the Alert is because of Forced Generation Outages, Above Normal Temps.
- 07/06/2012 12:30-18:30 EST - Market Footprint Maximum Generation Emergency **WARNING** The reason for the Alert is because of Forced Generation Outages, Above Normal Temps.
- 07/17/2012 12:00-13:00 EST - Market Footprint Maximum Generation Emergency **WARNING** The reason for the Alert is because of Above Normal Temps, Higher than Forecasted Load, Forced Generation Outages.
- 07/17/2012 13:00 – 17:45 EST: The MISO Reliability Coordinator (RC) is declaring a Maximum Generation Emergency **Alert** for the following entities: Market Footprint. The reason for the alert is Forced Generation Outages, Above Normal Temps.
- 07/17/2012 13:00-17:45 EST - Market Footprint Maximum Generation Emergency **Event Step - 1A.** The reason for the Alert is because of Above Normal Temps, Forced Generation Outages.

2013

07/17/2013 14:00-19:00 EST - The MISO Reliability Coordinator (RC) declared a Maximum Generation Emergency **Alert** for the following entities: Market Footprint due to Above Normal Temps, Higher than Forecasted Load

2014

- 01/07/2014 07:15-12:00 EST - Market Footprint Maximum Generation Emergency **ALERT** The reason for the Alert is because of Forced Generation Outages.
- 01/07/2014 07:30-11:15 EST - Market Footprint Maximum Generation Emergency WARNING The reason for the **Alert** is because of Forced Generation Outages.
- 01/07/2014 11:15 – 22:00 EST - Market Footprint Maximum Generation Emergency **ALERT** The reason for the Alert is because of Forced Generation Outages.
- 3/3/2014 05:30 EST – 11:00 EST: MISO Declared Maximum Generation Alert for the entire Market Footprint
- 3/4/2014 07:00 EST – 07:30 EST: MISO Maximum Generation **Alert** declared for MISO Balancing authority due to forced and unforced generation reductions combined with reduced NSI imports the reason.
- 3/4/2014 07:30 EST – 10:00 EST: MISO Maximum Generation **Event Step 1a** declared, AME units started, and external resources (Module E) scheduled into MISO.

2016

- 06/17/2016 12:00 – 20:00 EST: MISO declared Maximum Generation Emergency **Alert** for South Region area(s) of: AXLT, CLEC, EAI, EES, EMBA, LAFA, LAGN, LEPA, SME due to Forced Generation Outages and Above Normal temperatures
- 07/21/2016 12:00 – 13:00 EST: MISO declared Maximum Generation Emergency **Alert**
- 07/21/2016 13:00 – 13:00 EST: MISO declared Maximum Generation Emergency **Warning**. Emergency Pricing Offer Floor 1 initiated
- 07/21/2016 13:00 – 16:00 EST: MISO declared Maximum Generation Emergency **Event 1B/C** and Energy Emergency Alert Level 1 (EEA 1)
- 07/21/2016 16:00 – 18:00 EST: MISO downgraded to Maximum Generation Emergency **Alert** and Energy Emergency Alert Level 0 (EEA 0)
- 08/29/2016 12:00 – 22:00 EST: The MISO Reliability Coordinator (RC) declared a Maximum Generation **Alert** effective for the following entities: Central Region area(s) of: ALT, ALTE, AMIL, AMMO, AMRN, ATC, BREC, BWLT, CETO, CIN, CONS, CWLD, CWLP, HE, IPL, ITC, MCS-WPSC, MECS, METC, MGE, MIUP, NIPS, OVEC, SIGE, SIPC, UPPC, WEC, WPS and North Region area(s) of: ALTW, DPC, GRE, ITCM, MCS-BEPC, MCS-CBPC, MCS-CFU, MDU, MEC, MHEB, MP, MPCN, MPW, NSP, OTP, RPU, SMP, WMUT due to Higher than Forecasted Load and Forced Generation Outages
- 10/04/2016 16:30 – 19:00 EST: MISO declared a Maximum Generation **Alert** for the South Region of the MISO footprint including the area(s) of: CLEC, EAI, EES, EMBA, LAFA, LAGN, LEPA, SME due to forced generation outages and congestion
- 10/05/2016 13:00 – 15:00 EST: MISO declared Maximum Generation **Alert** for the South Region because of forced generation outages.
- 10/05/2016 15:00 – 15:00 EST: MISO declared Maximum Generation **Warning** and initiated Emergency Pricing Offer Floor 1 for the South Region area(s) of: CLEC, EAI, EES, EMBA, LAFA, LAGN, LEPA, SME due to forced generation outages
- 10/05/2016 15:00 – 18:00 EST: MISO downgrade from the Maximum Generation Warning Level to a Maximum Generation **Alert** for the South Region area(s) of CLEC, EAI, EES, EMBA, LAFA, LAGN, LEPA, SME due to an increase in schedule purchases from Southern Company (SOCO). The Maximum Generation Alert remained in effect due to forced generation outages

2017

- 04/04/2017 15:00-22:00 EST: MISO declared a Maximum Generation **Alert** declared for South Region area(s) of: CLEC, EAI, EES, EMBA, LAFA, LAGN, LEPA, SME due to Forced Generation and Transmission outages. Upgraded to MISO declared a Maximum Generation Event at 14:00 EST
- 04/04/2017 14:00-15:00 EST: MISO declared a Maximum Generation **Event Step 1b/c** and NERC EEA-1 for South Region area(s) of: CLEC, EAI, EES, EMBA, LAFA, LAGN, LEPA, SME due to Forced Generation and Transmission outages – emergency ranges enabled
- 04/04/2017 15:00-21:00 EST: MISO declared a Maximum Generation **Event Step 2a/b** and NERC EEA-2 for South Region area(s) of: CLEC, EAI, EES, EMBA, LAFA, LAGN, LEPA, SME because of Forced Generation and Transmission Outages. – LMM/LMRs implemented
- 04/28/2017 14:00 EST: MISO declared a Maximum Generation **Alert** for the MISO South Region due to long term Forced Generation Outages
- 04/28/2017 14:00 – 20:00 EST: MISO escalated the Maximum Generation **Alert** to a Maximum Generation **Warning** for the MISO South Region due to long term Forced Generation Outages
- 04/29/2017 13:00-15:30 EST: MISO declared a Maximum Generation **Alert** for the South Region due to long term Forced Generation Outages
- 09/21/2017 12:00 – 20:00 EST: MISO declared a Maximum Generation **Alert** for the MISO Market Footprint due to generation outages, above normal temperatures, seasonally high load, and heavy congestion
- 09/22/2017 12:30 – 14:00 EST: MISO declared a Maximum Generation **Alert** for the MISO Market Footprint due to generation outages, above normal temperatures, high loads, and heavy congestion
- 09/22/2017 14:00 – 14:30 EST: MISO declared a Maximum Generation **Event Step 1a (AME Resources**) due to generation outages, above normal temperatures, seasonally high load, and heavy congestion to access AME Resources
- 09/22/2017 14:30 – 18:15 EST: MISO declared a Maximum Generation **Event Step 1b/c** due to generation outages, above normal temperatures, seasonally high load, and heavy congestion to access Emergency Maximum Limits In addition, declared NERC EEA 1. All available Resources in use.
- 09/23/2017 13:00 – 14:00 EST: MISO declared a Maximum Generation **Alert** due to generation outages, above normal temperatures, seasonally high load, and heavy congestion

Maximum Generation Emergency Declarations

through June 2024

(Updated 08/30/2024)

- 09/23/2017 14:00 – 17:15 EST: MISO declared a Maximum Generation **Warning** due to generation outages, above normal temperatures, seasonally high load, and heavy congestion
- 09/25/2017 13:00 – 19:00 EST MISO declared a Maximum Generation **Alert** due to generation outages, above normal temperatures, seasonally high load, and heavy congestion

2018

- 01/17/2018 05:00 – 23:15 EST: MISO declared a Maximum Generation **Alert** for South Region area(s) of: AXLT, CLEC, EAI, EES, EMBA, LAFA, LAGN, LEPA, SME due to forced Generation Outages and higher than forecasted load
- 01/17/2018 06:00 – 09:00 EST : MISO declared Maximum Generation **Alert** for Central Region area(s) of: ALT, ALTE, AMIL, AMMO, AMRN, ATC, BREC, BWLT, CETO, CIN, CONS, CWLD, CWLP, HE, IPL, ITC, MCS-WPSC, MECS, METC, MGE, MIUP, NIPS, OVEC, SIGE, SIPC, UPPC, WEC, WPS and North Region area(s) of: ALTW, DPC, GRE, ITCM, MCS-BEPC, MCS-CBPC, MCS-CFU, MDU, MEC, MHEB, MP, MPCN, MPW, NSP, OTP, RPU, SMP, WMUT due to forced Generation Outages and higher than forecasted load
- 01/17/2018 07:00 – 12:00 EST: MISO declared a Maximum Generation **Event Step 2a/b** and NERC EEA 2 for South Region area(s) of: AXLT, CLEC, EAI, EES, EMBA, LAFA, LAGN, LEPA, SME due to Forced Generation Outages, Higher than Forecasted Load
- 01/17/2018 06:10 EST – 14:00 EST: MISO declared a Maximum Generation **Event Step 2c/d** (NERC EEA Level 2 already in effect) for the following entities: South Region area(s) of: AXLT, CLEC, EAI, EES, EMBA, LAFA, LAGN, LEPA, SME due to Forced Generation Outages, Higher than Forecasted Load.
- 01/17/2018 14:00 – 19:00 EST: MISO reduced to a Maximum Generation **Event Step 1a** for the following entities: South Region area(s) of: AXLT, CLEC, EAI, EES, EMBA, LAFA, LAGN, LEPA, SME
- 01/17/2018 19:00 – 20:55 EST: MISO advanced to a Maximum Generation **Event Step 2a/b** and NERC EEA 2 for the South Region area(s) of: AXLT, CLEC, EAI, EES, EMBA, LAFA, LAGN, LEPA, SME
- 01/17/2018 20:55 – 23:15 EST: MISO declared a Maximum Generation **Event Step 1b/c** and NERC EEA Level 1 for the South Region area(s) of: AXLT, CLEC, EAI, EES, EMBA, LAFA, LAGN, LEPA, SME
- 01/17/2018 23:15 EST – 01/18/2018 10:45: MISO declared a Maximum Generation **Alert** for South Region area(s) of: AXLT, CLEC, EAI, EES, EMBA, LAFA, LAGN, LEPA, SME
- 01/18/2018 06:00 – 10:45 EST: MISO declared to a Maximum Generation **Event Step 2c/d** and NERC EEA 2 for the South Region area(s) of: AXLT, CLEC, EAI, EES, EMBA, LAFA, LAGN, LEPA, SME
- 01/18/2018 06:00 – 10:45 EST: MISO declared a Maximum Generation **Event Step 2d (Public Appeals)** (NERC EEA Level 2 already in effect) for the South Region area(s) of: AXLT, CLEC, EAI, EES, EMBA, LAFA, LAGN, LEPA, SME

- 5/14/2018 12:00 EST – *5/13/2018 15:46 EST*: MISO declared a Maximum Generation **Alert** for the entire footprint effective Monday 05/14/2018 12:00 EST until Wednesday 05/16/2018 23:59 EST because of Forced Generation Outages and Above Normal Temps.
    - Maximum Generation Alert terminated on 05/13/2018 15:46 EST due to an increase in capacity.
- 06/04/2018 09:00 – 13:55 EST: MISO declared a Maximum Generation **Alert** for the following entities: South Region area(s) of: CLEC, EES, LAGN due to Forced Generation Outages
- 07/05/2018 11:00 – 17:30 EST: MISO declared a Maximum Generation **Alert** for the following entities: for the following entities: Central Region area(s) of: ALT, ALTE, AMIL, AMMO, AMRN, ATC, BREC, CIN, CONS, CWLD, CWLP, HE, IPL, ITC, MECS, METC, MGE, MIUP, NIPS, PION, SIGE, SIPC, UPPC, WEC, WPS and North Region area(s) of: ALTW, DPC, GRE, ITCM, MDU, MEC, MP, MPW, NSP, OTP, SMP due to Higher than Forecasted Load
- 09/13/2018: MISO issued a **Capacity Advisory** due to limited generation surplus on Monday September 17
- 09/14/2018: Capacity Advisory extended to include Tuesday September 18
- 09/15/2018 13:05 – 15:00 EST: MISO declared a Maximum Generation **Alert** for the South Region
- 09/15/2018 15:00 – 18:00 EST: MISO declared a NERC EEA-2 and Maximum Generation **Event Step 2 c/d** for the South Region
- 09/15/2018 18:00 – 18:30 EST: MISO lowered to a NERC EEA-1 and Maximum Generation **Event Step 1 b/c** for the South Region
- 09/17/2018 12:00 EST – 17:30 EST: MISO declared a Maximum Generation **Alert** for the entire MISO Balancing Authority footprint
- 10/05/2018: MISO issued a **Capacity Advisory** Communication for Monday 10/08/2018

2019

- 01/30/2019 05:00 – 12:00 EST: MISO declared a Maximum Generation **Event Step 1a** for the following entities: Central Region area(s) of: AEP, ALT, ALTE, AMIL, AMMO, AMRN, ATC, BREC, BWLT, CETO, CIN, CONS, CWLD, CWLP, DECO, HE, IPL, ITC, MCS-WPSC, MECS, METC, MGE, MIUP, NIPS, PION, SIGE, SIPC, UPPC, WEC, WPS and North Region area(s) of: ALTW, DPC, GRE, ITCM, MCS-BEPC, MCS-CBPC, MCS-CFU, MDU, MEC, MHEB, MP, MPCN, MPW, NSP, OTP, RPU, SMP, WMUT due to forced generation outages and high load.
- 01/30/2019 08:00 – 22:00 EST: MISO declared a Maximum Generation **Event Step 2a/b** and NERC EEA 2 for the following entities: Central Region area(s) of: ALT, ALTE, AMIL, AMMO, AMRN, ATC, BREC, CIN, CONS, CWLD, CWLP, DECO, HE, IPL, ITC, MECS, METC, MGE, MIUP, NIPS, PION, SIGE, SIPC, UPPC, WEC, WPS and North Region area(s) of: ALTW, DPC, GRE, ITCM, MDU, MEC, MP, MPW, NSP, OTP, SMP due to forced generation outages and high load.
- 01/30/2019 13:30 EST – 01/31/2019 11:00 EST: MISO declared a Maximum Generation **Event Step 1a** for the following entities: Central Region area(s) of: ALT, ALTE, AMIL, AMMO, AMRN, ATC, BREC, CIN, CONS, CWLD, CWLP, DECO, HE, IPL, ITC, MECS, METC, MGE, MIUP, NIPS, PION, SIGE, SIPC, UPPC, WEC, WPS and North Region area(s) of: ALTW, DPC, GRE, ITCM, MDU, MEC, MP, MPW, NSP, OTP, SMP. The reason for the Event is because of Higher than Forecasted Load, Forced Generation Outages.
- 01/31/2019 07:00 – 11:00 EST: MISO declared a Maximum Generation **Event Step 1b/c** and NERC EEA Level 1 for the following entities: Central Region area(s) of: ALT, ALTE, AMIL, AMMO, AMRN, ATC, BREC, CIN, CONS, CWLD, CWLP, DECO, HE, IPL, ITC, MECS, METC, MGE, MIUP, NIPS, PION, SIGE, SIPC, UPPC, WEC, WPS and North Region area(s) of: ALTW, DPC, GRE, ITCM, MDU, MEC, MP, MPW, NSP, OTP, SMP. The reason for the Event is because of extreme low temperatures and high loads
- 01/31/2019 09:30 – 11:00 EST: MISO declared a Maximum Generation **Warning** for the following entities: Central Region area(s) of: ALT, ALTE, AMIL, AMMO, AMRN, ATC, BREC, CIN, CONS, CWLD, CWLP, DECO, HE, IPL, ITC, MECS, METC, MGE, MIUP, NIPS, PION, SIGE, SIPC, UPPC, WEC, WPS and North Region area(s) of: ALTW, DPC, GRE, ITCM, MDU, MEC, MP, MPW, NSP, OTP, SMP due to extreme temperatures and high load
- 05/16/2019 12:00 EST – 05/18/2019 20:00 EST: MISO issued a Maximum Generation **Capacity Advisory** for the South Region. Forward looking capacity assessments indicated limited operating capacity margins.

- 05/16/2019 12:00 – 14:00 EST: MISO declared a Maximum Generation Emergency **Alert** for the South Region area(s) of: CLEC, EAI, EES, EMBA, LAFA, LAGN, LEPA, SME due to forced generation outages
- 05/16/2019 14:00 – 18:00 EST: MISO declared Maximum Generation Emergency **Event Step 2a** for South Region area(s) of: AXLT, CLEC, EAI, EES, EMBA, LAFA, LAGN, LEPA, SME due to forced generation outages
- 05/16/2019 18:00 – 20:00 EST: MISO downgraded to a Maximum Generation Emergency **Alert** for South Region area(s) of: AXLT, CLEC, EAI, EES, EMBA, LAFA, LAGN, LEPA, SME
- 05/17/2019 12:00 – 20:00 EST: MISO declared a Maximum Generation Emergency **Alert** for South Region area(s) of: AXLT, CLEC, EAI, EES, EMBA, LAFA, LAGN, LEPA, SME due to forced generation outages
- 05/20/2019 06:00 EST – 05/24/2019 22:00 EST: MISO declared a Maximum Generation **Capacity Advisory** for the South Region
- 05/23/2019 12:00 – 22:00 EST: MISO declared a Maximum Generation Emergency **Alert** for the South Region area(s) of: CLEC, EAI, EES, EMBA, LAFA, LAGN, LEPA, SME due to Planned and Forced Generation Outages, as well as Above Normal Temps.
- 06/03/2019 12:00 – 17:00 EST: MISO declares Maximum Generation Emergency **Alert** for the following entities: South Region area(s) of: AXLT, CLEC, EAI, EES, EMBA, LAFA, LAGN, LEPA, SME due to higher than forecasted Load and forced Generation Outages
- 06/03/2019 13:00 – 17:00 EST: MISO declares Maximum Generation Emergency **Warning** for the following entities: South Region area(s) of: AXLT, CLEC, EAI, EES, EMBA, LAFA, LAGN, LEPA, SME due to higher than forecasted load and forced generation outages
- 06/03/2019 17:00 EST – 06/04/2019 20:00 EST: MISO declares a Maximum Generation **Capacity Advisory** for MISO South Region
- 06/20/2019 14:00 – 17:30 EST: MISO declared Maximum Generation Emergency **Alert** for the following entities: South Region area(s) of: AXLT, CLEC, EAI, EES, EMBA, LAFA, LAGN, LEPA, SME due to forced transmission and generation outages.
- 07/19/2019 10:00 EST – 07/20/2019 20:00 EST: MISO declared a Maximum Generation **Capacity Advisory** for the entire MISO Market footprint.

2020

- 02/21/2020 07:30 – 09:00 EST: MISO Reliability Coordinator declared a Maximum Generation Emergency **Alert** for the following entities: South Region area(s) of CLEC, EAI, EES, EMBA, LAFA, LAGN, LEPA, SME due to cold weather and units not able to start. All reserve requirements and reliable operations were maintained during this time period.
  - Units unable to start prior to the morning peak resulted in maximum generation conditions
  - South Region weather was colder than normal but not unseasonably cold. Temperatures in Arkansas were in the low 20s.
- 07/06/2020 8:00 EST – 07/10/2020 14:00 EST: The MISO Reliability Coordinator is declaring a Maximum Generation **Capacity Advisory** for the MISO North and Central Regions of the Market Footprint.
- 07/07/2020 13:00 – 17:30 EST: MISO is declaring a Maximum Generation Emergency **Alert** for the MISO Central and North Regions.
- 07/07/2020 13:00 – 17:30 EST: MISO is escalating the Max Gen Alert to a Maximum Generation Emergency **Warning** for the MISO North and Central Regions only. While the included projected calculations show a slight shortage, this escalation to the Warning level allows some actions to be taken that will relieve the capacity shortage
- 07/07/2020 13:00 - 17:30 EST: MISO declared a Maximum Generation Event **Step 1a** for Central and North Regions (no EEA declared)
- 08/27/2020 11:00 EST – 22:54 EST: MISO is declaring a Maximum Generation Emergency **Warning** for the South Region Western half of the WOTAB load pocket (including all of the Western load pocket) due to forced generation and transmission outages and unpredictable load patterns resulting from Hurricane Laura
- 08/27/2020 11:00 EST – 22:54 EST: MISO is declaring a Maximum Generation Emergency **Event Step 5** for the South Region Western half of the WOTAB load pocket (including all of the Western load pocket) due to forced generation and transmission outages and unpredictable load patterns resulting from Hurricane Laura. EEA Level 3 and VOLL Pricing implemented.
  - 12:02 EST: 300 MW of Load Shed for the Max Gen area ordered
  - 13:22 EST: 200 MW of additional Load Shed was ordered for the Max Gen area.
  - Maximum Generation Emergency declarations terminated after transmission returned to service

2021

- 02/15/2021 07:00 – 22:00 EST: MISO is declaring a Maximum Generation Emergency **Alert** for the MISO South Region
- 02/15/2021 09:00 EST – 02/19/2021 11:00 EST: MISO is declaring a Maximum Generation **Capacity Advisory** for the South Region.
- 02/15/2021 18:00 – 23:59 EST: The MISO Reliability Coordinator is declaring a Maximum Generation Emergency **Warning** for the following entities: South Region area(s) of: AXLT, CLEC, EAI, EES, EMBA, LAFA, LAGN, LEPA, SME (EEA 0) due to Forced Generation Outages, and high loads due to Extreme Winter Temps
- 02/15/2021 18:00 – 23:59 EST: The MISO Reliability Coordinator is declaring a Maximum Generation Emergency **Event Step 2c** for the following entities: South Region area(s) of: AXLT, CLEC, EAI, EES, EMBA, LAFA, LAGN, LEPA, SME (EEA 2) due to Forced Generation Outages, Extreme cold Temps.
- 02/16/2021 00:00 – 12:00 EST: The MISO Reliability Coordinator is declaring a Maximum Generation Emergency **Warning** for the following entities: South Region area(s) of: AXLT, CLEC, EAI, EES, EMBA, LAFA, LAGN, LEPA, SME (EEA 0) due to Forced Generation Outages, Higher than Forecasted Load.'
- 02/16/2021 08:00 – 22:00 EST: MISO Reliability Coordinator is declaring a Maximum Generation Emergency **Event Step 2a** for the following entities: South Region area(s) of: AXLT, CLEC, EAI, EES, EMBA, LAFA, LAGN, LEPA, SME (EEA 2) due to Forced Generation Outages, Extreme Cold Temps
- 02/16/2021 07:30 – 14:00 EST: MISO Reliability Coordinator is declaring a Maximum Generation Emergency **Event Step 1b** for the following entities: Central Region area(s) of: ALT, ALTE, AMIL, AMMO, AMRN, ATC, BREC, CIN, CONS, CWLD, CWLP, DECO, GLH, HE, HMPL, IPL, ITC, MECS, METC, MGE, MIUP, NIPS, PION, RTX, SIGE, SIPC, UPPC, WEC, WPS and North Region area(s) of: ALTW, DPC, GRE, ITCM, MDU, MEC, MP, MPW, NSP, OTP, SMP (EEA 1) due to Forced Generation Outages and Transmission Constraints.
- 02/16/2021 18:35 EST – 02/17/2021 01:00 EST: MISO Reliability Coordinator is declaring a Maximum Generation Emergency **Event Step 2c** for the following entities: South Region area(s) of: AXLT, CLEC, EAI, EES, EMBA, LAFA, LAGN, LEPA, SME (EEA 2) due to Force Generation Outages, Higher than Forecasted Load
- 02/16/2021 19:40 EST – 02/17/2021 01:00 EST: MISO Reliability Coordinator is declaring a Maximum Generation Emergency **Event Step 5** for the following entities: South Region area(s) of: AXLT, CLEC, EAI, EES, EMBA, LAFA, LAGN, LEPA, SME (EEA 3) due to Forced Generation Outages, Higher than Forecasted Load

  - 19:50 EST: 700 MW Firm Load Shed requested
- 02/16/2021 22:00 EST – 02/17/2021 01:00 EST: MISO Reliability Coordinator is declaring a Maximum Generation Emergency **Event Step 2a** for the following entities: South Region area(s) of: AXLT, CLEC, EAI, EES, EMBA, LAFA, LAGN, LEPA, SME (EEA 2) due to Forced Generation Outages
- 02/17/2021 00:00 – 02:00 EST: MISO Reliability Coordinator is declaring a Maximum Generation Emergency **Event Step 1a** for the following entities: South Region area(s) of: AXLT, CLEC, EAI, EES, EMBA, LAFA, LAGN, LEPA, SME (EEA 2) due to Forced Generation Outages
- 02/17/2021 02:00 – 23:00 EST: MISO Reliability Coordinator is declaring a Maximum Generation Emergency **Alert** for the following entities: South Region area(s) of: AXLT, CLEC, EAI, EES, EMBA, LAFA, LAGN, LEPA, SME (EEA 0) due to forced generation outages.
- 02/17/2021 18:00 – 23:00 EST: MISO Reliability Coordinator is declaring a Maximum Generation Emergency **Event Step 2c** for the following entities: South Region area(s) of: AXLT, CLEC, EAI, EES, EMBA, LAFA, LAGN, LEPA, SME (EEA 2) due to Forced Generation Outages, Below Normal Temps
- 02/17/2021 21:30 EST – 02/19/2021 11:00 EST: MISO Reliability Coordinator is declaring a Maximum Generation Emergency **Alert** for the following entities: South Region area(s) of: AXLT, CLEC, EAI, EES, EMBA, LAFA, LAGN, LEPA, SME (EEA 0) due to Forced Generation Outages, Higher than Forecasted Load
- 06/08/2021 10:00 – 20:00 EST: The MISO Reliability Coordinator is declaring a Maximum Generation **Capacity Advisory** for the MISO North and Central Regions only The Reserve Margin for the North and Central Regions is forecasted to be 3.9% on 06/08/2021. This is below the 5% threshold.
- 06/10/2021 10:00 – 20:00 EST: MISO is declaring a Maximum Generation **Capacity Advisory** its North and Central Regions only – expanded to MISO footprint
- 06/10/2021 13:00 – 18:00 EST: The MISO Reliability Coordinator is declaring a Maximum Generation Emergency **Alert** for the following entities: Central Region area(s) of: ALT, ALTE, AMIL, AMMO, AMRN, ATC, BREC, CIN, CONS, CWLD, CWLP, DECO, GLH, HE, HMPL, IPL, ITC, MECS, METC, MGE, MIUP, NIPS, PION, RTX, SIGE, SIPC, UPPC, WEC, WPS and North Region area(s) of: ALTW, DPC, GRE, ITCM, MDU, MEC, MP, MPW, NSP, OTP, SMP due to Above Normal Temps, Forced Generation Outages.
- 06/10/2021 13:00 – 18:00 EST: The MISO Reliability Coordinator is declaring a Maximum Generation Emergency **Warning** for the following entities: Central Region area(s) of: ALT, ALTE, AMIL, AMMO, AMRN, ATC, BREC, CIN, CONS, CWLD,

CWLP, DECO, GLH, HE, HMPL, IPL, ITC, MECS, METC, MGE, MIUP, NIPS, PION, RTX, SIGE, SIPC, UPPC, WEC, WPS and North Region area(s) of: ALTW, DPC, GRE, ITCM, MDU, MEC, MP, MPW, NSP, OTP, SMP due to Forced Generation Outages, Above Normal Temps, Higher than Forecasted Load

- 06/10/2021 14:00 – 18:00 EST: The MISO Reliability Coordinator is declaring a Maximum Generation Emergency **Event Step 2a** for the following entities: Central Region area(s) of: ALT, ALTE, AMIL, AMMO, AMRN, ATC, BREC, CIN, CONS, CWLD, CWLP, DECO, GLH, HE, HMPL, IPL, ITC, MECS, METC, MGE, MIUP, NIPS, PION, RTX, SIGE, SIPC, UPPC, WEC, WPS and North Region area(s) of: ALTW, DPC, GRE, ITCM, MDU, MEC, MP, MPW, NSP, OTP, SMP due to Forced Generation Outages, Above Normal Temps, Higher than Forecasted Load.
- 06/10/2021 17:00 – 18:00 EST: The MISO Reliability Coordinator is declaring a Maximum Generation Emergency **Alert** for the following entities: Central Region area(s) of: AEP, ALT, ALTE, AMIL, AMMO, AMRN, ATC, BREC, BWLT, CETO, CIN, CONS, CWLD, CWLP, DECO, GLH, GLHB, HE, HMPL, IPL, ITC, MCS-WPSC, MECS, METC, MGE, MIUP, NIPS, PION, RTX, SIGE, SIPC, UPPC, WEC, WPS and North Region area(s) of: ALTW, DPC, GRE, ITCM, MCS-BEPC, MCS-CBPC, MCS-CFU, MDU, MEC, MHEB, MP, MPCN, MPW, NSP, OTP, RPU, SMP, WMUT due to Forced Generation Outages, Above Normal Temps, Higher than Forecasted Load.
- 06/28/2021 12:00 – 22:00 EST: The MISO Reliability Coordinator is declaring a Maximum Generation Emergency **Alert** for the following entities: Central Region area(s) of: ALT, ALTE, AMIL, AMMO, AMRN, ATC, BREC, CIN, CONS, CWLD, CWLP, DECO, GLH, HE, HMPL, IPL, ITC, MECS, METC, MGE, MIUP, NIPS, PION, RTX, SIGE, SIPC, UPPC, WEC, WPS and North Region area(s) of: ALTW, DPC, GRE, ITCM, MDU, MEC, MP, MPW, NSP, OTP, SMP due to Higher than Forecasted Load, Forced Generation Outages.
- 06/29/2021 11:00 – 22:00 EST: The MISO Reliability Coordinator is declaring a Maximum Generation Emergency **Alert** for the following entities: Central Region area(s) of: ALT, ALTE, AMIL, AMMO, AMRN, ATC, BREC, CIN, CONS, CWLD, CWLP, DECO, GLH, HE, HMPL, IPL, ITC, MECS, METC, MGE, MIUP, NIPS, PION, RTX, SIGE, SIPC, UPPC, WEC, WPS and North Region area(s) of: ALTW, DPC, GRE, ITCM, MDU, MEC, MP, MPW, NSP, OTP, SMP due to Forced Generation Outages.
- 07/05/2021 08:00 EST – 07/06/2021 18:30 EST: The MISO Reliability Coordinator is declaring a Maximum Generation **Capacity Advisory** for the North and Central Regions
- 07/06/2021 13:00 – 18:30 EST: The MISO Reliability Coordinator is declaring a Maximum Generation Emergency **Alert** for the following entities: Central Region

area(s) of: ALT, ALTE, AMIL, AMMO, AMRN, ATC, BREC, CIN, CONS, CWLD, CWLP, DECO, GLH, HE, HMPL, IPL, ITC, MECS, METC, MGE, MIUP, NIPS, PION, RTX, SIGE, SIPC, UPPC, WEC, WPS and North Region area(s) of: ALTW, DPC, GRE, ITCM, MDU, MEC, MP, MPW, NSP, OTP, SMP due to Higher than Forecasted Load, Forced Generation Outages.

- 07/19/2021 06:00 – 20:00 EST: The MISO Reliability Coordinator is declaring a Maximum Generation **Capacity Advisory** for North and Central Regions
- 07/27/2021 06:00 – 07/28/2021 22:00 EST: The MISO Reliability Coordinator is declaring a Maximum Generation **Capacity Advisory** for the entire market footprint
- 08/19/2021 12:00 – 22:10 EST: The MISO Reliability Coordinator is declaring a Maximum Generation **Capacity Advisory** NORTH and CENTRAL Regions
- 08/23/2021 08:00 EST – 08/25/2021 20:00 EST: MISO declared a Maximum Generation **Capacity Advisory** for entire MISO footprint
- 08/24/2021 15:00 – 19:00 EST: The MISO Reliability Coordinator is declaring a Maximum Generation Emergency **Alert** for the following entities: Central Region area(s) of: ALT, ALTE, AMIL, AMMO, AMRN, ATC, BREC, CIN, CONS, CWLD, CWLP, DECO, GLH, HE, HMPL, IPL, ITC, MECS, METC, MGE, MIUP, NIPS, PION, RTX, SIGE, SIPC, UPPC, WEC, WPS and North Region area(s) of: ALTW, DPC, GRE, ITCM, MDU, MEC, MP, MPW, NSP, OTP, SMP due to above normal temperatures, generation outages, heavy congestion.
- 08/25/2021 09:00 – 20:00 EST: MISO is declaring a Maximum Generation Emergency **Alert** for the North and Central Regions of MISO due to Above Normal Temps, Forced Generation Outages
- 10/04/2021 07:00 – 20:10 EST: MISO declared a **Capacity Advisory** for North and Central Regions due to forced generation outages and tight capacity conditions.
- 10/04/2021 12:00 – 12:00 EST: MISO declared a Maximum Generation Emergency **Alert** for Central Region area(s) of: AEP, ALT, ALTE, AMIL, AMMO, AMRN, ATC, BREC, BWLT, CETO, CIN, CONS, CWLD, CWLP, DECO, GLH, GLHB, HE, HMPL, IPL, ITC, MCS-WPSC, MECS, METC, MGE, MIUP, NIPS, PION, RTX, SIGE, SIPC, UPPC, WEC, WPS and North Region area(s) of: ALTW, DPC, GRE, ITCM, MCS-BEPC, MCS-CBPC, MCS-CFU, MDU, MEC, MHEB, MP, MPCN, MPW, NSP, OTP, RPU, SMP, WMUT due to forced generation outages.
    - System conditions improved prior to start time of the alert and was cancelled prior to start.
    - Although the Maximum Generation Alert was cancelled prior to start time due to improved system conditions, Conservative Operations and Capacity

Advisory were maintained to ensure continued reliability in tight capacity conditions.

2022

- 01/07/2022 06:00 – 09:30 EST: MISO Reliability Coordinator is declaring a Maximum Generation Emergency **Warning** the following entities: Central Region area(s) of: AEP, ALT, ALTE, AMIL, AMMO, AMRN, ATC, BREC, BWLT, CETO, CIN, CONS, CWLD, CWLP, DECO, GLH, GLHB, HE, HMPL, IPL, ITC, MCS-WPSC, MECS, METC, MGE, MIUP, NIPS, PION, RTX, SIGE, SIPC, UPPC, WEC, WPS and North Region area(s) of: ALTW, DPC, GRE, ITCM, MCS-BEPC, MCS-CBPC, MCS-CFU, MDU, MEC, MHEB, MP, MPCN, MPW, NSP, OTP, RPU, SMP, WMUT due to forced generation outages
- 05/12/2022 14:45 – 20:00 EST: The MISO Reliability Coordinator declared a Maximum Generation Emergency **Warning** for the following entities: MISO Balancing Authority Area due to Forced Generation Outages, Above Normal Temps.
- 05/12/2022 19:00 – 20:00 EST: The MISO Reliability Coordinator declared a Maximum Generation Emergency **Alert** for the following entities: MISO Balancing Authority Area due to Forced Generation Outages, Above Normal Temps, Higher than Forecasted Load.
    - This Alert is the de-escalation of the earlier Maximum Generation Warning.
- 05/13/2022 15:35 – 19:00 EST: The MISO Reliability Coordinator declared a Maximum Generation Emergency **Alert** for the following entities: Central Region area(s) of: ALT, ALTE, AMIL, AMMO, AMRN, ATC, BREC, CIN, CONS, CWLD, CWLP, DECO, GLH, HE, HMPL, IPL, ITC, MECS, METC, MGE, MIUP, NIPS, PION, RTX, SIGE, SIPC, UPPC, WEC, WPS due to Forced Generation Outages, Higher than Forecasted Load, Above Normal Temps
- 05/18/2022 08:30 EST – 05/19/2022 20:00 EST: The MISO Reliability Coordinator declared a Maximum Generation **Capacity Advisory** for the MISO South Region due to reduced reserve margins
- 05/18/2022 14:30 – 19:30 EST: The MISO Reliability Coordinator declared a Maximum Generation Emergency **Alert** for the following entities: South Region area(s) of: AXLT, CLEC, EAI, EES, EMBA, LAFA, LAGN, LEPA, SME due Forced Generation Outages, Above Normal Temperatures and Higher than Forecasted Load
- 06/15/2022 08:00 – 06/16/2022 22:00 EST: The MISO Reliability Coordinator declared a Maximum Generation Emergency **Capacity Advisory** for the MISO Market Footprint
- 06/13/2022 14:00 – 19:00 EST: The MISO Reliability Coordinator declared a Maximum Generation Emergency **Alert** for the following entities: South Region

area(s) of: AXLT, CLEC, EAI, EES, EMBA, LAFA, LAGN, LEPA, SME due to Forced Generation Outages, Above Normal Temps, High Congestion

- 06/15/2022 13:00 – 20:00 EST: The MISO Reliability Coordinator declared a Maximum Generation Emergency **Alert** for the following entities: MISO Balancing Authority Area due to Forced Generation Outages, Above Normal Temps, High Congestion
- 06/20/2022 06:00 – 22:00 EST: The MISO Reliability Coordinator declared a Maximum Generation **Capacity Advisory** for the South Region only
- 06/21/2022 06:00 EST – 06/23/2022 22:00 EST: The MISO Reliability Coordinator declared a Maximum Generation **Capacity Advisory** for the Market Footprint
- 07/05/2022 10:00 – 20:00 EST: The MISO Reliability Coordinator declared a Maximum Generation Emergency **Capacity Advisory** for the MISO Balancing Authority
- 09/20/2022 01:00 – 21:00 EST: The MISO Reliability Coordinator declared a Maximum Generation **Capacity Advisory** for the MISO Market footprint
- 10/12/2022 14:00 – 19:00 EST: The MISO Reliability Coordinator declared a Maximum Generation **Capacity Advisory** for the MISO Market South Region.
- 12/23/2022 09:15 – 13:00 EST: The MISO Reliability Coordinator declared a Maximum Generation Emergency **Warning** for the following entities: South Region area(s) of: AXLT, CLEC, EAI, EES, EMBA, LAFA, LAGN, LEPA, SME due to Higher than Forecasted Load, Forced Generation Outages
- 12/23/2022 16:30 – 17:30 EST: The MISO Reliability Coordinator declared a Maximum Generation Emergency **Warning** for the following entities: the ENTIRE MISO Balancing Authority Area due to Forced Generation Outages, Higher than Forecasted Load
- 12/23/2022 17:30 – 18:00 EST: The MISO Reliability Coordinator declared a Maximum Generation Emergency **Event Step 1b – EEA1** for the following entities: MISO Balancing Authority Area due to Forced Generation Outages, Higher than Forecasted Load
- 12/23/2022 18:00 – 21:00 EST: The MISO Reliability Coordinator declared a Maximum Generation Emergency **Event Step 2a – EEA2** for the following entities: MISO Balancing Authority Area due to Forced Generation Outages, Higher than Forecasted Load

2023

- 06/02/2023 07:00 - 21:00 EST: The MISO Reliability Coordinator is declaring a **Maximum Generation Capacity Advisory** due to elevated temperatures, forced generation outages, and higher than normal forecasted loads.
- 06/26/2023 13:00 - 16:07 EST: The MISO Reliability Coordinator is declaring a **Maximum Generation Capacity Advisory** for MISO South Region
- 06/29/2023 12:00 – 22:01 EST: The MISO Reliability Coordinator is declaring a **Maximum Generation Capacity Advisory** for the Market Footprint due to extreme heat and high load
- 07/26/2023 12:00 EST – 07/28/2023 20:00 EST: MISO Reliability Coordinator declared a **Maximum Generation Capacity Advisory** for the MISO North and Central Regions
- 07/27/2023 12:00 – 18:00 EST: MISO Reliability Coordinator declared a **Maximum Generation Emergency Ale**rt for the following entities: Central Region area(s) of: AEP, ALT, ALTE, AMIL, AMMO, AMRN, ATC, BREC, BWLT, CETO, CIN, CONS, CWLD, CWLP, DECO, GLH, GLHB, HE, HMPL, IPL, ITC, MCS-WPSC, MEC1, MECS, METC, MGE, MIUP, NIPS, PION, RTX, SIGE, SIPC, UPPC, WEC, WPS and North Region area(s) of: ALTW, DPC, GRE, ITCM, MCS-BEPC, MCS-CBPC, MCS-CFU, MDU, MEC, MHEB, MP, MPCN, MPW, NSP, OTP, RPU, SMP, WMUT due to Above Normal Temps, Forced Generation Outage
  - MISO is forecasting high load which may cause MISO to be within 500 MW of obligations for operating day Thursday 07/27/2023.
  - With increased risk and uncertainty, it may be necessary for MISO to escalate further based on changing system conditions
- 07/28/2023 12:00 – 20:00 EST: MISO Reliability Coordinator is declaring a **Maximum Generation Emergency Alert** for the following entities: Central Region area(s) of: AEP, ALT, ALTE, AMIL, AMMO, AMRN, ATC, BREC, BWLT, CETO, CIN, CONS, CWLD, CWLP, DECO, GLH, GLHB, HE, HMPL, IPL, ITC, MCS-WPSC, MEC1, MECS, METC, MGE, MIUP, NIPS, PION, RTX, SIGE, SIPC, UPPC, WEC, WPS and North Region area(s) of: ALTW, DPC, GRE, ITCM, MCS-BEPC, MCS-CBPC, MCS-CFU, MDU, MEC, MHEB, MP, MPCN, MPW, NSP, OTP, RPU, SMP, WMUT due to Forced Generation Outages, Above Normal Temps
- 08/14/2023 10:00 – 20:00 EST: The MISO Reliability Coordinator is declaring a Maximum Generation Capacity Advisory for the following entities: South Region area(s) of: AXLT, CLEC, EAI, EES, EMBA, LAFA, LAGN, LEPA, SME

- 08/21/2023 10:00 EST – 08/24/2023 23:00 EST: The MISO Reliability Coordinator is declaring a **Maximum Generation Capacity Advisory** for the MISO Market Footprint
- 08/24/2023 12:00 – 12:00 EST: The MISO Reliability Coordinator is declaring a **Maximum Generation Emergency Alert** for the following entities: MISO Balancing Authority Area
    - Escalated to Maximum Generation Emergency Step 2a before start of the Alert
- 08/24/2023 12:00 – 19:30 EST: MISO is escalating to a **Maximum Generation Emergency Event Step 2a** for the MISO Balancing Authority Area due to Forced Generation Outages, Above Normal Temps, Higher than Forecasted Load.
- 08/24/2023 19:30 – 21:00 EST: MISO is de-escalating Maximum Generation Event Step 2A to **Maximum Generation Warning**

2024

- 5/07/2024 11:00 – 19:00 EST: MISO declared **Capacity Advisory** for South Region areas of AXLT, CLEC, CWLT, EAI, EES, EMBA, LAFA, LAGN, LEPA, SME due to an increase of load forecast, forced generation outages, and limited transfer capabilities from the MISO Classic Region to the MISO South Region.

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Midcontinent Independent System Operator (MISO)	)))))	Order No. 202-25-3

Exhibit to
Motion to Intervene and Request for Rehearing and Stay of
Public Interest Organizations

Filed June 18, 2025

Exhibit 33

MISO Market Capacity Emergency

MISO Market Capacity Emergency

SO-P-EOP-11-002 Rev: 21

ROLE			ROLE	
BAO	☑		SM	☑
IRAC	☑		RC	☑
UDS	☑		G&I	☑
SOE	☑		LBA	☑
TOP	☑		MP	☑
GOP	☑		ORM	☑

Rev History	Reason for Issue	Revised By	Issue Date	Effective Date
21	Annual Review. Added actions under Step 4.2.8. Updated procedure number. Added Operations Risk Management (ORM) Role. Removed references to MCS when not related to LMM, LMR or EDR. Compliance Review Completed. Operating procedure owner approval on file.	Chris Hoffman/ Becca Skalko/ Bill Puller	03/03/2025	03/03/2025
20	Annual Review. No changes. Compliance Review Completed. Operating procedure owner approval on file.	Chris Benton/ Becca Skalko/ Bill Puller	06/01/2024	06/01/2024

1.0 Purpose

Provide a set of emergency Operating Plans to address Capacity Emergencies and Energy Emergencies within the MISO Balancing Authority Area (MBAA), which shall include the following:

1. Roles and responsibilities for the MISO Operators, Local Balancing Authorities (LBAs), Transmission Operators (TOPs), Generation Operators (GOPs), and Market Participants (MPs).
2. Process for preparation, management, and recovery from an Emergency.

2.0 Precautions and Limitations

1. As conditions require, MISO may provide instructions to move to any section or step in this procedure while providing instructions to complete actions described in earlier levels or steps as time permits.
2. Should sufficient relief be obtained during the implementation of one of the actions during a declaration step, subsequent actions within that declaration step need NOT be taken.
3. The Operating Reserve Requirement for the MBAA consists of Regulation and Contingency Reserve Requirements.
4. The Operating Reserve Requirement for a Region or Sub-Area consists of a Contingency Reserve Requirement based on the Most Severe Single Contingency (MSSC) within its boundaries.
5. Available Economic Resources are the Available Economic Max (including BTM but reduced by Resources that cannot be committed due to congestion or excessive Time-to-Start) and adjusted for Constraint Stranded MW and NSI Obligations.
6. South Region Available Economic Resources are the South Available Economic Max (including BTM but reduced by Resources that cannot be committed due to congestion or excessive Time-to-Start) and adjusted for South Constraint Stranded MW, the Regional Dispatch Transfer NSI (RDT NSI), and Resources from the Central and North Regions that are deliverable to the South via the RDT up to the Regional Dispatch Transfer Limit (RDTL, typically 3,000 MW).
7. The 5% Reserve Margin Entry Condition for an MBAA Capacity Advisory includes allowance for loss of the MSSC and subsequent recovery within 90 minutes for the second MSSC (if applicable), plus uncertainties.

8. Increasing the Reserve Margin Entry Condition may be required when relying on a significant amount of capacity returning from outage or if there are other forecasting uncertainties or risks to the interconnection.
9. MISO will use the Mid-term Load Forecast (MTLF) or Short-term Load forecast (STLF) where applicable to determine available Operating Reserves. MISO may adjust the load forecast values based on sustained error over time and will document the reasons for the adjustment.
10. Transmission System Emergencies that require immediate action will be declared and resolved through actions identified in MISO SO-P-EOP-00-004 Transmission System Emergency. Transmission constraints, which result in limitations in transferring energy into the MBAA or a sizable sub-area of the MBAA and result in a capacity or energy Emergency for such area will be managed through the current procedure.
11. Energy deficient BA obligations include immediate actions to mitigate any undue risk to the Interconnection, including Load shedding.
12. MISO posts Max Gen Declaration notification to the MISO Market and Operations - Real-Time Operations Website.
13. Depending on the urgency of the Max Gen Emergency, manual Load Shedding may be used to control the Emergency at any time. This includes the immediate shedding of load to return Area Control Error (ACE) to zero.
14. MISO's posting of the Max Gen Declaration notification to the RT Ops Website [via Operator Interface (OI)] serves as notice of the existence and duration of the conditions requiring the implementation of the procedures set forth in Section 40.2.20 of the Tariff. Historical Max Gen Declarations can be found on the MISO's Open Access Same Time Information System (OASIS) page.
15. MISO will render all available emergency assistance to others as requested, provided that the requesting entity has implemented its comparable emergency procedures, unless such actions would violate safety, equipment, regulatory or statutory requirements.
16. If MISO is NOT able to send Load Modifying Resource (LMR) availability reminders to MPs, MISO will communicate, via the Demand Side Resource Interface (DSRI) Tool, implementation instructions using the then current availability information in the tool, assuming it to be correct.
17. MISO Shift Manager (SM) should evaluate additional staffing requirements per SO-I-NOP-00-441 Real-Time Event Resolution.

18. The Reserve Procurement Enhancement (RPE) objective for the RDT North-to-South is to elevate MCP and energy prices in the South Region to clear additional Contingency Reserves to allow recovery of the RDT Flow to 116% post-contingent of the South MSSC. Operators must determine how to reduce the RDT Flow further to 100% from 116%. When RPE on RDT is violating, additional generation should be started.
19. An infographic of MISO's Market Capacity Emergency Procedure steps is included in Attachment 8 — Summary of Market Capacity Emergency Procedure Steps.

3.0 Entry Conditions

3.1 Capacity Advisory

1. Entry conditions are based on the Reserve Margin, which is the Total Operating Reserves compared to the Operating Reserve Requirement, either in MW or % of the Load, plus Operating Reserve Requirements. Attachment 1 — Reserve Margin Example Calculations has example calculations.
   - Reserve Margin:
     Total Operating Reserves - Operating Reserve Requirement
   - Reserve Margin (%):
     100 * (Total Operating Reserves - Operating Reserve Requirement) /(Load + Operating Reserve Requirement)
   - Total Operating Reserves MBAA:
     (Avail Eco Max - Constraint Stranded - NSI) - Load
   - Total Operating Reserves South Region:
     (Avail Eco Max - Constraint Stranded - RDT NSI + RDTL) - Load

ORM/SM

Note [□]

- IF a positive but somewhat low Reserve Margin is forecast THEN:
- A Capacity Advisory will typically be declared 2 to 3 days in advance, however, it may be declared in any time frame.
- A decision to declare a Capacity Advisory may take into account other information such as time frame, weather and other risk factors
- Increasing the Reserve Margin may be required when relying on a significant amount of capacity returning from outage or if there are other uncertainties or risks to the Interconnection.

1. IF any of the following conditions are identified THEN **PERFORM** Section 4.1 Capacity Advisory: [□]
   - MBAA, Region or Sub-Area forecasted Reserve Margin (%) is less than 5%
   - South Region forecasted Reserve Margin is less than 2,000 MW

3.2 Max Gen Alert

SM

Note [□]

- A positive but low Reserve Margin is forecasted in a Max Gen Alert.
- For a negative Reserve Margin, a Warning or Event should be declared.
- Increasing the Reserve Margin may be required when relying on a significant amount of capacity returning from outage or if there are other forecasting uncertainties or risks to the interconnection.

1. IF any of the following conditions are identified, THEN **PERFORM** Section 4.2.2 Max Gen Alert - MISO Actions: [□]
   - MBAA, Region or Sub-Area forecasted Reserve Margin is less than 1500 MW, or largest single contingency for Sub-Area
   - South Region forecasted Reserve Margin is less than 500 MW

3.3 Max Gen Warning

SM

Note [□]

A negative Reserve Margin means that Load and Operating Reserve Requirement cannot be met with normal Economic Resources. In that scenario a Max Gen Warning or Event should be declared.

1. IF the following condition is identified, THEN **PERFORM** Section 4.2.3 Max Gen Warning - MISO Actions: [□]
   - MBAA, Region, or Sub-Area actual or forecasted Reserve Margin is less than zero

3.4 Max Gen Event

SM

1. IF the following condition is identified, THEN **PERFORM** Section 4.2.4 Max Gen Event Step 1a - MISO Actions when: [□]
   - MBAA, Region, or Sub-Area actual or forecasted Reserve Margin is less than zero
   - Warning level actions are NOT sufficient

4.0 Instructions

4.1 Capacity Advisory

ORM/ SM

4.1.1 Capacity Advisory - MISO Actions

1. **COMMUNICATE** Capacity Advisory as follows: [□]
   A. **DEFINE** boundaries of Capacity Advisory area. [□]
   B. **DEFINE** start time of Capacity Advisory and **COMMUNICATE** potential end time to UDS Operator to allow STR Default and RPE MSSC Overrides to be entered. [□]

C. **SEND** Capacity Advisory declaration to affected members via OI per SO-I-NOP-00-448 Event Communications Matrix. [□]

D. **SEND** Capacity Advisory declaration via Reliability Coordinator Information System (RCIS). [□]

SM 2. IF OI is down or SM determines a conference call is necessary, THEN **PERFORM** conference call with affected reliability entities per SO-P-NOP-00-483 Reliability Coordination Conference Call. [□]

SM 3. IF a significant shortage of Operating Reserves is anticipated in any Reliability Assessment Commitment (RAC) process, THEN **DETERMINE** whether to issue LMR Scheduling Instructions in anticipation of a Max Gen Emergency Event Step 2a or higher. [□]

A. **SEND** informational message via MCS/OI to impacted area(s) that LMRs have been called in anticipation of a Max Gen Emergency. [□]

B. **SEND** LMR scheduling instructions (from longest to shortest lead time) via MCS for forecasted Max Gen Emergency. [□]

UDS

Note [□]

For Steps 4. through 7., REFER to Attachment 7 — UDS Operator Actions During MISO Market Capacity Emergency Conditions.

4. IF a Capacity Advisory is declared for the North/Central Region only, THEN **OVERRIDE** STR RPE MSSC Default value(s) as specified in SO-I-EOP-001 Utilizing Emergency Ranges and Emergency and VOLL Pricing for Non-Zone only in the EMD Global Reserve Requirements menu, for the duration of a Capacity Advisory or higher declaration. [□]

UDS 5. IF during the course of a Capacity Advisory or higher declaration for the North/Central Region, <u>and</u> a Capacity Advisory or higher declaration is declared for the South Region, THEN **OVERRIDE** System Wide STR Default value(s) <u>and</u> **OVERRIDE** South Region STR RPE MSSC in Zone 8 in the EMD Global Reserve Requirements menu, for the duration of the Capacity Advisory or Higher declaration, as specified in SO-I-EOP-001 Utilizing Emergency Ranges and Emergency and VOLL Pricing. [□]

UDS

6. IF a Capacity Advisory is declared for the South Region only, THEN **OVERRIDE** STR RPE MSSC Default value(s) in Zone 8 only in the EMD Global Reserve Requirements menu, for the duration of the Capacity Advisory or higher declaration, as specified in SO-I-EOP-001 Utilizing Emergency Ranges and Emergency and VOLL Pricing. [□]

UDS

7. IF during the course of a Capacity Advisory or higher declaration for the South Region, a Capacity Advisory or higher declaration is added for the North/Central Region, THEN **OVERRIDE** System Wide STR Default value(s) and **OVERRIDE** North/ Central STR RPE MSSC for Non-Zone in the EMD Global Reserve Requirements menu for the duration of Capacity Advisory or higher declaration, as specified in SO-I- EOP-001 Utilizing Emergency Ranges and Emergency and VOLL Pricing. [□]

8. IF a System Wide Capacity Advisory is declared, THEN **OVERRIDE** STR Default value(s) AND Override North/Central STR RPE MSSC for Non-Zone AND Override South Region STR RPE MSSC for Zone 8 as specified per SO-I-EOP-001 Utilizing Emergency Ranges and Emergency and VOLL Pricing in the EMD Global Reserve Requirements menu for the duration of Capacity Advisory or above declaration. [□]

ORM/ SM

9. NOTIFY Day Ahead (DA) and Forward Reliability Assessment and Commitment (FRAC) operators when STR update is complete. [□]

4.1.2 Capacity Advisory - MISO Stakeholder Actions

1. WHEN notified by MISO, THEN **ENSURE** all market data is updated with best available information for operating day(s) including the following: [□]
   - Facility and generation availability, outages and de-rates
   - Generation Offers, including any changes to reflect fuel availability
   - Fuel supply and inventory concerns
   - Fuel switching capabilities
   - Environmental constraints
   - Load forecast Values
   - LMR Availability in the DSRI
   - Voluntary Load Management information

- Load Management Measures (LMM) and any Voluntary Load Management in the MCS
- Emergency Demand Response (EDR) offers

MP

Note [□]

LMRs should be implemented NO less than the MW amount scheduled and within guidelines given by MISO.

2. IF notified by MISO, THEN **IMPLEMENT** LMRs. [□]

MP

3. **UPDATE** DSRI Tool as follows: [□]
   A. **NAVIGATE** to the Active Event by clicking either of the following: [□]
      - the Scheduling Instruction event banner
      - the Active Event from the dashboard, or
      - the Events tab
   B. **REVIEW** Event Timeline and LMR Instructions broken down by each LBA. [□]
   C. **ACKNOWLEDGE** LMR Scheduling Instructions. [□]
   D. **NAVIGATE** to Resource Deployment tab of the Active Event. [□]
   E. **ENTER** and **SUBMIT** MW Amounts of Resources that will be deployed in order to meet the LMR Scheduling Instruction obligation per LBA. [□]
   F. After receiving the LMR Scheduling Instruction, **UPDATE** LMR Availability of those Resources that were designated to respond to LMR Scheduling Instruction to reflect what is newly available to MISO. [□]

4.2 MISO Actions during a Max Gen Emergency

4.2.1 Max Gen Declaration - MISO Actions

SM 1. **DECLARE** applicable Max Gen Alert/Warning/Event as follows: [□]

A. **DEFINE** boundaries of declaration area. [□]

B. **DEFINE** start and end time of declaration. [□]

C. **SEND** Max Gen Declaration via OI per SO-I-NOP-00-448 Event Communications Matrix. [□]

D. SEND Max Gen declaration summary information via RCIS within 30 minutes. [□]

SM 2. **ENSURE** Conservative System Operations has been declared per SO-P-NOP-00-449 Conservative System Operations. [□]

SM 3. IF OI is down or SM determines a conference call is necessary, THEN **PERFORM** conference call with affected reliability entities per SO-P-NOP-00-483 Reliability Coordination Conference Call. [□]

4.2.2 Max Gen Alert - MISO Actions

SM 1. IF starting declaration at a Max Gen Alert, THEN **DECLARE** Max Gen Alert per Section 4.2.1 Max Gen Declaration - MISO Actions. [□]

UDS 2. **IMPLEMENT** Emergency Pricing Tier 0 per SO-I-EOP-00-001 Utilizing Emergency Ranges and Emergency and VOLL Pricing. [□]

SM **Note** [□]

> This survey is to gain an idea of amount of LMM load reduction to expect to be available if needed.

3. **SEND** survey via MCS LMM Tool in the Load Management Tab to LBAs to ensure LMM information is updated. [□]

A. IF the Drill Mode is currently on. THEN **ENSURE** to “Switch to Live Mode”. [□]

BAO 4. IF Operating Reserve availability changes are identified, THEN **NOTIFY** SM. [□]

IRAC 5. **ENSURE** available economic resources are committed to meet load, firm transactions, and reserve requirements. [□]

G&I

A. COORDINATE with MPs with Module E Resources as follows: [□]

(1.) **DETERMINE** available Resources for implementation during potential Warning declaration. [□]

B. IF MPs have remaining available External and Internal Resources (Module E registered Capacity Resources), THEN **REQUEST** amount available for implementation during potential Warning declaration. [□]

(1.) **ENSURE** MPs identify specific information on physical location and path External Resources (Module E registered Capacity Resources) would use to deliver energy into potential Warning area. [□]

SM
G&I

C. **NOTIFY** SM of Total MW of non-firm energy sales and MISO exporting Capacity Resources. [□]

RC

Note [□]

The following analysis should be completed in time for implementation during the potential Warning declaration.

D. **COORDINATE** with neighboring Reliability Coordinators (RCs) and MISO TOPs to raise transfer capability into declaration area or make available constraint stranded generation (on or off line) in declaration area including: review Transmission Loading Relief (TLR) activity, binding constraints, available reconfiguration options, and use of short term emergency ratings. [□]

UDS

E. **LOG** actions taken and relevant information in response to the declaration. [□]

Note [□]

- Actions are taken to attempt to preserve Resources dedicated to firm Load and maintaining Operating Reserves.
- Actions available at this level should be fully utilized, time permitting, for all entities within the defined declaration area prior to declaring an emergency.

4.2.3 Max Gen Warning - MISO Actions

SM

1. IF starting declaration at a Max Gen Warning or escalating from a Max Gen Alert, THEN **DECLARE** Max Gen Warning per Section 4.2.1 Max Gen Declaration - MISO Actions. [□]

UDS	2. **IMPLEMENT** Emergency Pricing Tier 1 per SO-I-EOP-00-001 Utilizing Emergency Ranges and Emergency and VOLL Pricing.	[□]
IRAC	3. **SUSPEND** Coordinated Transaction Scheduling (CTS) for the duration of the capacity emergency per SO-I-AOP-00-224 CTS Failure Modes.	[□]
G&I	4. **COMMUNICATE** CTS suspension with PJM.	[□]
SM	5. **REVIEW** EDR offers to determine EDR availability and MW amounts for Warning period.	[□]
SM	6. **OBTAIN** updated MW amounts of relief available during effective Warning period by LBA from MCS.	[□]
	• LMMs – Stage 1	
	• LMMs – Stage 2	
SM	7. **REVIEW** LMRs availability in MCS-LMR Tool for declaration period.	[□]
SM	8. **DIRECT** the following to raise forecasted capacity:	[□]
BAO	A. **TERMINATE** Inadvertent Payback process per SO-I-NOP-00-462 Inadvertent Interchange Management.	[□]
BAO	B. **DETERMINE** if request for time error correction termination should be made per SO-P-NOP-00-455 Balancing Authority Operations.	[□]
SM	9. **SEND** OI message to MPs to schedule remaining available External and Internal Resources (Module E Registered Capacity Resources) that would be deliverable to Warning area, given transmission constraints.	[□]
SM/ G&I	10. **COORDINATE** to notify MPs to schedule Module E Resources into MBAA declaration area as follows:	[□]
G&I	A. **PROVIDE** instructions on amount and time to schedule External and Internal Module E Resources into declaration area.	[□]
G&I	11. **NOTIFY** SM of forecasted changes in MBAA NSI due to loss of imports.	[□]
G&I	12. **COORDINATE** to determine amount of non-firm Export Schedules to curtail.	[□]

G&I	13. IF Export Schedule Limits are exceeded, THEN **CURTAIL** Export Schedules from declaration area in amounts required to relieve shortage condition in the following order per SO-I-EOP-00-006 Interchange Scheduling Operations during Emergency Conditions: A. Non-Firm Transmission Schedules. B. Firm Schedules from Capacity (Module E) Resources that are NOT meeting their Schedule requirements and Capacity requirements. C. Firm Schedules from non-Capacity (Module E) Resources that are NOT meeting their Schedule requirements. D. Firm Transmission schedules from Power Purchase Agreements (PPAs) that represent a Fleet of Resources, when those resources are NOT meeting their collective resource obligation.	[□]
G&I	14. **MODIFY** webTrans E-tag validation mode to reflect Max Gen in affected area (North, South, or All) per SO-I-EOP-00-006 Interchange Scheduling Operations during Emergency Conditions.	[□]
RC	15. **NOTIFY** TOP to implement reconfiguration options agreed upon to raise transfer capability into declaration area or alleviate constraint stranded generation in declaration area.	[□]
ALL	16. **LOG** actions taken and relevant information in response to the declaration.	[□]

4.2.4 Max Gen Event Step 1a - MISO Actions

SM

Note [□]

Actions in this section are taken to attempt to preserve Resources dedicated to firm Load and maintaining Regulating Reserves.

1. IF starting declaration at a Max Gen Event Step 1a or escalating from a lower Max Gen level, THEN **DECLARE** Max Gen Event 1a per Section 4.2.1 Max Gen Declaration - MISO Actions. [□]

SM

2. **NOTIFY** Director On-Call to implement SO-P-AOP-00-217 MISO and State Officials 24X7 Communication Protocols During Emergencies. [□]

IRAC

Note [□]

AME are resources with a commit status of Emergency.

3. **COMMIT** the following Available Max Emergency (AME) designated resources: [□]
   - Generation Resources
   - Demand Response Resources – Type 1
   - Demand Response Resources – Type 2

4.2.5 Max Gen Event Step 1b - MISO Actions

SM

1. IF starting declaration at a Max Gen Event Step 1b or escalating from a lower Max Gen level, THEN **DECLARE** Max Gen Event Step 1b and EEA1
per Section 4.2.1 Max Gen Declaration - MISO Actions. [□]

IRAC

Note [□]

IRAC Operator ensuring emergency ranges are available for use by UDS and UDS Operator verifying these ranges are preliminary actions to implementing these ranges in Event Step 1b.

2. **ENSURE** unit emergency ranges are pushed per SO-I-EOP-00-001 Utilizing Emergency Ranges and Emergency and VOLL Pricing. [□]

UDS

Note [□]

Resources selected to provide Regulating Reserve for each Generation Resource, Demand Response Resource – Type II and External Asynchronous Resource for use in MISO's RAC, Automatic Generation Control (AGC), and UDS for the MBAA (or sub-area due to a transmission constraint) are to be excluded when implementing Emergency Maximum Limits.

3. **ACTIVATE** Emergency Maximum Limits per SO-I-EOP-00-001 Utilizing Emergency Ranges and Emergency and VOLL Pricing. [□]

ALL 4. **LOG** actions taken and relevant information in response to the declaration. [□]

4.2.6 Max Gen Event Step 2a - MISO Actions

SM

Note [□]

- LMM – Stage 1 and LMRs are utilized on a pro-rata basis within the declaration area based on availability of those actions, with the exception of EDRs, which are committed in merit order.
- LMRs can be called in anticipation up to one hour prior to their required notification time. If MISO does NOT declare a Max Gen Emergency Event Step 2a or higher at least two hours prior to the start of the Scheduling Instructions issued in anticipation, the LMRs are NOT obligated to perform.

1. IF starting declaration at a Max Gen Event Step 2a or escalating from a lower Max Gen level, THEN **DECLARE** Event Step 2a and EEA2 per Section 4.2.1 Max Gen Declaration - MISO Actions. [□]

UDS 2. **ENSURE** emergency pricing has been implemented as follows:
   - If previously implemented, THEN **CHANGE** to Tier 2. [□]
   - If NOT previously implemented, THEN **IMPLEMENT** Emergency Pricing Tier 2 per SO-I-EOP-00-001 Utilizing Emergency Ranges and Emergency and VOLL Pricing. [□]

SM 3. **DETERMINE** Manitoba Hydro's EEA status. [□]

SM 4. IF Manitoba Hydro is in an EEA concurrently with MISO's EEA2 or higher, THEN PERFORM SO-I-NOP-00-481MISO-Manitoba Hydro Concurrent EEA. [□]

SM **Note** [□]

- One MW value will be provided per LBA for load reduction.
- Determination of individual LMMs to be utilized will be managed at the LBA level.
- Reduction MW amounts by LBA will be determined by proration of total amount available in declaration area.
- If OI is unavailable, notifications will be made via phone.
- LMR load reduction amounts to LBAs are for information only. LBAs do not implement LMRs

5. **NOTIFY** LBAs of required Load reduction via LMM – Stage 1 and LMRs in MW amounts via MCS. [□]

SM 6. **COORDINATE** with MPs on implementing LMRs as follows: [□]

Note [□]

LMR implementation amounts are determined by taking prorated amount of LMR availability in each LBA area as compared to total available in declaration area, and based upon registration profile of each LMR, within the tolerances as set in the MCS-LMR Tool.

A. **DETERMINE** LMR implementation amounts by MPs. [□]

B. **PROVIDE** a MW minimum implementation amount to each MP based upon this pro-ration and profile of registered LMRs via MISO Communication System (MCS)-LMR Tool. [□]

SM 7. **DETERMINE** OE-417 reporting responsibilities per SO-P-NOP-04 MISO Event Reporting Operations Plan. [□]

SM 8. **ENSURE** required notifications are performed per SO-I-NOP-00-448 Event Communications Matrix. [□]

ALL 9. **LOG** actions taken and relevant information in response to the declaration. [□]

4.2.7 Max Gen Event Step 2b - MISO Actions

SM 1. IF starting declaration at a Max Gen Event Step 2b or escalating from a lower Max Gen level, THEN **DECLARE** Event Step 2b per Section 4.2.1 Max Gen Declaration - MISO Actions. [□]

SM 2. **COMMIT** EDR resources, in merit order, to alleviate capacity shortage within declaration area per SO-I-NOP-00-404 Emergency Demand Response Implementation. [□]

ALL 3. **LOG** actions taken and relevant information in response to the declaration. [□]

4.2.8 Max Gen Event Step 2c - MISO Actions

SM	1.	IF starting declaration at a Max Gen Event Step 2c or escalating from a lower Max Gen level, THEN **DECLARE** Event Step 2c per Section 4.2.1 Max Gen Declaration - MISO Actions.	[□]
SM/ RC	2.	**COORDINATE** with neighboring RCs and BAs to determine Emergency energy available from external sources.	[□]
SM/ G&I	3.	**IMPLEMENT** Emergency energy purchases from neighboring BAs through existing Emergency contractual agreements in order to conserve Operating Reserves per SO-I-NOP-00-479 Purchasing and Selling Emergency Energy.	[□]
SM	4.	**EVALUATE** opportunities to reduce internal energy usage, such as sending non-essential personnel home, reducing lighting that is non-essential for personnel safety and reducing large electric loads.	[□]

SM

Note [□]

DOE Form OE-417 filing requirements for issuing Public Appeals is the responsibility of the LBA.

5. **INSTRUCT** LBAs in declaration area to issue public appeals to reduce demand per their internal procedures. [□]

ALL	6. **LOG** actions taken and relevant information in response to the declaration.	[□]

4.2.9 Max Gen Event Step 3a - MISO Actions

SM	1. IF starting declaration at a Max Gen Event Step 3a or escalating from a lower Max Gen level, THEN **DECLARE** Event Step 3a per Section 4.2.1 Max Gen Declaration - MISO Actions.	[□]
SM	2. **NOTIFY** GOPs, via OI, in the declaration area who have Generators with de-rates from environmental restrictions to request waivers from appropriate government agencies.	[□]
BAO	3. **IMPLEMENT** use of all spinning and supplemental reserves as needed and as time permits.	[□]
SM	4. IF Contingency Reserves fall below minimum required (MSSC) for greater than 30 minutes and NO reasonable actions exist to restore within 90 minutes, THEN **DECLARE** an EEA3 per Section 4.2.1 Max Gen Declaration - MISO Actions.	[□]

4.2.10 Max Gen Event Step 3b - MISO Actions

SM	1. IF starting declaration at a Max Gen Event Step 3b or escalating from a lower Max Gen level, THEN **DECLARE** Event Step 3b per Section 4.2.1 Max Gen Declaration - MISO Actions.	[□]

SM

Note [□]

Reduction MW amounts by LBA will be determined by pro-rata of total amount available in declaration area.

	2. **NOTIFY** LBAs, via MCS, of required Load reduction via LMM – Stage 2 in MW of interruptible demands.	[□]
RC	3. IF TLR is called and MISO imports are being curtailed, THEN **COORDINATE** with SM to evaluate Priority 6-NN tags to exclude.	[□]
SM/ G&I	4. **COORDINATE** to elevate identified Priority 6-NN tags per SO-I-EOP-00-006 Interchange Scheduling Operations during Emergency Conditions.	[□]
SM/ G&I	5. **NOTIFY** RCs of tags that are being elevated to Firm.	[□]

ALL	6. **LOG** actions taken and relevant information in response to the declaration.	[□]

4.2.11 Max Gen Event Step 4a - MISO Actions

SM	1. IF starting declaration at a Max Gen Event Step 4a or escalating from a lower Max Gen level, THEN **DECLARE** Event Step 4a per Section 4.2.1 Max Gen Declaration - MISO Actions.	[□]
BAO	2. **IMPLEMENT** Reserve Call from Contingency Reserve Sharing Group (CRSG).	[□]

4.2.12 Max Gen Event Step 4b - MISO Actions

SM	1. IF starting declaration at a Max Gen Event Step 4b or escalating from a lower Max Gen level, THEN **DECLARE** Event Step 4b per Section 4.2.1 Max Gen Declaration - MISO Actions.	[□]
RC	2. **COORDINATE** with neighboring RCs and BAs to identify additional available Emergency energy, including their Operating Reserves.	[□]
G&I	3. **IMPLEMENT** Emergency energy purchases from neighboring BAs through existing Emergency contractual agreements and SO-I-NOP-00-479 Purchasing and Selling Emergency Energy.	[□]
SM	4. IF Contingency Reserves fall below minimum required (MSSC) for greater than 30 minutes and NO **reasonable** actions exist to restore within 90 minutes, THEN DELARE an EEA3 per Section 4.2.1 Max Gen Declaration - MISO Actions.	[□]
IRAC	5. **EVALUATE** excluding Regulating Units that have room between RegMax and Emergency Max from clearing Reg per SO-I-EOP-00-001 Utilizing Emergency Ranges and Emergency and VOLL Pricing.	[□]
ALL	6. **LOG** actions taken and relevant information in response to the declaration.	[□]

4.2.13 Max Gen Event Step 5 - MISO Actions

SM 1. IF starting declaration at a Max Gen Event Step 5 or escalating from a lower Max Gen level, THEN **DECLARE** Max Gen Event Step 5 and EEA3per Section 4.2.1 Max Gen Declaration - MISO Actions. [□]

SM **Note** [□]

Attachment 4 — Slice-of-System PPAs Load/Schedule Curtailment provides additional information regarding sharing of load shedding with Slice of System PPAs.

2. **DETERMINE** manual Load Shedding requirements. [□]

SM **Note** [□]

Issuing Emergency Operating Instructions for firm Load shed is based on the ratio of LBA forecasted or actual Load to the total forecasted or actual Load of the declaration area, taking into account applicable transmission security requirements.

3. **ISSUE** Emergency Operating Instructions to LBAs, in declaration area, of MW amounts of load to shed via MCS Firm Load Shed Tool or verbally per SO-P-NOP-00-431 Communications Protocol For Operating Instructions. [□]

UDS **Note** [□]

Refer to SO-I-EOP-00-001 Utilizing Emergency Ranges and Emergency and VOLL Pricing.

4. WHEN notified by MISO SM, THEN **PERFORM** the following:
   - A. **CHECK** appropriate box(es) in the Energy Market Display (EMD) for the applicable LBAs in the column titled "Is Voll Price Enforced" [□]
   - B. **SAVE** updates. [□]

SM 5. IF firm Load Shed is greater than 100 MW, THEN **DETERMINE** OE-417 reporting responsibilities per SO-P-NOP-04 MISO Event Reporting Operations Plan. [□]

SM 6. **ENSURE** required notifications are performed per SO-I-NOP-00-448 Event Communications Matrix. [□]

ALL 7. **LOG** actions taken and relevant information in response to the declaration. [□]

4.2.14 Max Gen Event Downgrade/Termination - MISO Actions

SM

Note [□]

- Steps and levels during Termination may be skipped as appropriate based on system conditions and projections.
- Emergency steps shall be exited in a controlled and deliberate manner so to NOT adversely affect system reliability while minimizing the impact of these emergency actions on the Load Serving Entities (LSEs).

1. WHEN actual obligations return below total MISO capability, THEN **DOWNGRADE/TERMINATE** Max Gen Event as follows: [□]

SM — A. **SEND** Max Gen Downgrade/Termination to affected members via OI per Section 4.2.1 Max Gen Declaration - MISO Actions. [□]

UDS — B. IF Max Gen Event Step 5 is being terminated, THEN **UNCHECK** flag in EMD, which previously set all LMPs and MCPs to the Value of Lost Load (VOLL). [□]

IRAC/ G&I — C. ENSURE CTS is enabled per SO-I-AOP-00-224 CTS Failure Modes. [□]

UDS — D. **UPDATE** or **TERMINATE** emergency pricing and emergency ranges per SO-I-EOP-00-001 as applicable. [□]

G&I — E. **RETURN** webTrans E-tag validation to normal mode per SO-I-EOP-00-006 Interchange Scheduling Operations during Emergency Conditions. [□]

IRAC — F. **EVALUATE** and **DECOMMIT** any online emergency generation (AME) that has met its Min Run. [□]

SM — G. **PERFORM** necessary actions to back out of steps taken in reverse order. [□]

UDS — H. IF STR requirement override is NOT needed for remainder of the declared emergency, THEN **REMOVE** STR requirement override in EMD from STR Default and STR MSSC Non-Zone and South Zone 8. [□]

SM — 2. **ENSURE** all SO-I-NOP-00-448 Event Communications Matrix notifications are performed. [□]

ALL — 3. **LOG** actions taken and relevant information in response to the declaration. [□]

4.3 MISO Stakeholder Actions during a Max Gen Emergency

4.3.1 Max Gen Alert Level Actions - MISO Stakeholder Actions

LBA/ TOP/ GOP

Note [□]

Deferring generation/transmission maintenance until the Max Gen declaration has been terminated ensures trips are minimized.

1. **FOLLOW** MISO's SO-P-NOP-00-449 Conservative System Operations procedure. [□]

LBA/ TOP

2. **DETERMINE** potential exclusions of constrained pockets within declaration area where there is expected to be adequate generation that may NOT be transferred to other parts of declaration area due to local constraints. [□]

TOP

3. **INFORM** MISO RC of identified areas. [□]

GOP

4. IF generators are derated, THEN **PERFORM** the following:

GOP

   A. INFORM the following of capacity limited facilities: [□]
      - LBAs
      - TOPs
      - MISO G&I Operator

GOP

5. **UPDATE** Limits and Offers. [□]

MP

Note [□]

- Schedules that source from a resource that is identified as a Capacity Resource in Module E for a MISO LSE must be identified in the tagging process per MISO BPM-007 Physical Scheduling Business Practice Manual Section 16 - Capacity Resource Scheduling.
- This also includes a Generation Resource internal to the MBAA that is identified as a Capacity Resource for an external BA.
- This identification allows for proper curtailment of non-firm imports and exports during a capacity emergency event.

6. **UPDATE** energy interchange transaction e-tags, sourcing or sinking, in MBAA to reflect the firmness of their Capacity Resources. [□]

MP

Note [□]

MISO will provide instructions on when and how much the MP should schedule into MISO during Max Gen Warning.

7. **NOTIFY** MISO G&I Operator of Available External and Internal Resources (Module E registered Capacity Resources) deliverable to the declaration area, including amount available. [□]

MP	8. **ENSURE** accuracy of LMR availability and Self-Scheduled/ Voluntary Load Management LMRs in the DSRI Tool.	[□]
LBA	9. **ENSURE** accuracy of Non-LMR Voluntary Load Management/ Self-Scheduled LMM information in the MCS-LMR Tool.	[□]
TOP	10. **COORDINATE** with MISO RC to determine reconfiguration options to raise transfer capability to declaration area or alleviate constraint stranded generation in declaration area.	[□]

4.3.2 Max Gen Warning - MISO Stakeholder Actions

LBA	1. Based on Load Shed methodology, **MAKE** preparations for potential Load Shed during an Event stage.	[□]
MP	2. **UPDATE** EDR offers for availability and MW amounts for declaration period.	[□]
LBA	3. **SUBMIT** LMM availability via MCS per Attachment 3 — Load Management Update Form Example.	[□]
MP	4. **ENSURE** accuracy of registered LMR availability in the DSRI Tool.	[□]
MP	5. WHEN notified by MISO, THEN **SCHEDULE** remaining available External and Internal Resources (Module E Registered Capacity Resources) that would be deliverable to declaration area, given transmission constraints.	[□]
LBA	6. **NOTIFY** Interruptible Loads of potential interruption.	[□]
LBA/ MP/ TOP/ GOP	7. **LOWER** energy use to a minimum using conservative measures.	[□]
TOP	8. **IMPLEMENT** agreed upon reconfiguration options to raise transfer capability into declaration area or make available constraint stranded generation in declaration area.	[□]

4.3.3 Max Gen Event Step 1a - MISO Stakeholder Actions

GOP	1. WHEN notified by MISO, THEN **START** applicable off-line AME Generation Resources.	[□]

4.3.4 Max Gen Event Step 1b - MISO Stakeholder Actions

GOP

Note [□]

MPs should ensure Emergency Range limits reflect actual resource capabilities. Specific information, limitations, and concerns on Emergency Range usage should be communicated to MISO G&I Operators as applicable.

1. WHEN Resources are dispatched, THEN **ENSURE** Resources move into Emergency range. [□]

GOP 2. **ENSURE** all co-generation and independent power producers are at maximum output and availability. [□]

GOP 3. **NOTIFY** MISO G&I Operator of change in output. [□]

GOP 4. IF additional reliable capacity is available (such as adding additional mills, duct burners, etc.), THEN **COORDINATE** adjustments with MISO G&I Operator. [□]

4.3.5 Max Gen Event Step 2a - MISO Stakeholder Actions

LBA 1. IF in declaration area and notified by MISO to reduce load, THEN **PERFORM** the following: [□]

LBA A. **REDUCE** load via LMM – Stage 1. [□]

LBA **Note** [□]

- Reductions through Load Management are NOT precise to the MW.
- Determination of individual LMMs to be utilized will be managed at the LBA level.

B. WHEN load reduction actions have been implemented, THEN **NOTIFY** MISO. [□]

MP **Note** [□]

LMRs should be implemented NO less than the MW amount scheduled and within guidelines given by MISO.

2. WHEN notified by MISO, THEN **IMPLEMENT** LMRs. [□]

MP 3. UPDATE DSRI Tool as follows: [□]

A. **NAVIGATE** to the Active Event by clicking either of the following: [□]
   - the Scheduling Instruction event banner
   - the Active Event from the dashboard, or
   - the Events tab

B. **REVIEW** Event Timeline and LMR Instructions broken down by each LBA. [□]

C. **ACKNOWLEDGE** LMR Scheduling Instructions. [□]

D. **NAVIGATE** to Resource Deployment tab of the Active Event. [□]

E. **ENTER** and **SUBMIT** MW Amounts of Resources that will be deployed in order to meet the LMR Scheduling Instruction obligation per LBA. [□]

F. After receiving the LMR Scheduling Instruction, **UPDATE** LMR Availability of those Resources that were designated to respond to LMR Scheduling Instruction to reflect what is newly available to MISO. [□]

4.3.6 Max Gen Event Step 2b - MISO Stakeholder Actions

MP

1. WHEN notified by MISO, THEN **COMMIT** EDR Resources. [□]

4.3.7 Max Gen Event Step 2c - MISO Stakeholder Actions

LBA

Note [□]

- Public appeals to reduce demand is based on internal LBA procedures, system conditions, and Event projections provided by MISO.
- The public appeals should include an educational message on how the public may reduce demand and conserve power.
- DOE Form OE-417 filing requirements for issuing Public Appeals is the responsibility of the LBA.

1. WHEN instructed by MISO, THEN **ISSUE** public appeals to reduce demand per internal procedures. [□]

LBA

2. IF in declaration area, THEN **PREPARE** to shed load. [□]

4.3.8 Max Gen Event Step 3a - MISO Stakeholder Actions

GOP

1. IF requested by MISO to dispatch available capacity in Event Step 3a, THEN **DISPATCH** as follows: [□]
   A. **VERIFY** Generators in declaration area with de-rates from environmental restrictions. [□]
   B. IF approved waiver from government regulations, THEN **DISPATCH** available generation. [□]

4.3.9 Max Gen Event Step 3b - MISO Stakeholder Actions

LBA

1. IF in declaration area and notified by MISO to reduce Load during Event Step 3b, THEN **PERFORM** the following:
   A. REDUCE Load via LMM – Stage 2. [□]

Note [□]

- Reductions through LMMs are NOT precise to the MW.
- Determination of individual LMMs to be utilized will be managed at the LBA level.

   B. WHEN Load reduction actions have been implemented, THEN **NOTIFY** MISO via MCS. [□]

4.3.10 Max Gen Event Step 4a/b - MISO Stakeholder Actions

GOP/MP

1. **REVIEW** Offers. [□]

GOP/MP

2. **ENSURE** all available Emergency range and resources are offered. [□]

GOP/MP

Note [□]

All Resources should be committed, producing energy or committed for reserves, except emergency ranges on Resources providing Regulating Reserves.

3. IF there are available Resources or capacity NOT being utilized, THEN **NOTIFY** MISO. [□]

4.3.11 Max Gen Event Step 5 - MISO Stakeholder Actions

LBA

Note [□]

In addition to ensuring load shed schemes are capable of implementation in a time frame adequate for mitigating the Emergency for load shed directed by MISO, LBAs are responsible to coordinate with TOPs for any load shed requirements, critical load evaluation in load shed schemes, and coordination including rotation of selected loads, with any other automatic load shed schemes such as Underfrequency and Undervoltage. The minimum MISO directed load shed per LBA should be maintained at all times, until load restore directions are provided by MISO.

1. **SHED** firm Loads per MISO issued Emergency Operating Instruction. [□]

LBA

2. **CONFIRM** actions taken with MISO RC via MCS Firm Load Shed Tool or verbally per SO-P-NOP-00-431 Communications Protocol For Operating Instructions. [□]

LBA

3. IF requested by MISO during Event Step 5, THEN **COMPLETE** Department of Energy (DOE) Form OE-417 as follows: [□]
   A. **COMPLETE** DOE Form OE-417 for actions taken to reduce Load via Load Management Procedures per NERC EOP-004-4 and SO-P-NOP-04 MISO Event Reporting Operations Plan. [□]
   B. **SUBMIT** completed DOE Form OE-417 to the following: [□]
      - DOE
      - NERC
   C. **FORWARD** a copy of the submitted DOE Form OE-417 to the following: [□]
      - Regional Entities
      - MISO @ RTOpsCompliance@misoenergy.org

4.3.12 Max Gen Event Downgrade/Termination - MISO Stakeholder Actions

LBA/ MP/ TOP/ GOP

1. **PERFORM** requests of MISO SM or designee to back out of each level. [□]

5.0 Definitions

1. **Reserve Margin** - The difference between Total Operating Reserves and the Operating Reserve Requirement.
2. **Constraint Stranded MW** - Resource MW that are NOT available to meet load due to congestion on the electric grid.
3. **Emergency Demand Response (EDR)** - Load reductions, behind the meter generation, and other demand resources that are available to reduce demand or increase generation in exchange for guaranteed recovery of costs associated with the response in accordance with Schedule 30 (EDR Provisions) of the Tariff.
4. **Load Management Measures (LMM) Stage 1** – Load management actions that can be taken to reduce demand to preserve or maintain Operating Reserves that are NOT included in EDRs or LMRs.
5. **Load Management Measures (LMM) Stage 2** – Load management actions that can be taken to reduce demand including voltage reductions and reducing Loads that, by contract, can NOT be interrupted until reserves are being or are expected to be depleted and energy from Emergency Offers by Market Participants are being or are expected to be depleted. These do NOT include EDRs or LMRs.
6. **Load Modifying Resource (LMR)** - These are either Demand resources or Behind the Meter Generation that have an obligation to reduce demand or increase generation during declared system emergencies
7. **Maximum Generation (Max Gen) Capacity Advisory** - Provides advanced notice of forecasted capacity shortage and will request stakeholder update data.
8. Max Gen Alert - Provides an early alert that system conditions may require the use of MISO's generation Emergency procedures.
9. **Max Gen Warning** - MISO foresees or is experiencing conditions where all available economic Resources are committed to meet Load, firm transactions, and reserve requirements, and is concerned about sustaining required Operating Reserves.

10. **Max Gen Event** - MISO's forecasted or real-time energy demand and Operating Reserve Requirements within the MBAA (or sub-area due to a transmission constraint) can NOT be satisfied with Economic Maximum Limits of all available Resources; MISO issues a Max Gen Event due to a shortage of economic Resources.
11. **MBAA Sub-Region** - Sub-region may consist of a single LBA area, a group of LBA areas, or portions of an LBA area (for portions of an LBA area, a 1000 MW minimum threshold will generally be used).

6.0 References

6.1 NERC References

1. EOP-011-4 Emergency Operations
   - R2.2.1[Section 4.1.1 Step 1.]
   - R2.2.2 [Section 4.2.5 Step 1.][Section 4.2.6 Step 1.] [Section 4.2.13 Step 1.]
   - R2.2.3 [Section 4.1.2]
   - R2.2.4 [Section 4.2.8 Step 5.]
   - R2.2.5 [Section 4.2.9 Step 2.]
   - R2.2.6 [Section 4.2.8]
   - R2.2.7 [Section 4.2.3 Step 6.][Section 4.2.4 Step 3.][Section 4.2.6 Step 6.][Section 4.2.7 Step 2.]
   - R2.2.9 [Section 4.2.13 Step 3.]
   - R2.2.10 [Section 3.1 Note after Step 1]
   - R5 [Section 4.2.1 Step 1.D.]
   - R6 [Section 4.2.5 Step 1.][Section 4.2.6 Step 1.] [Section 4.2.1][Section 4.2.13 Step 1.]
2. IRO-014-4 Coordination Among Reliability Coordinators
3. R1 [Section 4.1][Section 4.2]
4. TOP-001-6 Transmission Operations
   - R2 [Section 4.1][Section 4.2]

6.2 FERC References

1. MISO Open Access Transmission, Energy, and Operating Reserve Markets Tariff, Section 40.2.20

6.3 MISO References

1. SO-P-EOP-11 MISO Emergency Operating Plan
2. BPM-007 Physical Scheduling Business Practice Manual Section 16 – Capacity Resource Scheduling
3. SO-I-EOP-00-001 Utilizing Emergency Ranges and Emergency and VOLL Pricing
4. SO-I-EOP-00-006 Interchange Scheduling Operations during Emergency Conditions
5. SO-I-AOP-00-224 CTS Failure Modes
6. SO-I-NOP-00-404 Emergency Demand Response Implementation
7. SO-I-NOP-00-441 Operations Real-Time Event Resolution
8. SO-I-NOP-00-448 Event Communications Matrix
9. SO-I-NOP-00-462 Inadvertent Interchange Management
10. SO-I-NOP-00-481
11. SO-I-NOP-00-483 Reliability Coordination Conference Call
12. SO-P-EOP-00-004 Transmission System Emergency
13. SO-P-AOP-00-217 MISO and State Officials 24X7 Communication Protocols During Emergencies
14. SO-P-NOP-00-431 Communications Protocol For Operating Instructions
15. SO-P-NOP-00-449 Conservative System Operations
16. SO-P-NOP-00-455 Balancing Authority Operations
17. SO-P-NOP-04 MISO Event Reporting Operating Plan
18. SO-I-NOP-00-479 Purchasing and Selling Emergency Energy

Attachment 1 — Reserve Margin Example Calculations

1.0 Example 1: Projection for MBAA

Table 1: Calculation

Description	Value
MBAA Peak Load Forecast:	100,000
Operating Reserve Requirement:	2,410
Load plus Operating Reserve Requirement:	102,410
Available Economic Maximum in Area:	97,000
Constraint Stranded MW:	2,000
Available Economic Resources in Area:	95,000
Net Scheduled Interchange (NSI) into Area:	8,000
Reserve Margin = 95,000+8,000-102,410	+ 590
Reserve Margin (%) = (590/102,410)*100:	+ 0.6%

Assessment: Reserve Margin is forecasted to be +590 MW. Load plus Operating Reserve Requirement is met, however the Reserve Margin is less than 1500 MW. A Max Gen Alert declaration may be necessary.

2.0 Example 2: Projection for South Region

Table 2: Calculation

Description	Value
MBAA Peak Load Forecast:	30,000
Operating Reserve Requirement:	1,500
Load plus Operating Reserve Requirement:	31,500
Available Economic Maximum in Area:	29,000
Constraint Stranded MW:	1,000
Available Economic Resources in Area:	28,000
Net Scheduled Interchange (NSI) into Area (RDT NSI):	400
RDT Import Capability up to RDTL of 3,000	3,000
Reserve Margin = 28,000+3,400-31,500	-100
Reserve Margin (%) = (-100/31,500)*100:	- 0.3%

Assessment: Reserve Margin is -100 MW, meaning the South Region Load plus Operating Reserve Requirement is 100 MW short of being met. This means Load will be covered but the 1,500 MW Operating Reserve Requirement will not be. A Max Gen Warning or Event declaration may be necessary.

Attachment 2 — Maximum Generation Declaration Template

Maximum Generation Declaration Type: [Alert/Warning/Event]

The MISO RC is Declaring/Updating a Maximum Generation Alert/Warning/Event effective from [MM/DD/YYYY] [HH:MM] EST and [MM/DD/YYYY] [HH:MM] EST for the following entities:

[List the affected entities within the boundaries of the declaration by LBA. Include any constrained pockets within the declaration area with adequate generation that should be excluded from the Maximum Generation Emergency.]

The reason for the declaration is:
State the reason(s): Forced Transmission Outage, Forced Generation Outage, Higher than Forecasted Load, Above/Below Normal Temperatures, Loss of Import Interchange Schedules, Reduction in RDT limit, etc.

Members are to prepare for a Maximum Generation Emergency by performing the applicable MISO Member Maximum Generation [Alert/Warning/Event] Level Actions of SO-P-EOP-002 MISO Market Capacity Emergency procedure.

CTS Suspension: Attention Market Participants: CTS (Coordinated Transaction Scheduling) is Suspended as of [MM/DD/YYYY] [HH:MM] EST. Alternative scheduling methods should be utilized.

Projections (to LBAs and TOPs only):

- Peak hour for Area is Hour Ending [MM/DD/YYYY] [HH:MM] EST.
- Load plus Operating Reserve Requirement for Area: ____________
- Amount of Available Economic Resources in Area: ____________
- Imports into Area: ____________
- Reserve Margin shortfall(-)/surplus(+) for Area: ____________

1. Summary information (only) in the top of the OI Message/template will be communicated to MPs via the following:
   - A. OI
   - B. MISO public web site – Real Time Notifications Tab via OI View Real-Time Operations Updates at https://www.misoenergy.org/markets-and-operations/notifications-overview/

2. Completed OI message/template (summary & projections) will be communicated to TOPs, LBAs, BAs and neighboring BAs, and RCs as follows:
   A. OI
   B. RCIS
3. MISO will provide summary information to the following email exploder lists via OI message:
   - *MISO Alerts BA and TO
   - *MISO Alerts FERC, State Comm., RRO, Neighboring RCs and BAs
   - *RT Ops Notification

Attachment 3 — Load Management Update Form Example

Local Balancing Authorities report via MCS or phone to the RC Load reductions that would be available, time permitting, via Load Management should a Maximum Generation Emergency Event be implemented during the same time frame the Warning is effective. MISO will provide the expected notification time* for LBAs to assume when completing form.

Load Management may include but are NOT limited to public appeals, voltage reduction, and interruption of end use loads in accordance with applicable contracts, demand-side management, utility load conservation measures, and starting behind the meter generation*.

Load Management is separated into LMM – Stage 1 and LMM – Stage 2.

*Excludes Registered DRR Type 1 and DRR Type 2 Resources

Table 3: LBAs report the following estimated values:

LBA:	
Notification time for Load Management Measures (i.e. less than 4 hours)	
LMM Stage 1 available:	10
LMM Stage 2 available:	5
Total:	15
LBAs should list, LMM Stage 1 and LMM Stage 2 that are already or projected to be implemented at the Event time:	
LMM Stage 1:	100
LMM Stage 2:	0
Total:	100

Attachment 4 — Slice-of-System PPAs Load/Schedule Curtailment

1.0 Slice-of-System Power Purchase Agreements (PPAs) Curtailed Pro-Rata with Load in the Source Balancing Authority when Source Balancing Authority is in Emergency Procedures

1. PPAs in this category will continue to qualify as Planning Resources so long as the PPA only will be curtailed pro-rata along with load in the source Balancing Authority and only when the source Balancing Authority is operating under Emergency Procedures.
2. Under this situation, a PPA with a 1,000 MW export schedule from an external Balancing Authority with a 3,000 MW load will be curtailed pro-rata along with the load when the external Balancing Authority is operating under Emergency Procedures. That is, curtailment would take place three-quarters to firm load and one quarter to the firm schedule. This pro-rata treatment is triggered when MISO experiences emergency conditions at the same time as the external Balancing Authority.

2.0 Slice-of-System PPA in a Balancing Authority that Coordinates Planning Reserve Qualifications and Shares Emergency Responsibilities with MISO's Balancing Authority

1. In addition to the slice-of-system PPA treatment noted in category (B) above, slice-of-system PPAs can continue to qualify as External Resources under this category, and MISO and the external BA will share Load Shedding on a pro-rata basis in proportion to the load in the area under the Capacity Emergency, so long as the requirements of this category are met.
2. This qualification category has several requirements for the host BA:
   A. It must be in MISO's RC area.
   B. It must share Operating Reserves with the MISO BA.
   C. It must have a Seams Operating Agreement with MISO containing several features.
3. Seams Operating Agreement must specify the following:
   A. The host BA has established planning reserve processes and criteria similar to MISO's.
   B. Actions that will be taken by both entities – MISO and the host BA – during Emergency Procedures prior to implementing Load Shedding.
   C. BA responsibilities include:
      (1.) Submitting load estimates to MISO in a similar manner as submitted by other Load entities under Module E-1.

(2.) Providing generator testing data for all resources used to serve firm requirements of the host Balancing Authority.

(3.) Providing transparency to such resource plans in the form of a Fixed Resource Adequacy Plan, pursuant to Module E-1.

4. With these requirements in place, when both BAs have exhausted other emergency operating actions and are in a firm load shedding event, load shedding is shared on a pro-rata basis in proportion to the load in the area under the capacity emergency.

Example 1

If the load of an external BA in capacity emergency is 3000 MW and the load of the area in MISO in capacity emergency is 17,000 MW, then pro-rata load shed is 3/20 of the total for the external Balancing Authority and 17/20 for the area in MISO in the capacity emergency.

---

5. This treatment is appropriate for BAs that meet the requirements indicated above because MISO can count on the fact that the external BA is planning and testing its resources in an equivalent manner to MISO, and is part of MISO's RC area and subject to emergency procedures it has developed with MISO. It has also agreed to operate its system in a similar manner, including the agreement to share its Operating Reserves with MISO during emergency conditions.

3.0 When MISO is in an EEA and the external BA with PPA is not, then MISO will determine if the PPA should flow or determine the curtailable MWs of the PPA.

1. LBA NET(Excess Capability) =
   Σ (LBA_online RTmw - LBA_online MaxObligation)
   - Where RTmw = Current RT MWs of Resource
   - Where MaxObligation = The lesser of a resource's Effective ICAP (capacity obligation) and their Real-Time Must Offer availability
2. Prior to any curtailments, MISO will contact the external BA by phone.
3. If the BA indicates that the curtailment will cause the BA to enter an EEA, then MISO will initiate SO-I-NOP-00-481.
4. If the BA indicates that the curtailment will NOT cause the BA to enter an EEA, then MISO will curtail any relevant schedule(s).

Attachment 5 — Additional Information

1.0 Max Gen Emergency

1. MISO may call for a Max Gen Alert, Warning or Event, or EEA level prior to the actual forecasted start time of such Alert, Warning, Event or EEA level.
   A. The purpose of this would be to communicate forecasted conditions that meet the criteria of these levels, as well as to provide notice of certain implementation steps which require longer notifications times.
   B. An example would be an LMR which has a 4-hour notification time, requiring implementation instructions to be sent prior to the actual start time of the Event, or EEA.
   C. Due to the dynamic nature of the Bulk Electric System (BES) these preliminary declarations and instructions may be canceled prior to the actual start time of the forecasted Alert, Warning, Event or EEA as conditions warrant.
   D. At the Max Gen Alert level, Emergency Pricing Tier 0 is in effect until termination of the Alert or increasing Max Gen level to Warning level or higher.
2. Max Gen Warning
   A. EDRs may also be registered as LMRs in Module E. If a MP has decided to offer in all or part of their resource as an EDR for an operating day, the MP should reduce the availability of that resource as an LMR in the DSRI Tool for all 24 hours of the same operating day by the maximum MW amount offered in for that resource as an EDR. In addition, if an MP has implemented any resources voluntarily, which are registered as an LMR, the MP should adjust the availability of that resource in the DSRI Tool.
   B. Tier 1 prices are in effect from Max Gen Warning until an Emergency Event Step 2a, when Tier 2 prices are implemented. This is an ex-post ELMP pricing change and does NOT affect system commitment or dispatch. Emergency Pricing will be utilized as necessary on an LBA basis.
3. Max Gen Event
   A. MISO will implement Emergency Pricing Offer Tier 2 during Step 2a of an Emergency Event. This is an ex-post ELMP pricing change and does NOT affect system commitment or dispatch. Emergency Pricing will be utilized as necessary on an LBA basis.

Attachment 6 — Maximum Generation Emergency Overview

The following is an overview of Max Gen Emergency actions and should be used for reference only during an actual event.

Table 4: Maximum Generation Emergency Overview

Level	MISO Major Actions	Stakeholder Major Actions
Declaration	Send OI Declaration message	Prepare to implement this procedure and follow internal procedures for emergency conditions
	Declare Conservative System Operations	Follow instructions per Conservative System Operations procedure and declaration
	Increase STR Default if System Wide or STR MSSC if North/Central or South Region	
Alert	Identity available Module E Resources	MPs communicate available Module E Resources
	Identify non-firm Export Schedules	MPs update energy interchange transaction E-tags of Capacity Resources
	Implement Emergency Pricing - Tier 0	LBA/TOP provide potential exclusion of constrained pockets within the declaration area
	Raise transfer capability or make constraint stranded generation available	TOPs coordinate with MISO RC to identify potential reconfiguration options
	Request MPs/LBAs ensure accuracy of LMM/ LMR availability and Self Scheduled values	LBAs/MPs ensure accuracy of LMM/LMR availability and Self Scheduled values in MCS/ DSRI Tools
	Send LBAs LMM survey	Affected GOPs communicate capacity limited facilities to MISO and update limits and offers

Table 4: Maximum Generation Emergency Overview

Level	MISO Major Actions	Stakeholder Major Actions
Warning	Implement Emergency pricing - Tier 1	
	Suspend CTS	
	Determine EDR availability and MW amounts	MPs update EDR availability and MW amounts
	Obtain updated MW amounts of relief available via Load Management Form in MCS	LBAs update LMM availability via Load Management Form in the MCS
	Review LMR availability using MCS-LMR tool	MPs ensure LMR availability data is correct in the DSRI Tool
	Schedule available Module E Resources into declaration area	As directed by MISO, MPs schedule available Module E Resources into the declaration area
	Curtail Export Schedules as required	
	Instruct TOPs to implement reconfiguration options	As directed by MISO RC, MPs implement reconfiguration options
Event Step 1a	Commit AME resources	As directed by MISO, LBAs/GOPs/MPs start AME Resources
Event Step 1b/EEA1	Declare EEA1	MPs review Offers and ensure all available Emergency ranges and Resources are offered
	Activate Emergency Maximum Limits	
Event Step 2a/EEA2	Declare EEA2	
	Implement Emergency pricing - Tier 2	
	Instruct Load to be reduced via LMMs - Stage 1 and LMRs	As directed by MISO, LBAs reduce load via LMM - Stage 1
	Implement LMRs	MPs implement LMRs via DSRI Tool
Event Step 2b	Commit EDR Resources	As directed by MISO, MPs commit EDRs

Table 4: Maximum Generation Emergency Overview

Level	MISO Major Actions	Stakeholder Major Actions
Event Step 2c	Implement Emergency energy purchases	LBAs issue public appeals to reduce demand per internal procedures and OE-417 filings
	Instruct LBAs to issue Public Appeals	
		LBAs in defined Event area shall prepare to shed Load
Event Step 3a	Notify affected GOPs with Generator de-rates to request waivers	Affected GOPs dispatch de-rated Generators with waivers from government regulations
	Implement spinning and supplemental reserves	
Event Step 3b	Elevate identified Priority 6-NN tags	
	Instruct Load to be reduced via LMMs - Stage 2	Affected LBAs reduce load via LMM - Stage 2
Event Step 4a	Implement Reserve Call from CRSG	MPs review Offers and ensure all available Emergency ranges and Resources are offered
Event Step 4b	Implement Emergency energy purchases from neighboring BAs (Operating Reserves)	
Event Step 5/EEA3	Declare EEA3	
	Issue Emergency Operating Instruction to shed load	LBAs shed load per MISO and confirm action via MCS Firm Load Shed Tool
	Set LMPs and MCPs to the VOLL	LBAs review OE-417 filing requirements

Attachment 7 — UDS Operator Actions During MISO Market Capacity Emergency Conditions

- If a North/Central declaration is in place and a South declaration is subsequently implemented, Increase STR Default Values as specified in SO-I-EOP-00-001 Utilizing Emergency Ranges and Emergency and VOLL Pricing procedure.
- Implementation of these steps are outlined in SO-I-EOP-00-001 Utilizing Emergency Ranges and Emergency and VOLL Pricing
- Does not include Max Gen Event Downgrade/Termination Actions as noted in section 4.2.1.14
- * STR RPE & STR Default Values are specified in SO-I-EOP-001 Utilizing Emergency Ranges and Emergency and VOLL Pricing procedure

SO-P-EOP-00-002 MISO Market Capacity Emergency - UDS Operator Actions

		Increase STR RPE MSSC Default Values for Zone 8 (South) if not done in previous declaration*	Increase STR RPE MSSC Default Values for Non-Zone (N/C) if not done in previous declaration*	Increase STR Default Values for System Current (System Wide) if not done in previous declaration*	Implement Emergency Pricing Tier 0	Implement Emergency Pricing Tier 1	Activate Emergency Limits	Implement Emergency Pricing Tier 2	Check Is VOLL Price Enforced in EMD
System Wide Declaration Level	Capacity Advisory								
	Max Gen Alert								
	Max Gen Warning								
	Max Gen Event Step 1a								
	Max Gen Event Step 1b								
	Max Gen Event Step 2a and above								
	Max Gen Event Step 5								
North/Central Declaration Level	Capacity Advisory								
	Max Gen Alert								
	Max Gen Warning								
	Max Gen Event Step 1a								
	Max Gen Event Step 1b								
	Max Gen Event Step 2a and above								
	Max Gen Event Step 5								
South Declaration Level	Capacity Advisory								
	Max Gen Alert								
	Max Gen Warning								
	Max Gen Event Step 1a								
	Max Gen Event Step 1b								
	Max Gen Event Step 2a and above								
	Max Gen Event Step 5								
Single Region (North or Central) Declaration Level	Capacity Advisory								
	Max Gen Alert								
	Max Gen Warning								
	Max Gen Event Step 1a								
	Max Gen Event Step 1b								
	Max Gen Event Step 2a and above								
	Max Gen Event Step 5								

Figure 1: UDS Operator Actions During MISO Market Capacity Emergency Conditions

Attachment 8 — Summary of Market Capacity Emergency Procedure Steps

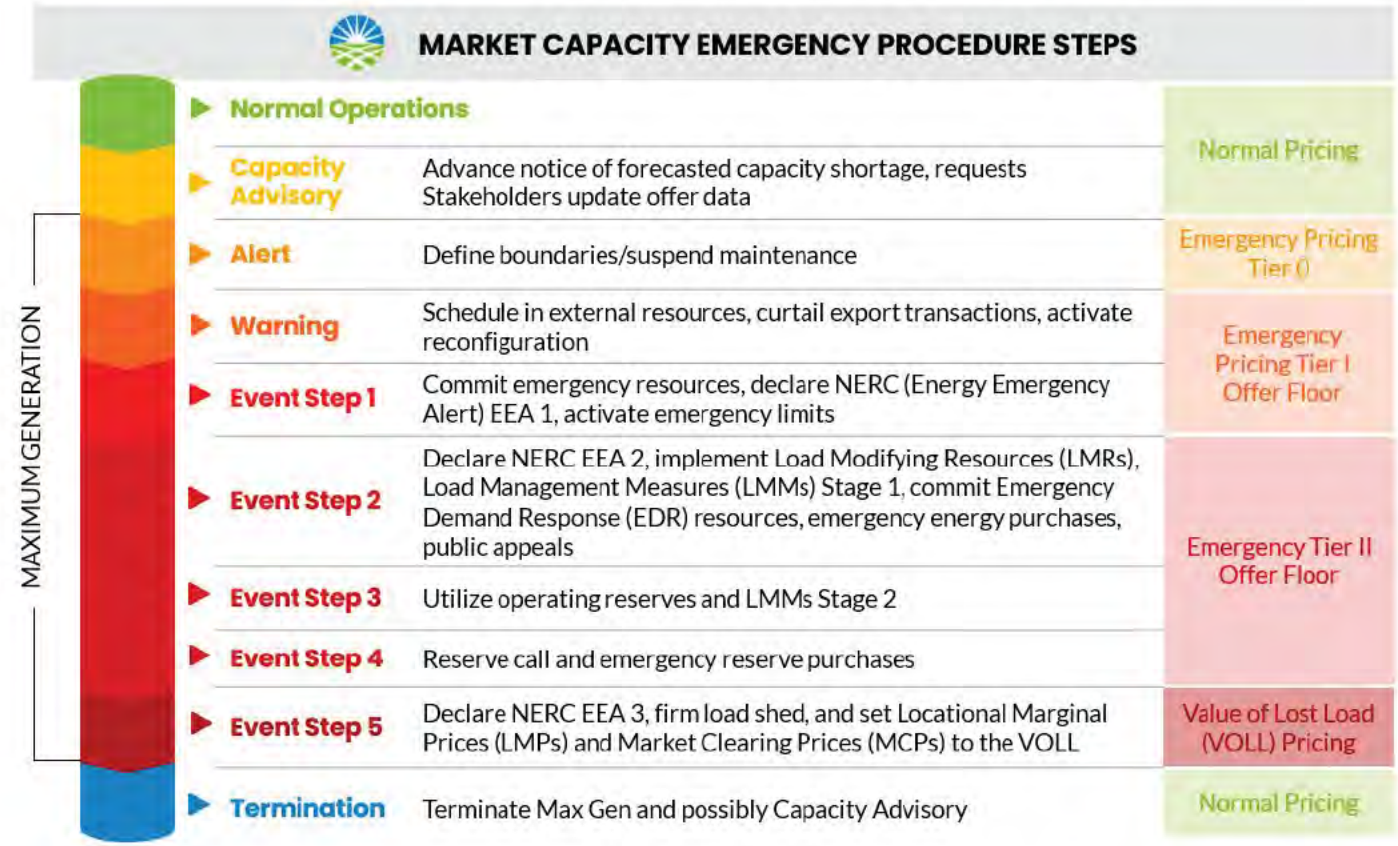


Figure 2: Market Capacity Emergency Procedure Steps

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Midcontinent Independent System Operator (MISO)	)))))	Order No. 202-25-3

Exhibit to
Motion to Intervene and Request for Rehearing and Stay of
Public Interest Organizations

Filed June 18, 2025

Exhibit 34

Ramey MISO Comments

UNITED STATES OF AMERICA

BEFORE THE

FEDERAL ENERGY REGULATORY COMMISSION

	)	
Technical Conference Regarding	)	
The Challenge of Resource	)	**Docket No. AD24-11-000**
Adequacy In Regional Transmission	)	
Organization and Independent	)	
System Operator Regions	)	

COMMENTS OF TODD RAMEY
ON BEHALF OF
MIDCONTINENT ISO INC.

I. INTRODUCTION

<u>MISO's Resource Adequacy Challenge</u>

The electricity grid today is facing a significant transition at a pace never seen before. To ensure that our nation's bulk electric system remains reliable, it is important to recognize and stay ahead of the challenges and trends that are impacting electricity production and consumption. Today, the MISO region faces resource adequacy and reliability challenges due to the changing characteristics of the electric generating fleet, insufficient transmission system infrastructure, growing pressures from extreme weather, and rapid load growth. The ultimate responsibility for resource adequacy in the MISO region lies with its member states and other Relevant Electric Retail Regulatory Authorities ("RERRAs"). MISO works closely with stakeholders, including the states, to provide market tools and information necessary to support regional transparency that, in turn, support and inform resource investment decisions relating to resource adequacy. MISO has made significant advancements over the past several years enhancing its market price signals, improving resource accreditation, assessing expected resource needs and improving its generation interconnection queue processes and tools.

The MISO region predominantly consists of vertically integrated utilities with responsibility for providing adequate electric generation to meet load for their area and states having jurisdiction over resource adequacy decisions. This is distinct from some other RTOs, which rely more heavily on competitive markets to shape electric resource adequacy needs. A combination of state and federal policies and consumer demand for carbon free energy has resulted in rapid growth of wind and solar energy accompanied by the retirement of many coal and natural gas power plants. While weather-dependent resources like solar and wind are being added in large numbers and provide many benefits, including lower electricity production costs than natural gas or coal as well as the lack of carbon emissions, they typically do not provide the same 24/7 availability, flexibility, and duration attributes as the retiring power plants they are replacing. For example, MISO has experienced 11 wind droughts since 2020, including one lasting 40 consecutive hours. Similarly, solar output is dramatically reduced in overcast or cloudy weather conditions, as often occur in winter storms, and output is virtually zero in the overnight hours. While energy storage technology is beginning to integrate into MISO's markets, we are not expected to see the volume of such resources be deployable in order to help support meeting resource adequacy and reliability needs for several more years. MISO works collaboratively with the states, utilizing its regional perspectives and insights, to ensure they have an understanding of evolving system needs and conditions. This is accomplished, in part, through MISO's work on long-term load forecasting, resource accreditation, and Futures Planning Scenarios.

MISO has a healthy partnership with the Organization of MISO States ("OMS"), an independent organization with its own dedicated staff representing the collective interests of state and local utility regulators in the MISO region. Many of the changes MISO has implemented were made possible due to their collaboration and role in communicating and facilitating the insights of the RERRAs in the MISO region.

By coordinating with states and other RERRAs, MISO is able to develop a range of expected outcomes we call Future Planning Scenarios. MISO's Future Planning Scenarios estimate that while the total amount of installed electric generation will increase significantly over the next 20 years due to the rapid growth of wind and solar, the actual amount of electricity available to the system during could face a net decline of about 32 GW[1] due to the operational characteristics of these new resources. Emerging technologies with the needed characteristics, such as longer-duration battery storage and small modular nuclear reactors, hold great promise in the future but are likely years away from grid-scale viability.

MISO also creates significant value for the region, which is quantified in the MISO Value Proposition study.[2] While resource development is critical, we must also recognize that the existing electric transmission infrastructure is vital in supporting resource adequacy and is a significant value driver by reducing the overall resource obligation to each load serving entity in the MISO region. The largest value driver in the MISO Value Proposition is the savings associated with the reduction in reserve margin needed to meet resource adequacy targets. Our work to maintain reliability, administer wholesale markets and conduct transmission planning on a regional scale generates substantial benefits. In 2024 alone MISO created approximately $5.1 billion in savings for the region, and over $50 billion since 2007. Ultimately, this results in lower costs to consumers. To continue driving high levels of value and low costs, the transmission system needs to keep pace with the location of the resources that will be developed to provide the energy that will be

---

[1] This projection is found in MISO Future 2A found in the MISO Futures Report developed in November 2023. More information on MISO Futures Series 2A Report can be found here https://cdn.misoenergy.org/Series1A_Futures_Report630735.pdf

[2] MISO's Value Proposition is an annual study that breaks MISO's business model into recognized categories of benefits and calculates a range of dollar values for each defined category. In 2024, MISO's annual benefit was valued at $5.1 billion. More information available at https://www.misoenergy.org/meet-miso/MISO_Strategy/miso-value-proposition/

needed in future years, and to provide the connectivity to move energy across the generation fleets to population centers.

MISO's region, like most of the country, is also experiencing changing weather patterns, including more frequent occurrences of extreme weather, particularly winter storms affecting large areas of the country. These extreme weather events create challenging operating conditions, with high demand for electricity sometimes accompanied by reduced solar or wind output and, in some instances, challenges with adequate fuel supplies for natural gas and coal power plants. This highlights the need for a diverse electric generation fleet and a robust transmission system to move energy over long distances.

Finally, demand for electricity is growing at an accelerated pace. Over the last few decades, we have experienced growth in electrification through electronic devices, smart home products, and electric vehicles, but minimal growth in electric peak demand, largely due to increasing energy efficiency. Looking ahead, however, we expect much stronger growth from continued electrification efforts, a resurgence in manufacturing, and an unexpected demand for energy hungry data centers to support artificial intelligence. In fact, based on the current trajectory, peak electric load in the MISO region is projected to grow at a 1.6% compound annual growth rate ("CAGR").[3] This compares to an average 0.5% CAGR between 2009 and 2024 and threatens to outpace new electric resource additions if urgent action isn't taken.

This combination of factors significantly increases operational challenges, uncertainty, and reliability risks to the electric grid. This, in turn, creates significant economic and security risks for our nation. If electricity production and delivery from all sources cannot keep up with growing demand, then the planned growth of manufacturing, artificial intelligence, and data centers cannot occur. A timely and coordinated approach is necessary if we are to continue meeting the nation's need for reliable and low-cost electricity. MISO is committed to meeting this challenge in coordination with our states, members and stakeholders as articulated by our Reliability Imperative effort.

MISO Reliability Imperative

The electric industry in general, and the MISO Region in particular, are changing in significant ways. In the past, MISO maintained a reliability standard significantly above the "one day in ten years" that is the minimum acceptable rate of reliability. However, as MISO has been emphasizing since 2022, we have seen resource margins and reliability standards decline due to policy drivers, aging resources and financial incentives. Today, the MISO region is meeting the 1:10 minimum, and we are working to maintain at least this level going forward.

Looking ahead, we have four tools for maintaining reliability: 1) maintain existing generation, as needed for resource adequacy; 2) enhance the utilization of demand response; 3) build new generation and transmission when existing resources are

[3] More information on the current trajectory of peak load growth can be found in MISO's Long-Term Load Forecast published in December 2024 and found here https://cdn misoenergy.org/MISO%20Long-Term%20Load%20Forecast%20Whitepaper_December%202024667166.pdf

unavailable to support new load growth; and 4) be prepared for more frequent instances of targeted load shed to ensure system reliability during extreme operating conditions.

The sharing of responsibility between MISO, Load Serving Entities ("LSEs"), and RERRAs is needed to address the challenges of rapid fleet change, increased frequency and severity of extreme weather events, and other factors that pose a threat to reliability in the MISO Region. MISO calls this shared responsibility the 'Reliability Imperative.' The word 'imperative' is appropriate for several reasons. First, the work we are doing is not optional—to maintain system reliability, we must respond to the unprecedented change we and our members face. Second, this work cannot be put off for months or years—much of it has long lead times, so we need to act now. And third, our stakeholders are counting on us—regulatory agencies, utilities and other entities are looking to MISO to identify problems and find solutions."[4]

MISO published a report in December 2020 that documents these trends and explains why these trends create a Reliability Imperative for the region.[5] MISO's response to these issues focuses on four pillars: (1) Market Redefinition; (2) Operations of the Future; (3) Transmission Evolution; and (4) Systems Enhancements (formerly called Market System Enhancements). Pillars #1 and #3 profoundly affect resource adequacy.

As explained by MISO's Chief Executive Officer, John Bear: "The industry's longtime reliance on conventional baseload power plants is declining sharply, driven by economic factors and consumer preferences for clean energy, among other things. Meanwhile, the grid is becoming increasingly reliant on wind and solar resources that are available only when the wind is blowing or the sun is shining. To be sure, there are upsides and opportunities associated with these trends. But the changes we are seeing also pose a host of complex and urgent challenges to electric system reliability in the MISO Region. Utilities, states, and MISO all have roles to play in addressing these challenges."[6]

Pillar #1: Market Redefinition

MISO's market design guiding principles are an important guide to evaluating and developing market enhancements that have been used as a foundation for conducting the Planning Resource Auction (PRA). MISO's Market Design Guiding Principles are as follows:

- Support an economically efficient wholesale market system that minimizes cost to distribute and deliver electricity,
- Facilitate non-discriminatory market participation regardless of resource type, business model, sector, or location,
- Develop transparent market prices reflective of marginal system cost, and cost allocation reflective of cost-causation and service beneficiaries,

[4] See MISO's Response to the Reliability Imperative (December 2020), available at https://cdn misoenergy.org/MISO%20Response%20to%20the%20Reliability%20Imperative%20FINAL504018.pdf.

[5] More information on MISO's Reliability Imperative at https://www misoenergy.org/meet-miso/MISO_Strategy/reliability-imperative/

[6] MISO's Response to the Reliability Imperative, found here https://cdn misoenergy.org/MISO%20Response%20to%20the%20Reliability%20Imperative%20FINAL504018.pdf

- Support Market Participants ("MPs") in making efficient operational and investment decisions, and
- Maximize alignment of market requirements with system reliability requirements

All aspects of MISO's resource adequacy construct have been and are being evaluated to better ensure energy readiness under this Reliability Imperative. Specific efforts in this area include providing a longer-term and deeper assessment of system needs across all hours of the year, including required capabilities such as flexibility, shifting to verifying sufficient generation adequacy across all hours of the year, improving how resources are accredited, ensuring that prices accurately reflect market conditions, especially during emergencies, and developing market products that provide the right incentives for resources to maintain system reliability The initiatives in this category aim to ensure that resources with the types of capabilities and attributes the system needs will be available in all 8,760 hours of the year. Hence, MISO has moved from an annual auction to a seasonal one. This is important because as noted above, the region is increasingly facing reliability risks outside of the summer peak-load months that historically posed the greatest challenges. On the supply side, MISO has improved accreditation efforts, to reflect the availability of resources during hours in each season exhibiting low capacity margins.

On the demand side, MISO determined that the implementation of a Reliability Based Demand Curve ("RBDC") (sometimes referred to as a "sloped demand curve") in the PRA will support MPs by establishing more efficient capacity prices based on market fundamentals, where the marginal reliability benefit of the last MW procured is equal to its marginal cost.

With better price formation and improved capacity accreditation, MPs can make better informed operational, retirement, and investment decisions, and the PRA will significantly improve alignment of market requirements with system reliability requirements.

Pillar #3: Transmission Evolution

Over the last several years, MISO has approved over $30 billion in new transmission lines through a Reliability Imperative initiative called Long-Range Transmission Planning, or LRTP, with more expected in the coming years. These projects are projected to have a benefit-to-cost ratio of approximately 2.6 to 1 and will substantially improve electric transfer capabilities and enable the electric reliability and associated economic growth being planned across the nation.

Intermittent resources such as wind and solar work with the transmission system very differently than conventional power plants. For this reason, the ongoing trend of conventional resources retiring from service as intermittent renewables continue to grow poses significant challenges to the reliability of the transmission system in the MISO region. These challenges are framed up in MISO's Renewable Integration Impact Assessment work. Fortunately, MISO can leverage its large footprint and resources to ease some of the challenges. One of the keys will be transmission projects that support these new resources in the region. LRTP is designed to assess the region's future transmission needs, starting from a base of the utility and state plans on where to site and build new resources. LRTP does not replace other transmission-planning efforts that have long existed at MISO, such as the annual studies contained in the MISO Transmission Expansion Plan ("MTEP"). LRTP will coordinate closely with those efforts, and it will also be a transparent and cooperative part of the MISO stakeholder process.

LRTP is a comprehensive "transmission roadmap" that will identify and drive investments in transmission projects addressing all needs of the region as the resource fleet continues to evolve. The roadmap will be updated as needed to align with evolving resource fleets and business plans, state energy/environmental policies, and other dynamic factors that affect the region's transmission needs. As solutions are identified through LRTP, they are moved into the ongoing MTEP process for final approval by MISO management and Board of Directors.

Recent Accomplishments

MISO and its stakeholders have made great progress under the Reliability Imperative in recent years. Some of our key accomplishments to date include:

> *Seasonal Resource Adequacy Construct*: In August 2022, the Federal Energy Regulatory Commission ("the Commission") approved MISO's proposal to shift from its summer-focused resource adequacy construct to a new, four-season construct that better reflects the risks the region now faces in winter and shoulder seasons due to fleet change, more frequent and severe extreme weather, electrification, and other factors. This new construct seeks to ensure that resources will be available when they are needed most by aligning resource accreditation with availability during the highest risk periods in each season.
>
> *LRTP Tranche 1*: The first of four planned portfolios of LRTP projects was approved by the MISO Board of Directors in July 2022. This tranche of 18 projects represents a total investment of $10.3 billion — the largest portfolio of transmission projects ever approved by a U.S. Regional Transmission Organization. These projects will integrate new generation resources built in MISO's North and Central subregions, supporting the reliable and affordable transition of the fleet and further hardening the grid against extreme weather events.
>
> *Reliability-Based Demand Curve*: MISO's Planning Resource Auction (PRA) was not originally designed to establish appropriate capacity clearing prices based on the reliability risk of clearing MWs above or below the one-day-in-ten reliability standard. This lack of a "warning signal" when reserve margins decline can mask an imminent shortfall — as occurred with the 2022 PRA. Efficient capacity pricing is also crucial to make effective investment and retirement decisions. MISO worked with its stakeholders to design an RBDC that will improve price signals in the PRA. Full implementation began in the 2025 PRA, with first year results demonstrating that the refined PRA is working as designed.
>
> *Futures Refresh*: The MISO Futures utilize a range of economic, policy and technological inputs to develop three scenarios that "bookend" what the region's resource mix might look like in 20 years. In 2023, MISO updated its Futures to

lay the groundwork for LRTP Tranche 2 and to better reflect evolving decarbonization plans of MISO members and states. The refreshed Futures also model how the financial incentives for clean energy in the 2022 Inflation Reduction Act could further accelerate fleet change. The refreshed Futures are indicated with an "A" (e.g., Future 2 was updated and renamed Future 2A).

Queue Reforms: MISO has instituted several reforms to speed up the queue cycles, including a cap on the number of projects that can enter the queue in a given cycle, and is working on several technological enhancements and process improvements to eventually get to a one-year queue cycle. In the interim, an Expedited Resource Addition Study, or ERAS, process was recently submitted to the Commission for consideration. If approved, this process would provide a temporary framework, sunsetting by the end of 2028, for the accelerated study of electric generation projects that are required to address urgent resource adequacy and reliability needs

MISO's extensive analysis and operational experience make it clear that no single electric generating resource, transmission line, process improvement, emerging technology, or other solutions will solve all our challenges. Addressing our nation's future electricity needs requires a multi-faceted and coordinated approach that leverages all of these tools.

Next Steps

The operational challenges and reliability risks of the MISO region are largely mirrored across the country. To address them, we need to take several important steps to turn around the decline in available energy and expedite the construction of new electric generation and the transmission lines necessary to move necessary energy from where it is produced to where it is needed. Specifically:

- Ensure that states and utilities have the information they need to make prudent electric resource decisions to support resource adequacy.
- Continue to improve the loss-of-load modeling effort which underpins the planning reserve margins determined to meet the reliability standards. This includes better representation of all resources' availability and outage patterns, continued effort to model load growth and variability, and incorporate correlated impacts across both supply and demand.
- Let reliability needs help inform the pace of retirement of existing electric generating resources. Having the right mix of resources on the system means that we don't have to choose between decarbonization and reliability.
- Continue developing new resources at a rapid pace. Streamline the approval of new electric generation and transmission projects, and work to mitigate the regulatory, supply chain, and workforce challenges that can hinder development of these projects.
- Leverage an "all of the above" approach that includes a mixture of solar, wind, natural gas, storage, emerging technologies, and transmission to achieve reliability.

- Continue reforms, like MISO's ERAS and Demand Response and Emergency Resource reforms, that enable the more effective and efficient utilization of existing resources and capabilities.
- Continue exploring Distributed Energy Resources ("DERs") as a potential additional tool to address resource adequacy and reliability challenges.
- Support and encourage continuous interregional collaboration on future transmission needs and operational protocols that maximize the use of the existing system.

II. PANEL 1: THE RESOURCE ADEQUACY CHALLENGE IN RTOs/ISOs

***Question 1*: What is the current state of resource adequacy across RTO/ISO regions?**

a. Is this static or variable? Are resource adequacy challenges more acute in RTO/ISO regions with capacity markets compared to those RTO/ISO regions with alternative resource adequacy constructs? Why or why not?

MISO has seen surplus capacity margins declining over the last several years. When considering capacity margins, MISO particularly views the level of "accredited capacity" as the key factor to assess resource adequacy. It is essential to consider the accredited value of capacity, rather than the simple "nameplate" value, since accredited is the only value that can be relied upon to ensure that energy will be provided by a resource during the periods of greatest need. The decline in accredited capacity is primarily due to the retirement of existing dispatchable generation, while new capacity additions have generally been non-dispatchable resources with lower accreditation values.

The reduction in reserve margin is a significant concern. MISO has continued to work closely with the states and stakeholders to ensure that the region remains, in excess of the 1-day-in-10-year Loss of Load Expectation (LOLE) reliability standard. Over the past several years, MISO has (1) initiated reforms to improve capacity accreditation to better signal the value of needed resource additions, (2) converted to a seasonal capacity construct to better reflect differing seasonal operating needs and characteristics, (3) continued collaboration with states with a transparent survey of future capacity expectation to inform policy makers, (4) provided longer term assessment of the resource mix changes in our Regional Resource Assessment ("RRA") to further inform long term policy and investment decisions, and (5) enhanced risk modeling to better align between the manner in which seasonal risk is being evaluated and resources are being accredited to meet the designated need.

The 15 states in the MISO region take their rights and responsibilities towards resource adequacy seriously and the MISO capacity market recognizes that. The OMS has supported developments in pursuit of MISO's Reliability Imperative. The Reliability Imperative was developed in 2020 to address urgent and complex issues facing the grid and contains four pillars: Market Redefinition, Operations of the Future, Transmission Evolution, and System Enhancements. Collaboration between MISO and the OMS allows for a reliable grid amongst changes in the diverse MISO footprint. MISO provides transparency in expectations of future resource adequacy plans through Futures

Modeling, the RRA, and the OMS-MISO Survey. We are confident that the footprint will continue to be resource adequate in the near and longer term.

MISO uses a few tools to assess the state of resource adequacy in its footprint. The RRA[7] is one of the periodic studies MISO conducts to forecast how the mix of electricity-generating resources in the MISO region could evolve going forward. Another is the OMS-MISO Survey. While RRA and the OMS-MISO Survey are similar in some ways, there are some key differences that provide resource planners. The RRA is a 20-year outlook based on publicly announced resource plans and policy goals. It projects that members and states will add new generation capacity at an unprecedented rate of 17 GW/year (compared to the average of 4.7 GW/year added over the last decade) for the next 20 years to reliably achieve their publicly announced resource plans and policy goals.[i] Accordingly, the RRA projects capacity surpluses in 2030 and beyond. In contrast, the OMS-MISO Survey is more focused on the near term and projects new installed capacity coming online at the pace at which resources have received interconnection agreements and come online in recent history. The 2024 OMS-MISO Survey therefore forecasted a range of possible outcomes, varying from capacity deficits beginning in 2025 (which did not materialize) to capacity surpluses through 2029. Again, these divergent results reflect that the RRA and the OMS-MISO Survey were designed for different purposes and use different data inputs, methodologies, assumptions.

MISO is confident that its current capacity construct is the best tool to identify, analyze, and address resource adequacy issues in the MISO region. The MISO capacity construct works because:

- The Reliability Imperative describes the shared responsibility between LSEs, states and RERRAs, and MISO to maintain a reliable grid.
- MISO respects states' rights toward resource adequacy and acknowledges that LSEs have the obligation to serve their end-use customers. In fact, most LSEs engage in some form of integrated resource planning that is used to meet these obligations and filed with their appropriate RERRA.
- This type of resource planning makes sense because investments in generation have expected lifetimes of well over 30 years, so asset owners require some level of confidence that these builds can recover their capital costs.
- MISO works closely with the OMS and RERRAs to communicate regional needs to maintain resource adequacy. Both the OMS-MISO Survey and the RRA provide information to MISO and MISO members on where resource adequacy conditions are trending. From this state-specific information, MISO conducts analyses that are made public around the different types and amounts of resources necessary to meet the reliability standards being imposed by NERC.
- The "1-day-in-10-years" LOLE criterion established by NERC and codified in our Tariff has served the region well and sets the benchmark used to design an adequate system.[8] MISO translates this LOLE criterion into an amount of planning reserve margins that LSEs are obligated to have.

[7] More information on MISO's 2024 Regional Resource Assessment can be found here https://cdn.misoenergy.org/2024%20RRA%20Report_Final676241.pdf

[8] MISO's reply to question 6 below recognizes that other reliability metrics on resource adequacy may be of use in the future.

- MISO conducts its prompt PRA to inform LSEs and RERRAs of resource adequacy trends in MISO. A one year clearing price is akin to the role of energy prices in MISO's real time market; well over 95% of an LSE's obligation for energy is procured in the day-ahead market, the real time market is an imbalance market but real time prices can drive Power Purchase Agreements ("PPAs") and expected day-ahead prices. Well over 90% of the obligations of LSEs in any PRA are met with owned or contracted for resources, which is consistent with integrated resource planning processes of the LSEs.
- The PRA has, since inception, served as a residual capacity auction, giving those LSEs that are long or short an opportunity to sell or buy, but the PRA is a voluntary auction.
- The PRA is conducted a few months before the beginning of the Planning Year, and conducted on a seasonal basis to recognize the differences in risks across the seasons.
- The prompt nature of the PRA significantly reduces uncertainty around where demand is heading and which resources are available to meet that demand for the upcoming Planning Year.
- With the adoption of the RBDC design, capacity prices are more reflective of the reliability contributions of the amount of MWs cleared, but they can still vary based, in part, on the amount and offer prices of supply.
- MISO's Value Proposition, highlighted above, shows the savings MISO members achieve in reduced reserve margins while maintaining the 1-in-10 LOLE through the risk sharing pool they participate in.

MISO's recent shift to a seasonal capacity market with seasonal accredited capacity better reflects extreme weather conditions that have become more prevalent. These weather conditions affect both the seasonal peak demand and the available seasonal supply. In addition, the seasonal construct better reflects the seasonal planned & forced outage patterns of supply. The recent implementation of the RBDC reflects the contributions to reliability incremental MWs can add to the system. On the supply side, resources are being accredited based on availability during all times of need, across all seasons (Schedule 53, seasonal accredited capacity resources).

***<u>Question 2</u>*: Given load growth and generation forecasts, what are your resource adequacy challenges going forward?**

MISO's challenge is ensuring that the new generation in the region is able to keep pace to reliably meet the expected load growth while older generation resources with strong reliability attributes continue to retire. Existing dispatchable generation with flexibility attributes, such as natural gas and coal, is retiring rapidly and is being replaced by weather-dependent generation such as wind and solar that does not have the same 24/7 availability. Carbon-free resources that can provide the needed attributes – such as longer-duration battery, hydrogen, and small modular nuclear – is likely several years away from grid-scale viability.

This gap between dispatchable generation and highly accredited carbon-free replacements caused capacity shortfalls in the 2022/2023 planning year, being short in the North subregion by 1,230 MWs. Additionally, the extreme price volatility in the vertical demand curve auctions may have eroded confidence in the capacity construct by sending inefficient price signals, but this has been addressed with RBDC. Changes to the resource adequacy construct highlighted in the previous question, and the information provided through the OMS-MISO survey and RRA effort have initiated renewed efforts on the part of LSEs and RERRAs to address resource adequacy requirements.

Reliably navigating the energy transition requires more than just having sufficient generating capacity; it also requires urgent action to avoid a looming shortage of broader system reliability attributes. In 2023, MISO completed a foundational analysis of attributes, with a focus on three priority attributes where risk for the MISO system is most acute. System adequacy is the ability to meet electric load requirements during periods of high risk. MISO focused on the near-term risk factors of availability, energy assurance, and fuel assurance. Flexibility is the extent to which a power system can adjust electric production or consumption in response to changing system conditions. MISO focused on the near-term risk factors of rapid start-up and ramp-up capability. System stability is the ability to remain in a state of operating equilibrium under normal operating conditions and to recover from disturbances. MISO focused on the nearest-term risk factor of voltage stability. No single type of resource provides every needed system attribute; the needs of the system have always been met by a fleet of diverse resources. However, in many instances, the new weather-dependent resources that are being built today do not have the same characteristics as the dispatchable resources they are replacing. While studies show it is possible to reliably operate the system with substantially lower levels of dispatchable resources, the transformational changes require MISO and its members to study, measure, incentivize, and implement changes to ensure that new resources provide adequate levels of the needed system attributes.

In December 2023, MISO published an Attributes Roadmap report that recommends urgent action to advance a portfolio of market reforms and system requirements and to provide ongoing attributes visibility through regular reporting.[9]

***Question 3*: How do you reconcile your RTO's/ISO's resource adequacy objectives with state public policy requirements, which may accelerate the retirement of certain resource types or limit the entry of other resource types? For example, in light of such state public policy requirements and particularly in multi-state RTOs/ISOs, how does your RTO/ISO ensure resource adequacy?**

MISO's resource adequacy objectives are formally communicated through the resource planning obligations on LSEs. As a general matter, the responsibility to assure resource adequacy belongs to the states. MISO runs an annual PRA to provide a tool for LSEs to complement their long-term resource adequacy procurement decisions under the supervision of their state regulatory authority.

MISO further supports adequacy objectives with state public policy requirements by assessing, analyzing, and providing states and other RERRAs with information on where resource adequacy conditions are moving. MISO uses the OMS-MISO Survey and RRA

[9] More information on the MISO Attributes Roadmap can be found here https://cdn.misoenergy.org/2023%20Attributes%20Roadmap631174.pdf.

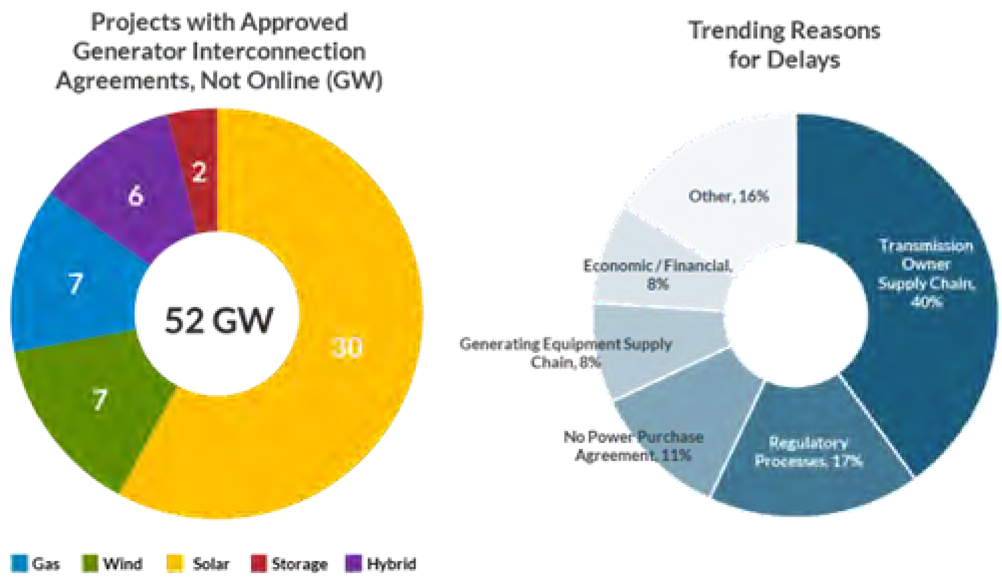
studies to highlight the needs of the entire footprint on a macro level. MISO is responsible for facilitating residual capacity transactions throughout the footprint through the PRA. Since MISO's inception, deference has been made to the jurisdictional authority of the states and other RERRAs with respect to resource adequacy rights and responsibilities that RERRAs take seriously. MISO respects states' rights towards resource adequacy and acknowledges that LSEs have an obligation to serve their end-use customers. As a result, MISO takes the resources offered into MISO's markets as given and procures resources to meet the margin requirements at least cost. This analysis is highlighted in the OMS-MISO survey and RRA studies. MISO has the obligation to translate the 1-in-10 LOLE requirements into planning reserve requirements and to facilitate residual capacity transactions through the PRA.

***Question 4*: What are the key drivers that cause delays in the construction and interconnection of generators in your RTO/ISO? What can be done to accelerate the interconnection of generators to help meet the resource adequacy challenge? How have factors external to your RTO/ISO, such as supply chains and siting/permitting, impacted generator interconnection timelines? What is the composition of resources in the queue? Will accelerating queue processes help address the challenge of resource adequacy? How many resources (by number and aggregate nameplate capacity) have received approval for interconnection but have not been constructed? How, if at all, are the expected resource adequacy contributions of a resource in the interconnection queue considered during the interconnection process?**

There is a combination of factors that contribute to delays in the construction and interconnection of new resources on the grid. This includes delays in the process to provide generation interconnection agreements to new generation resources and delays in those resource with generation interconnection agreements getting to commercial operation. MISO is taking significant steps to improve the queue processing delays and provide transparency to the delays in commercial operation dates to help facilitate identification of potential solutions to the problem.

The current reality is that study cycles are taking 3+ years in MISO's Generator Interconnection Queue process. This is, in part, due to the dramatic increase in the number of project submissions in recent years, which does not support the region's needs. Once a project receives a Generator Interconnection Agreement ("GIA") and is approved for construction, there may be construction delays due to supply chain challenges, regulatory hurdles, and other issues. More than half of all delays are attributable to transmission owner supply chain issues and regulatory processes. The next largest factor is lack of PPAs.

Figure I.A.[10]



An expedited study process that balances the responsibility for providing grid reliability and resource adequacy in the MISO region between MISO, LSEs, and the states can solve many of these problems. Projects that prove they have resolved the aforementioned barriers to success (such as funding, citing and permitting, etc.) should be able to enter a separate process to bring new generation online in the short-term to meet resource adequacy and reliability needs. This is especially needed in light of load growth and data center build out. Currently, data centers do not have a process in place to come online as quickly as the market would require. An expedited queue process can handle expected load growth, such as this, during a time when dispatchable resources are expected to leave the region at a rate much higher than accredited capacity can keep up with.

MISO found internal improvements to reduce study times as well. MISO's recently approved queue cap proposal will ensure a more manageable volume of projects, driving lower study times. Additionally, MISO's implementation of Suite of Unified Grid Analyses with Renewables ("SUGAR") software utilizes advanced data and analytics using machine learning and artificial intelligence to create reliable and informed planning and operations, as well as significantly lower study and modeling times. Full implementation of SUGAR will take study times from 3+ years to under 1 year. But it will likely take about 4 years for full implementation of SUGAR. Allowing for an accelerated study process for certain projects will address queue backlog until the entire queue process is improved to a 1-year timeframe.

To address supply chain issues MISO encourages long-term stability and certainty in federal energy policy. This will promote investments that are discouraged by volatility.

---

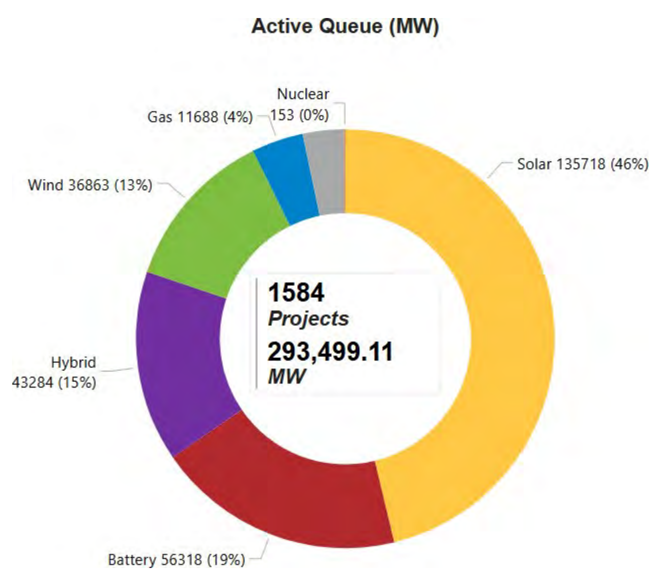
[10] Figure I.A. Compares 52 GW worth of generator interconnection projects with an Approved Generator Interconnection Agreement that have not come online with a breakdown of reported developmental delays. As of March 26, 2025.

Citing and permitting issues certainly causes delays, but these issues are not very different than they were 3-5 years ago. Generally, these factors should be addressed and resolved prior to entering the interconnection queue.

As a transmission planning organization, MISO is resource neutral and does not consider resource adequacy contributions during the interconnection process.

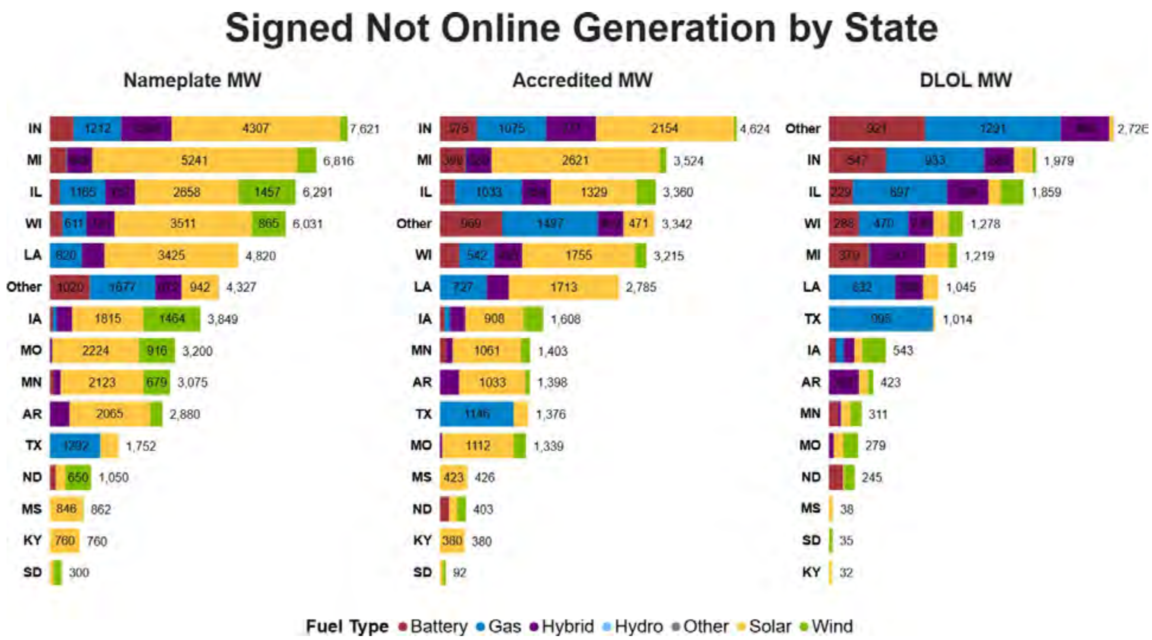
The current composition of resources in MISO's generation interconnection queue is illustrated in Figure I.B. This breakdown of capacity in the queue supports the points made in our answer to question 2 above about the potential looming shortage of broader system reliability attributes, being analyzed in the Attributes Roadmap report. Figure I.C. illustrates a breakdown of projects with signed GIAs that are not yet online.

Figure I.B.[11]



[11] MISO's Active Generator Interconnection Queue as of May 15, 2025.

<u>Figure I.C.</u>[12]



<u>Question 5</u>: Are there additional concerns that may affect resource adequacy in the near term (e.g., over the next five years) and in the longer term (e.g., ten years and beyond)?

In the long-term, an emerging gap between installed capacity[13] and accredited capacity[14] is a high priority. The MISO Futures utilize a range of economic, policy and technological inputs to develop three scenarios that "bookend" what the region's resource mix might look like in 20 years.[15]

Figure I.D. shows projected capacity change from 2022 to 2042 for all three Futures based on existing and member-planned resources, published in Series 1A MISO Futures Report. As the charts show, the region's level of *installed* capacity – the blue line – is forecasted to increase due to the many new resources – primarily wind and solar – that utilities and states plan to build in that 20-year time period. But because those new wind and solar resources have significantly lower accreditation values than the conventional resources that utilities and states plan to retire in the same 20-year period, the region's level of *accredited* capacity – the red line – is forecast to decline by 2042. With each Future increasing the total retirement of highly accredited thermal resources, this negative net change is more pronounced across Futures: Future 1A projects an 18 GW negative

---

[12] Figure I.C. is a breakdown of signed generator interconnection agreements that have not yet reached their commercial operation date. This is displayed in nameplate capacity, accredited capacity, and projected implementation of approved capacity using <u>Direct Loss of Load (DLOL)</u>-based methodology, which will be implemented in 2028/2029.[12]

[13] Installed capacity, or ICAP, is the hypothetical amount of energy that can be produced under optimal conditions.

[14] Accredited capacity is the actual amount of energy that can be expected under real-life conditions.

[15] More information on MISO Futures Scenarios can be found here https://www.misoenergy.org/planning/futures-development/

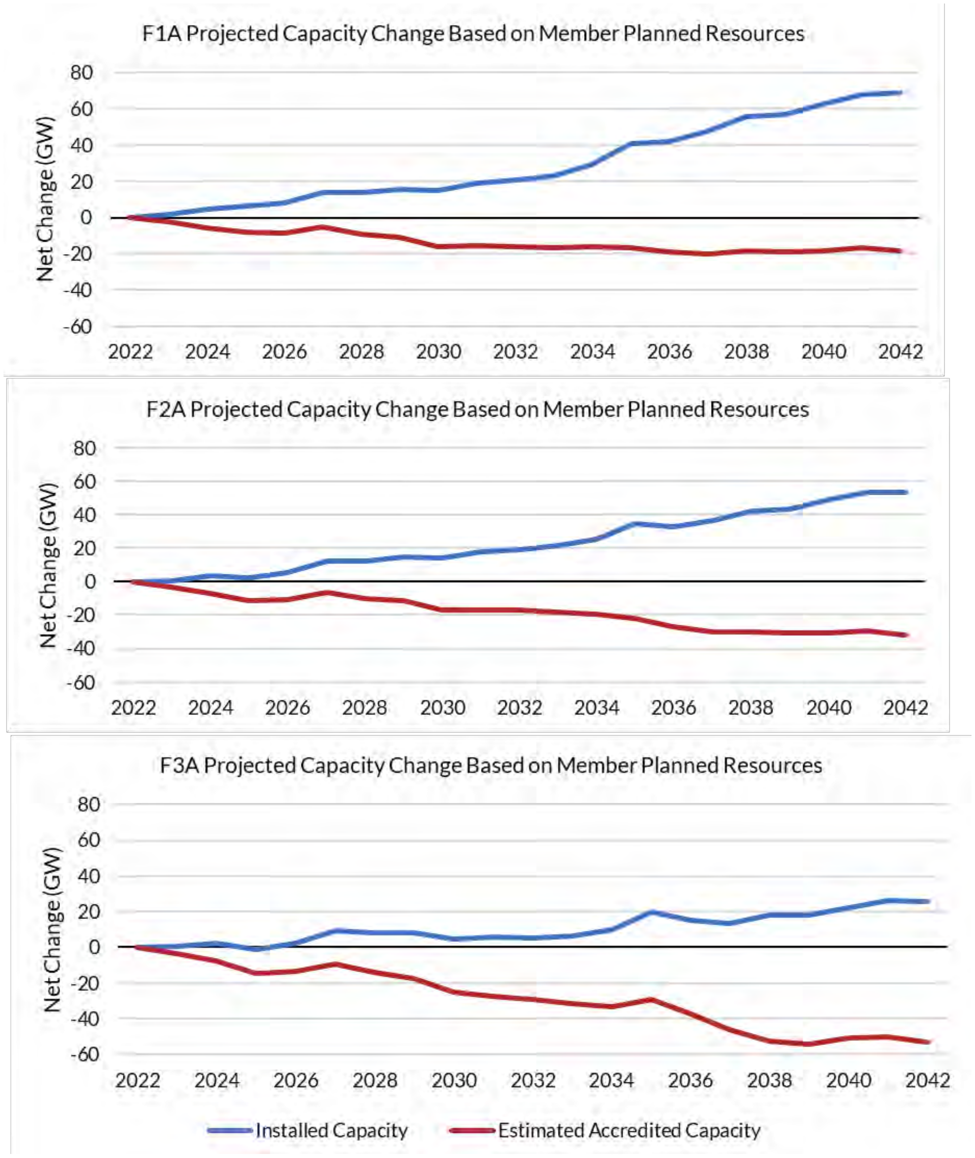
change in estimated accredited capacity across the study period, F2A projects a 32 GW negative net change, and F3A projects a 53 GW negative net change.

MISO modeling indicates that a reduction of that magnitude could result in load interruptions of three to four hours in length for 13-26 days per year when energy output from wind and solar resources is reduced or unavailable. Such interruptions would most likely occur after sunset on hot summer days with low wind output and on cold winter days before sunrise and after sunset.

Futures modeling is the key to addressing this shortfall. The MISO Futures team added 29 GW of Flexible Attribute Unit ("Flex") capacity to the Future 2A expansion and siting. Flex units are proxy resources that refer to a non-exhaustive range of existing and nascent technologies, representing potential generation that is highly available, highly accredited, low- or non-carbon emitting, and long in duration. As a proxy, potential Flex resources could be, but are not limited to: Reciprocating Internal Combustion Engines ("RICE") units, long-duration battery[16], traditional peaking resources, combined-cycle with carbon capture and sequestration, nuclear Small Modular Reactors ("SMRs"), green hydrogen, enhanced geothermal systems, and other emerging technologies. Flex units do not take away the need for previously identified resources but rather supplement them in periods of energy inadequacy.

[16] Greater than four hours.

<u>Figure I.D.</u>[17]



<u>Question 6</u>: In NERC's view, what aspects of resource adequacy planning could be improved? For example, what type of reliability metric (or metrics) should be used in resource adequacy planning models? What elements of resource adequacy planning can be improved or could serve as best practices?

The 1-in-10 LOLE has served the region well and set the benchmark used to design an adequate system. However, many industry experts, including NERC, have raised questions about this framework's effectiveness in addressing future system risks. Of particular concern is the ability of the future resource fleet to serve load over extended

[17] Figure I.D. comes from Series 1A MISO Futures Report published November 1, 2023. MISO is currently in the process of working with stakeholders to develop an updated Futures Report to reflect current circumstances. More information on Futures Redesign Workshop can be found here www misoenergy.org/engage/committees/futures/

periods of time, with conditions that may lead to an energy-constrained system. For instance, a future system with no legacy thermal capacity and an abundance of variable and energy-limited generation may experience events much larger in magnitude and longer in duration than today's system. In response to Question 5, MISO's modeling indicates that a reduction of that magnitude could result in load interruptions of three to four hours in length for 13-26 days per year when energy output from wind and solar resources is reduced or unavailable. In 2024, MISO reviewed industry recommendations and new trends in the use of resource adequacy metrics. MISO also reviewed and analyzed adequacy metrics calculated in previous MISO studies. The result of this recommends a collaborative approach with states and the industry to revisit the 1-in-10 LOLE criterion, explore alternatives, and provide visibility to complementary metrics.[18] The Resource Adequacy Metrics and Critical Roadmap explores this issue and identifies the next steps by collaborating with the jurisdictions responsible for ensuring resource adequacy in the MISO region, including through the recently formed OMS Resource Adequacy Committee. MISO intends to continue engaging with stakeholders, provide a gap analysis to identify conditions under which energy adequacy materially erodes in a MISO system planned to 1-in-10 LOLE, and collaborate with OMS to develop a framework for identifying thresholds in risk metrics that may warrant potential changes to criteria in MISO's resource adequacy construct. Additionally, MISO plans to publish additional metrics more consistently across resource adequacy studies. MISO also seeks to increase industry collaboration, notably collaborating with other ISOs and research organizations and participating in the NERC drafting team of the new Planning Energy Assurance standard.[19]

<u>Question 7</u>: How does your RTO/ISO approach capacity accreditation? What are the benefits and drawbacks of harmonizing capacity accreditation methods across regions versus allowing for regional variation?

a. ***the current 1-in-10 LOLE criterion and the identification of additional analysis needed to evaluate whether there are gaps that need to be addressed. The Resource Adequacy Metrics Given that many regions use the same probabilistic models for both evaluating resource adequacy and/or reserve margins and for Effective Load Carrying Capability (ELCC) accreditation, are there best practices in approaches that NERC is observing that could help align various regions across the country in using the best modeling methodologies or data sources, etc.?***
b. ***What are the potential strengths, weaknesses, and implementation considerations of alternatives to ELCC when evaluating the contribution of various types of resources in meeting resource adequacy requirements?***

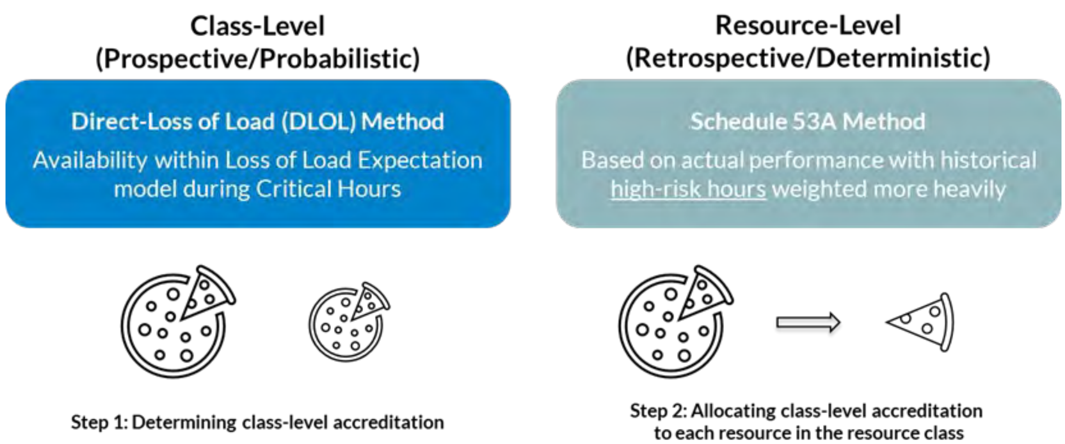
MISO has made significant reforms to improve the resource accreditation methodology to meet the regional reliability needs in the region. These reforms provide a strong foundation to ensure that LSEs bring the resources needed for MISO's operators to

[18] Recommended through the Resource Adequacy Metrics and Criteria Roadmap document.
[19] More information on the NERC Planning Energy Assurance standard can be found here https://www.nerc.com/pa/Stand/Pages/Project-2024-02-Planning-Energy-Assurance.aspx

dispatch resources to meet customer demand for every hour in the day and the resource adequacy market provides a transparent signal for needed resource investment.

MISO is currently transitioning to a two-step accreditation approach (the "Direct Loss-of-Load" or "DLOL"-based methodology) that accredits capacity based on marginal contribution to reliability during periods of highest system risk ("marginal effective load carrying capability" or "marginal ELCC") and on Resource Class. MISO's DLOL-based methodology combines both probabilistic and deterministic elements into a single resource accreditation process. Simply described, the DLOL-based methodology takes two steps by first determining the size of the pie, and second, divvying up the pie.

<u>Figure I.E.</u>



Regional diversity evolved for various reasons and a prescriptive process is not optimal or productive. For example, the Tariff interregional study process with SPP, which has been in place 2020, has yielded no new projects. MISO supports allowing for regional variation to allow RTOs/ISOs to address the unique needs of their regions. MISO has a very diverse footprint: 6 out of 16 regulatory jurisdictions are elected, 4 jurisdictions have moderate to aggressive renewable portfolio standards, 7 jurisdictions lean towards a traditional, fossil fuel approach, and 5 jurisdictions take a balanced approach. The one uniform metric across all states and all RTOs/ISOs is 100% for grid reliability. But MISO does actively engage with all other RTOs in North America, in part through the ISO/RTO Council ("IRC") Markets Committee and also in part with direct discussions with RTO staff to follow best practices in the industry. If design attributes in another RTO look to potentially address MISO issues, we vet these before the stakeholder community and adopt them as appropriate. An example of this is the RBDC design being similar in nature to some of the eastern RTOs construct.

MISO does not speak on behalf of NERC, but MISO agrees with the Commission's previous statements that "using the same model for determining the amount of capacity required and the amount of capacity a resource is capable of providing is a reasonable modeling methodology. This method allows risk to be evaluated on a more granular level and provides for consistency between the system's resource adequacy requirements and resource accreditation to meet those requirements."[20]

MISO strongly believes that, while respecting regional variations, capacity should be accredited based on performance during times of high risk to properly recognize that not all capacity is created equal, nor will all capacity perform equal in any given situation. Weighing hours based on margin recognizes that not all the simulated events are equal, by assigning greater weights to those hours that have the highest unserved energy. It also provides a distinction between loss of load hours with negative margins and low margin hours with zero or small positive margins by providing higher weight to the former. This ensures that the expected reliability risk during critical hours is being appropriately accounted for in the resource class-level accreditation calculation.

MISO has considered a number of approaches and has found that approaches that accredit an entire class of resources based on the average contribution of the entire fleet do not align with the assumption that capacity exchange in the capacity market is fungible. Instead, marginal accreditation that measures the contribution of the next incremental addition to the resource fleet is a statistically robust method for measuring the incremental, or marginal, contribution to system reliability for any resource that reflects its availability during the hours of highest reliability risk.

The contribution of various resources in meeting resource adequacy requirements must be weighed in relation to their impacts on the system during high-risk hours. MISO has considered alternative weighting schemes, ranging from equal weights for all hours, weights based on the amount of unserved energy, combining the loss of load hours and low margin hours with a fixed ratio, and alternative weighting based on margin. None of these alternative schemes provide consistent emphasis on the hours with highest unserved energy to the level that weighing hours based on margin does. This properly accounts for the magnitude of expected reliability risks in each hour. This construct provides numerically stable results regardless of whether the group of hours include only loss-of-load hours, a few low margin hours, or a large number of low margin hours.

<u>Question 8</u>: How can the RTOs/ISOs ensure that their demand forecasts adequately take into account load growth from data centers and other large loads? How can the RTOs/ISOs ensure there is sufficient supply to meet these demands, and what will those sources of supply be?

Appropriately forecasting load growth from data centers and other large loads is a significant challenge across the industry. The issue is present in both RTO and non-RTO regions. The visibility and transparency of the RTO framework allows the challenge to be more clearly identified and visible in the RTO regions. MISO ensures that there is ample supply to meet demand through a prompt capacity market, resource forecasts provided by the OMS-MISO survey, conducted annually, and the RRA effort. MISO works closely with the OMS coordinating and collaborating with all potential PRA reforms to better support grid reliability.

20 See PJM Interconnection, L.L.C., 186 FERC ¶ 61,080 (2024)("PJM Order").

Longer term load forecasts[21] originate with the LSEs. MISO validates and utilizes these forecasts to adequately take into account load growth from data centers and other large loads. MISO subject matter experts validate forecasts for the upcoming planning year through a random sampling approach. Included in this sampling is an assessment of the accuracy of the past year's forecasts which outlines a set of detailed questions related to the forecasts that each LSE must answer. Accounting for load growth from data centers and other large loads is asked directly to LSEs with a requirement on the LSE show support for their assumptions.

MISO recently updated our long-term[22] load forecasting process to better account for the impact of new sources of load growth on long-term planning. The process uses bottoms-up estimates of load for each of a set of drivers (e.g. data center announcements) along with assessed probabilities (e.g. likelihood of an announced data center being built on time) to develop a range of credible forecasts. These forecast are benchmarked against the LSE-provided forecast in the first few years. Longer-term load forecasts support MISO's transmission planning efforts and inform member resource planning decisions.

<u>Question 9</u>: How can demand flexibility and demand-side management solutions be utilized to address load growth and resource adequacy concerns?

Demand resources acting as supply are viable alternatives for LSEs to use in meeting their capacity obligations, and are used quite abundantly in MISO. MISO continues to explore future implementation of DERs to assist in resource adequacy challenges and is working closely with the OMS to be transparent around any future reliability issues. MISO has also recently filed reforms intended to better accredit demand-side resources to ensure those are resources appropriately valued as a resource adequacy tool.

<u>Question 10</u>: How do you reflect transmission availability—both regional and interregional—in your resource adequacy planning and requirements? To what extent do your transmission planning processes capture the resource adequacy benefits of regional and interregional transmission?

The changing resource mix requires more transmission to get generation to load. MISO's Tranche 2 portfolio of LRTP projects is progressing, with approval from MISO's Board of Directors in 2024. Planning is complex, but MISO has balanced the need to move quickly to meet resource adequacy objectives with the need to develop a robust, lowest-cost portfolio. Through the roll out of LRTP projects, transmission projects are in progress in areas with the greatest need based on ranges of economic, policy, and regulatory inputs. Availability of regional transmission capability affects the ability to import/export resources across the MISO footprint. MISO captures these capabilities in the capacity import and export limits modeled and respected in the PRA. These import/export limits are reevaluated annually and modeled in the PRA, allowing resources to meet local and regional capacity requirements.

[21] Anything longer than a week or two out or any load forecasts that are not used in the Energy and Operating Reserve markets.
[22] 20-year.

To get customers to build out generation, they mainly need reasonable costs and cost certainty. MISO's JTIQ ("Joint Transmission Interconnection Queue") addresses this by spreading costs among interconnection customers so that customers do not hesitate to build out due to fear of being the project that triggers a higher cost than what is feasible. This allows all parties to pay reasonable costs that they can anticipate in advance.

Panel 5: MISO's Resource Adequacy Challenge

***Question 1**: What is the state of resource adequacy in MISO in the near term (e.g., over the next five years) and over the longer term (e.g., ten years and beyond)?*

a. Is MISO's resource adequacy construct delivering resource adequacy in MISO?

b. What are the benefits and drawbacks to MISO's resource adequacy construct and residual capacity auction?

There are urgent and complex challenges facing electric system reliability in the MISO region. These challenges include generation fleet change, regulatory hurdles, extreme weather events, and load additions, to name a few. In light of this, utilities, states and MISO have taken steps to coordinate with urgency to avoid any mismatch between the pace of adding new resources and the retirement of older resources. MISO is confident that by addressing the four pillars of the Reliability Imperative the region will remain in excess of the 1-in-10 LOLE Standard.

MISO uses a few tools to assess the state of resource adequacy in its footprint. The RRA is one of the periodic studies MISO conducts to forecast how the mix of electricity-generating resources in the MISO region could evolve going forward. In contrast, the OMS-MISO Survey is focused on the near term and is based on much lower expectations of new installed capacity, reflecting the pace at which resources have received interconnection agreements and come online in recent history. Each study was designed for a different purpose, uses different data inputs, covers different time periods, and uses different methodologies and modeling assumptions. Accordingly, the results differ. For example, the RRA assumes members and states will be able to add new generation capacity at an unprecedented rate of 17 GW/year for the next 20 years to reliably achieve their publicly announced resource plans and policy goals. Accordingly, the RRA projects capacity surpluses in 2030 and beyond. The 2024 OMS-MISO Survey therefore forecasted a range of possible outcomes, varying from capacity deficits beginning in 2025 to capacity surpluses through 2029. These divergent results reflect that the RRA and the OMS-MISO Survey were designed for different purposes and use different data inputs, methodologies, assumptions and time horizons.

In sum, given that the MISO states have rights towards resource adequacy, take their roles and responsibilities seriously, and MISO is providing transparency in expectations of future resource adequacy plans, we are confident that the footprint will continue to be resource adequate in the near and longer term. Capacity margins are declining but remain in excess of the 1-in-10 LOLE standard. MISO successfully implemented the RBDC in the capacity market for the 2025-2026 PRA. This construct provides more accurate price signals and encourages resource investments by reflecting the contributions to reliability incremental megawatts can add to the system. The capacity market has changed from an annual to a seasonal construct to better reflect the risks to resource adequacy shifting from mainly the summer peak demand conditions to periods across all seasons and time periods. On the supply side, resources are being accredited based on availability during all times of need, across all seasons. In the most recent PRA, the megawatts that cleared in the summer season exceeded 1-in-10 LOLE by an additional 2 percentage points because the reliability contribution of these additional megawatts exceeded the cost to procure them.

The RBDC construct values the reliability contribution of incremental MWs, the price signals that reflect that reliability value, and the prompt and residual nature of the capacity market. Prompt auctions have less uncertainty around demand values and supply availability. The residual nature recognizes that, in MISO, most LSEs come with resources that meet their requirements. There is the possibility that, without other actions, the prompt nature leaves little time to address any issues that arise, like shortfalls. This potential drawback is addressed through the OMS-MISO survey and RRA effort, providing more transparent information around future reliability requirements and resource margins.

***Question 2*: How have the recent outcomes of MISO's capacity auctions affected market participants and consumers in MISO? Do states and stakeholders have confidence that the MISO capacity market will be effective to achieve resource adequacy at just and reasonable rates?**

The capacity shortfalls that occurred in the 2022/2023 planning year promoted a greater sense of urgency to MISO's ongoing efforts to continually enhance its market design. The vertical demand curve served the region well for many years but as the resource mix has changed and extreme weather events have increased, customer confidence in the capacity market eroded. The vertical demand curve created extreme price volatility that disincentivized investments. The RBDC, implemented for the first time in the 2025/26 PRA, has addressed this by providing more accurate price signals and encouraging resource investments by reflecting the contributions to reliability that incremental megawatts can add to the system. Most LSEs within MISO either have owned or contracted for resources that meet their obligations but, regardless, the more efficient capacity prices being established through the RBDC construct provide much better information to LSEs, RERRAs and generation owners to make more informed going forward investment decisions. This is akin to how Real Time energy market prices work – a very small percent of transactions are subject to real time prices, but Day Ahead prices are informed by what happens in real time. Changes to the resource adequacy construct highlighted above and the information provided through the OMS-MISO survey and RRA effort have initiated renewed efforts on the part of LSEs and RERRAs to address resource adequacy requirements.

States and stakeholders have shown confidence in the MISO capacity market to achieve resource adequacy at just and reasonable rates. This is in large part due to the collaborative relationship between MISO and its stakeholders. Since MISO's start, deference has been made to the states and other RERRAs with respect to resource adequacy rights. MISO has worked closely with OMS, the Independent Market Monitor ("IMM"), and other stakeholders to change the capacity market to a seasonal construct and implement the RBDC. OMS has reinforced the need for MISO's seasonal capacity construct and RBDC to properly accredit capacity in a world with more extreme weather and faster load growth than ever.

***Question 3*: How have the seasonal resource adequacy requirements and revised capacity accreditation methods worked in MISO to date? Have they helped MISO more accurately determine its resource adequacy needs? What issues or challenges has MISO experienced in implementing a seasonal construct and revising capacity accreditation, and how does MISO plan to address those issues or challenges?**

The seasonal construct has highlighted the seasonal differences in the planning reserve margins required to meet the reliability standards, the varying Loss of Load Probability distributed across the seasons, the variability in the values of accreditation for resources by season (the Seasonal Accredited Capacity, or, "SAC") and significant differences in load variability season by season. This has helped MISO more accurately determine its resource adequacy needs as extreme weather has reconfigured what it means to be resource adequate. Being resource adequate on the hottest day in the summer does not necessarily mean that an LSE is resource adequate on the coldest day in the winter. SAC allows MISO to stay reliable throughout the entire year by targeting the unique needs of each season.

Accreditation changes, SAC in particular, are much more reflective of availability of resources to meet needs in each season.[23] The changes MISO has made to accreditation has a prospective and retrospective tint to it on purpose, as it captures the class level performance during projected risk conditions, while still being grounded and calibrated against the reality of how actual units performed over the last 3 years. This allows good performers to continue having a great incentive to continue that performance. Spring & fall seasons can be quite variable with summer and winter weather patterns bleeding into the shoulder seasons. For example, as the weather changes, winter weather may continue into early spring. Each successive planning year provides MISO with additional data to support market design. Currently there is a limited sample size for assessing accreditation. MISO is addressing these and other issues with renewed effort on appropriate LOLE modeling, shared with stakeholders.

***Question 4*: How does MISO establish its load and resource forecasts?**

a. ***How does MISO integrate the load forecasts provided by load-serving entities and electric distribution companies into their planning reserve margin requirements?***

b. ***Does MISO verify the forecast methodologies and accuracy of forecasts?***

c. ***Have the assumptions driving load and resource forecasts changed over time? If so, how?***

[23] The answer to question 7 in the above panel more fully describes the changes we have made.

d. ***How do the forecast models weight different inputs? Are some assumptions more uncertain, important, or impactful than others?***

e. ***How have the forecasts performed historically and are parties considering any changes to forecasting models or processes? For example, are you considering requiring demonstration of commercial readiness from prospective new large load additions?***

Anything longer than a few weeks or any load forecasts that are not used in the Energy and Operating Reserve markets are considered “longer-term forecasts” and originate with the LSEs. With such a wide and diverse footprint in MISO, LSEs are best positioned to have information on where energy & demand is moving in its localized area. Resource forecasts are provided by the OMS-MISO survey and the RRA efforts and are conducted annually.

MISO integrates previous LSE forecasts as direct inputs into the LOLE modeling which determines the planning reserve margin requirements. MISO verifies the forecast methodologies and accuracy of forecasts provided by LSEs. LSEs submit documentation, including a narrative with a complete description of the type of models being used, statistical model results, and spreadsheets with historic and forecast data, to MISO to support the LSEs’ forecast demands. MISO then draws a random sample of these LSEs broken up into identified segments. Current segments are large LSEs (demand greater than 1000 MWs), medium LSEs (demand between 100 MWs and 1000 MWs), and small LSEs (demand less than 100 MWs). MISO subject matter experts then assess and validate the credibility of the LSE’s submittals. Included in this is an assessment of the accuracy of the past year’s forecasts.

The values for the variables used in the forecast have changed over time and been updated to weigh different inputs appropriately. The variables themselves have not necessarily changed. For example, LSEs consistently see new commercial and industrial facilities being built and older facilities being closed, but more recently, new load growth predominantly from data centers has driven expectations of higher load growth in the near term. Statistical models calculate the weights endogenously.

Certainly, some assumptions are more uncertain than others. On the resource side, getting through the queue process has significant uncertainty. On the demand side, for instance, significant load additions, like data centers, have to be studied for reliability impacts and come with uncertain timing of these additions.

The forecasts have performed to acceptable industry standards in the past, though load growth has been minimal over recent time periods. MISO, however, is strengthening its load forecast validation process, providing more guidance on acceptable practices, and looking for discrete changes to the load forecasts.

Given the prompt nature of the PRA, demonstration of commercial readiness of prospective new load additions has always been a consideration.

<u>Question 5</u>: To what extent are barriers to entry (e.g., the interconnection queue backlog, supply chain limitations, siting and permitting delays, etc.) affecting resource adequacy in the MISO footprint?

The barriers affecting resource adequacy in the MISO footprint are less to entry, but rather barriers to success once projects exit the interconnection queue. Factors such as funding, off-taker agreements, supply chain, and permitting and citing delay projects from being built once they exit the generator interconnection process. There is over 50 GW of projects that have a signed generator interconnection agreement and are not yet online. Over half of them are already signaling they are delayed and cannot meet their originally expected in service date. New long-term stability and certainty in federal energy policy has further worsened these expected delays. A clearer signal on federal energy policies and import tariffs impacting necessary electrical components would promote investments and ease these delays. To improve visibility into these generators with interconnection agreements signed but not yet online, MISO created a Commercial Operation Date Dashboard on our website to help stakeholders understand when these resources are expected to come online.[24]

Another concern is the queue backlogs themselves. Although there is a significant amount of generation with a GIA waiting to come online, these resources may not have all the attributes necessary to ensure long term resource adequacy. The MISO queue has historically represented wind, solar, and battery storage projects. This includes 86% of the resources with a GIA waiting to come online, and over 96% of the 300 GW of projects in ongoing queue cycles. A significant shift is occurring for MISO's next queue cycle that will close in September of 2025. Currently there are 44 GW of projects submitted in the 2025 queue, and 26% of that is new natural gas resources. The queue backlog and delays mean these new resources may have to wait years to get an interconnection agreement.

To aid in the development of resources needed to address resource adequacy, MISO introduced a new process to study select projects outside the interconnection queue. The ERAS process was filed at Commission in March. This process would allow MISO to study individual projects, acknowledged by their RERRA and an off-taker agreement, with load to be studied by MISO through ERAS. This process would allow these projects to receive a GIA within months instead of years. This temporary process will only be in place until the queue backlog and delays have been mitigated.

<u>Question 6</u>: To what extent does the availability of regional and interregional transmission capability affect resource adequacy planning in MISO? How can MISO better address the effect of transmission capability on resource adequacy?

---

[24] See the C.O.D. dashboard here https://app.powerbigov.us/view?r=eyJrIjoiOTU1ODlhNTktMjZjZC00N2I2LWJhYjMtMDEwOGNmZDM5ODk0IiwidCI6IjYwNDA5MTViLTlkZmYtNGQ0Ny1iYjM1LThhYzljOWE1ZGMxOCJ9&pageName=983a2cc8ca3ccf63608a.

Availability of regional transmission capability affects the ability to import/export resources across the MISO footprint. MISO captures these capabilities in the capacity import and export limits modeled and respected in the PRA.

MISO can increase study effectiveness to better address transmission capabilities. MISO is implementing the generator interconnection request cap ("queue cap") and interconnection process improvements to achieve this. The queue cap limits requests at 50% of each region's non-coincident peak load. This follows a first-in, first-selected approach to allow for more manageable request numbers which will improve effectiveness and efficiency. MISO is also implementing SUGAR software which has shown significant time reduction for preliminary studies so far. Additionally, a new application portal will be available for customers in June with improved interface and data quality.

***Question 7**: Would an alternative resource adequacy construct used by another RTO/ISO be more effective at delivering resource adequacy in MISO? If so, why?*

No, the enhanced reforms with the DLOL construct provide an effective tool to deliver resource adequacy. The DLOL-based methodology respects states' rights and responsibilities over resource adequacy. RERRAs have well established processes in place to meet the resource adequacy requirements determined by MISO and are expected to continue to do so. The residual nature of the resource adequacy construct is working as intended. The RRA studies and the OMS-MISO survey further support resource adequacy decision and planning across the footprint.

Additionally, MISO is not aware of any alternatives to the current residual market that would perform better in MISO at this time. Recent capacity market enhancements such as SAC, RBDC, and DLOL-based methodology will continue to be implemented, improve market signals, and support needed resource availability. MISO continues, however, to consider design changes to the resource adequacy construct that can enhance reliability and support needed resource investment decisions.

***Question 8**: What should be the allocation of roles and responsibilities between MISO and the states to ensure resource adequacy in the MISO region? How does MISO work with the states to identify and meet the region's resource adequacy needs at just and reasonable rates? Has MISO studied the effects of state public policy on either resource adequacy or capacity market outcomes?*

Every effort in pursuit of the Reliability Imperative is centered around the shared responsibility between MISO-member electricity providers, states, and MISO to maintain a reliable grid. MISO appreciates states' responsibility for resource adequacy and acknowledges that LSEs have the obligation to serve their end-use customers. Both LSEs and RERRAs take their responsibilities seriously. Continued coordination is critical. With the pace of change confronting the electricity system, the impending influx of large data centers and the evolving generation portfolio there is heightened urgency to ensure the system remains reliable. Given this, MISO can assess, analyze and provide transparency on where resource adequacy conditions are moving, providing additional macro level views on the issues to help inform states and LSEs. MISO translates the 1-in-10 LOLE into planning reserve requirements and the responsibility of MISO to facilitate residual capacity transactions through the PRA.

MISO works closely with the OMS and RERRAs to communicate regional needs to maintain resource adequacy. Both the OMS-MISO Survey and the RRA provide information to MISO on state-specific forecasts. From this state-specific information, MISO conducts analyses that are made public around the need for different types of resources to meet the reliability standards being imposed by NERC.

MISO has not directly studied the effects of state public policy. MISO has, however, in its RRA studies, provided detailed analyses around the implications of state public policy. One example of this is increasing renewable energy trends. MISO puts priority on maintaining independence from individual MPs. We are fuel source and policy neutral, meaning we do not favor, prefer, or advocate any particular fuel or policy outcome. That doesn't mean, however, that we are disinterested observers. Our mission is to ensure the continued reliability of the bulk electric system.

III. CONCLUSION

MISO appreciates the opportunity to provide these responses to the Commission's questions regarding Challenge of Resource Adequacy in Regional Transmission Organization and Independent System Operator Regions.

Respectfully submitted,

/s/ Todd Ramey

Todd Ramey

Senior Vice President of Markets and Digital Strategy
Midcontinent Independent System Operator, Inc.

Appendix I

Appendix I summarizes data provided in this written statement through graphs, charts, and other images.

Figure I.A.

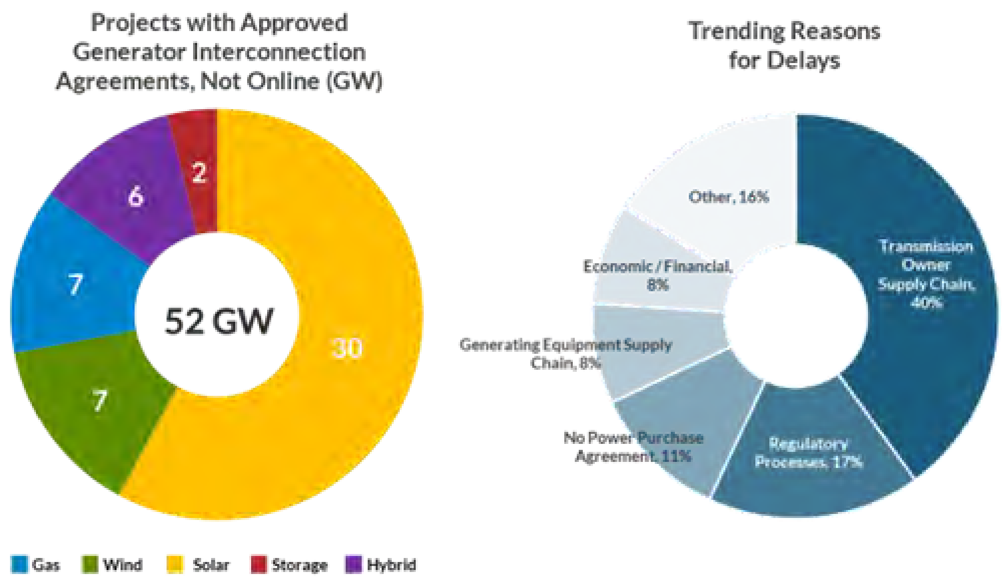


Figure I.A., found on page 13, compares 52 GW of Approved Generator Interconnection Requests in MISO with a breakdown of reasons for reported developmental delays and the percentage of delays affected by such set back.

Figure I.B.

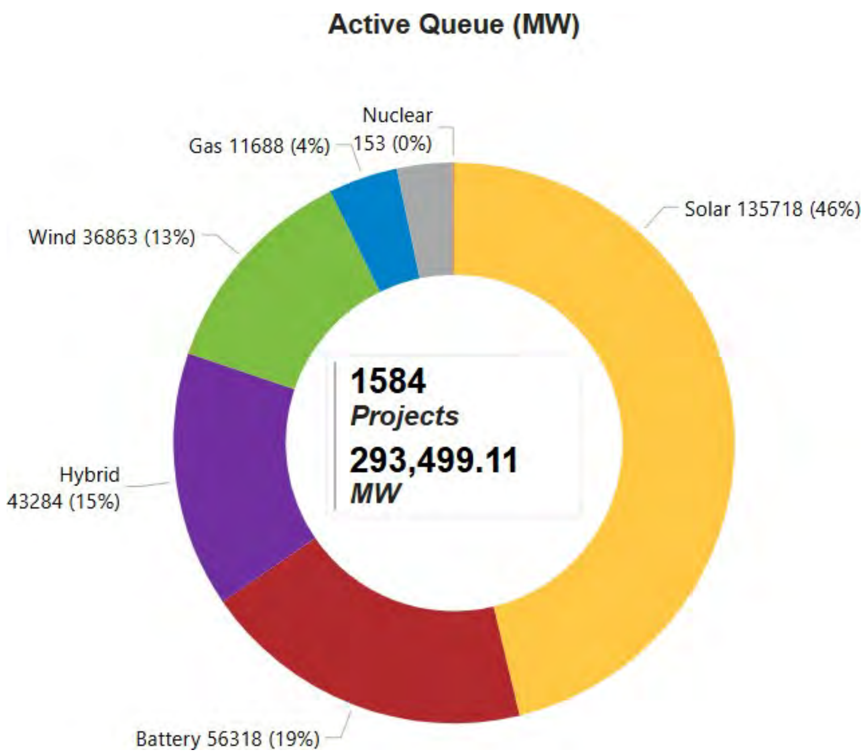


Figure I.B., found on page 14, illustrates the active MISO Generator Interconnection Queue by resource type. Does not reflect additional nameplate capacity from repowering existing generating facilities. As of February 6, 2025.

Figure I.C.

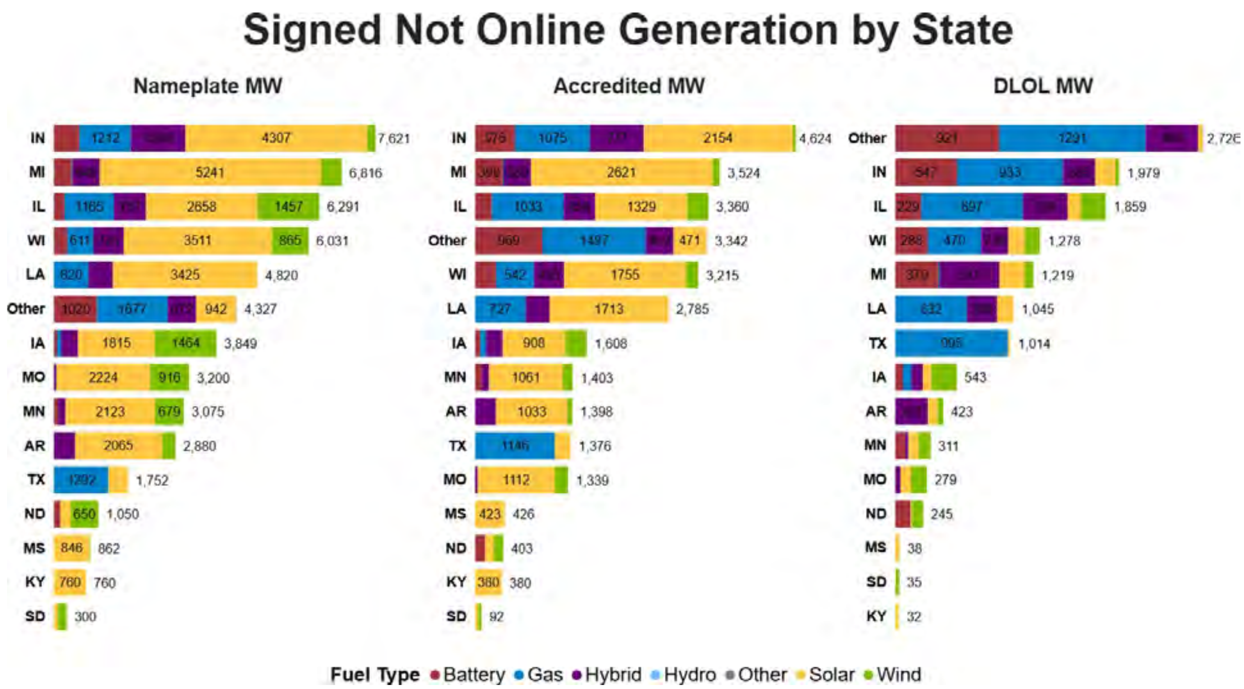


Figure I.C., found on page 15, illustrates a state-by-state comparison of MWs of Approved Generator Interconnection requests in nameplate capacity, accredited capacity, and DLOL-based methodology. The DLOL-based capacity accreditation assumptions are based on the fuel-based class average assumptions that are expected to be in place for the 2028/2029 planning year. The 2028/2029 Planning Resource Auction will be the first to utilize the DLOL-based methodology.

Figure I.D.

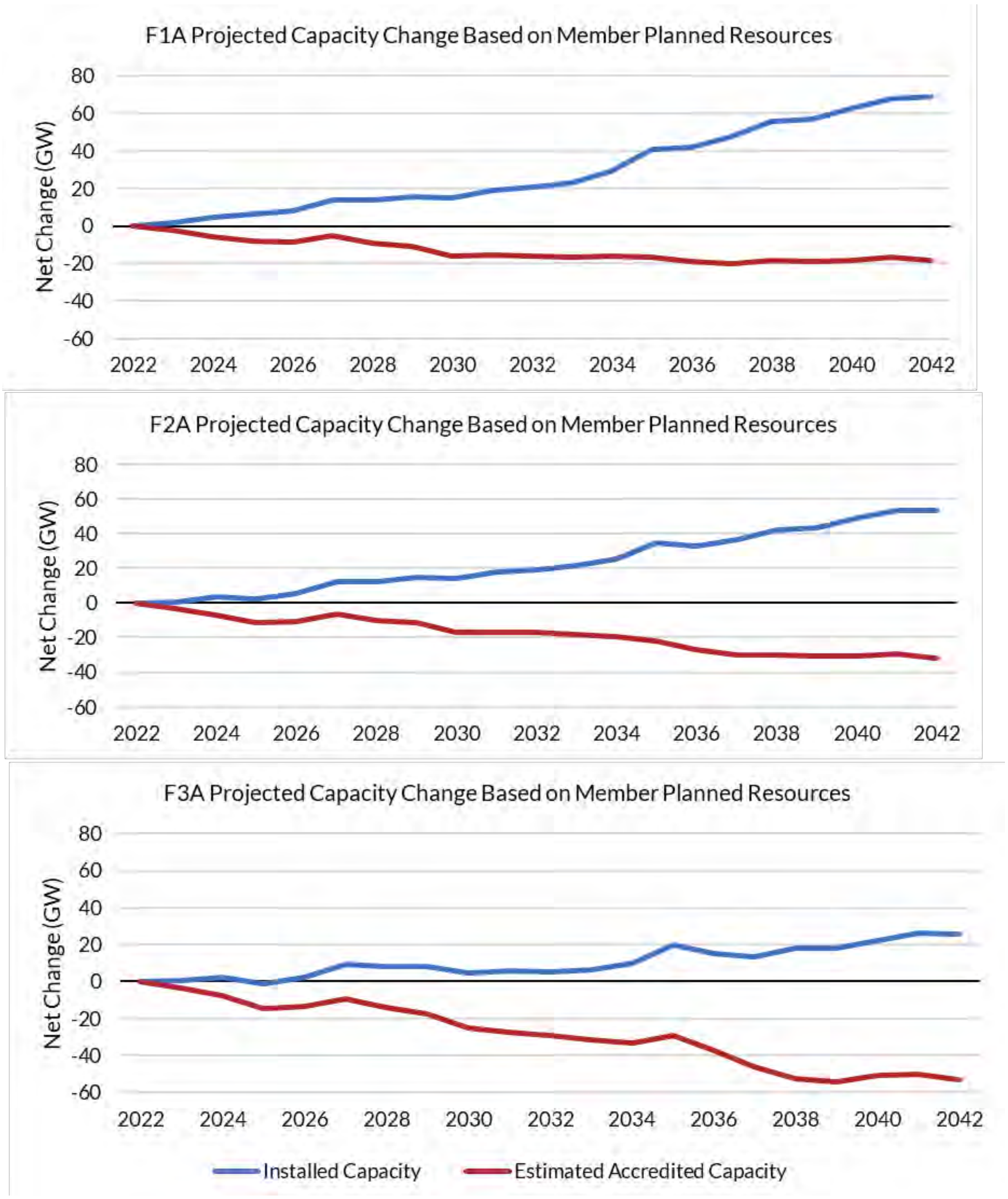


Figure I.D., found on page 17, shows projected capacity change from 2022 to 2042 for all three Futures based on existing and member-planned resources. Differences in the net change of installed and estimated accredited capacity are driven by the varying age-based retirement assumptions applied to existing resources across Futures. Figure I.D. is sourced from Series 1A MISO Futures Report. More information on this report can be found here https://cdn.misoenergy.org/Series1A_Futures_Report630735.pdf.

Figure I.E.

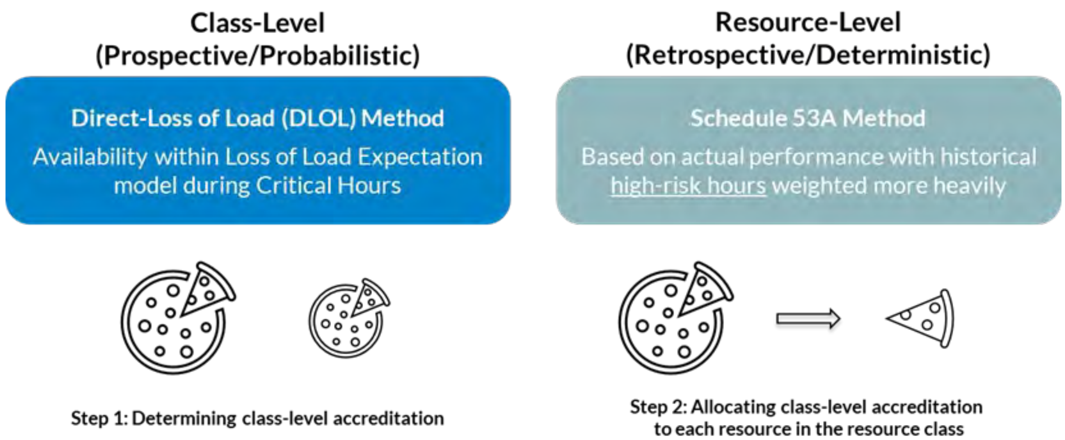


Figure I.E. explains the two-step DLOL-based resource accreditation methodology, further explained on pages 19. The DLOL-based capacity accreditation assumptions are based on the fuel-based class average assumptions that are expected to be in place for the 2028/2029 planning year. The 2028/2029 Planning Resource Auction will be the first to utilize the DLOL-based methodology.

Appendix II

Appendix II supplements information provided in this written statement with additional data on state generation retirements and additions.

Figure II.A.

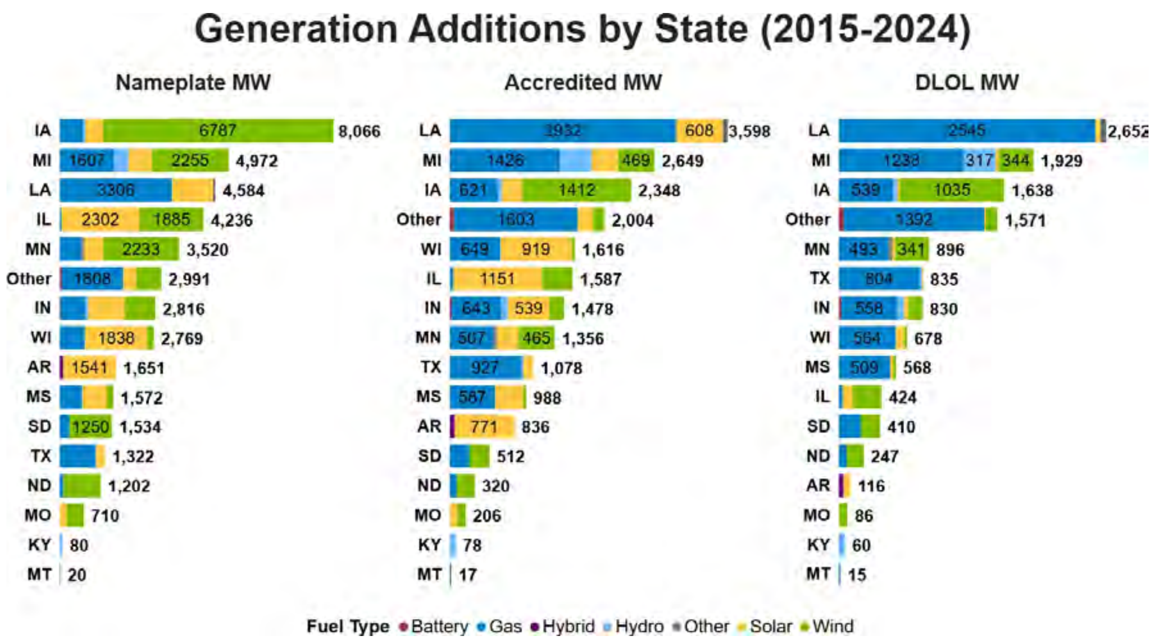


Figure II.A. illustrates a state-by-state comparison of generation that has come online over the last 10 years in the MISO region through new generation, surplus, and replacements. This is measured by nameplate capacity, current accredited capacity, and DLOL-based methodology. The DLOL-based capacity accreditation assumptions are based on the fuel-based class average assumptions that are expected to be in place for the 2028/2029 planning year. The 2028/2029 Planning Resource Auction will be the first to utilize the DLOL-based methodology.

<u>Figure II.B.</u>

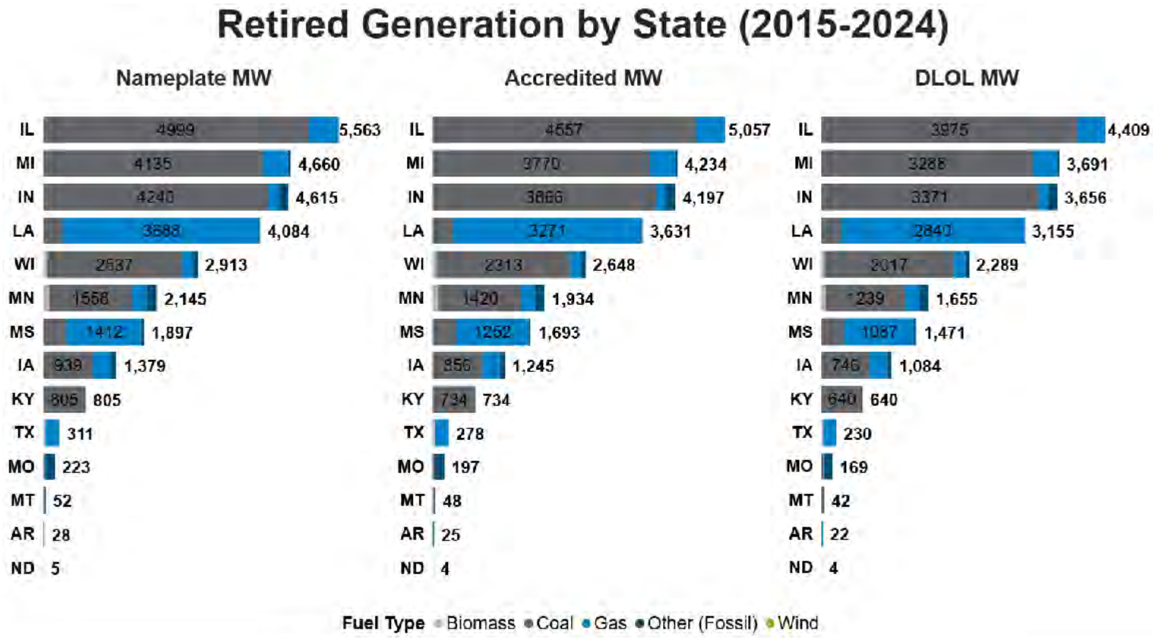


Figure II.B. illustrates a state-by-state comparison of retired generation over the last 10 years in the MISO region, measured by nameplate capacity, current accredited capacity, and DLOL-based methodology. The DLOL-based capacity accreditation assumptions are based on the fuel-based class average assumptions that are expected to be in place for the 2028/2029 planning year. The 2028/2029 Planning Resource Auction will be the first to utilize the DLOL-based methodology.

Figure II.C.

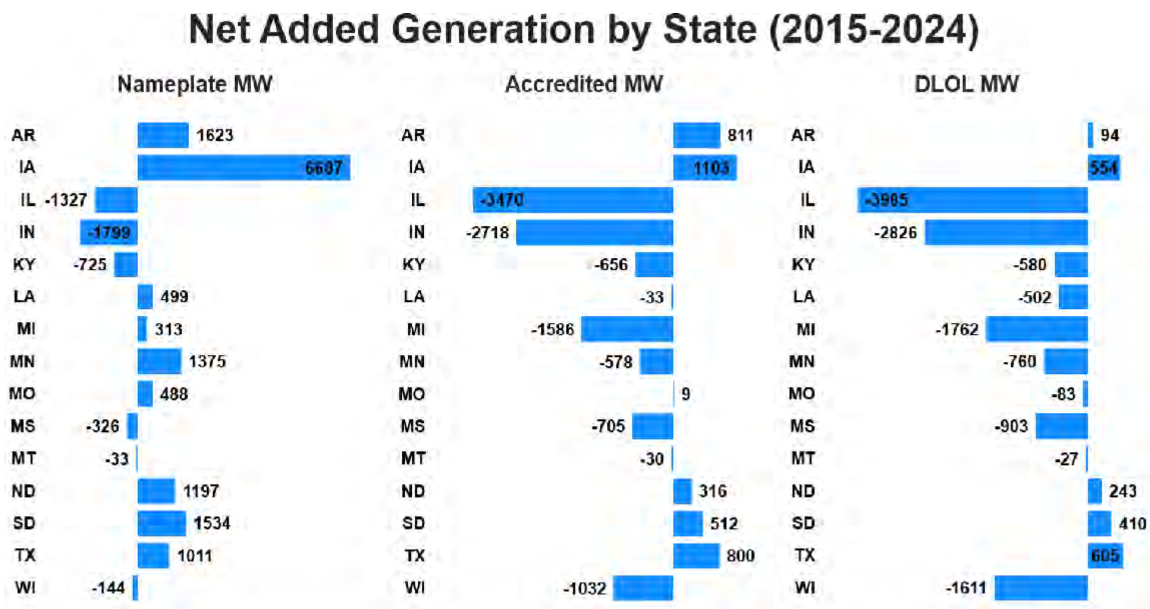


Figure II.C. illustrates a state-by-state comparison of net generation changes in megawatts over the last 10 years in the MISO region, measured by nameplate capacity, current accreditation, and DLOL-based methodology. The DLOL-based capacity accreditation assumptions are based on the fuel-based class average assumptions that are expected to be in place for the 2028/2029 planning year. The 2028/2029 Planning Resource Auction will be the first to utilize the DLOL-based methodology.

Document Content(s)

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Midcontinent Independent System Operator (MISO)	)))))	Order No. 202-25-3

Exhibit to
Motion to Intervene and Request for Rehearing and Stay of
Public Interest Organizations

Filed June 18, 2025

Exhibit 35

Patton MISO Comments

TECHNICAL CONFERENCE COMMENTS OF
DAVID B. PATTON, PH.D.
MISO INDEPENDENT MARKET MONITOR

Meeting the Challenge of Resource Adequacy in RTO and ISO Regions
Docket No. AD25-7-000
June 4-5, 2025

Summary Bullets

- The resource adequacy challenges and risks in MISO are not nearly daunting as portrayed by MISO planning reports or the NERC 2024 Long-Term Reliability Assessment.
- For the first time, MISO has assembled all of the design elements needed to allow its capacity market to facilitate long-term decisions that achieve resources adequacy:
  - Prompt, seasonal market framework;
  - Demand aligned with reliability: reliability-based demand curves; and
  - Supply aligned with reliability: marginal reliability-based resource accreditation (to be implemented in 2028).
- The threats or issues achieving resource adequacy are now not related to the market design or rules, they include:
  - *State regulatory alignment with markets*: states must facilitate planning by their regulated entities that achieve both state policy goals and reliability objectives.
  - *Misalignment of MISO planning and markets*: planning and markets must be well-aligned to prevent uneconomic planned investment from undermining the incentives to invest in resources signaled by the markets. We have substantial concerns in this area.
  - *Market instability:* The most well-designed markets will fail to motivate efficient investment over the long term if the regulatory risk associated with changing market rules is large.
- There are many reasons to be optimistic about long-term resource adequacy in MISO:
  - MISO has made tremendous progress toward an efficient market design that will provide clear, efficient locational capacity price signals.
  - MISO's states and utilities are committed to maintaining the reliability of the system, in addition to meeting state policy goals.
  - I hope to continue to recommend changes to MISO's planning processes to improve their alignment with resource development trends, state goals, and market signals.
  - Hence, I recommend that the Commission not pursue or mandate substantial changes to MISO's capacity market.

WRITTEN STATEMENT OF DAVID B. PATTON, PH.D.
MISO INDEPENDENT MARKET MONITOR

The increase in projected load growth, the transition of the generating portfolio to much higher reliance on intermittent resources, and accelerating retirements of conventional dispatchable resources has increased resource adequacy concerns. I appreciate the opportunity to address questions regarding resource adequacy in the MISO region today.

Current Status of Resource Adequacy and Planning Projections

MISO is more than adequate moving into the Summer of 2025, and we do not have substantial concerns about the MISO region in the near term. The Commission cites the findings in the NERC 2024 Long-Term Reliability Assessment that MISO is at risk of running short of supply as soon as the Summer of 2025. We have reviewed this report and do not believe its results are accurate because it understates MISO's capacity in the areas of demand response, behind-the-meter generation, and firm capacity imports by more than 8 GW. Additionally, they consider potential retirements of coal, oil, and gas-fired resources that have not materialized.

Additionally, it is important to recognize that, unlike some other RTOs, MISO has tremendous import capability that is routinely utilized during tight conditions to supplement its internal resources. During emergency conditions, it has typically imported well over 4 GW of additional supply. Hence, we have no substantial concerns regarding the adequacy of resources in the MISO region in the near term.

The Commission also cites MISO's 2024 Regional Resource Assessment which asserts that 17 GW of new resources will need to be built every year for the next 20 years. For reasons I have documented for MISO and its stakeholders, this is not a credible forecast. MISO planning models assume that virtually all of the new capacity to be built over the next 20 years will be intermittent renewable resources, despite the fact that their reliability value under MISO's future marginal accreditation approach will fall to close to zero.

This is partly why such a massive amount of new capacity are reported to be needed. If one were to assume that participants will rationally build hybrid renewables, storage and dispatchable resources, the 17 GW per year of new resources falls to roughly 2 to 3 GW per year. Some of this demand for resources in the near term is likely to be satisfied by delayed retirements now that MISO's capacity market is beginning to send more efficient price signals to the market participants.

Further, investment in these classes of controllable resources will still allow MISO states to achieve its carbon goals and greatly reduces the transmission needs in the MISO region, which I have also indicated to MISO and its stakeholders.

Achieving Resource Adequacy in the Long-Term in MISO (or any RTO)

Few topics in wholesale electricity markets have engendered the debate and controversy as have resource adequacy. At the outset, it is helpful to review why capacity markets exist. Most RTOs and ISOs minimum planning requirements that correspond to a prescribed level of reliability, the most common of which is the one loss of load event in ten-year standard. The RTOs determine the resources that are needed to meet this standard.

The primary economic issue is that the 1-in-10 reliability standard implies a value of lost load (VOLL) in excess of $200,000 per MWh. Since the RTOs and ISO's do not price shortages in the energy and reserve markets based on a VOLL this high, energy and operating reserve markets will typically not provide enough revenue to keep this maintain capacity margins that will satisfy this reliability standard.

The capacity markets were developed to supplement the RTOs' energy and ancillary services markets to provide the necessary economic signals to inform long-term capacity decisions, including investment, retirement, and maintenance of resources. However, capacity markets are not the only approach for pursuing resource adequacy. In general, there are three primary approaches to achieve adequate resources through competitive wholesale electricity markets:

1. Capacity market – Designed to directly procure a sufficient quantity of capacity to satisfy a specified reliability standard.

   - Pros: Predictably generates the net revenues needed to incent suppliers to invest in new resources and maintain existing resources to satisfy the reliability standard.
   - Cons: Requires more complicated rules related to accreditation of generation and load resources. Poor rules can undermine the performance of the market, e.g., the vertical demand curve that had previously used in the MISO capacity market.

2. Decentralized capacity requirements – Some markets require LSEs to self-supply or procure capacity to satisfy a specified capacity requirement. This is effectively a decentralized capacity market that operates bilaterally.

   - Pros: Increases the likelihood of satisfying the specified reliability standard compared to an energy-only market.

   Cons: Prices and procurements are likely to be much less efficient compared to a centralized capacity market. It is also difficult to model transmission constraints and system requirements as accurately as in a centralized capacity market.

3. Energy-only market – this market relies primarily on expected shortage revenues in the energy and ancillary services markets to motivate investment.

- Pros: Provides strong performance and availability incentives and it is closely aligned with reliability.
- Cons: Capacity levels are likely to be less than needed to satisfy the reliability standard. Even if a very aggressive VOLL is selected to price shortages, higher capacity margins produce less frequent shortages making it difficult to generate sufficient revenue. This market alternative can also produce highly volatile year-to-year costs and revenues that can be hedged by contracts.

If an RTO adopts a reliability standard that must be satisfied, a well-designed capacity market will generally be the most efficient means of doing so. However, MISO has struggled historically to develop an efficient capacity market design on both the supply and demand side. In recent years, most of the design issues have been addressed. MISO has now developed and has or will implement:

- A seasonal capacity market framework that operates in a prompt timeframe, roughly two months before the planning year commences.
- Reliability-based demand curves in 2025 that, for the first time, aligns the market demand with the reliability that the capacity provides.
- Marginal reliability-based capacity resource accreditation, which will be implemented in 2028. This ensures that the relative reliability value of different types of capacity resources is accurately reflected in the market.

Together, these fundamental elements will provide for efficient capacity procurement and prices that will efficiently facilitate investment and retirement decisions to maintain resource adequacy. Many of these decisions are made through utility and state planning processes, and others will be made by unregulated market participants. An efficient capacity market will facilitate both types of decisions.

To illustrate the importance of these design improvements, we can look at the results of MISO's recent 2025/2026 Planning Resource Auction (PRA). This was the first year under MISO's new reliability-based demand curves in its seasonal capacity market. The market cleared at $667 per MW-day in the summer and averaged more than $210 per MW-day for the entire planning year. This reflects almost 90 percent of the Cost of New Entry (CONE) of a gas peaking resources net of the energy and ancillary service net revenues the markets provide. This price level is efficient and reflects the marginal reliability value of resources in MISO because it procured only 2 percent more capacity than the minimum requirement. Importantly, these prices send clear signals to both developers and owners of existing generators regarding the value of resources in the MISO region.

In contrast, under the vertical demand curve that MISO had previously utilized, prices would have cleared at roughly $20 per MW-day. These prices would provide little incentive to build new units or maintain older existing units. We have shown in prior reports that the vertical demand curve contributed to large quantities of retirements of merchant resources and contributed to the tight capacity conditions that currently exist in the Midwest region.

Given MISO's tremendous progress in the design and implementation of its capacity market, we see no benefit in considering fundamental reforms to MISO's capacity market or alternative resource adequacy approaches.

Threats or Challenges to Resource Adequacy in MISO

Although it is essential for MISO's capacity market to be well-designed and competitive so it will produce efficient economic signals to support resource adequacy, there are other issues outside of the market that must be addressed or coordinated.

First, because most of the load is served by regulated utilities in MISO, state policy and regulation will play a key role in achieving resource adequacy. Although many of the states in MISO have aggressive carbon reduction goals, I believe they are also committed to reliability. Mandating and overseeing planning processes by regulated utilities that are designed to achieve both environmental and reliability objectives will be critical. In my discussions with states and with the regulated utilities, I believe they are committed to both objectives. The reforms MISO has implemented, particularly the transition to marginal accreditation, will inform these processes and facilitate success in achieving both objectives.

Second, MISO's planning processes must be well-aligned with its markets. While MISO does not determine the future development of resources in the region, it projects such development and load growth that together determine the MISO's transmission needs. Ultimately, therefore, these planning process help determine the future transmission investment in the region. Transmission investment that occurs outside of the market must be well-coordinated with investment in resources that are in-part or fully facilitated by the market. Excessive uneconomic investment in transmission that is guaranteed by regulated customers will undermine the incentives to invest in resources that can address the same transmission bottlenecks.

For example, strategically located storage resources in generation pockets can charge at low or negative prices when intermittent resources produce at very high levels would otherwise need to be curtailed to avoid overloading a transmission constraint. MISO's transmission congestion can create profitable opportunities for resources to site in these types of areas at no cost to regulated customers in order to relieve the congestion. Hence, it is critical to avoid excessive investment in uneconomic transmission, which I believe requires independent oversight given the concerns the IMM has identified in recent planning cycles.

Ideally, such oversight would be provided by the Commission but, unfortunately, FERC does not review or approve the portfolios of new transmission emerging from MISO's transmission planning process before these costs are embedded in transmission rates. This raises the potential for uneconomic transmission investment to raise RTOs' transmission rates to unreasonable levels. We believe the Commission should consider solutions to address this regulatory gap.

Finally, the most well-designed markets will fail to motivate efficient investment over the long term if the regulatory risk associated with changing market rules is large. This is because developers will discount future expected market revenues if they believe there is a reasonable probability that the RTO or the Commission will make substantial changes to the market rules or eliminate the market. Given the progress MISO has made to improve the design and performance of the capacity market, I recommend that the Commission not pursue or mandate substantial changes to it.

This concludes my written statement.

Document Content(s)

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Midcontinent Independent System Operator (MISO)	)))))	Order No. 202-25-3

Exhibit to
Motion to Intervene and Request for Rehearing and Stay of
Public Interest Organizations

Filed June 18, 2025

Exhibit 36

MISO Elliott Max. Gen. Event Overview

Overview of Winter Storm Elliott December 23, Maximum Generation Event

Reliability Subcommittee

January 17, 2023

All data included in this presentation is preliminary as of January 12, 2023, and is subject to change

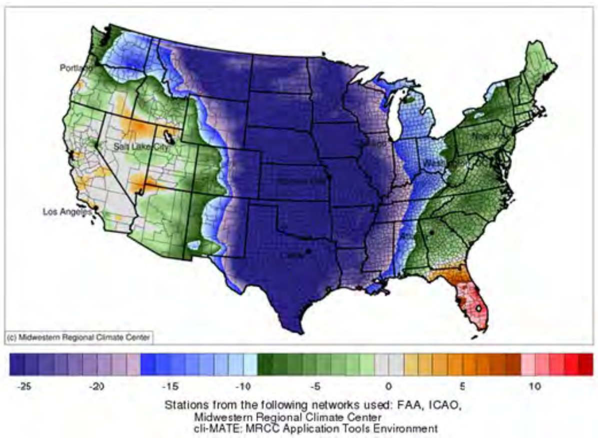
Executive Summary

- Winter Storm Elliott delivered rapid, extreme cold to the Eastern Interconnect in December as well as gas supply challenges and historic load forecast volatility
- MISO had enough capacity to manage uncertainty while serving exports to our neighbors
- There were no customer interruptions
- Lessons learned from Winter Storm Uri contributed to successful operations during Elliott; subsequent analysis will lead to additional lessons learned
- Load forecast uncertainty and fuel supply availability are examples of the increasing uncertainty being addressed under MISO's Reliability Imperative

On December 23, Winter Storm Elliott brought significantly below normal temperatures to MISO, driving high demand for heating; drawing similarities to Winter Storm Uri in 2021

WINTER STORM URI
FEBRUARY 12-18, 2021

Average Temperature:
Departure from 30-Year Normal

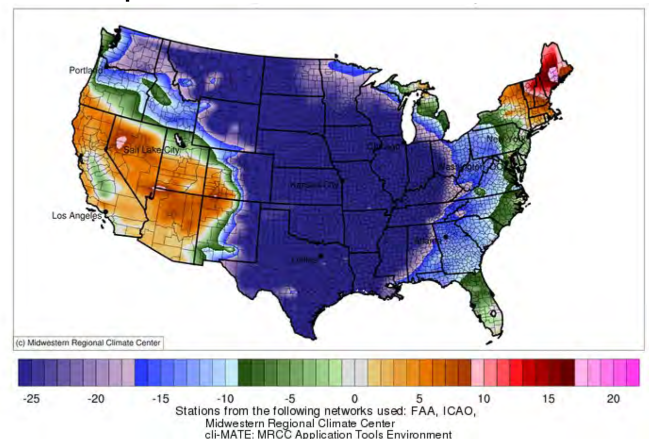


System Peak Load	103 GW
Unplanned Outages *(South)*	18 GW
Scheduled Load Modifying Resources*	531 MW
RDT Max Flow & Direction	3.2 GW N-S

Precipitation: *Abundant snowfall across MISO's South and Central regions*

WINTER STORM ELLIOTT
DECEMBER 23, 2022

Average Temperature:
Departure from 30-Year Normal



System Peak Load	107 GW
Unplanned Outages *(additional from previous day system-wide)*	19 GW
Scheduled Load Modifying Resources*	1.2 GW
RDT Max Flow & Direction	2.7 GW N-S

Precipitation: *Modest snowfall across MISO's North and Central regions*

**Load Modifying Resources requested for the peak load hour for the noted storm time period*

Emergency operations were required to access additional capacity to mitigate uncertainty and support our neighbors

ALERTS

Cold Weather Alert (South)
DEC 22, noon EST   DEC 26, noon EST

Unseasonably cold weather expected across MISO

WARNINGS

Maximum Generation Warning (South)
DEC 23, 9:15 a.m.   12:45 p.m. EST

Conservative Operations (South)
DEC 23, 9:15 a.m. EST   DEC 26, midnight EST

Tightened conditions due to unit trips and failures to start (~2 GW), higher-than-forecast South load (~2.5 GW), and reduced RDT flow limit N-S (to 1.5 GW)

Maximum Generation Warning (Footprint)
DEC 23, 4:30 p.m.

Conservative Operations (Footprint)
DEC 23, 9 p.m. EST   DEC 24, noon EST

Tighter conditions due to higher-than-forecast system-wide loads, forced outages driven primarily by fuel supply issues and units that failed to start

EVENTS

Maximum Generation Event, Step 1b (Footprint)
DEC 23, 5:30 p.m.

Tight conditions worsened with real-time transmission congestion and diminishing generation deliverability

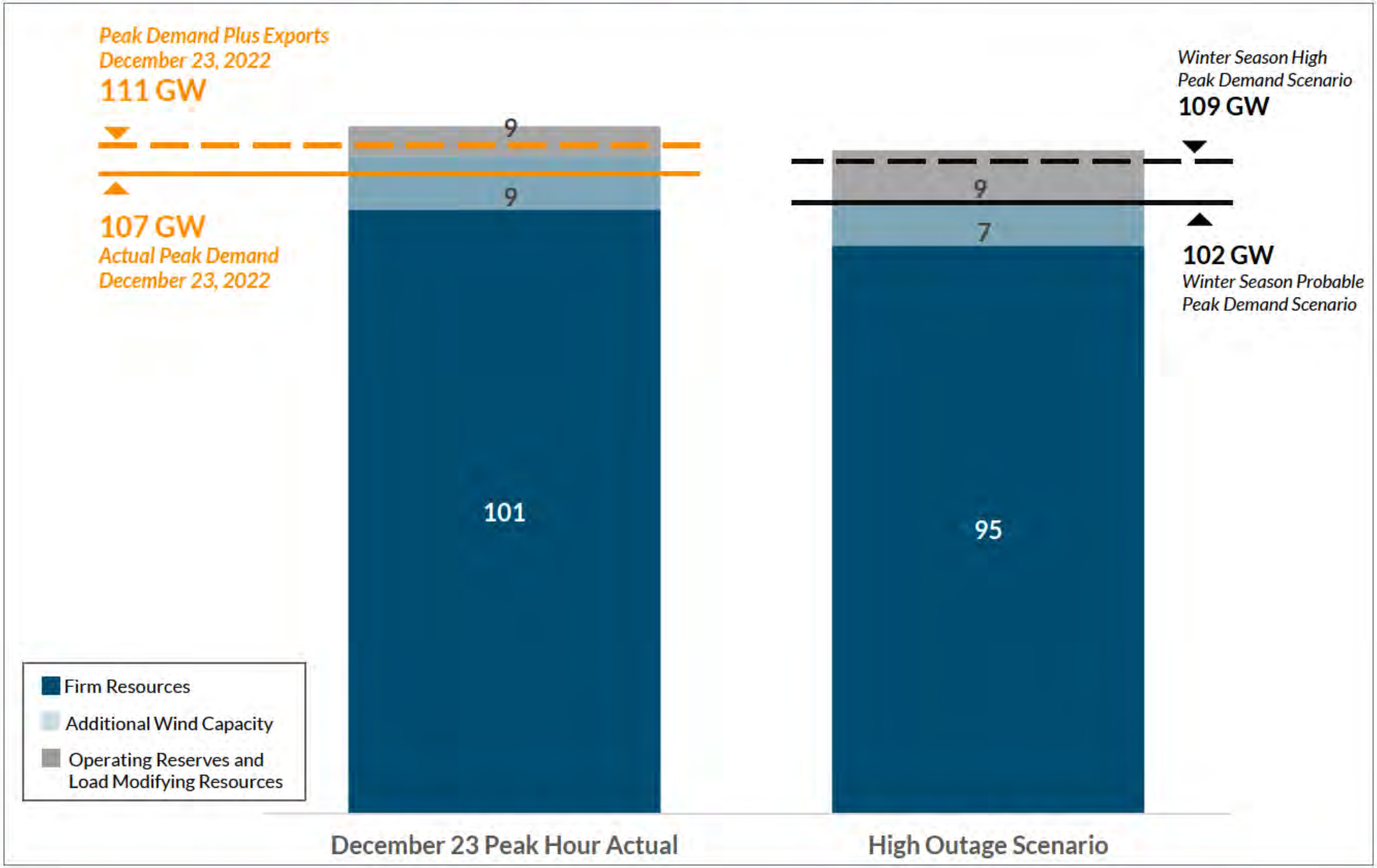
---

Maximum Generation Event, Step 2a (Footprint)
DEC 23, 6 p.m.   9 p.m. EST

Emergency procedures allowed access to demand response, which reduced the peak demand

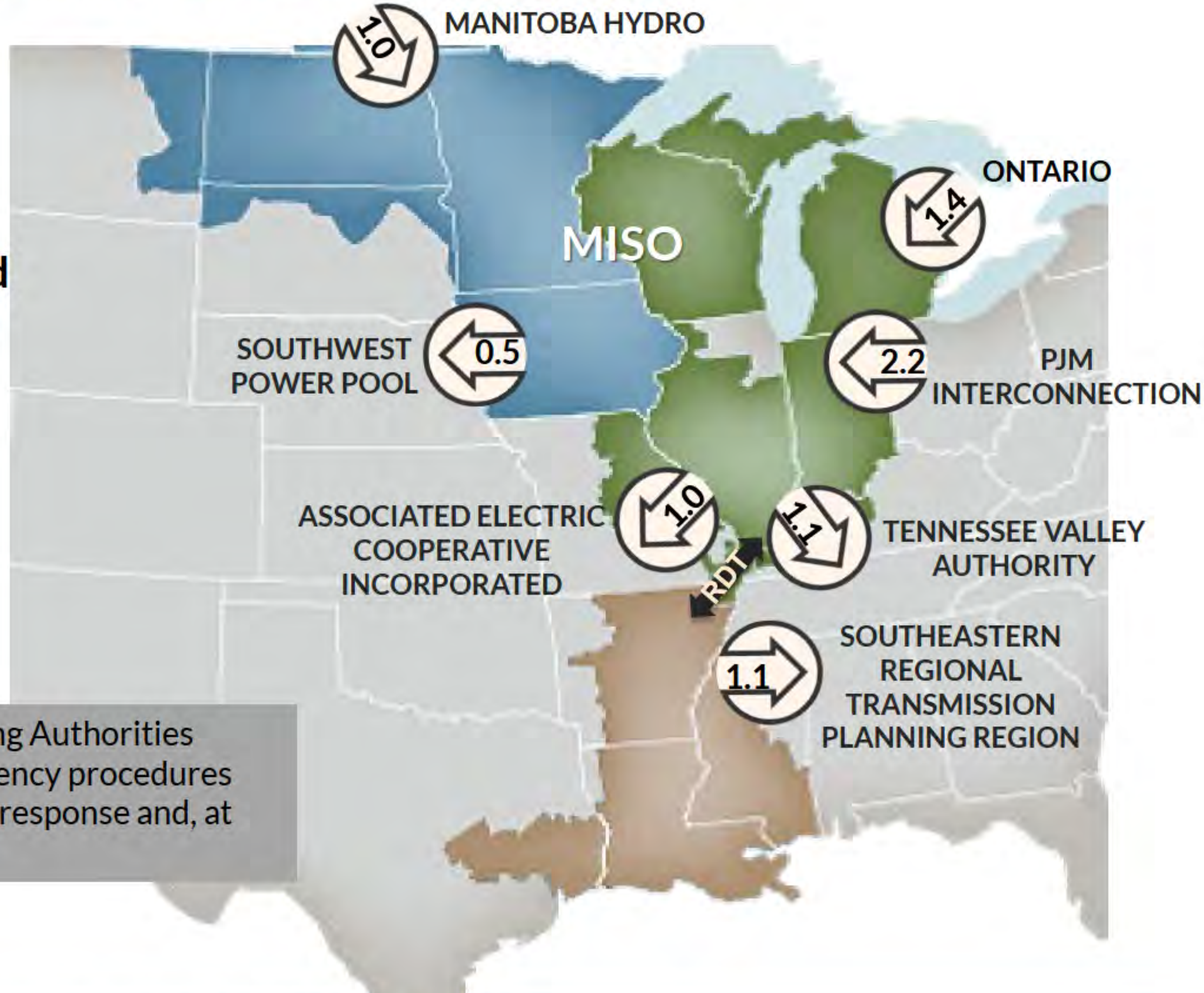
Note: All times indicate the effective time of each declaration

Reserve capacity was closely monitored, and exports would have been curtailed if conditions had worsened



MISO consistently exported power to southern neighbors with a maximum value of nearly 5 GW

Net Scheduled Interchange (GW)

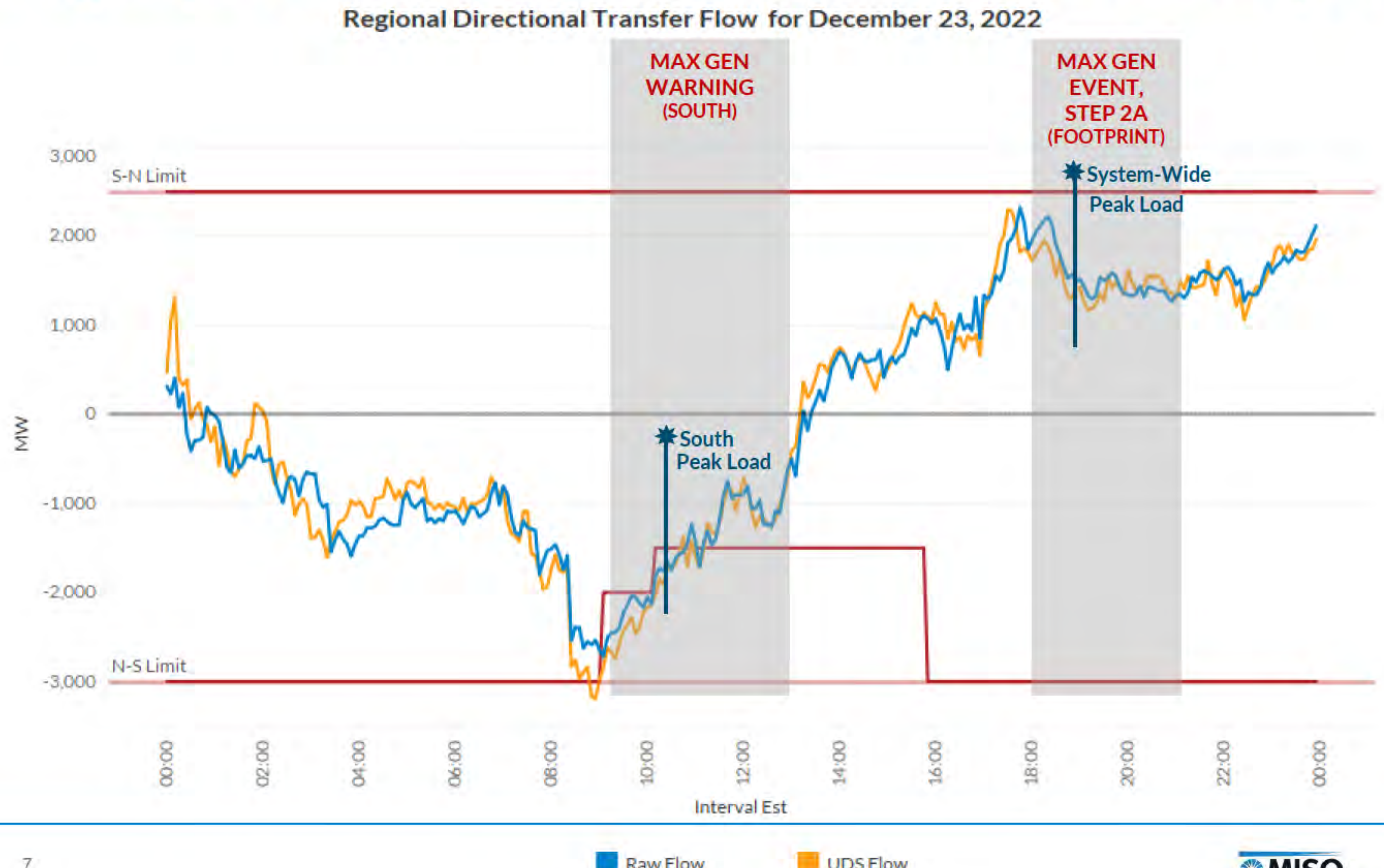


Multiple Balancing Authorities employed emergency procedures utilizing demand response and, at times, load shed

Image represents average flows into and out of MISO December 23, 2022

RDT = Regional Directional Transfer, which has a North-South limit of 3.0 GW and South-North limit of 2.5 GW

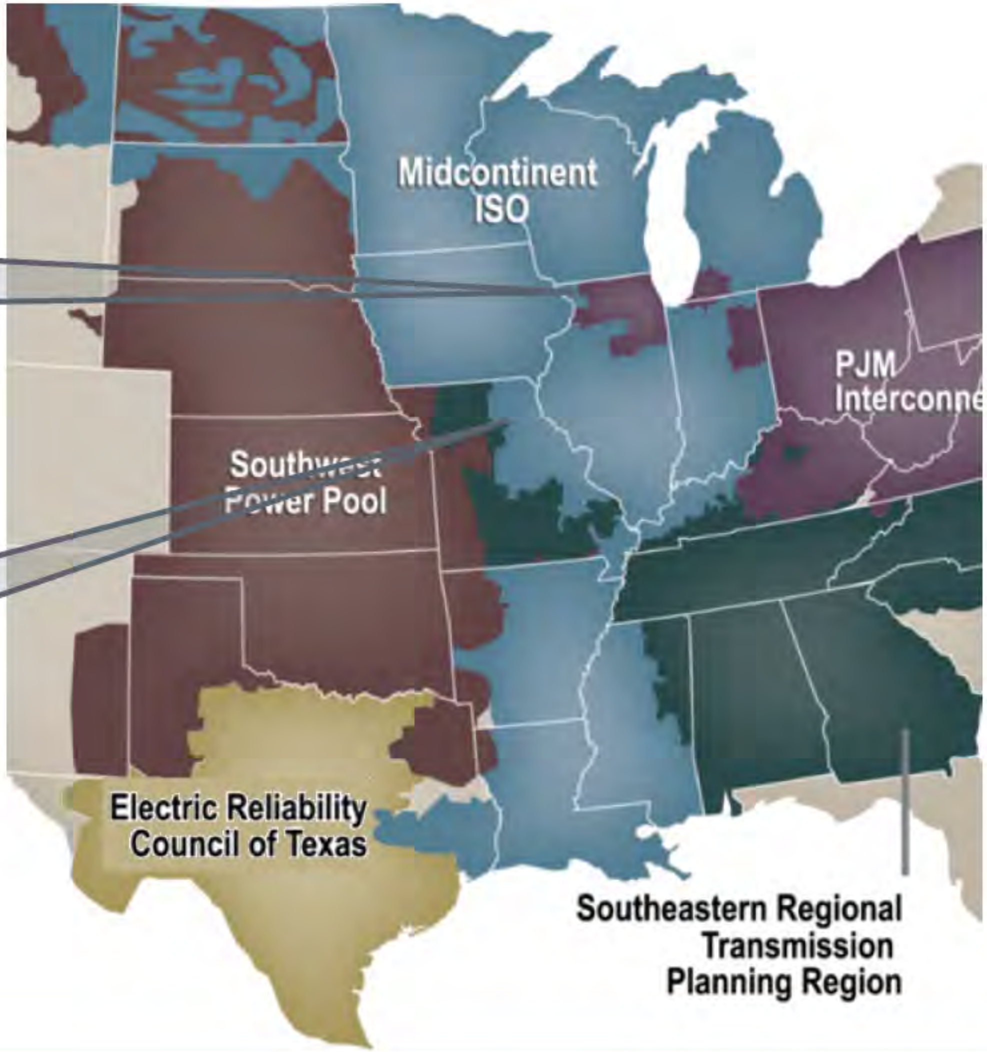
MISO complied with Joint Parties requests to reduce flows by 1,500 MW during the morning peak, which contributed to an emergency declaration in the South and a recall of non-firm exports



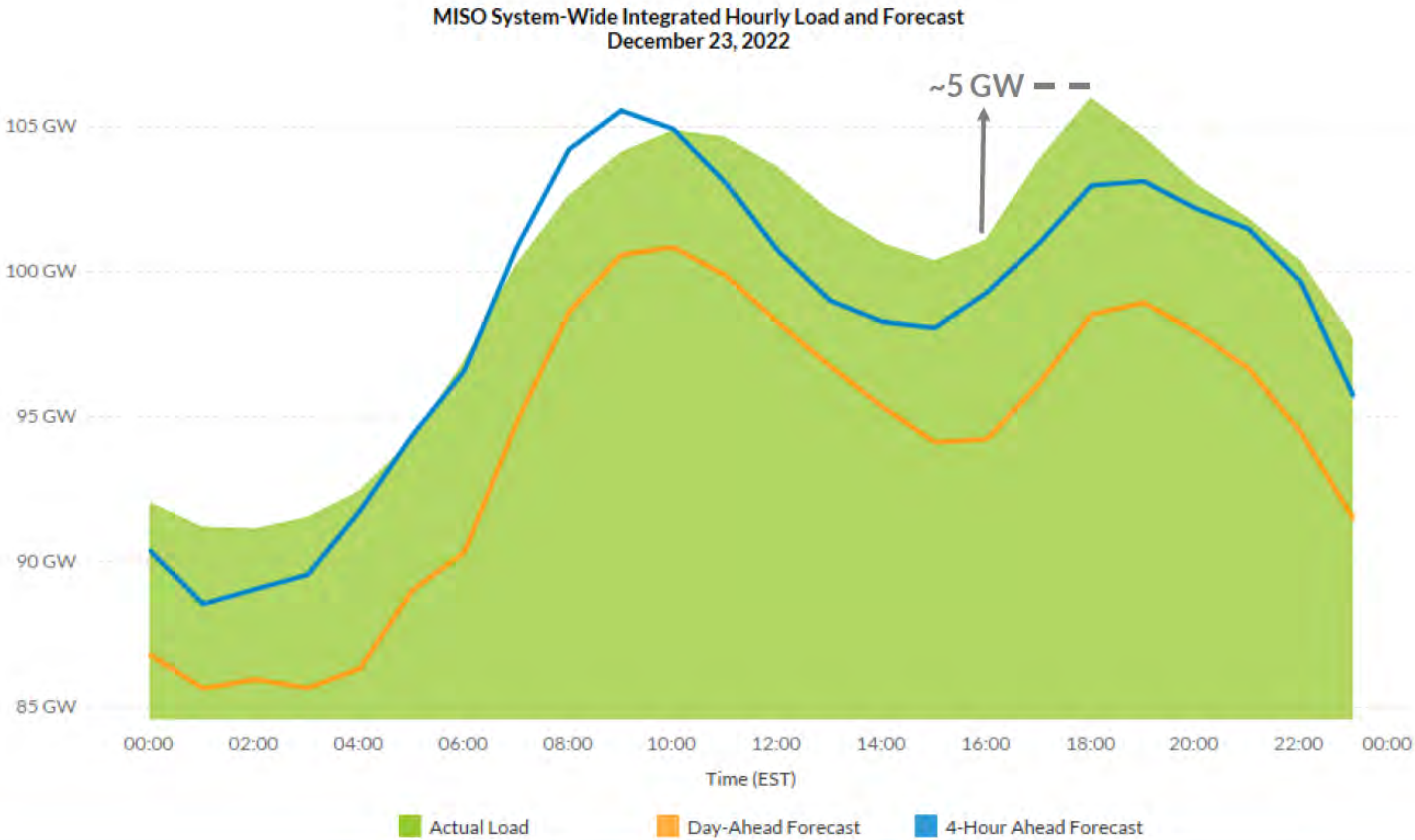
Two local transmission emergencies were declared to manage severe congestion on transmission lines

Local Transmission Emergency
SE Wisconsin
6:45 p.m. – 8 p.m. EST
December 23
(No customer interruptions)

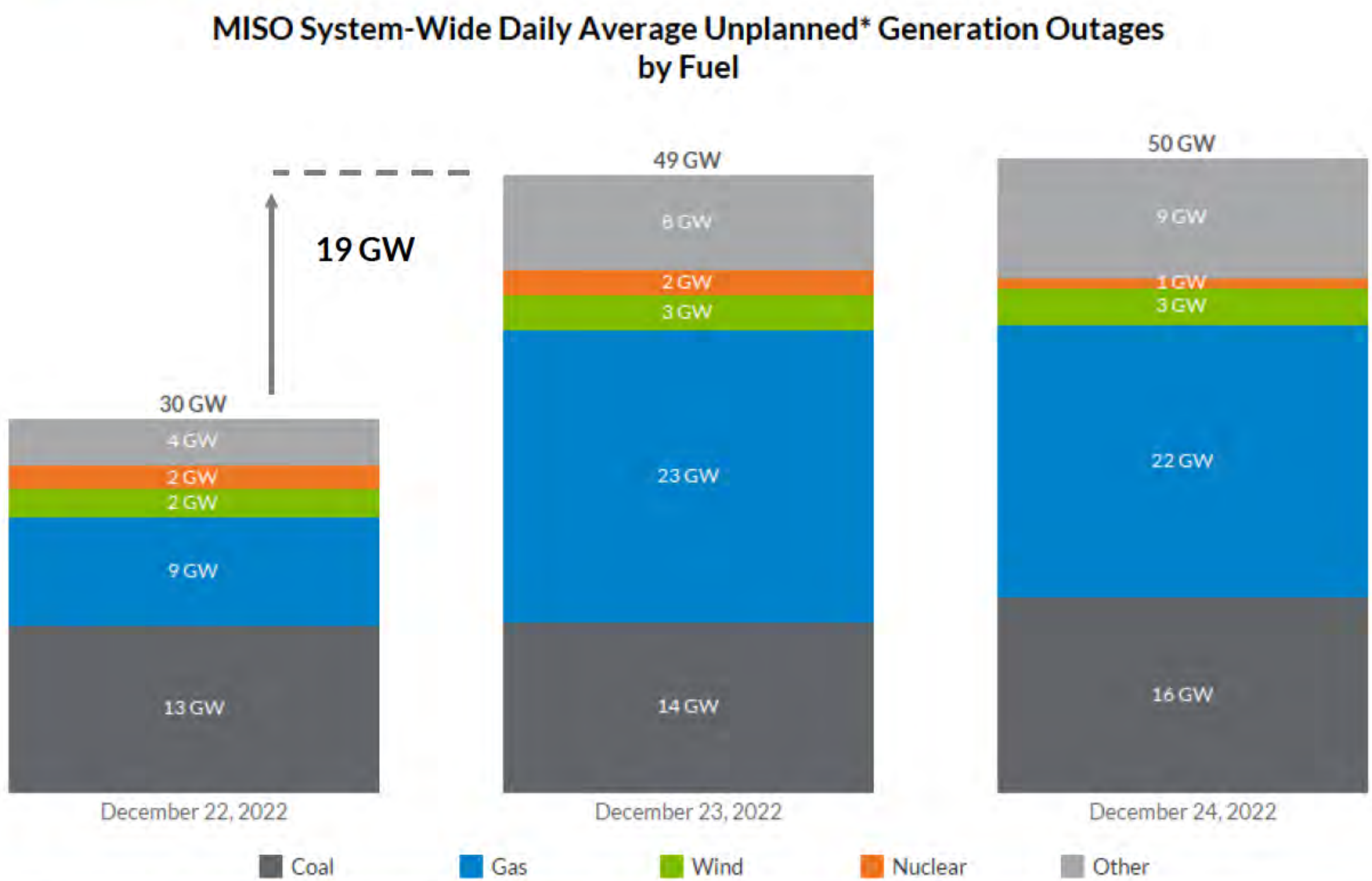
Local Transmission Emergency
Central Missouri
6:27 p.m. – 8 p.m. EST
December 23
(No customer interruptions)



Abnormally high load forecasting errors occurred due to a lack of historical data for similar extreme conditions in December



Gas supply availability contributed to increased unplanned outages, particularly in the afternoon, that pushed MISO into emergency procedures

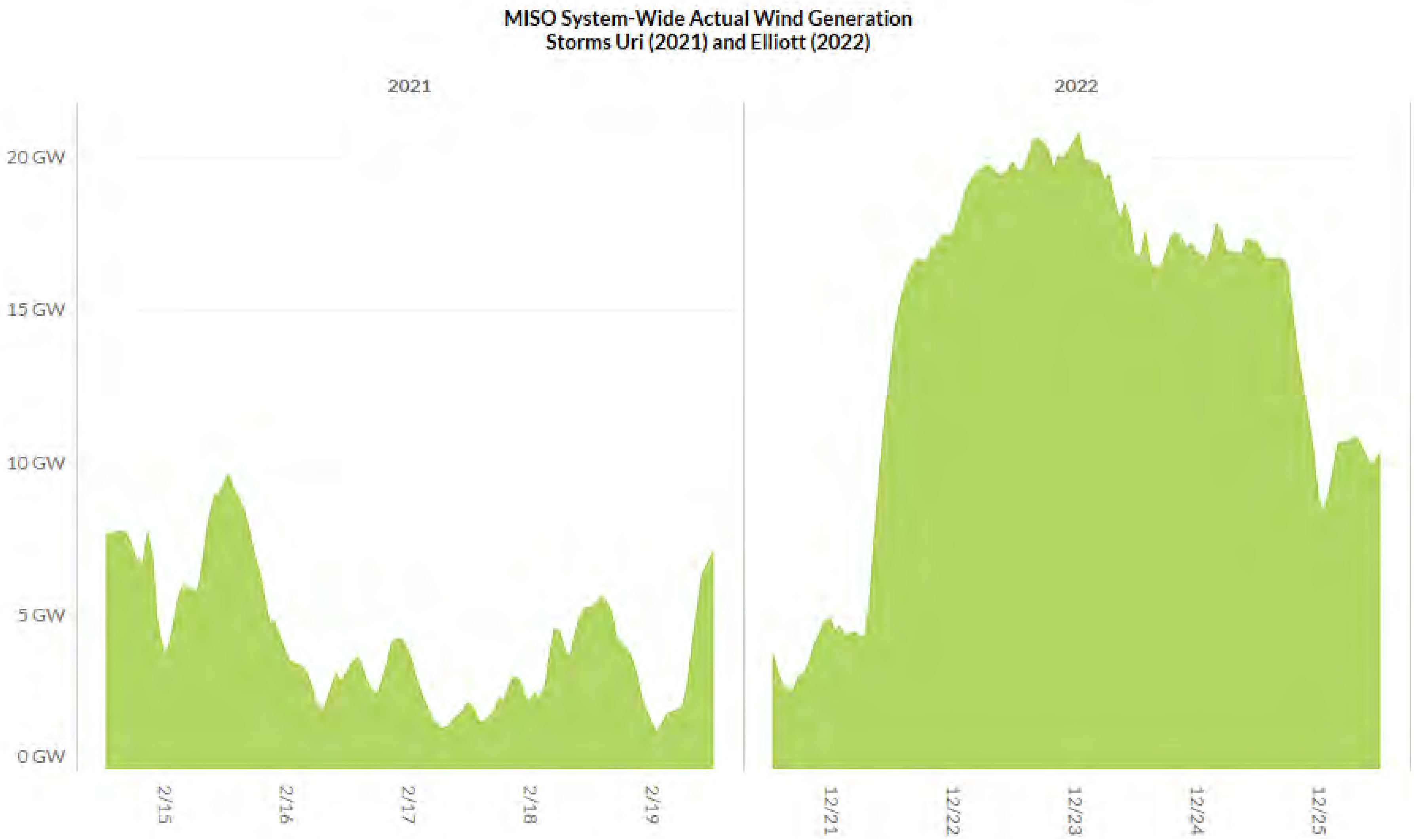


Unplanned = forced outages and derates

Charts reflect data in the CROW outage system on January 5, 2023

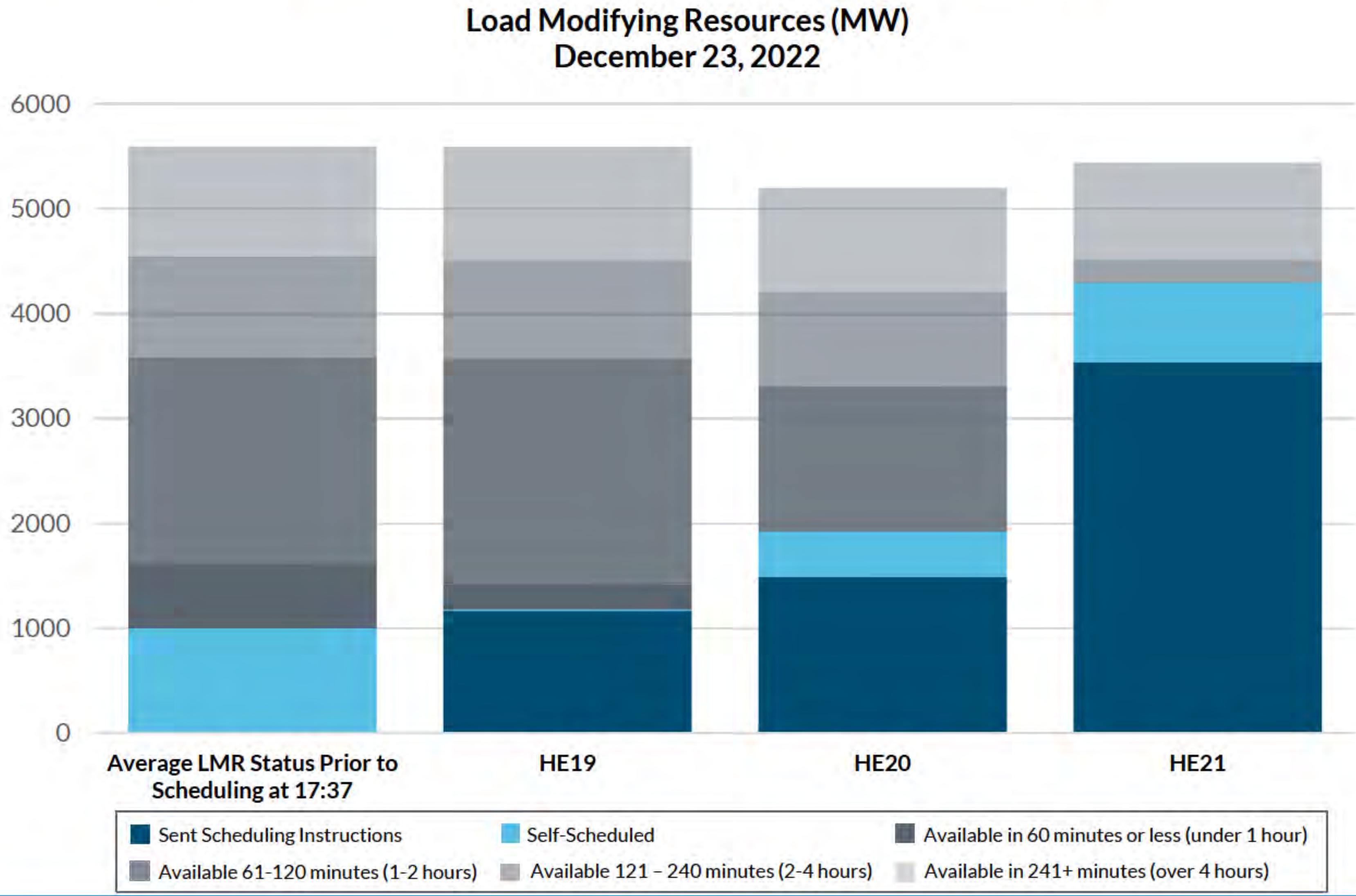
Wind often reported as derated over the time period

Wind production remained high during Winter Storm Elliott, providing support to the transmission system



MISO

Requested 3 GW of Load Modifying Resources at 17:37 to meet increasing load and continue exports to neighbors



MISO

While each storm is unique, lessons learned from Winter Storm Uri in 2021 contributed to successful operations during Elliott

REFINED WINTER READINESS ACTIVITIES

- Increased focus on extreme scenarios
- Improved understanding of generator winter preparedness through coordinated seasonal assessment and fuel and consumables data requests
- Implemented cold weather-specific operator drills in addition to emergency procedure drills and winter readiness workshops

PROCESS IMPROVEMENTS

- Process Improvements to Unit Commitment Processes and Operator Situational Awareness improved our ability to respond to changing risk profile during the operating day

IMPROVED COORDINATION

- Improved coordination activities with our neighbors that resulted in quicker decision making during the storm

View the complete February Arctic Event report on the MISO website

Appendix

MISO's operating procedures ensure reliability and gain access to additional resources during extreme situations

MARKET CAPACITY EMERGENCY PROCEDURE STEPS

MAXIMUM GENERATION

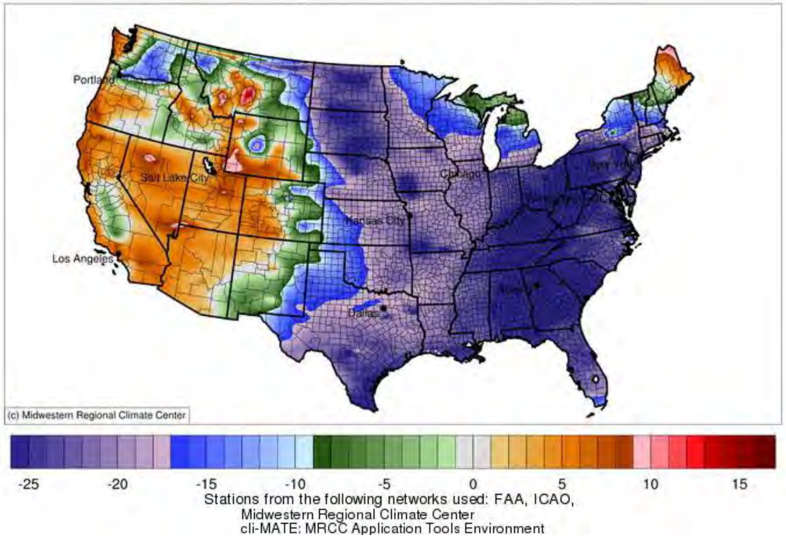
Step	Action	Pricing
Normal Operations		Normal Pricing
Capacity Advisory	Advance notice of forecasted capacity shortage, requests Stakeholders update offer data	
Alert	Define boundaries/suspend maintenance	Emergency Pricing Tier 0
Warning	Schedule in external resources, curtail export transactions, activate reconfiguration	Emergency Pricing Tier I Offer Floor
Event Step 1	Commit emergency resources, declare NERC (Energy Emergency Alert) EEA 1, activate emergency limits	
Event Step 2	Declare NERC EEA 2, implement Load Modifying Resources (LMRs), Load Management Measures (LMMs) Stage 1, commit Emergency Demand Response (EDR) resources, emergency energy purchases, public appeals	Emergency Tier II Offer Floor
Event Step 3	Utilize operating reserves and LMMs Stage 2	
Event Step 4	Reserve call and emergency reserve purchases	
Event Step 5	Declare NERC EEA 3, firm load shed, and set Locational Marginal Prices (LMPs) and Market Clearing Prices (MCPs) to the VOLL	Value of Lost Load (VOLL) Pricing
Termination	Terminate Max Gen and possibly Capacity Advisory	Normal Pricing

Data Source: SO-P-EOP-00-002 Rev 14 MISO Market Capacity Emergency

Winter Storm Elliott continued to impact the Eastern Interconnect through December 25

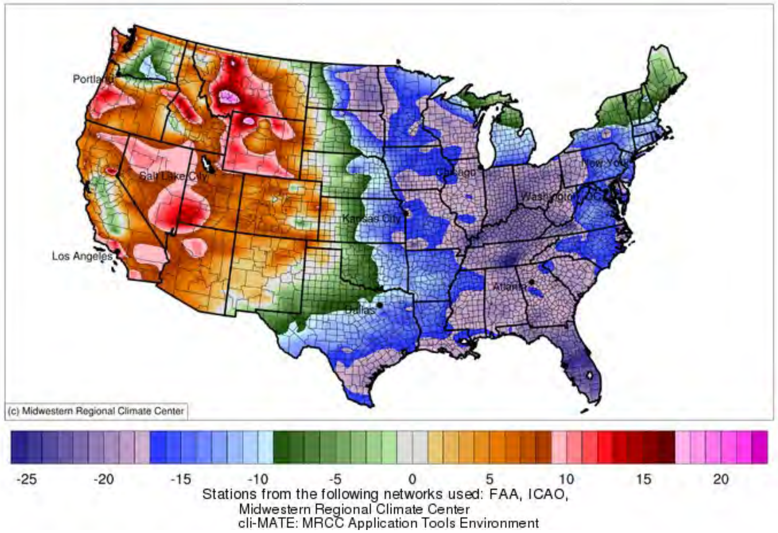
WINTER STORM ELLIOTT DECEMBER 24, 2022

Average Temperature:
Departure from 30-Year Normal

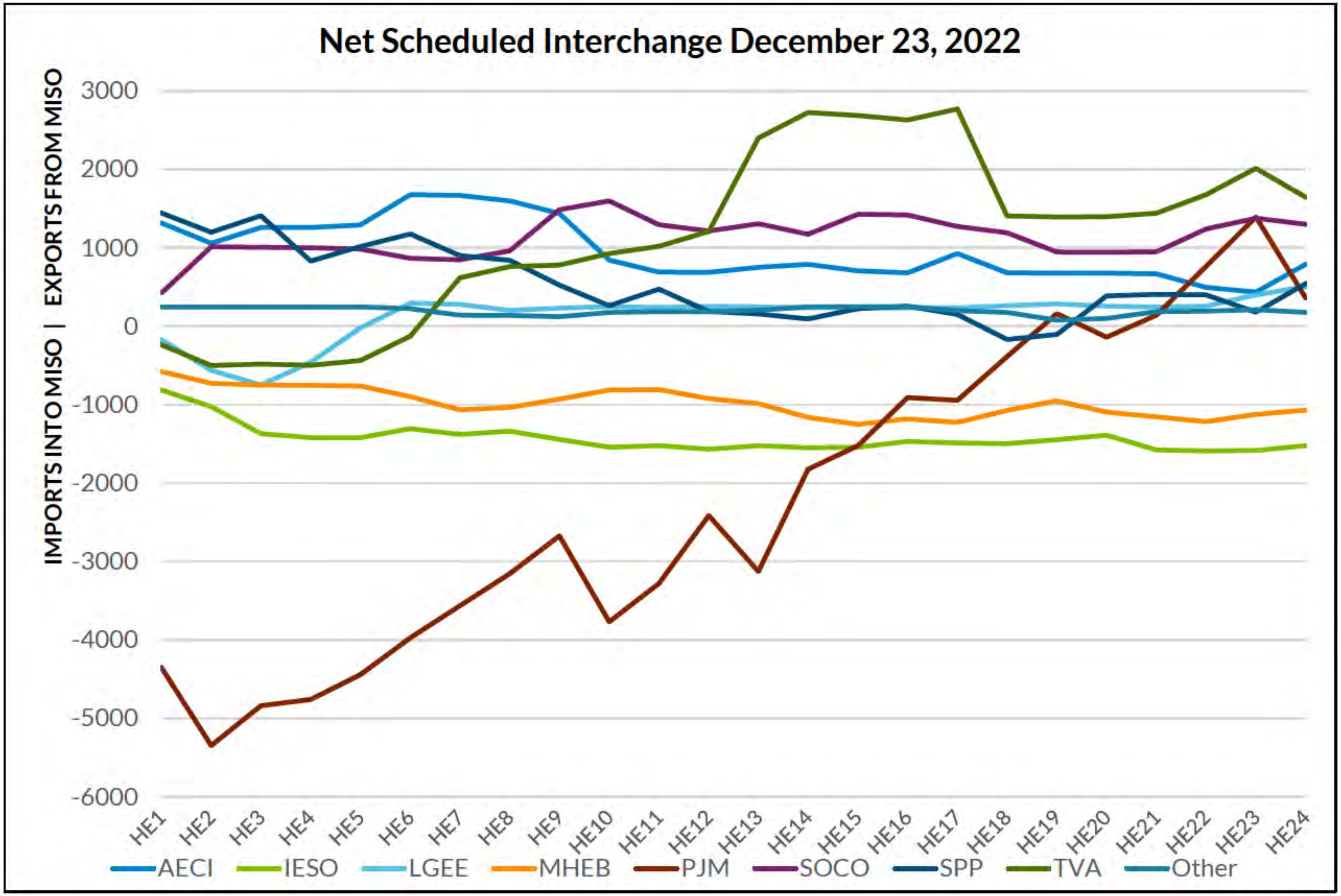


WINTER STORM ELLIOTT DECEMBER 25, 2022

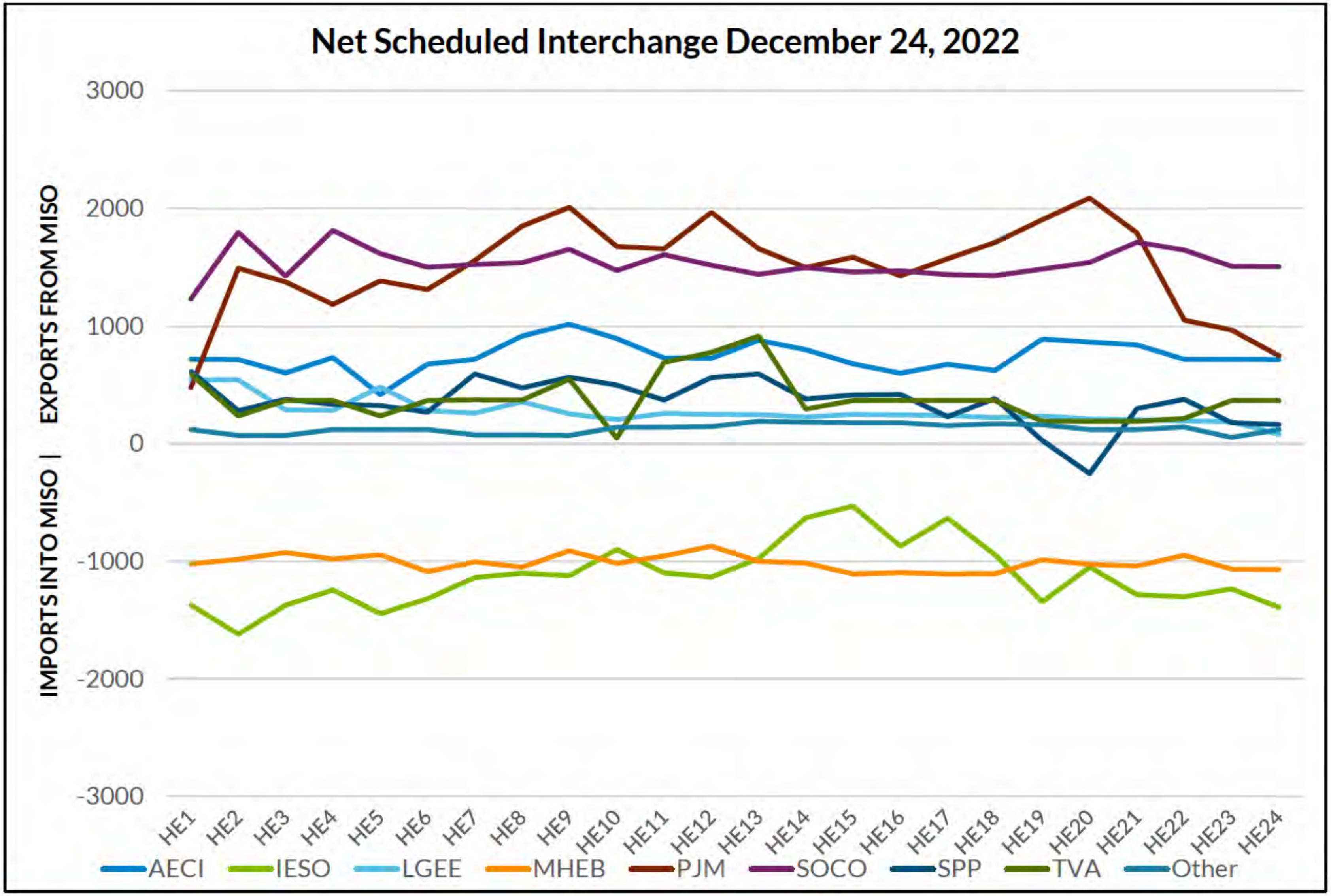
Average Temperature:
Departure from 30-Year Normal



MISO maintained its support for neighbors December 23-24



MISO maintained its support for neighbors December 23-24



BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c)	)	
Emergency Order: Midcontinent	)	Order No. 202-25-3
Independent System Operator	)	
(MISO)	)	
	)	

Exhibit to
Motion to Intervene and Request for Rehearing and Stay of
Public Interest Organizations

Filed June 18, 2025

Exhibit 37

MISO 2025-2026 CIL/CEL Final Results

2025-2026 PY Seasonal CIL/CEL Final Results

LOLE Working Group

October 24, 2024

Corrected Slides 6 & 17
10/24/2024

Purpose & Key Takeaways

Purpose:

Present the final Seasonal CIL/CEL Results for Planning Year 2025-2026

Key Takeaways:

- Highlight and discuss changes between the preliminary and final results due to stakeholder feedback
    - Generation and load was adjusted in the Summer 2025 model in LRZ 3, which resulted in a rerun of the Summer 2025 CIL/CEL model for LRZs 1-7
    - Line ratings were adjusted in LRZ 6 (Gibson – Douglas – Francisco) in the Summer 2025 model and resulted in a rerun of the Summer 2025 model for LRZ 7
- Finalize Planning Year 2025-2026 CIL/CEL results. It is important to note that a change in Controllable Export amounts could adjust results before the March 2025 Planning Resource Auction

Changes between Preliminary Results and Final Results

Season	Preliminary	Final	Reason
Summer 2025 Zone 1 CIL	2,897	6,025	Iowa LRZ 3 Load and Generation Update
Summer 2025 Zone 2 CIL	4,200	4,370	Iowa LRZ 3 Load and Generation Update
Summer 2025 Zone 3 CIL	5,274	5,518	Iowa LRZ 3 Load and Generation Update
Summer 2025 Zone 4 CIL	8,542	8,649	Iowa LRZ 3 Load and Generation Update
Summer 2025 Zone 5 CIL	3,403	4,117	Iowa LRZ 3 Load and Generation Update
Summer 2025 Zone 6 CIL	8,469	8,650	Iowa LRZ 3 Load and Generation Update
Summer 2025 Zone 7 CIL	2,973	3,579	Iowa LRZ 3 Load and Generation Update Gibson – Douglas – Francisco Line Rating Update
Summer 2025 Zone 1 CEL	3,418	3,991	Iowa LRZ 3 Load and Generation Update
Summer 2025 Zone 2 CEL	4,954	4,614	Iowa LRZ 3 Load and Generation Update
Summer 2025 Zone 3 CEL	1,272	4,655	Iowa LRZ 3 Load and Generation Update
Summer 2025 Zone 4 CEL	3,751	4,460	Iowa LRZ 3 Load and Generation Update
Summer 2025 Zone 6 CEL	6,866	6,881	Iowa LRZ 3 Load and Generation Update
Summer 2025 Zone 7 CEL	6,250	5,716	Iowa LRZ 3 Load and Generation Update

2025-2026 PY Zonal Import Ability Results

LRZ	Summer ZIA (MW)	Fall ZIA (MW)	Winter ZIA (MW)	Spring ZIA (MW)
1	6,023	5,688	5,575	6,396
2	4,370	6,537	6,435	6,439
3	5,460	7,704	5,785	7,726
4	7,757	7,013	6,457	7,373
5	4,117	4,679	4,922	4,453
6	8,366	8,672	7,690	9,176
7	3,569	5,115	4,762	5,166
8	2,358	5,675	3,432	6,085
9	4,361	4,741	4,418	4,855
10	4,474	4,508	3,458	4,365

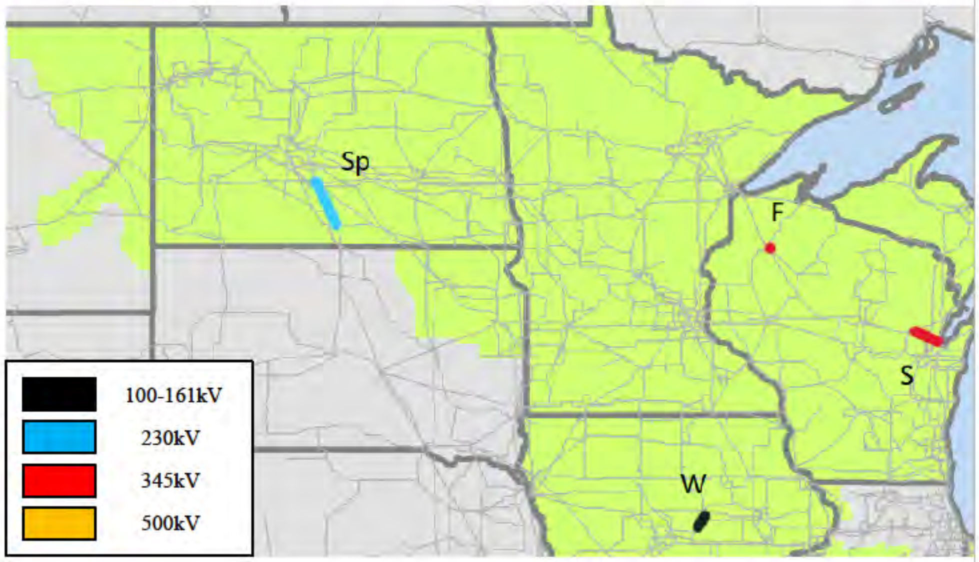
2025-2026 PY Zonal Export Ability Results

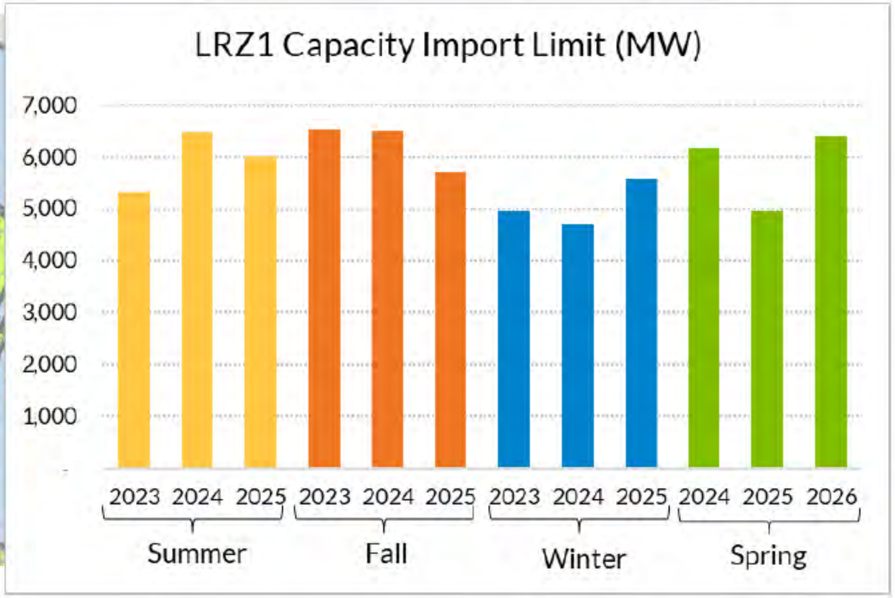
LRZ	Summer ZEA (MW)	Fall ZEA (MW)	Winter ZEA (MW)	Spring ZEA (MW)
1	3,993	6,167	3,593	5,285
2	4,614	4,259	4,793	6,119
3	4,713	5,924	7,480	6,039
4	5,352	5,069	5,531	5,880
5	3,939	5,816	4,814	5,797
6	7,165	5,471	1,911	6,706
7	5,726	5,168	5,712	5,499
8	6,509	4,219	3,783	3,724
9	4,286	4,173	3,618	4,146
10	2,097	3,164	2,028	3,072

Planning Year 2025-2026 CIL Final Results

Capacity Import Limits
Zone 1: MN, MT, ND, SD and WI

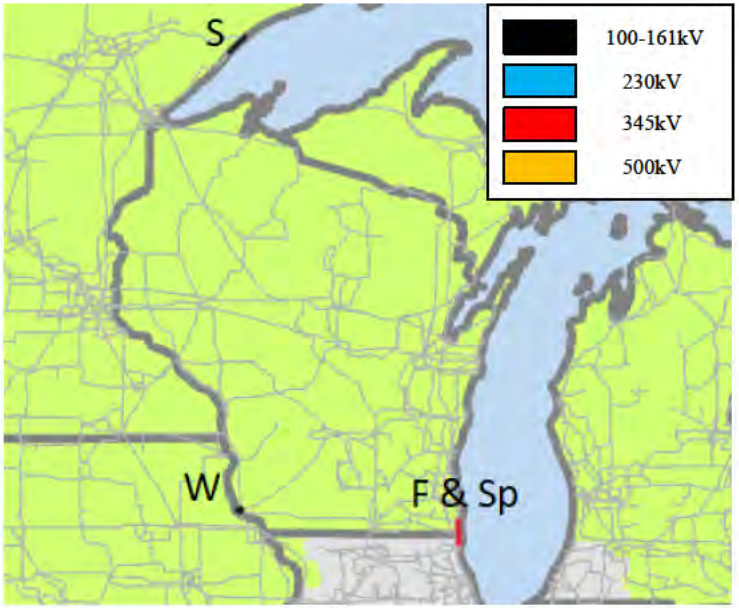
LRZ1	Monitored Element	Contingency	GLT	RDS	ZIA	CIL
Summer 2025	North Appleton - Werner West 345 kV	North Appleton - Morgan 345 kV	10%	460MWx2	6023	6025
Fall 2025	Stone Lake 345/161 kV Transformer	Arrowhead 345/230 kV Transformer	None	515MWx2	5688	5690
Winter 2025-26	Laurel - Jasper 161 kV	Story County - Fernald 161 kV	None	601MWx2	5575	5577
Spring 2026	Mound City - Bismark 230 kV	Ft Thompson 1 - Chapelle 345 kV	None	352MWx2	6396	6398

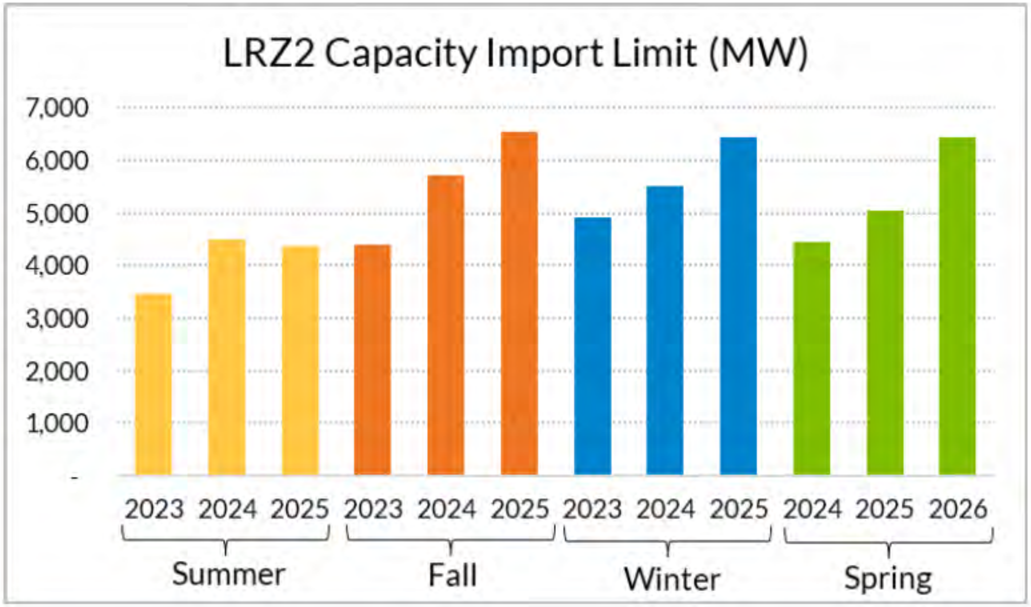




Capacity Import Limits
Zone 2: WI and MI

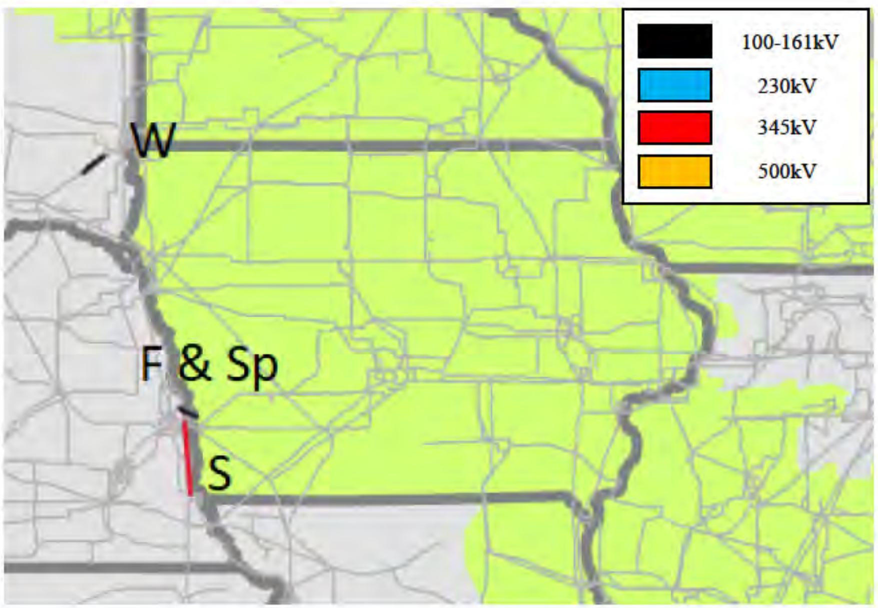
LRZ2	Monitored Element	Contingency	GLT	RDS	ZIA	CIL
Summer 2025	Two Harbors - Silver Bay 115 kV	Taconite Harbor - LTV Hoyt Lakes 115 kV	None	439MWx2	4370	4370
Fall 2025	Zion - Pleasant Prairie 345 kV	Zion EC - Pleasant Prairie 345 kV	None	666MWx2	6537	6537
Winter 2025-26	Nelson Dewey 161/138 kV Transformer	Hickory Creek - Hill Valley 345 kV	None	1000MWx2	6435	6435
Spring 2026	Zion EC - Pleasant Prairie 345 kV	Zion - Pleasant Prairie 345 kV	None	624MWx2	6439	6439

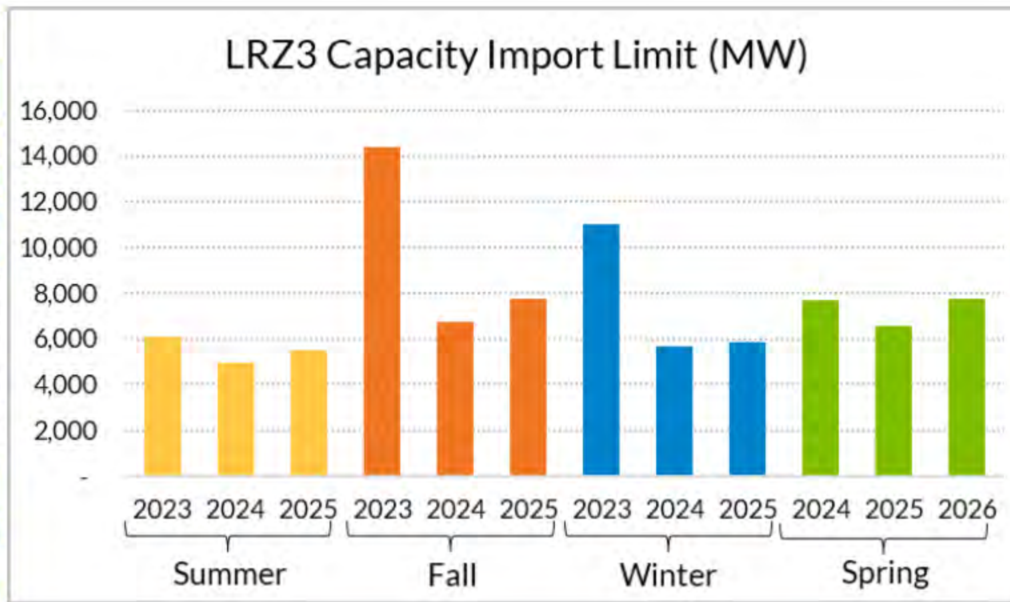




Capacity Import Limits
Zone 3: IA

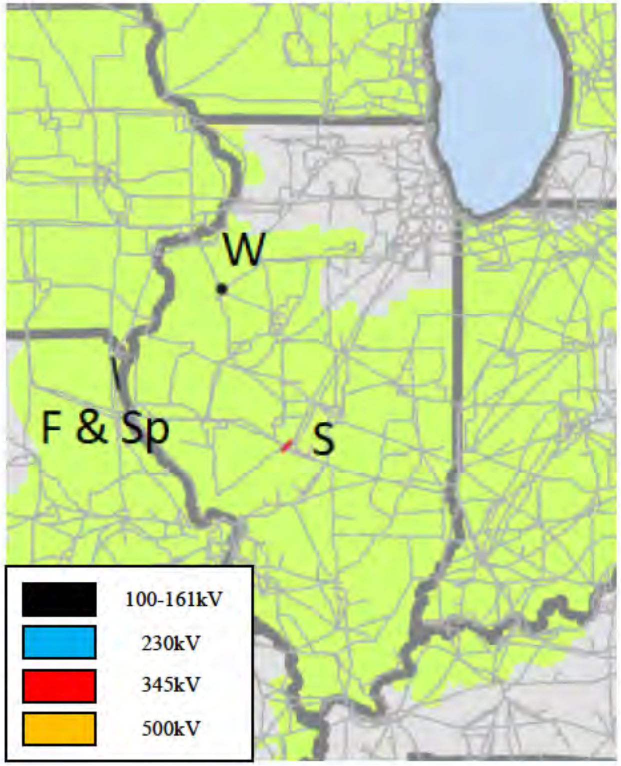
LRZ3	Monitored Element	Contingency	GLT	RDS	ZIA	CIL
Summer 2025	Sub 3458 (Nebraska City) - Sub 3456 345 kV	Sub 3455 - Sub 3740 345 kV	None	302MWx2	5460	5518
Fall 2025	Sub 1211 - Sub 701 161 kV	Sub 3456 - Council Bluffs 345 kV	None	177MWx2	7704	7766
Winter 2025-26	Split Rock 7 - Split Rock 4 115 kV	Split Rock 3 - Sioux City 345 kV	None	1000MWx2	5785	5853
Spring 2026	Sub 1211 - Sub 701 161 kV	Sub 3456 - Council Bluffs 345 kV	None	138MWx2	7726	7784

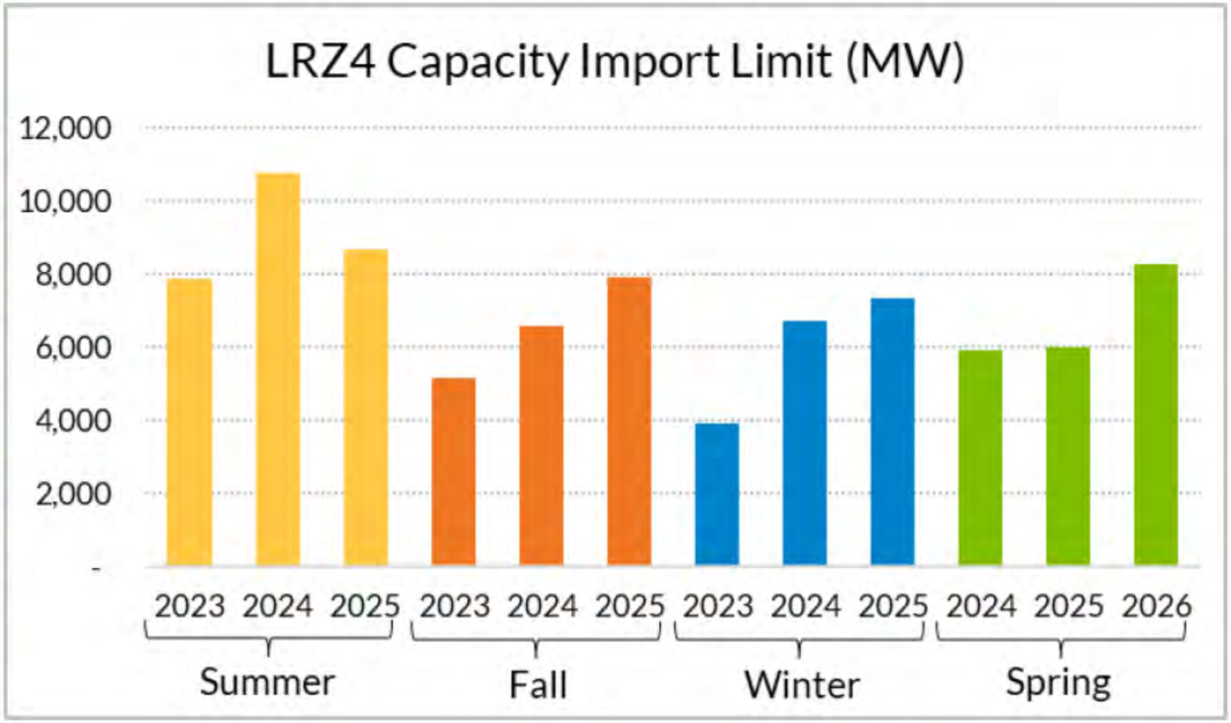




Capacity Import Limits
Zone 4: IL

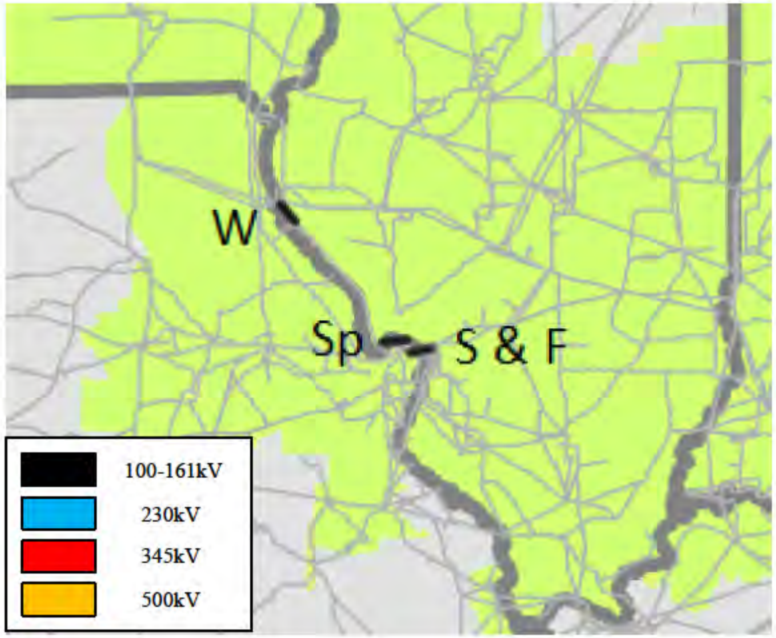
LRZ4	Monitored Element	Contingency	GLT	RDS	ZIA	CIL
Summer 2025	Kincaid - Austin 345 kV	Lincoln Land Generator	5%	247MWx2	7757	8649
Fall 2025	Palmyra - Marblehead North 161 kV	Herleman - Palmyra Tap 345 kV	25%	880MWx2	7013	7908
Winter 2025-26	Sandburg 161/138 kV Transformer	Galesburg - Oak Grove 345 kV	None	1000MWx2	6457	7353
Spring 2026	Palmyra - Marblehead North 161 kV	Herleman - Palmyra Tap 345 kV	25%	866MWx2	7373	8272

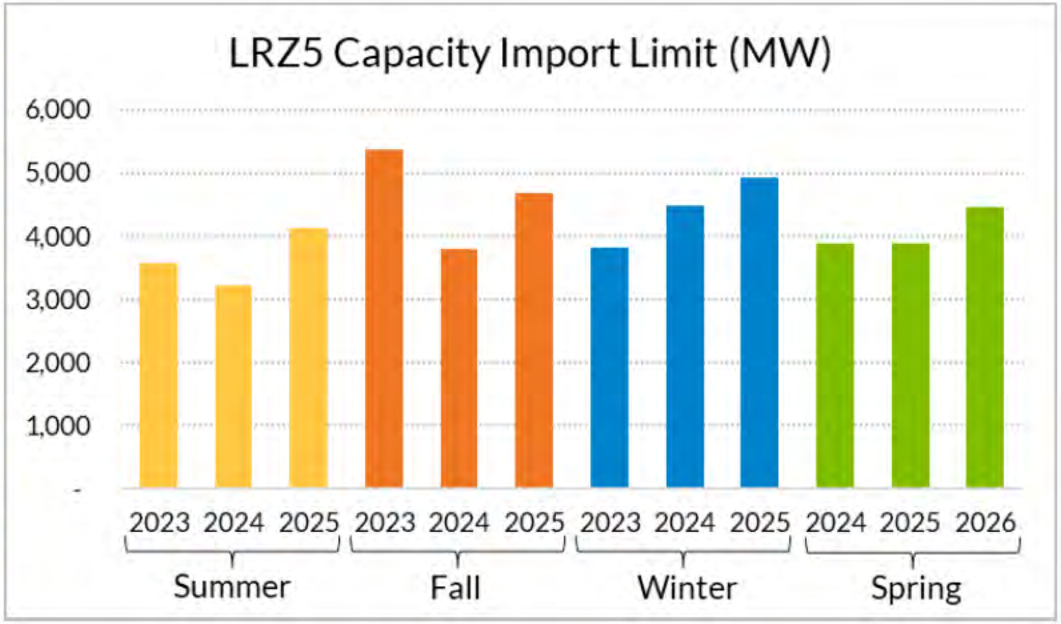




Capacity Import Limits
Zone 5: MO

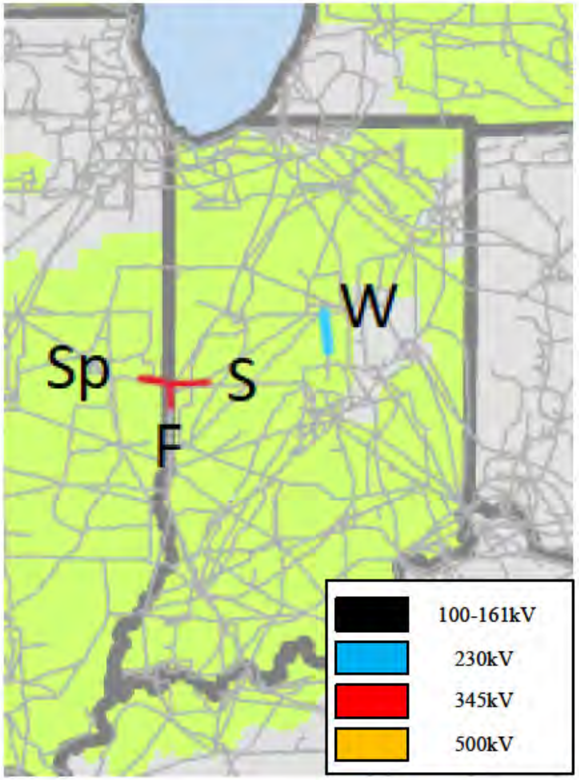
LRZ5	Monitored Element	Contingency	GLT	RDS	ZIA	CIL
Summer 2025	Rezzy - Moro 138 kV	Redhawk - Moro 345 kV	None	697MWx2	4117	4117
Fall 2025	Rezzy - Moro 138 kV	Redhawk - Moro 345 kV	25%	608MWx2	4679	4679
Winter 2025-26	Hannibal West - Spalding 161 kV	Palmyra - Spencer Creek 345 kV	None	1000MWx2	4922	4922
Spring 2026	Mississippi Tap - Sioux 138 kV	Sioux Generator	10%	217MWx2	4453	4453

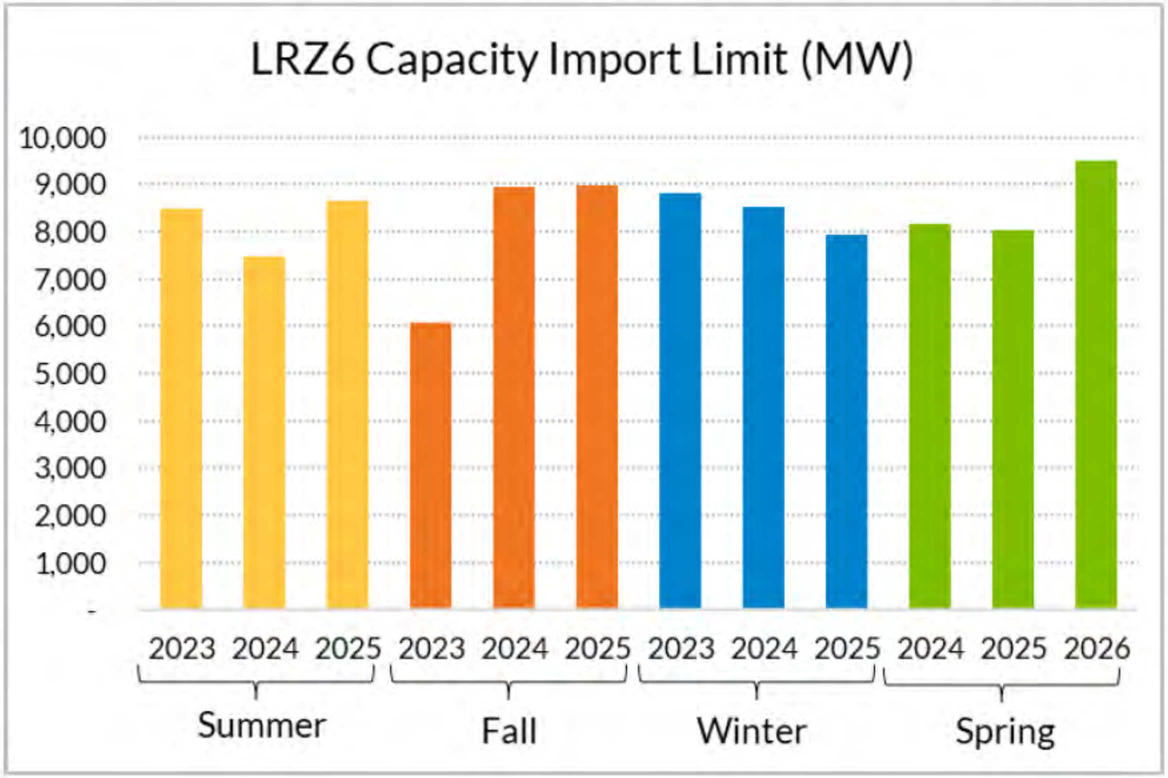




Capacity Import Limits
Zone 6: IN and KY

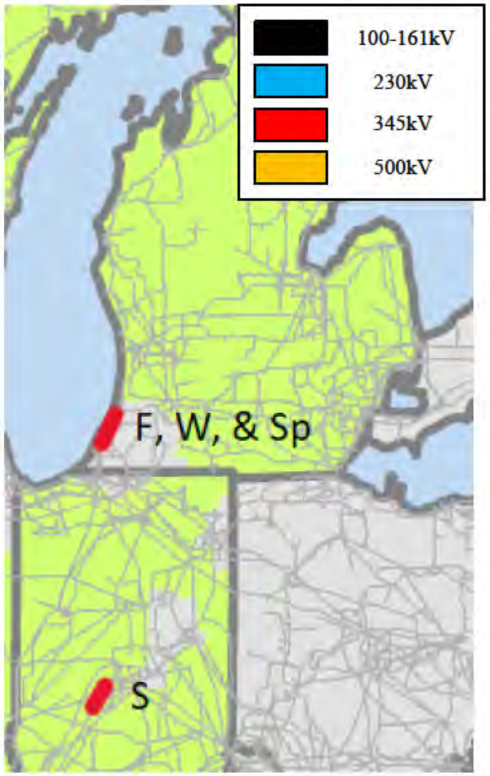
LRZ6	Monitored Element	Contingency	GLT	RDS	ZIA	CIL
Summer 2025	Cayuga - Nucor 345 kV	Dresser - Sugar Creek 345 kV	10%	571MWx2	8366	8650
Fall 2025	Cayuga - Cayuga Sub 345 kV	Kansas West - Sugar Creek 345 kV	None	162MWx2	8672	8970
Winter 2025-26	Kokomo Highland Park - Tipton 230 kV	Cayuga - Nucor 345 kV	None	1000MWx2	7690	7936
Spring 2026	Eugene - Cayuga Sub 345 kV	Kansas West - Sugar Creek 345 kV	None	431MWx2	9176	9491

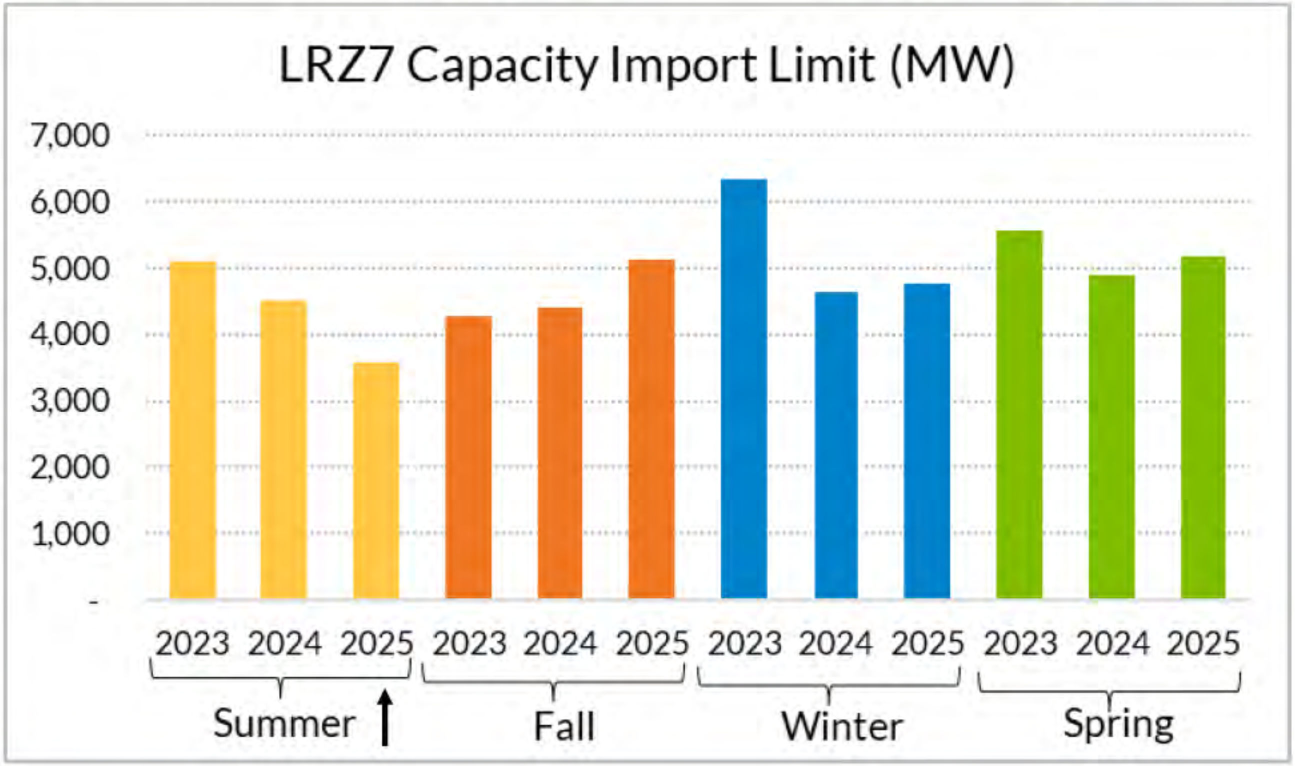




Capacity Import Limits
Zone 7: MI

LRZ7	Monitored Element	Contingency	GLT	RDS	ZIA	CIL
Summer 2025	Amo - Qualitech Steel 345 kV	Gibson - Wheatland 345 kV	None	1000MWx2	3569	3579
Fall 2025	Benton Harbor - Segreto 345 kV	Cook - Segreto 345 kV	None	1000MWx2	5115	5125
Winter 2025-26	Benton Harbor - Segreto 345 kV	Cook - Segreto 345 kV	None	1000MWx2	4762	4762
Spring 2026	Benton Harbor - Segreto 345 kV	Cook - Segreto 345 kV	None	643MWx2	5166	5166



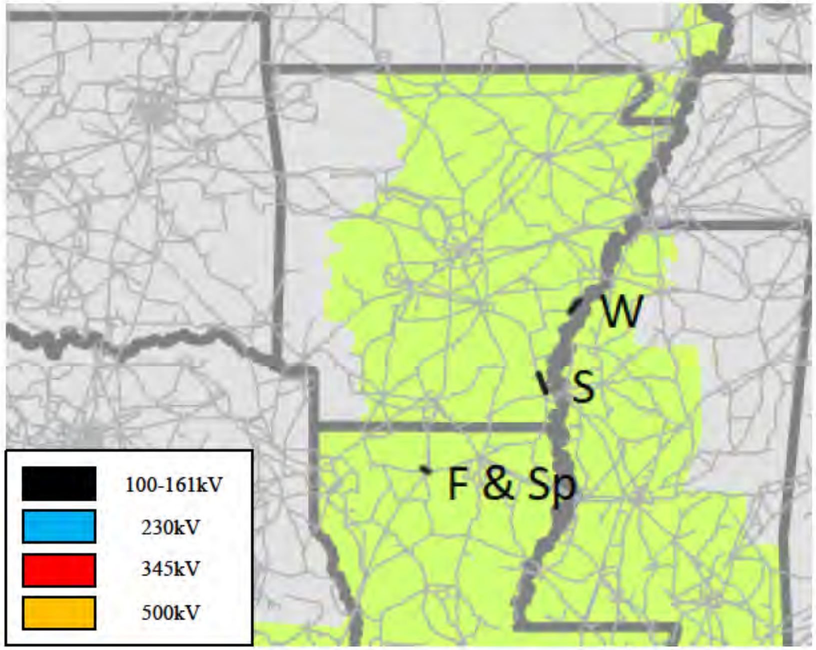


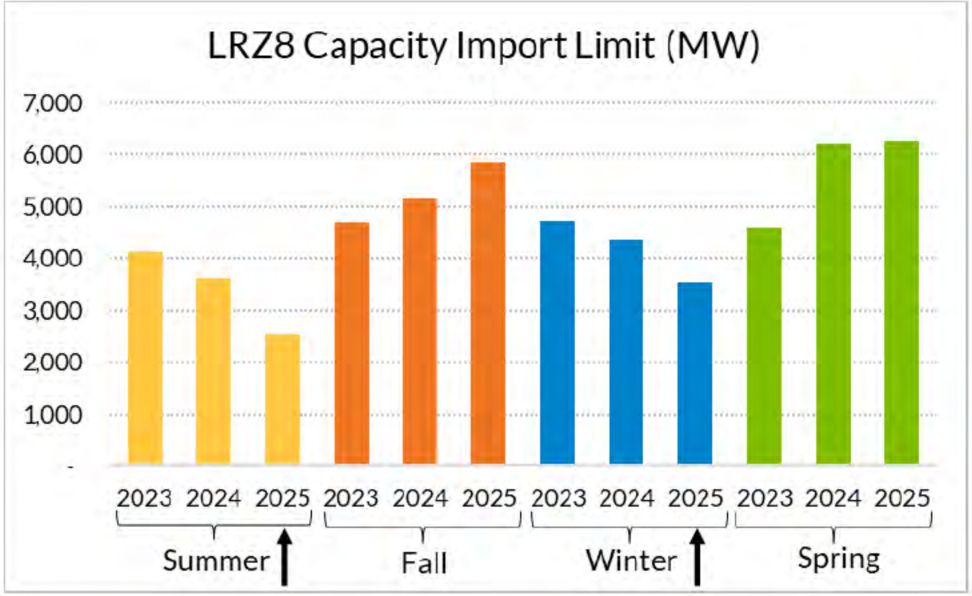
Primary Driver: Remaining resources binding earlier than previously due to lack of flexibility

Capacity Import Limits

Zone 8: AR

LRZ8	Monitored Element	Contingency	GLT	RDS	ZIA	CIL
Summer 2025	J620 - Dermott 115 kV	Lake Village Bagby - Reed SS 115 kV	None	697MWx2	2358	2522
Fall 2025	Mount Olive - Vienna 115 kV	Mount Olive - Eldorado 500 kV	None	1000MWx2	5675	5870
Winter 2025-26	Clarksdale - Lyon 115 kV	Moon Lake - Clarkesdale 230 kV	None	1000MWx2	3432	3534
Spring 2026	Mount Olive - Vienna 115 kV	Mount Olive - Eldorado 500 kV	None	1000MWx2	6085	6250

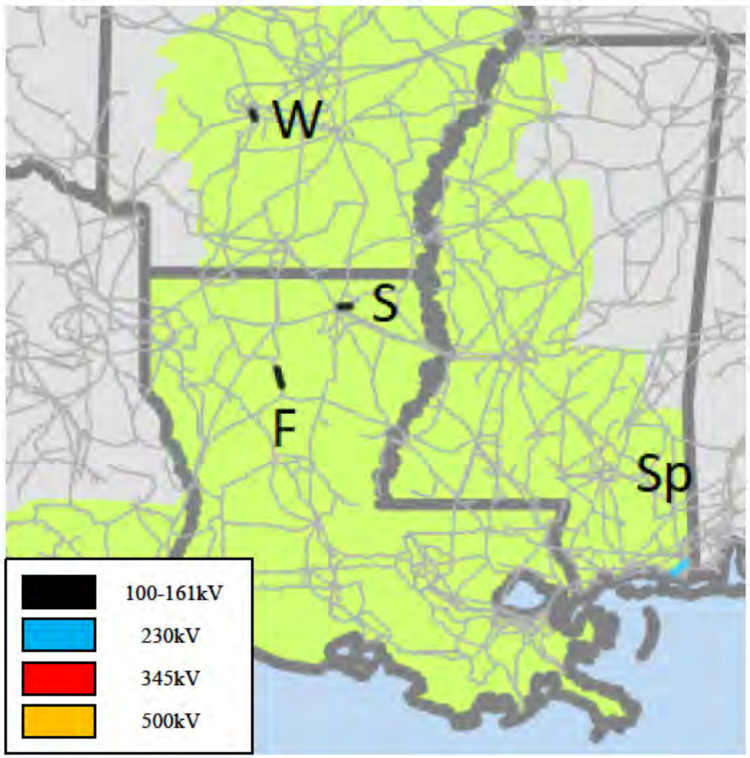


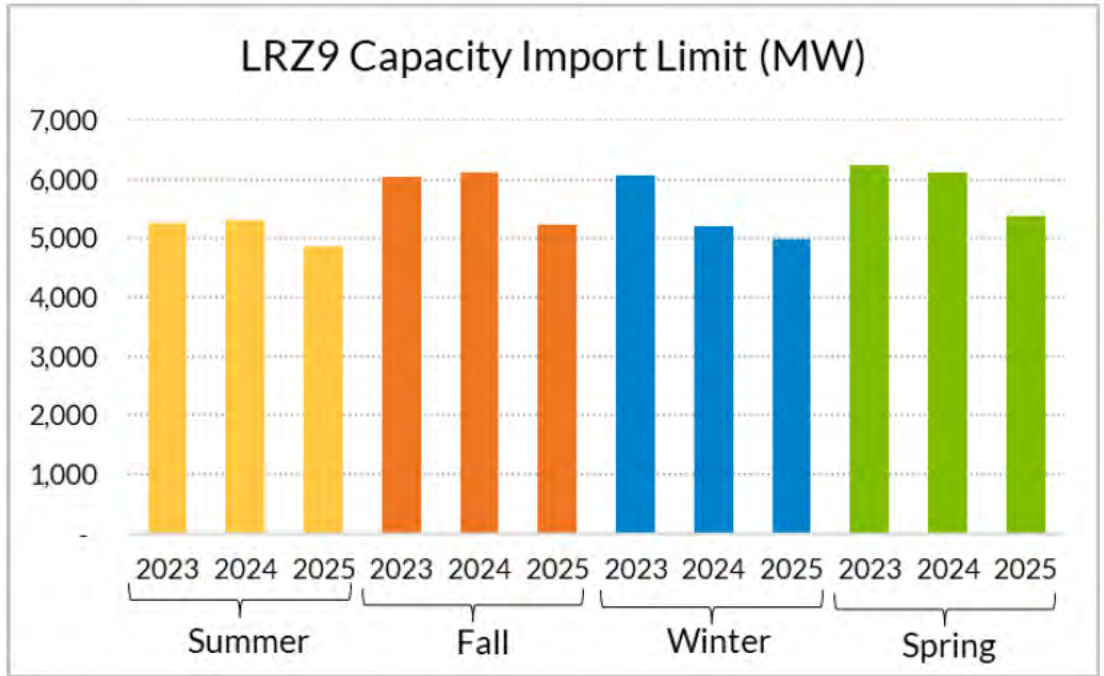


Primary Driver: New Resources are causing different flow patterns in base model, leading to earlier congestion

Capacity Import Limits
Zone 9: LA and TX

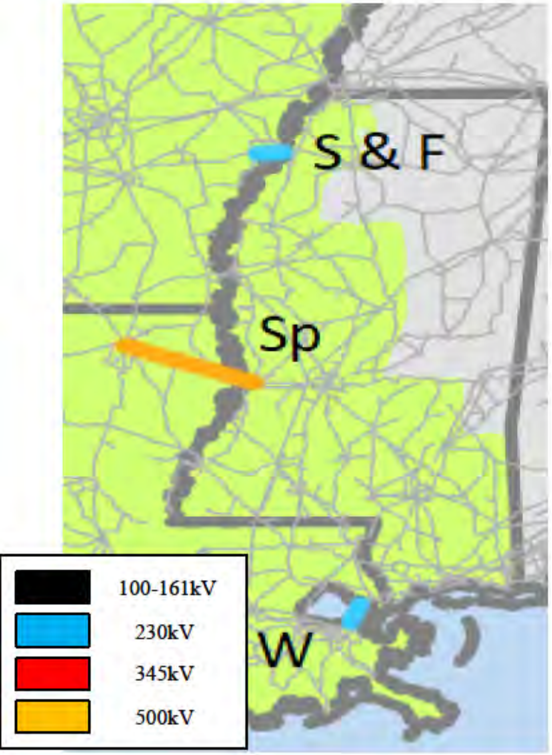
LRZ9	Monitored Element	Contingency	GLT	RDS	ZIA	CIL
Summer 2025	Sterlington - Downsville 115 kV	Mount Olive - Eldorado 500 kV	None	1000MWx2	4361	4872
Fall 2025	Danville - Dodson 115 kV	Mount Olive - Layfield 500 kV	None	1000MWx2	4741	5242
Winter 2025-26	Arklahoma - Hot Springs East 115 kV	Arklahoma - Hot Springs West 115 kV	None	1000MWx2	4418	4995
Spring 2026	Daniel - Daniel Intermediate 1 230 kV	Daniel - Daniel Intermediate 2 230 kV	None	1000MWx2	4855	5370

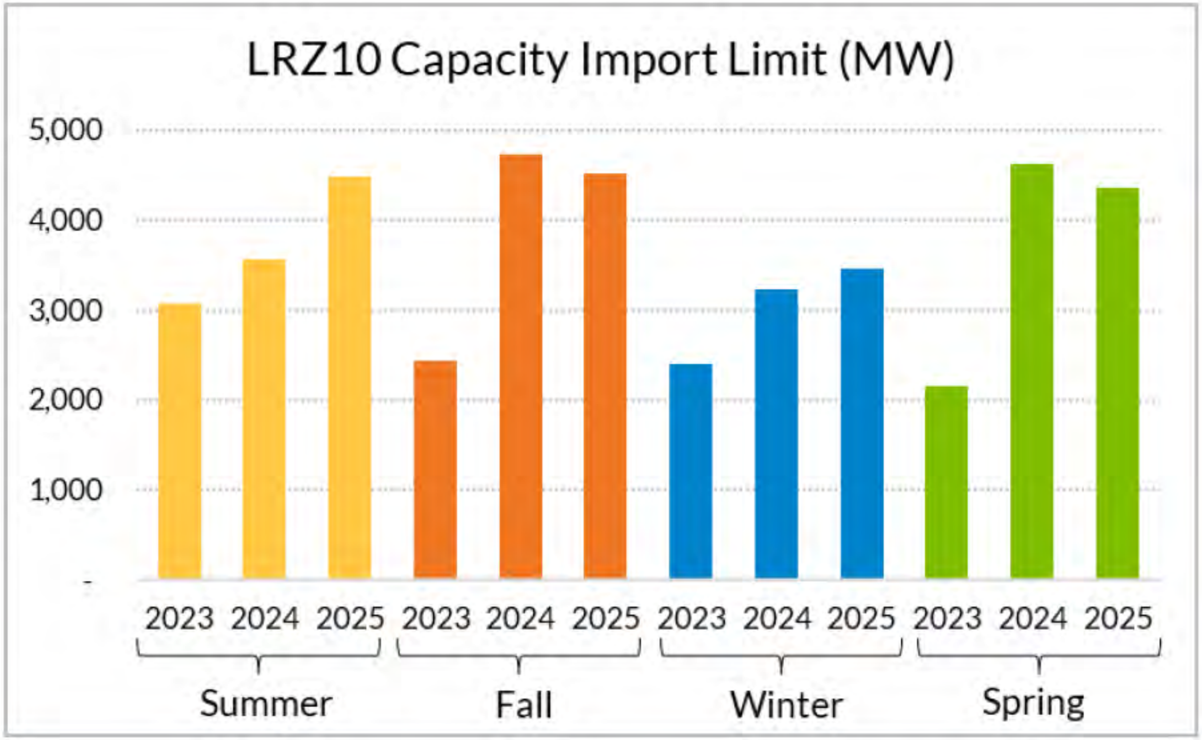




Capacity Import Limits
Zone 10: MS

LRZ 10	Monitored Element	Contingency	GLT	RDS	ZIA	CIL
Summer 2025	Ritchie - Moon Lake 230 kV	Perryville - Baxter Wilson 500 kV	None	1000MWx2	4474	4474
Fall 2025	Ritchie - Moon Lake 230 kV	Perryville - Baxter Wilson 500 kV	None	602MWx2	4508	4508
Winter 2025-26	Little Gypsy - Fairview 230 kV	Michoud - Front Street 230 kV	None	1000MWx2	3458	3458
Spring 2026	Perryvile - Baxter Wilson 500 kV	Grand Gulf Generator	None	1000MWx2	4365	4365





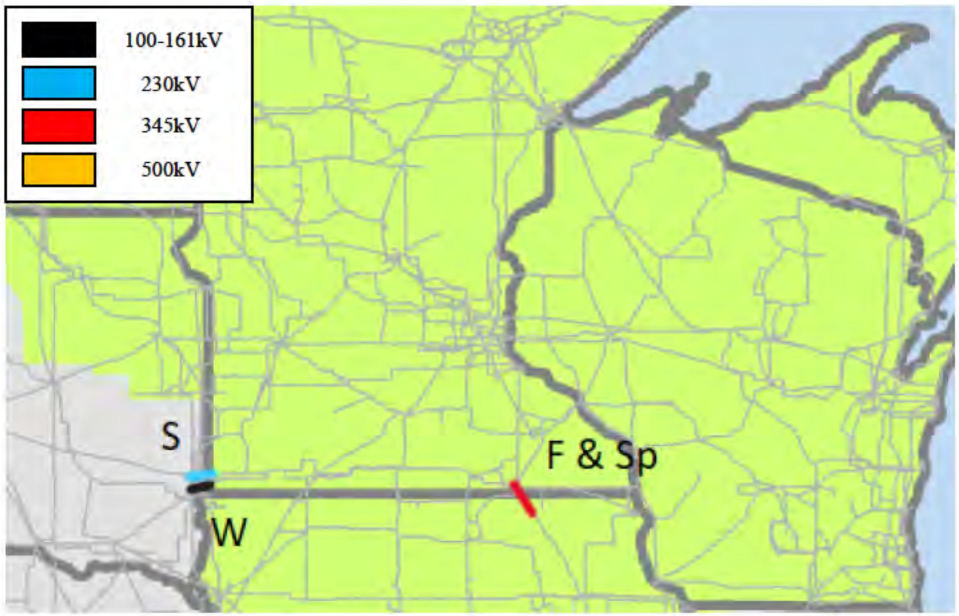
MISO

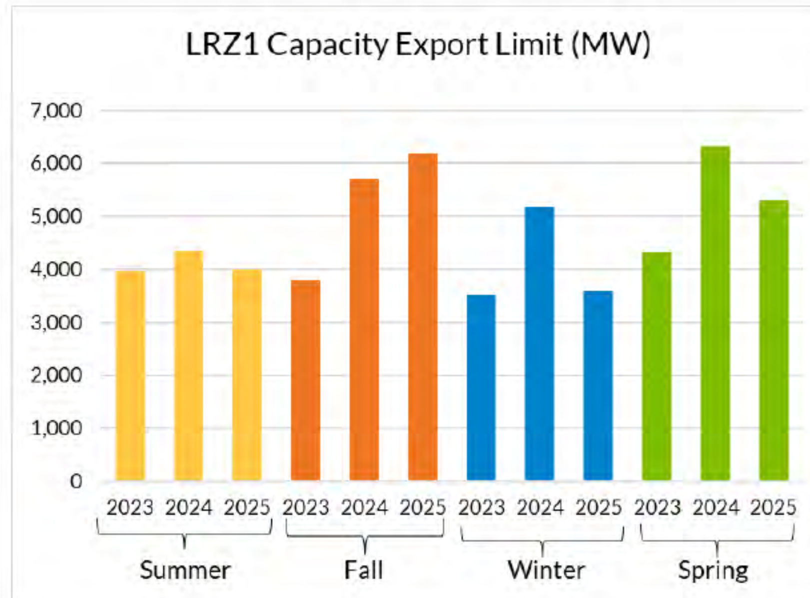
Planning Year 2025-2026 Final CEL Results

Capacity Export Limits

Zone 1: MN, MT, ND, SD and WI

LRZ1	Monitored Element	Contingency	GLT	RDS	ZEA	CEL
Summer 2025	Split Rock 4 - Sioux Falls 230 kV	Split Rock 3 - Sioux City 345 kV	None	293MWx2	3993	3991
Fall 2025	Adams - Mitchell County 345 kV	Disconnect Blackhawk Reactor	None	270MWx2	6167	6165
Winter 2025-26	Split Rock 7 - Split Rock 4 115 kV	Split Rock - Sioux City 345 kV	None	721MWx2	3593	3591
Spring 2026	Adams - Mitchell County 345 kV	Disconnect Blackhawk Reactor	None	279MWx2	5285	5283

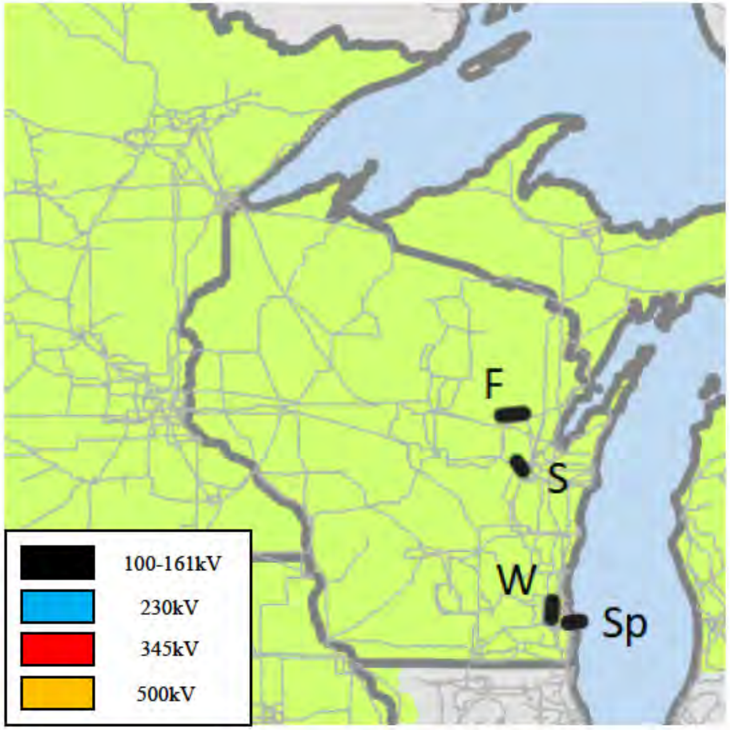


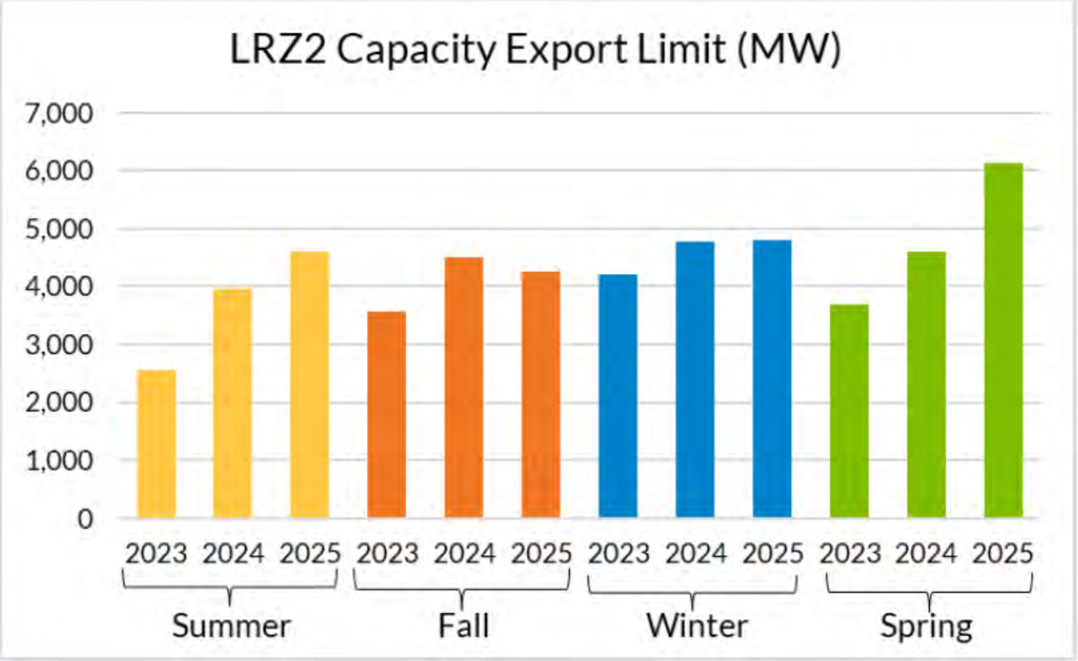


Capacity Export Limits

Zone 2: WI and MI

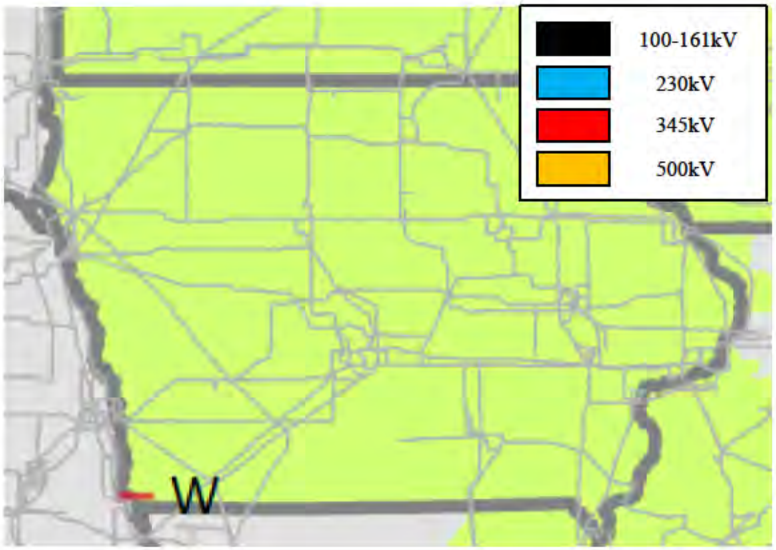
LRZ2	Monitored Element	Contingency	GLT	RDS	ZEA	CEL
Summer 2025	Neevin - Butte Des Morts 138 kV	Neevin-Woodenshoe 138 kV	25%	633MWx2	4614	4614
Fall 2025	Sherman Street - Sunnyvale 115 kV	Arpin - Rocky Run 345 kV	10%	909MWx2	4259	4259
Winter 2025-26	Granville - Butler 138 kV	Arcadian-Granville 345 kV	20%	561MWx2	4793	4793
Spring 2026	Berryville - Paris 138 kV	Paris 345/138 kV Transformer	30%	674MWx2	6119	6119

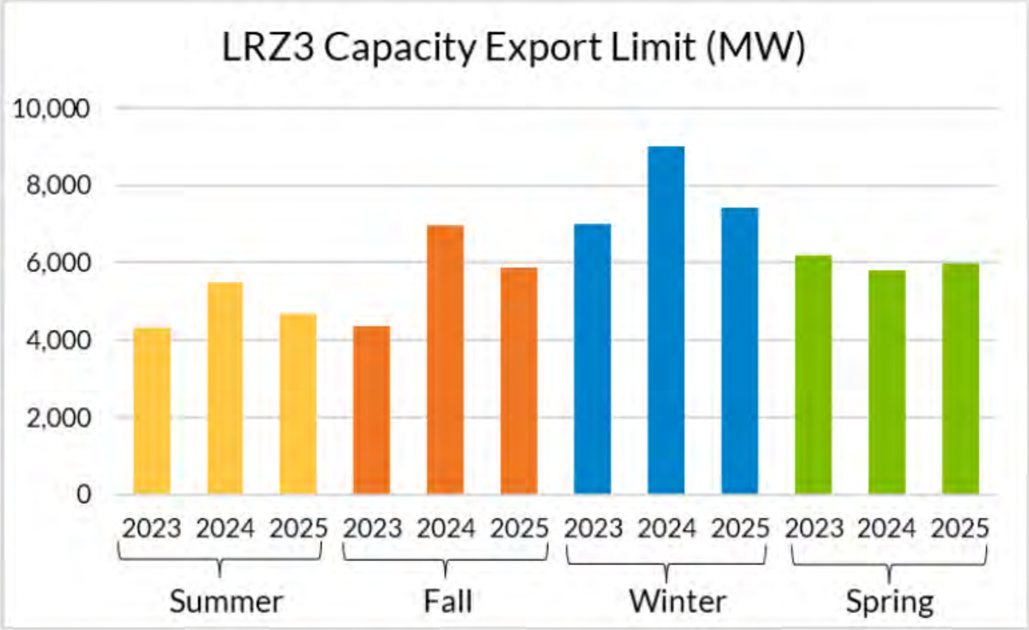




Capacity Export Limits
Zone 3: IA

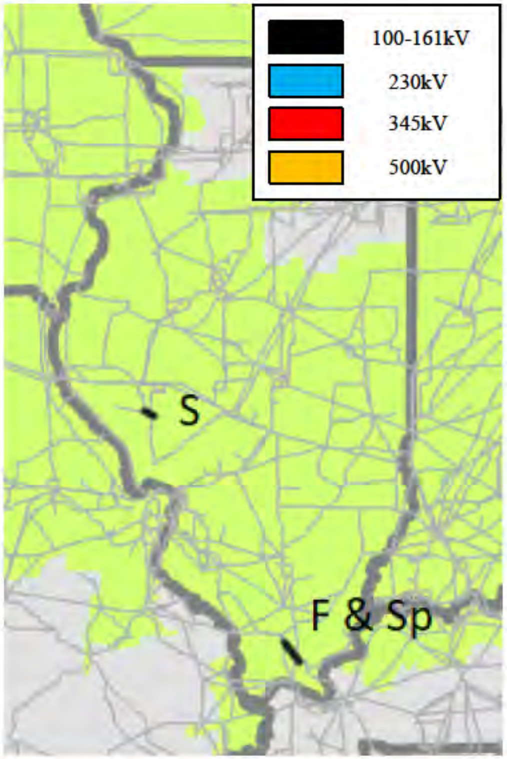
LRZ3	Monitored Element	Contingency	GLT	RDS	ZEA	CEL
Summer 2025	No Limiting Element	None	50%	None	4713	4655
Fall 2025	No Limiting Element	None	50%	None	5924	5862
Winter 2025-26	Council Bluffs - Sub 3456 345 kV	Arbor Hill - Raccoon Trail 345 kV	None	561MWx2	7480	7412
Spring 2026	No Limiting Element	None	50%	None	6039	5981

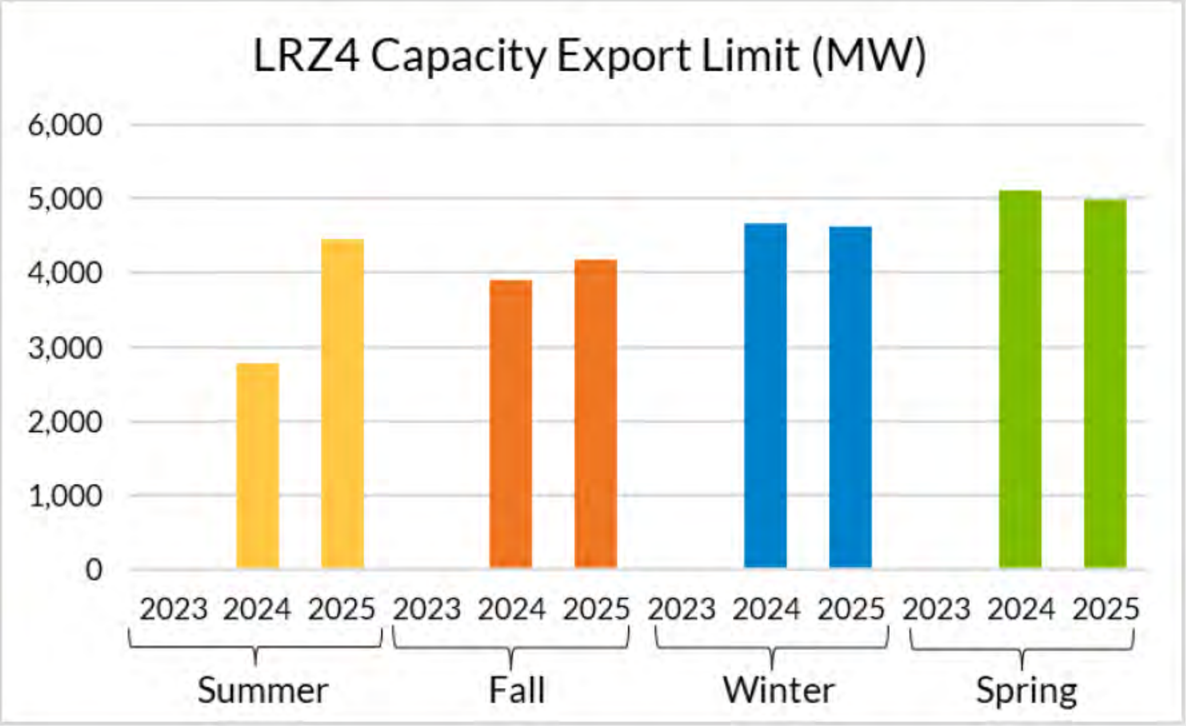




Capacity Export Limits
Zone 4: IL

LRZ4	Monitored Element	Contingency	GLT	RDS	ZEA	CEL
Summer 2025	Alsey - Winchester 138 kV	Alsey - Ballard 138 kV	40%	577MWx2	5352	4460
Fall 2025	Marion - Marion South 161 kV	Silver Mine Substation	None	1000MWx2	5069	4174
Winter 2025-26	No Limiting Element	None	50%	None	5531	4635
Spring 2026	Marion - Marion South 161 kV	Silver Mine Substation	None	212MWx2	5880	4981





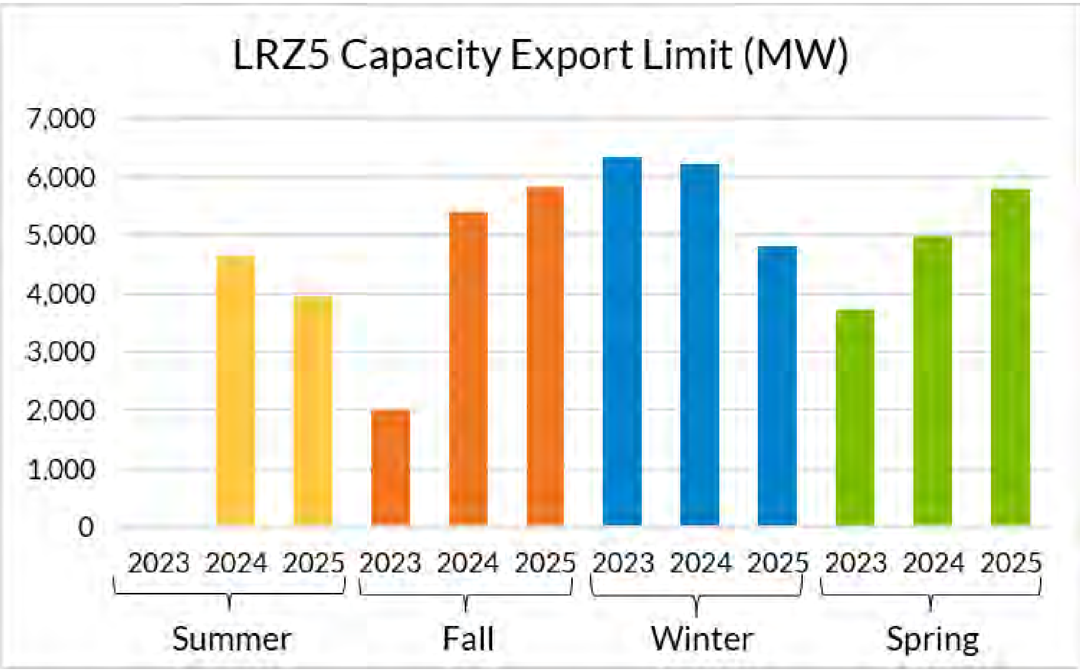
Capacity Export Limits
Zone 5: MO

LRZ5	Monitored Element	Contingency	GLT	RDS	ZEA	CEL
Summer 2025	No Limiting Element	None	45%	None	3939	3939
Fall 2025	No Limiting Element	None	50%	None	5816	5816
Winter 2025-26	No Limiting Element	None	50%	None	4814	4814
Spring 2026	No Limiting Element	None	50%	None	5797	5797

Limit: No Limit Found

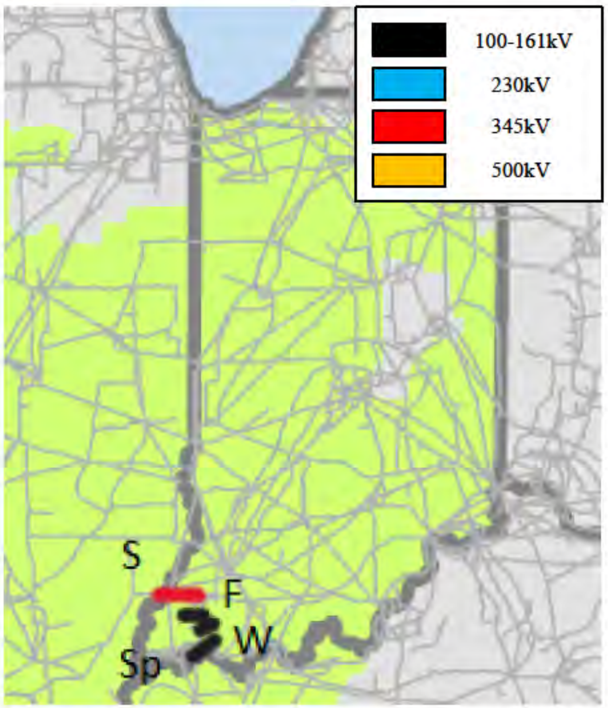
Per language in Section 5.2.2.1 of BPM-011 on Generation Limited Transfer for CIL/CEL:

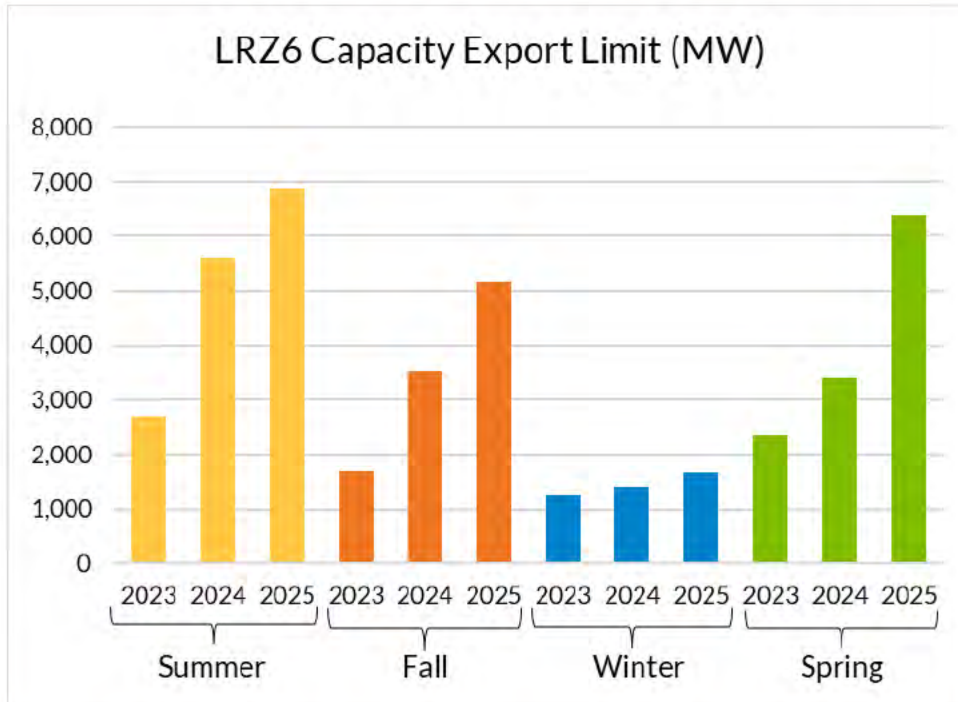
If the GLT does not produce a limit for a zone(s), due to a valid constraint not being identified, or due to other considerations as listed in the prior paragraph, MISO shall report the LRZ as having no limit and ensure that the limit will not bind in the first iteration of the Simultaneous Feasibility Test (SFT).



Capacity Export Limits
Zone 6: IN and KY

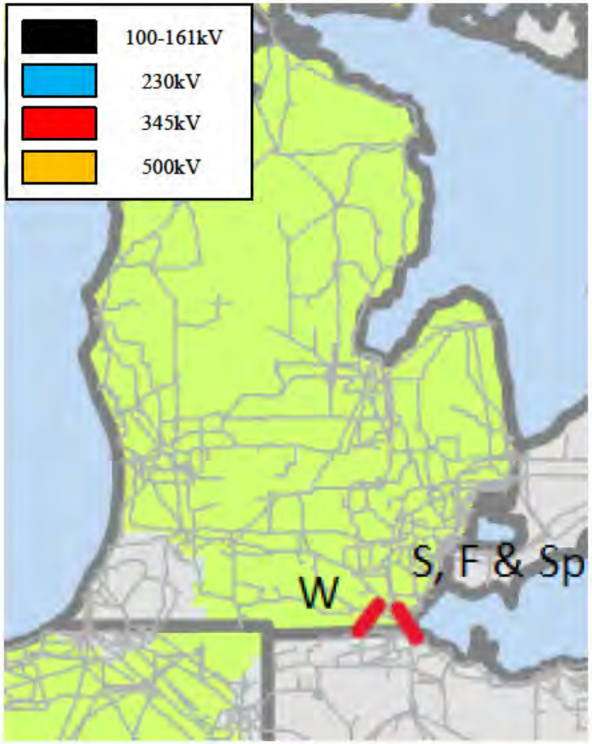
LRZ6	Monitored Element	Contingency	GLT	RDS	ZEA	CEL
Summer 2025	Gibson - Douglas 345 kV	AB Brown - Posey East 345 kV	40%	70MWx2	7165	6881
Fall 2025	AEP Rockport - Grandview 138 kV	AB Brown - Reid 345 kV	None	539MWx2	5471	5173
Winter 2025-26	AB Brown - AB Brown Reactor 138 kV	AB Brown - Reid 345 kV	None	518MWx2	1911	1665
Spring 2026	Holland - Dubois 138 kV	Duff - Francisco 345 kV	None	487MWx2	6706	6391

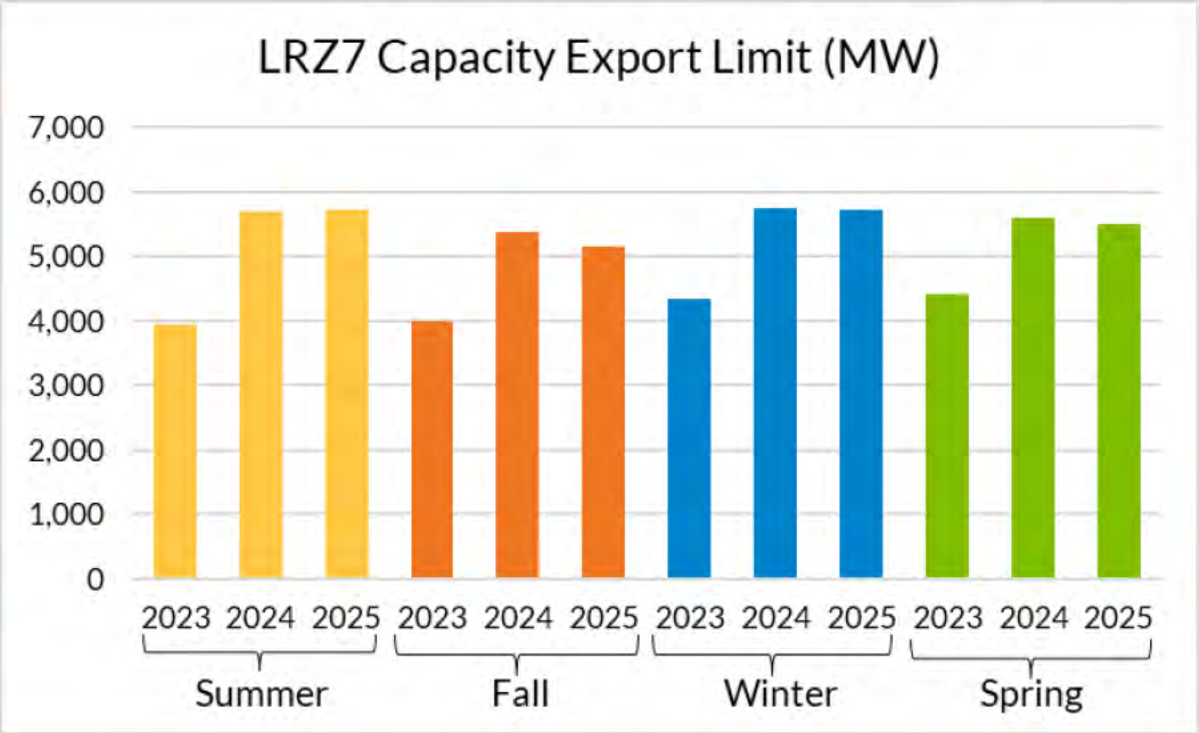




Capacity Export Limits
Zone 7: MI

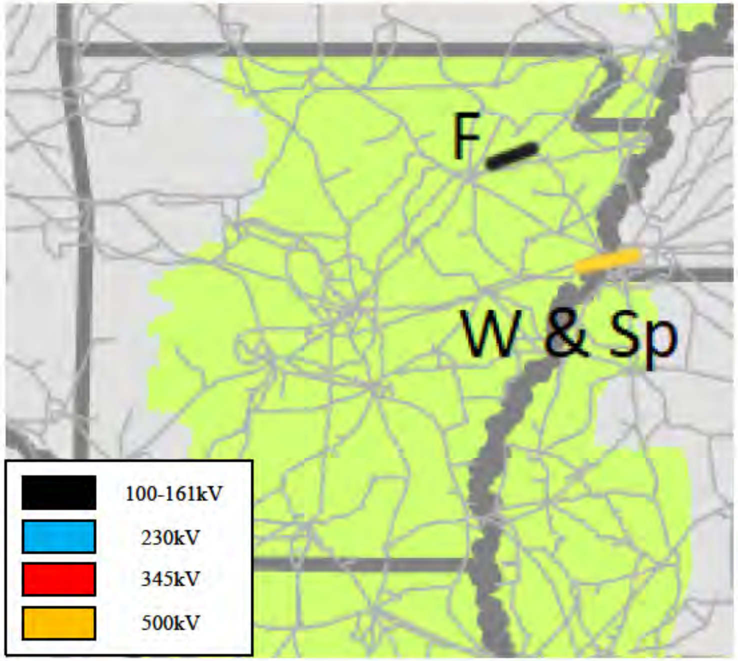
LRZ7	Monitored Element	Contingency	GLT	RDS	ZEA	CEL
Summer 2025	Monroe - Lallendorf 345 kV	Morocco - Allen Junction 345 kV	15%	1000MWx2	5726	5716
Fall 2025	Monroe - Lallendorf 345 kV	Morocco - Allen Junction 345 kV	None	1000MWx2	5168	5158
Winter 2025-26	Morocco - Allen Junction 345 kV	Monroe - Lallendorf 345 kV	None	1000MWx2	5712	5712
Spring 2026	Monroe - Lallendorf 345 kV	Morocco - Allen Junction 345 kV	None	1000MWx2	5499	5499

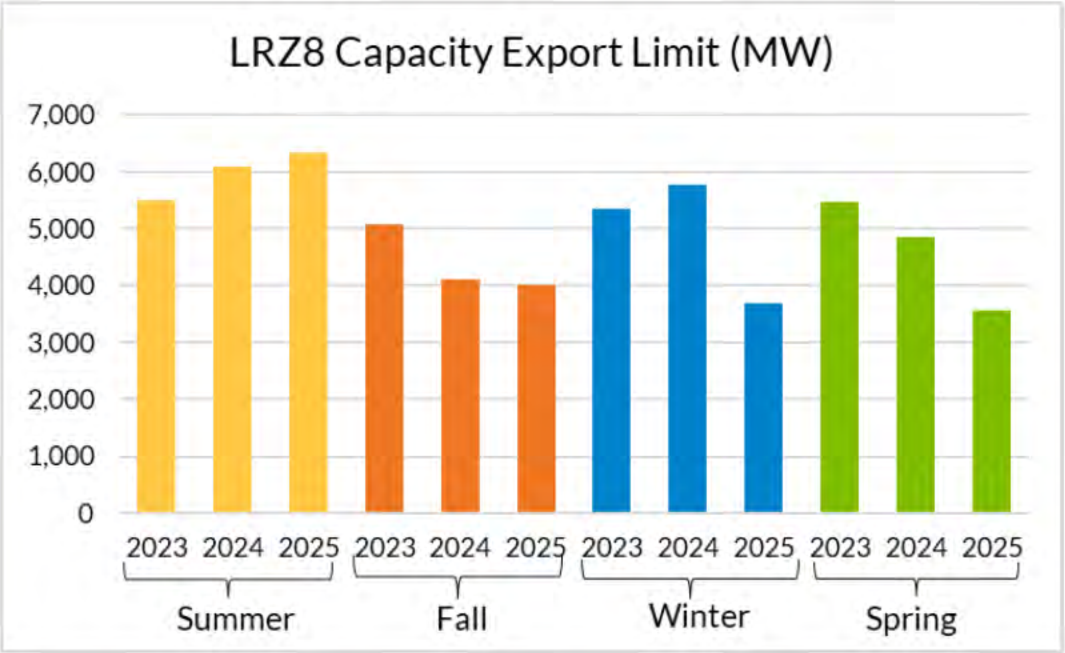




Capacity Export Limits
Zone 8: AR

LRZ8	Monitored Element	Contingency	GLT	RDS	ZEA	CEL
Summer 2025	No Limiting Element	None	50%	641MWx2	6509	6345
Fall 2025	Cash - Jonesboro 161 kV	Independence - Power Line Road 500 kV	None	1000MWx2	4219	4024
Winter 2025-26	Freeport - Cordova 500 kV	Sans Souci - Driver 500 kV	20%	422MWx2	3783	3681
Spring 2026	Freeport - Cordova 500 kV	Sans Souci - Driver 500 kV	None	382MWx2	3724	3559

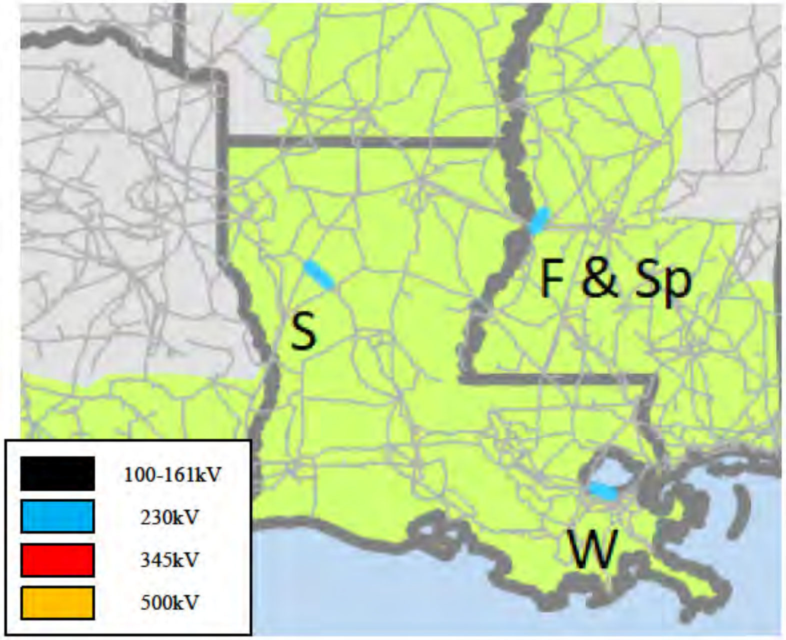


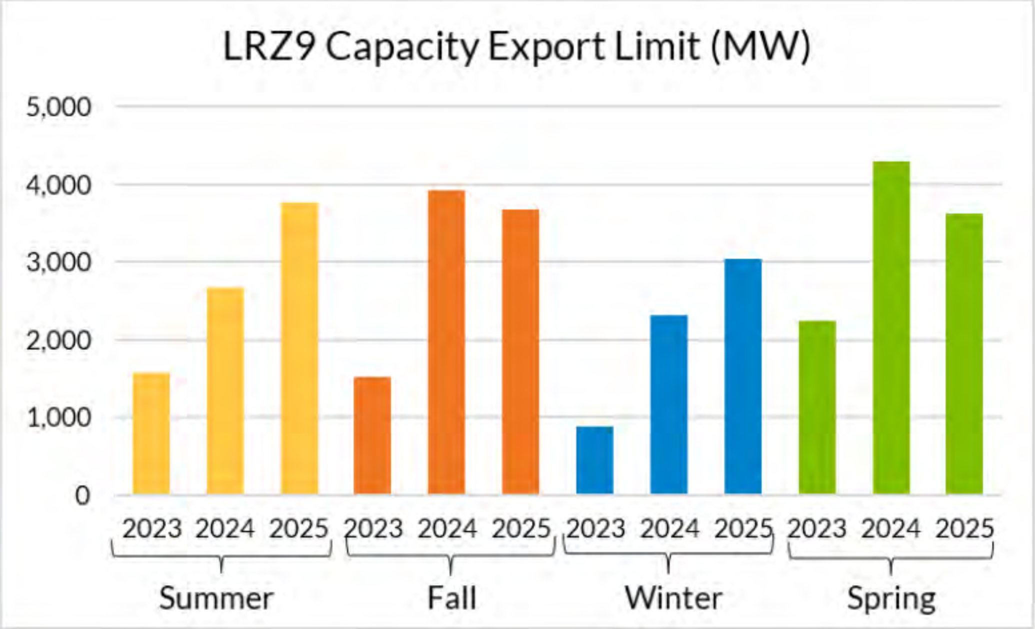


Primary Driver for Winter 2025-2026 & Spring 2026: New Resources are causing different flow patterns in the base model, leading to earlier congestion

Capacity Export Limits
Zone 9: LA and TX

LRZ9	Monitored Element	Contingency	GLT	RDS	ZEA	CEL
Summer 2025	Montgomery - Clarence 230 kV	Montgomery - Winfield 230 kV	None	1000MWx2	4286	3775
Fall 2025	Ray Braswell - Northside Drive 230 kV	Ray Braswell - Lakeover 500 kV	None	1000MWx2	4173	3672
Winter 2025-26	Little Gypsey - Fairview 230 kV	Michoud - Front Street 230 kV	None	1000MWx2	3618	3041
Spring 2026	Ray Braswell - Northside Drive 230 kV	Ray Braswell - Lakeover 500 kV	None	1000MWx2	4146	3631

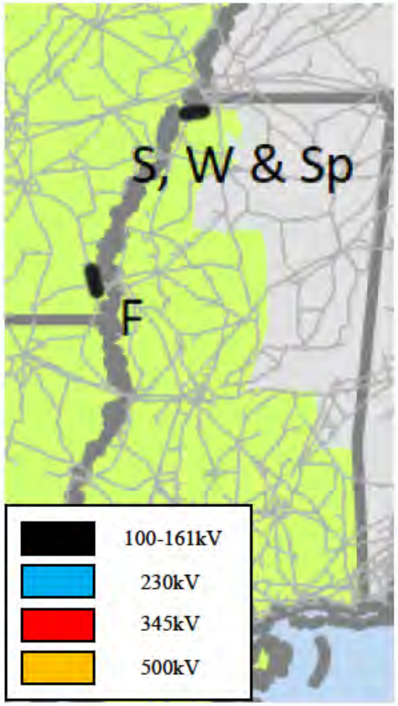


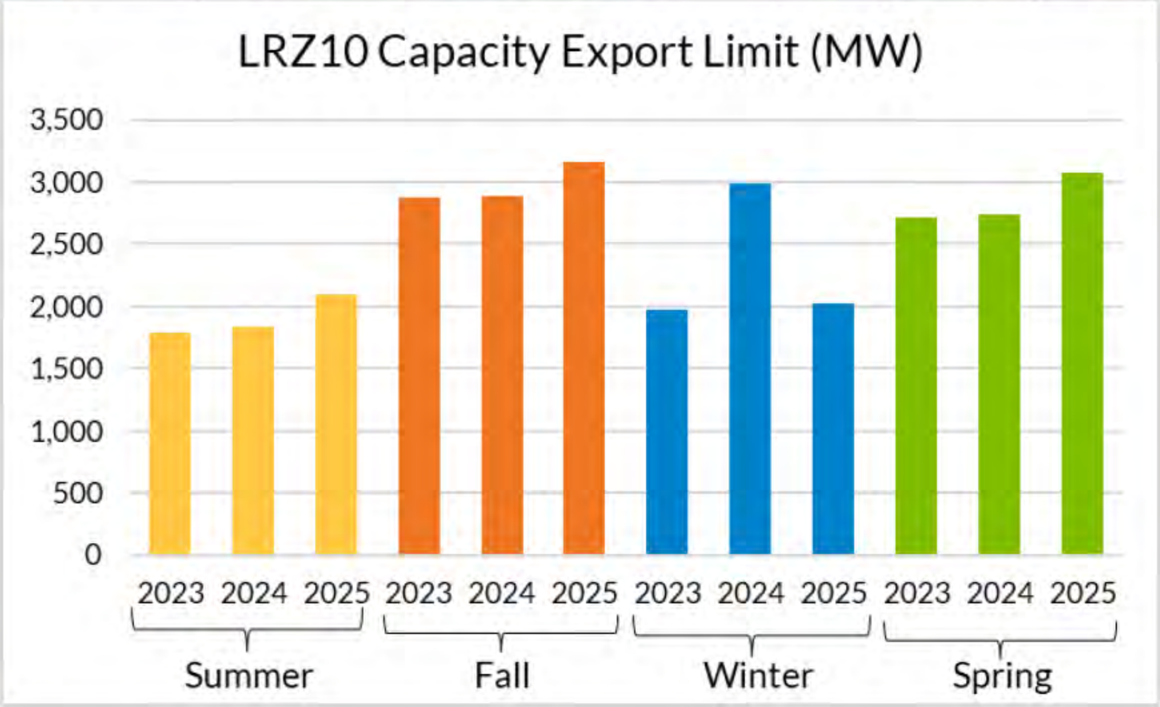


Capacity Export Limits

Zone 10: MS

LRZ10	Monitored Element	Contingency	GLT	RDS	ZEA	CEL
Summer 2025	Batesville - Tallahatchie 161 kV	Batesville - East Batesville 161 kV	None	710MWx2	2097	2097
Fall 2025	Lake Village Bagby - Macon Lake 115 kV	Lake Village Bagby - Reed 115 kV	None	650MWx2	3164	3164
Winter 2025-26	Batesville - Tallahatchie 161 kV	Choctaw - Clay 500 kV	None	710MWx2	2028	2028
Spring 2026	Batesville - Tallahatchie 161 kV	Batesville - East Batesville 161 kV	None	526MWx2	3072	3072





Primary Driver for Winter 2025-2026: New Resources are causing different flow patterns in the base model, leading to earlier congestion

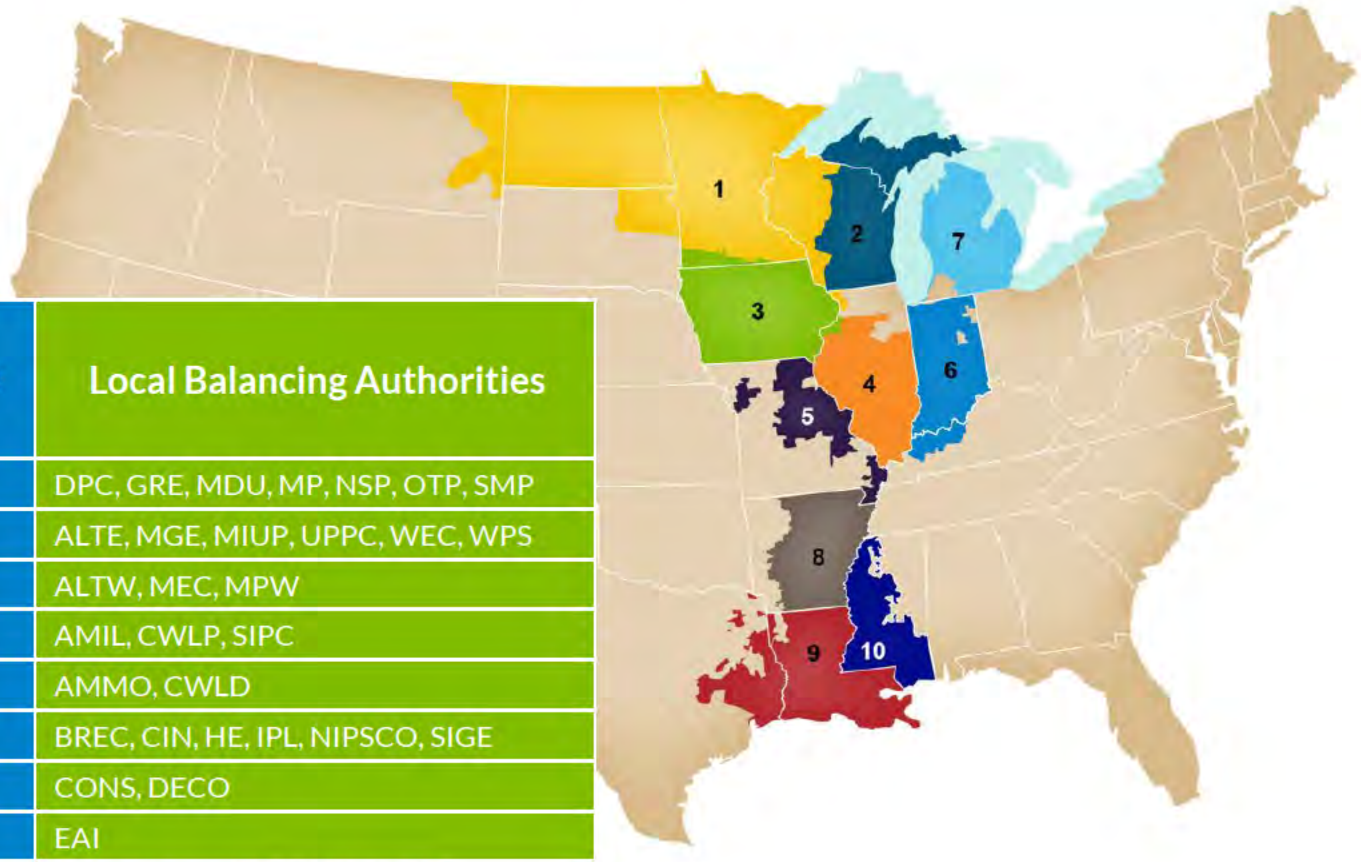
Next Steps

- Planning Year 2025-2026 CIL/CEL values are finalized and will be entered in MECT.
- March 2025 – MISO will receive a final list of Controllable Exports and will adjust CIL/CEL values if necessary.

Contact

jdibasilio@misoenergy.org
MISO Help Center:
https://help.misoenergy.org/

MISO Local Resource Zones



Local Resource Zone	Local Balancing Authorities
1	DPC, GRE, MDU, MP, NSP, OTP, SMP
2	ALTE, MGE, MIUP, UPPC, WEC, WPS
3	ALTW, MEC, MPW
4	AMIL, CWLP, SIPC
5	AMMO, CWLD
6	BREC, CIN, HE, IPL, NIPSCO, SIGE
7	CONS, DECO
8	EAI
9	CLEC, EES, LAFA, LAGN, LEPA
10	EMBA, SME

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Midcontinent Independent System Operator (MISO)	)))))	Order No. 202-25-3

Exhibit to
Motion to Intervene and Request for Rehearing and Stay of
Public Interest Organizations

Filed June 18, 2025

Exhibit 38

MISO LOLE Presentation

LOLE 101: Probabilistic Analyses

LOLE 101 Training

5/8/2018

Loss of Load Expectation (LOLE) 101 Sections

- LOLE Background & History
- LOLE Study Connections to other MISO Processes
- Generating Availability Data System (GADS) Overview
- LOLE Modeling
- Strategic Energy Risk Valuation Model (SERVM)
- LOLE Results Walkthrough
- Takeaways
- Reference Materials

Loss of Load Expectation (LOLE) Definition

LOLE is the measure of how long, on average, the available generation capacity is likely to fall short of the load demand

Loss of Load Probability (LOLP) is the probability in a given hour	Sum of the Daily Peak LOLP values is an expectation (LOLE)	Sum of all LOLP values is called Loss of Load Hours (LOLH)

↓

LOLE is used to study Generation (Resource) Adequacy

Generally considered to be the existence of sufficient resources, within a system, to satisfy consumer demand. A product of unit availability, "perfect storm". The study of low probability, high impact events.

1-day in 10-years LOLE Criteria

MISO Resource Adequacy criteria for Planning Reserve target is the industry standard LOLE objective:

<1-day in 10-years

=

NERC Standard BAL-502-RF-03

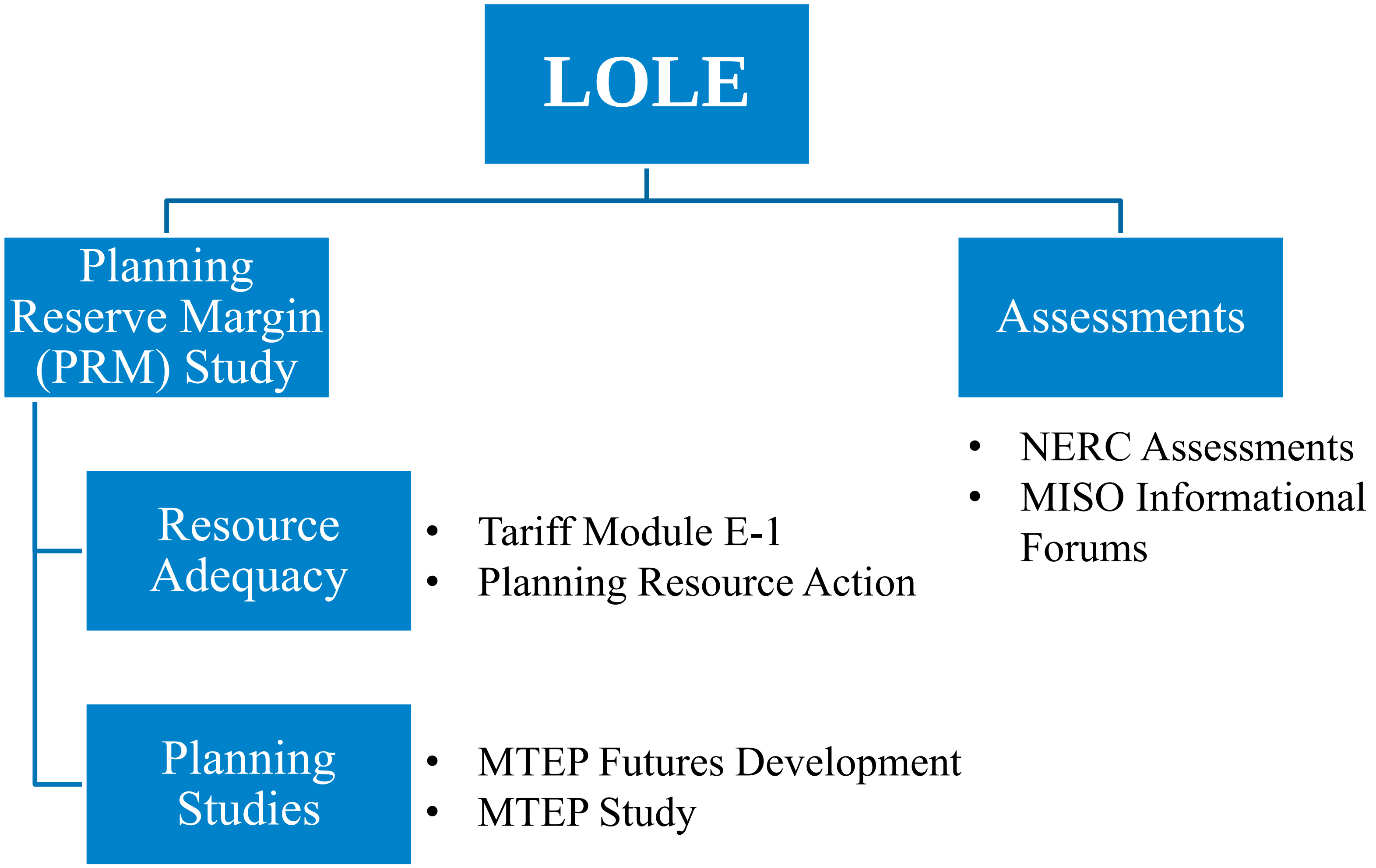
- Calculate a planning reserve margin that will result in the sum of the probabilities for loss of Load for the integrated peak hour for all days of each planning year analyzed being equal to 0.1. (This is comparable to a "one day in 10 year" criterion).

Common Terminology Misconceptions

- 1 day in 10 years LOLE ≠ 24 hours in 10 years LOLH
  - Example: 2 hours of firm load shed = 2 loss of load hours and 1 day of loss of load
  - By definition 1 day/ 10 years LOLE ≤ 24 hours / 10 years LOLH

- Cannot calculate Loss of Energy Expectation (LOEE) from LOLH without running complete analysis

LOLE Connections to Various MISO Processes



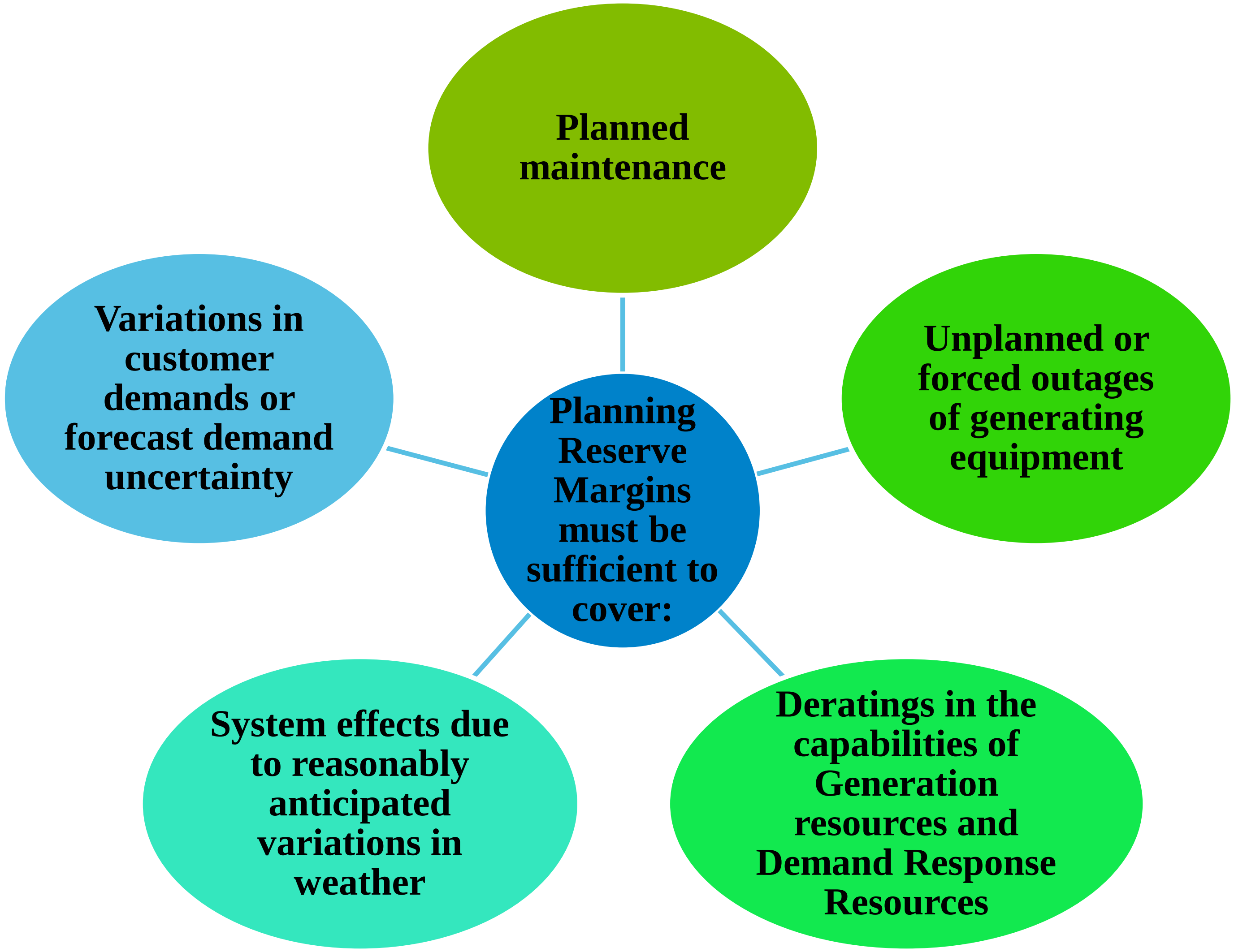
Resource Adequacy Overview

- Achieving reliability in the bulk electric systems requires that the amount of resources exceeds customer demand by an adequate margin

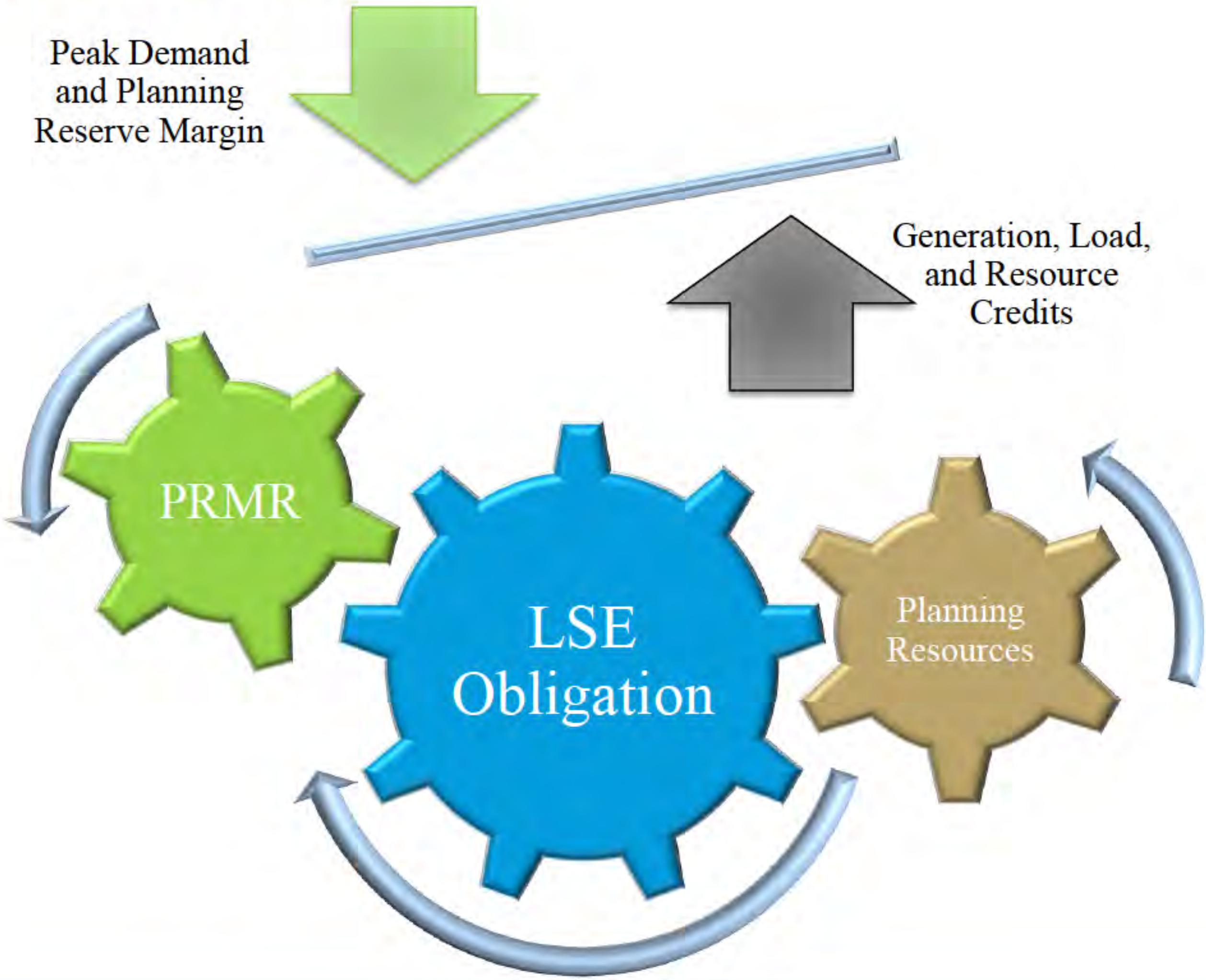
Margins necessary to promote Resource Adequacy need to be assessed on:

Longer-term planning basis	Near-term operational basis
Focus of MISO's RA Construct is on the longer-term planning margins used to provide sufficient resources to reliably serve load on a forward-looking basis	Resources dedicated to meet Demand have an obligation to be available to meet real-time customer demand and contingencies

Planning Reserve Margins (PRMs)



Overview of MISO Resource Adequacy Requirements



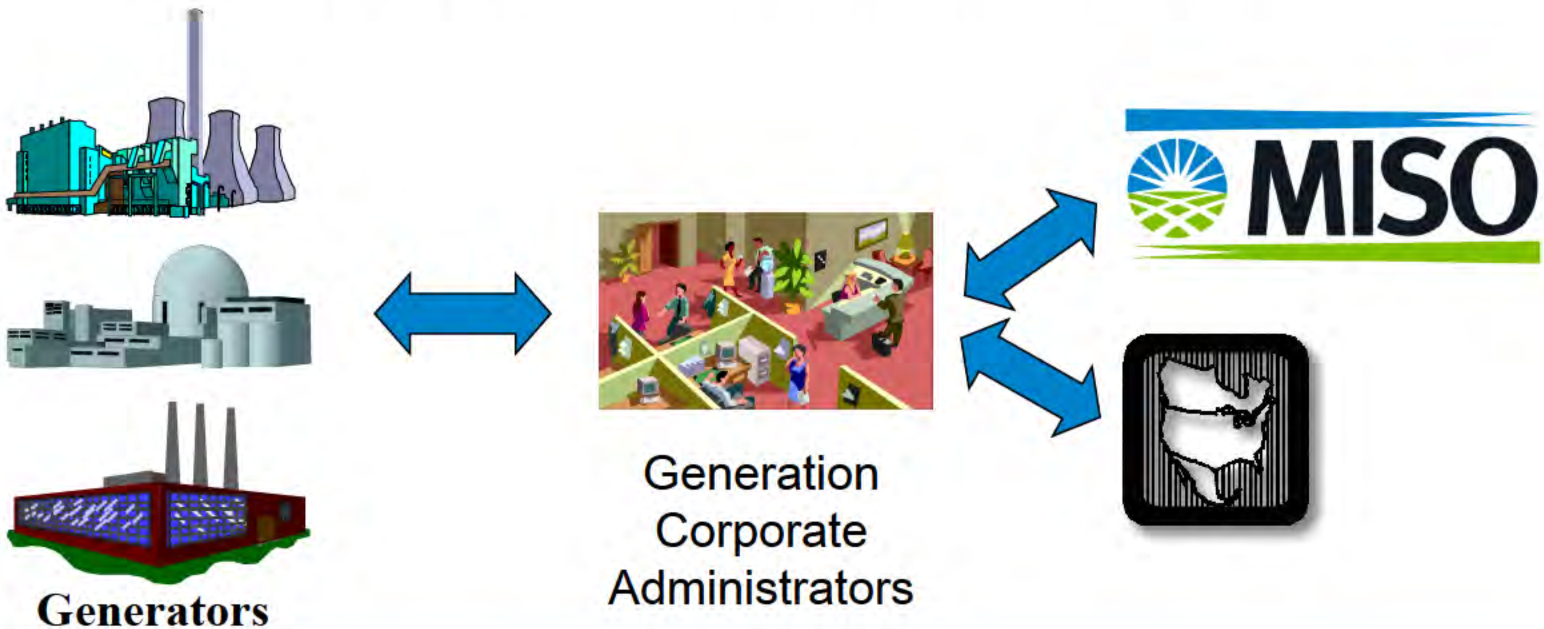
PowerGADS – Performance & Reliability System

For capacity planning and reliability study purposes,

all generating facilities declared as <u>capacity resources</u> in the MISO market

are required to submit GADS <u>event and performance</u> data

to determine the value of the facility as an unforced capacity resource



GADS Data Requirements…

- Generation Resources
- External Resources
- Demand Response Resources backed by behind the meter generation
- or Behind the Meter Generation (BTMG)

Greater than or equal to 10 MW, based on Generation Verification Test Capacity (GVTC)

- Must submit generator availability data (including, but not limited to, NERC GADS) into PowerGADS through the Market Portal

Less than 10 MW, based on (GVTC), that begin reporting generator availability data

- Must continue to report such information

GADS Data Requirements…

- Quarterly Submittal of Data
  - Stakeholders are expected to submit data on a quarterly basis
  - Quarterly GADS data must be received by the last day of the month following the operating quarter
  - Quarterly GADS data must be Level 2 Validated by the last day of the month following the operating quarter

GADS Data Requirements…

- A unit will receive 100% EFORd if it fails to submit GADS data and successfully Level 2 Validate

- Assigning 100% EFORd will impact a unit's unforced capacity calculation
  - $UCAP = GVTC \; * (1 - EFORd)$

Three Types of Data are to be Collected…

Event Data

- Each time a unit has a change in operating status or capability, an *event* is recorded
- From these event reports a unit's operational history can be reconstructed

Generation Performance Data

- A unit's actual generation, hours of operations, and operational characteristics

Fuel Performance Data (optional)

- A unit's actual fuel consumption and fuel quality data

PowerGADS – Event Data

Event data – to be collected:

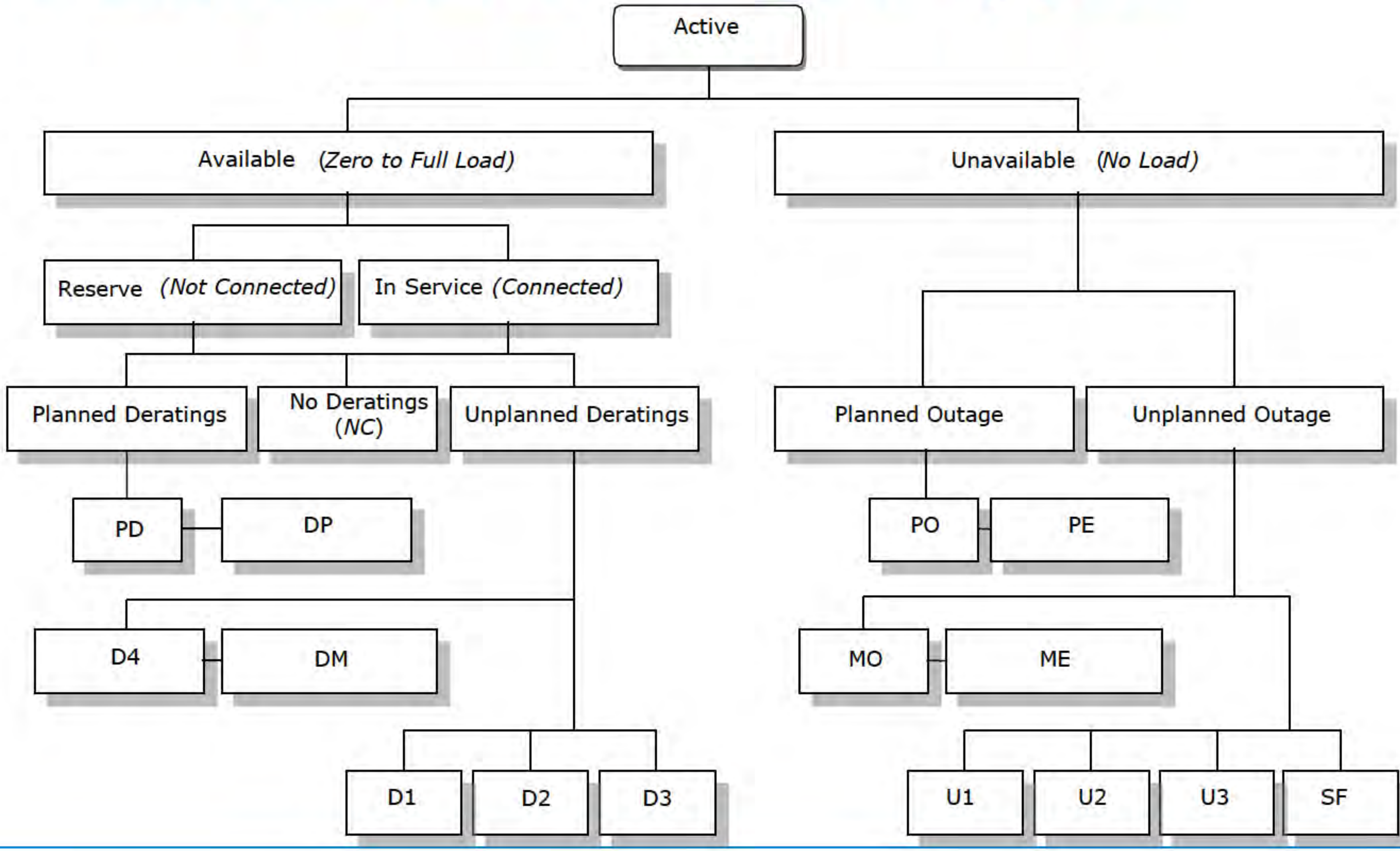
- Event Number
- Event Type
- Start of Event
- End of Event (Can be blank if event is ongoing)
- Net Available Capacity
- Primary Cause Code
- Additional Cause Code (Optional)
- Event Contribution Code
  - describes impact or contribution that this cause or component had on the event
- Verbal Description (Optional)
- Failure Code (Optional)

PowerGADS – Performance Data

Performance data – to be collected:

- Net Maximum Capacity
- Net Dependable Capacity
- Net Actual Generation
- Typical Unit Loading Code
- Loading Verbal Description
  (If Typical Unit Loading Code is 6)
- Attempted Unit Starts
- Actual Unit Starts
- Unit Service Hours
- Reserve Shutdown Hours
- Pumping Hours
- Synchronous Condensing Hours

PowerGADS – Event Types



LOLE Model Inputs Include:

Generation Resources
- Operating Parameters
- Unit Forced Outage Rates
- Planned Maintenance Schedules & Rates
- Dispatch Limits for Demand Response

Study System
- Zone & Pool definition
- External Tie Limits
- External System Model

Load
- Demand and Energy Forecast
- Load Shape/Profile
- Load Uncertainty

LOLE Model Inputs

Source of LOLE Model Input Data

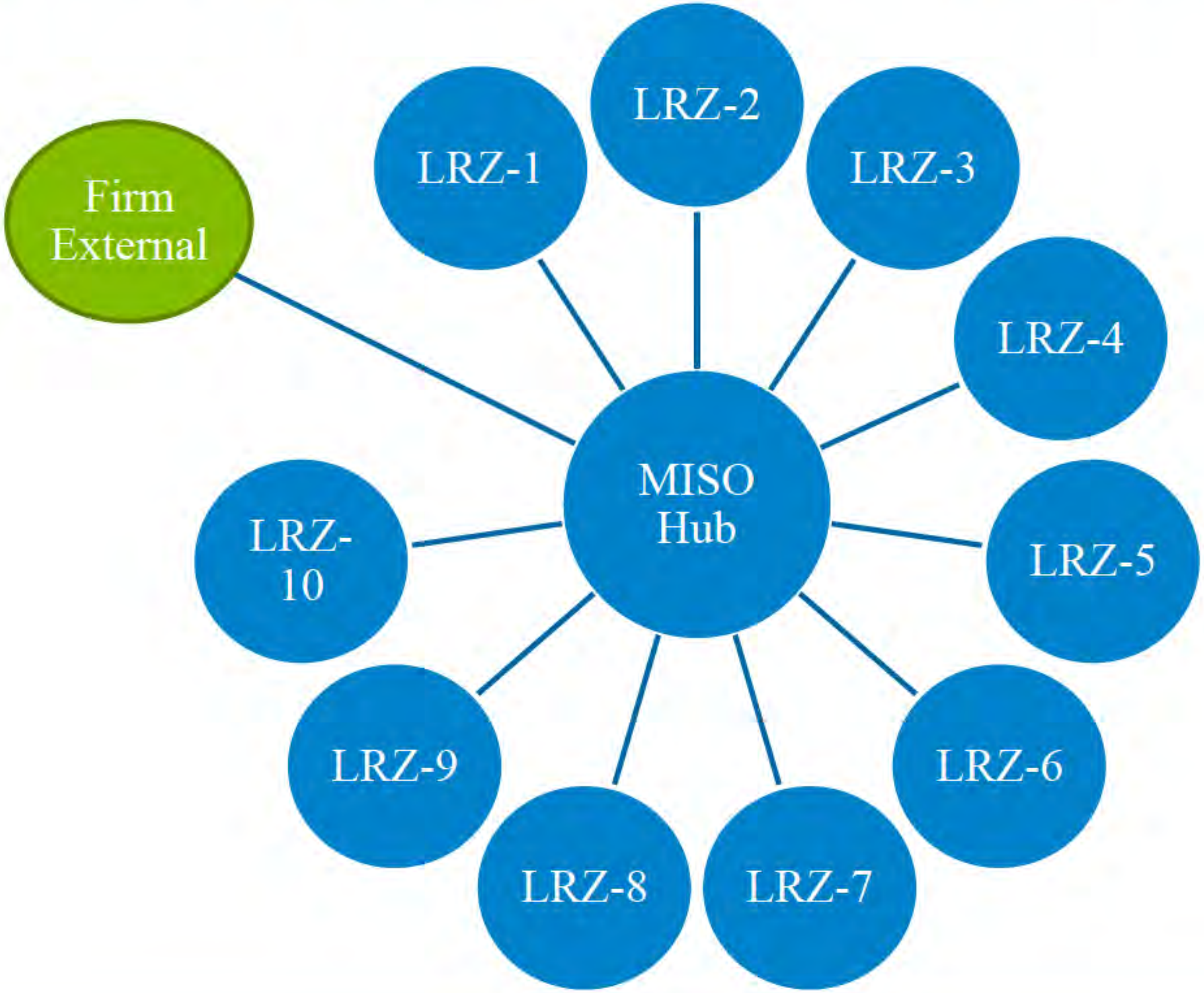
Generation Resources

- Generating Availability Data System (GADS)
  - Unit performance statistics used to calculate forced outage rates
  - Data is uploaded into the MISO system one month after end of each quarter
- Generation Verification Test Capacity (GVTC)
  - Units need to demonstrate maximum output level

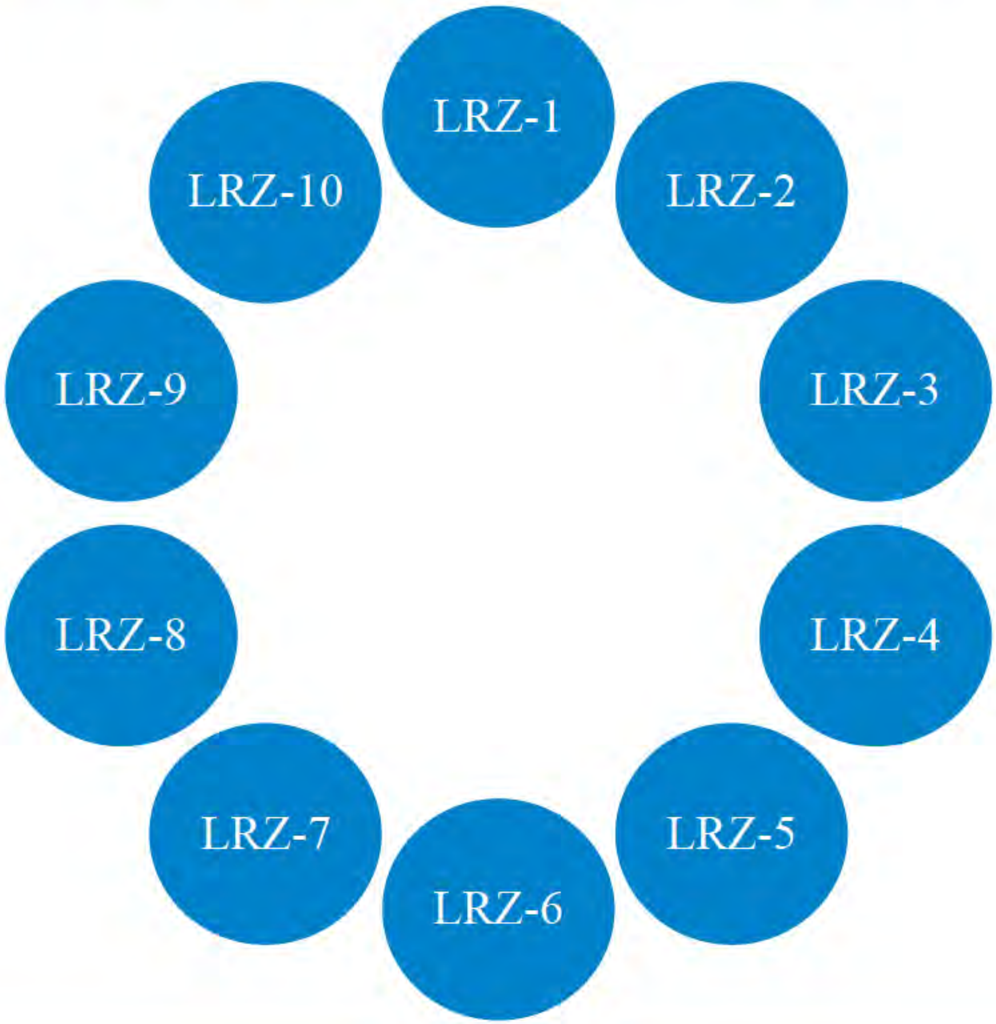
Load

- Load training using historical load and weather data
- Monthly Peak Demand, MISO Coincident Demand and Energy Forecast are uploaded by Load Serving Entities (LSEs) into the Module-E Capacity Tracking (MECT) Tool (deadline Nov. 1st)
- MISO reviews Forecast and Finalize review by March

MISO System LOLE Model



Local Resource Zone LOLE Model



MISO uses the Strategic Energy Risk Valuation Model (SERVM) Software

Managed by Astrapé Consulting

Originated within Southern Company back in the early 1980's

Uses a sequential Monte Carlo simulation

- Steps through time chronologically and randomly drawing unit availability
- Replicating simulation with different sets of random events until statistical convergence is obtained

SERVM resource adequacy metrics consider

- Wide Variation of Load Shapes
- Growth Uncertainty
- Unit Performance

Utilizes a SQL Server database

Analytical vs. Monte Carlo approach to analysis

- Analytical methods work well for small systems and represent a system using mathematical model (A direct mathematical solution)

- Monte Carlo methods simulate the actual process and repeat simulation until convergence criteria is met

- For complex systems, a Monte Carlo “brute force” approach is more appropriate

Types of Monte Carlo Analysis

- Non-Sequential Monte Carlo Simulation
  - Each hour is independent of every other hour
  - Inability to model time-correlated issues
  - Inability to calculate frequency and duration indices
- Sequential Monte Carlo Simulation
  - Steps through time chronologically
  - Ability to model time correlated issues and calculate frequency and duration indices
  - Requires more detailed system data

Utilized SERVM Characteristics

- Multi Area Model
- Multiple Weather Years (supports up to 50 years)
- Detailed DR Representation
- Granular LOLE Calculations

Additional SERVM Characteristics

- Renewable Generation Modeling
- Transportation model to represent multiple neighbors and interconnections
- Full Economic Dispatch of Resources Allowing for Dispatch Constraints on Resources
- Alternative Dispatch During Reliability Events
- Operating Reserves Modeled Based on NERC Guidelines
- Economic Calculations
- Scarcity Pricing Algorithms
- Production Costing Ability

Utilized SERVM Modeling Components

- Weather Years
  - Multiple load shapes
- Economic Load Forecast Error (LFE)
- Unit Outage Modeling
- Energy Limited Resource Modeling
  - Demand Side Options

Additional SERVM Modeling Components

- Weather Years
  - Thermal Capacity/Hydro
- Energy Limited Resource Modeling
  - Hydro and Pump Storage
  - Renewable resources (.i.e. Wind & Solar)
- Scarcity Pricing, Neighbor Modeling, and Transmission Modeling
- Emergency Operating Procedures

Importance of Load Modeling in LOLE Analysis

- Loss of Load Expectation analysis is largely driven by two factors
  - Generation Uncertainty
  - Load Uncertainty
- Accurately capturing uncertainty is crucial to LOLE analysis
- Load Uncertainty
  - Load Shape
  - Weather Uncertainty
  - Economic Uncertainty

Load Modeling Framework

- Use historic weather years to capture load uncertainty
  - Variance in peak demand
  - Variance in load shape

- Results in more diverse and comprehensive load modeling
  - More accurate shoulder and non-peak load variance and uncertainty

- Utilize Neural-Net software to “train” data

Load Training Process

Historical load and weather data formatting

↓

5-year load growth adjustment

↓

Neural-net training

↓

Neural-net predicting

↓

Extreme temperature adjustment

↓

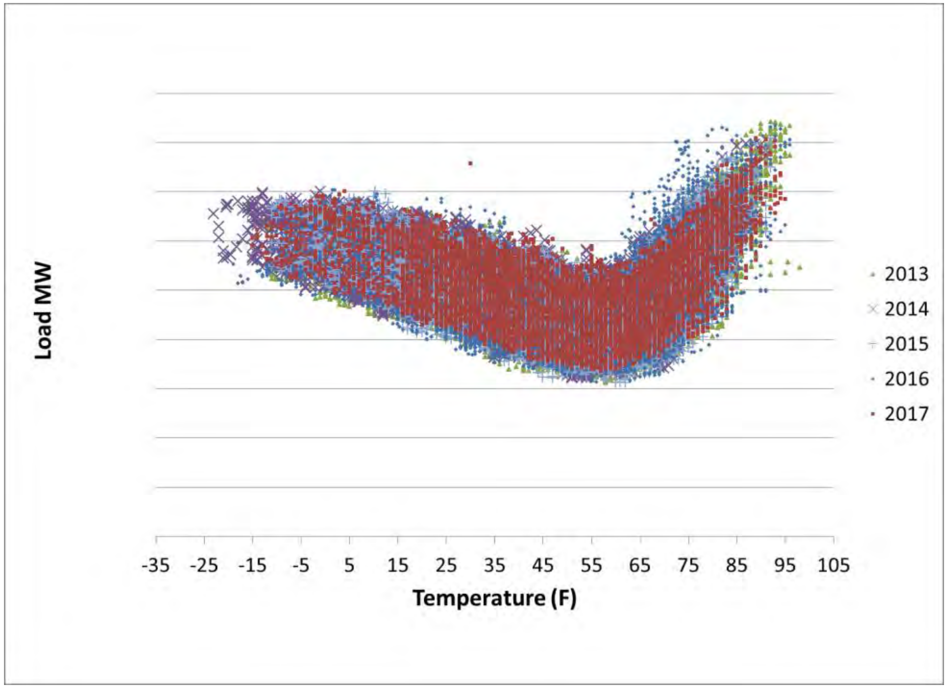
Load forecast adjustment

Data Sources for Load Training

- Historical real-time settlement load data
  - Source: MISO
  - 2013 to 2017
- Historical real-time LMR performance
  - Source: MISO
  - Voluntary and MISO deployments
  - 2015-2017
- Historical weather data
  - Source: NOAA
  - 1989 to 2017
- LSE load forecasts
  - Source: LSE submittals to MECT

Historical Load and Weather Formatting

- 5 years of hourly load and temperature (2013-2017)
- Weather data (2013-2017)
  - Month
  - Temperature
  - Time of Day
  - Day of Week
  - 24 hour ago Temperature
  - 48 hour ago Temperature
- Holidays are set to Sunday
  - New Year's Day
  - Memorial Day
  - Independence Day
  - Labor Day, Thanksgiving Day & Christmas Day



5-Year Load Growth Adjustment

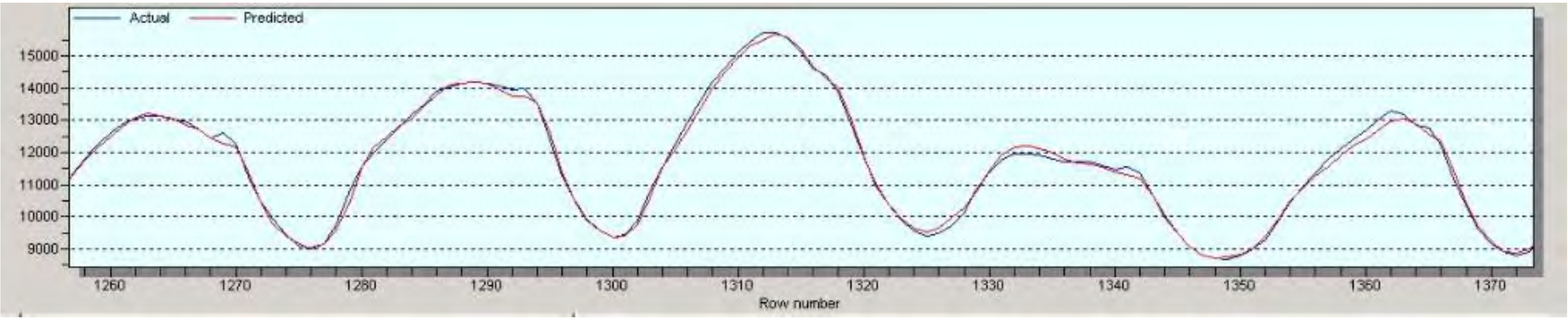
- 5 years of load data should not include load growth due to economics
- Load normalized to consistent economics
- Adjustment calculated based off high temperature load analysis i.e. 90 degrees and above

NeuroShell Predictor Software

- Ward Systems Group Software
- Used for pattern recognition of multi-variable problems
- Makes predictions based off of established neural-net functional relationships
- Software tutorial can be found at the link below:
  - http://www.wardsystems.com/predictortutorial.asp
- Load Training Input Variables:
  - Month
  - Day of week
  - Time of day
  - Previous hour load
  - Temperature
  - 24 hour ago temperature
  - 48 hour ago temperature
- Load Training Output Variables:
  - Actual Load

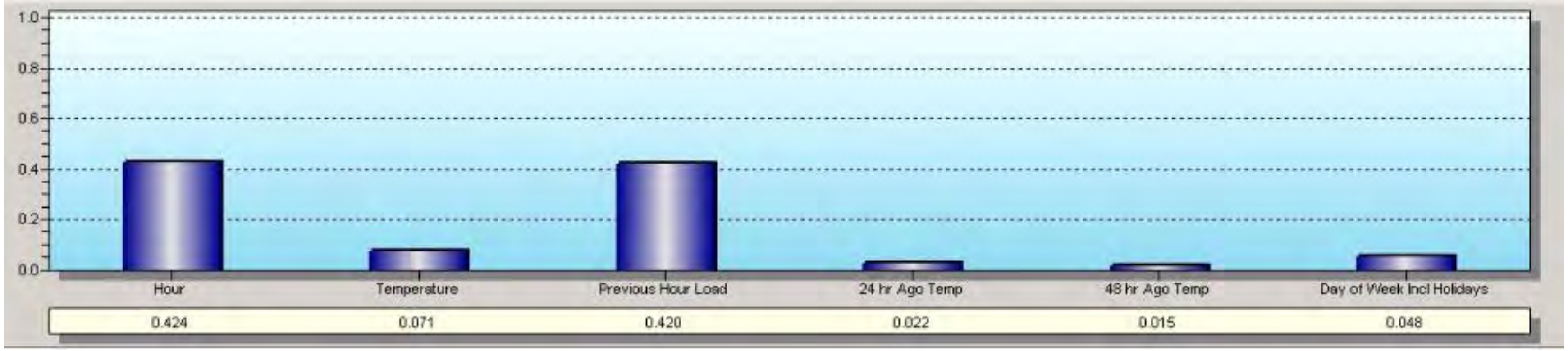
	Hour	Temperature	Previous Hour Load	24 hr Ago Temp	48 hr Ago Temp	Day of Week Incl Holidays	Actual Load
1	0	84	12984.172	78.5	82	1	12052.491
2	1	83	12052.491	70	80	1	11406.383
3	2	83	11406.383	69	76	1	10984.624
4	3	82	10984.624	69	75	1	10747.635
5	4	82	10747.635	72	75	1	10849.012
6	5	81	10849.012	73	74	1	11433.276
7	6	79	11433.276	74	74	1	12365.329
8	7	79	12365.329	74	74	1	13136.045
9	8	78	13136.045	76	75	1	13864.401
10	9	79	13864.401	78	77	1	14259.09
11	10	79	14259.09	82	80	1	14576.561
12	11	78	14576.561	83.5	82	1	14729.459
13	12	79	14729.459	85	84	1	14715.28
14	13	79	14715.28	84	86	1	14659.616
15	14	79	14659.616	67.33333333	87	1	14398.177
16	15	72.75	14398.177	88.5	88	1	14239.96
17	16	73	14239.96	90.5	89	1	14212.895
18	17	73.33333333	14212.895	92	89	1	14188.923
19	18	77.66666667	14188.923	92	90	1	14075.644
20	19	78	14075.644	92	90	1	13852.38
21	20	78	13852.38	90	89	1	13712.71
22	21	80	13712.71	90	87	1	13681.636
23	22	78	13681.636	88	86	1	12928.871
24	23	78	12928.871	87	85	1	12130.917
25	0	77	12130.917	84	78.5	2	11450.251
26	1	78	11450.251	83	70	2	10956.724
27	2	79	10956.724	83	69	2	10612.272

Neural-Net Training



Best net statistics

R-squared	0.996521
Avg.error	91.26518
Correlation	0.99829
MSE	13960.78
RMSE	118.1557
% in range	0.0%
% same sign	100.0%

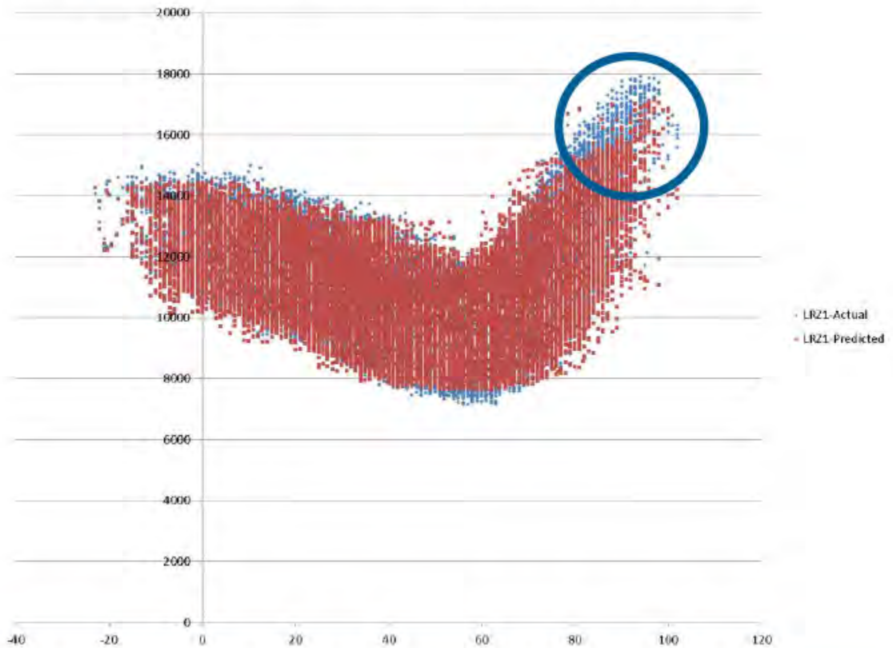


Neural-Net Predicting

- 30 years of historical weather
  - 1989 to 2017
- Neural-Net applied to 30 years of historical weather to predict load
- Output is 30 weather year load shapes at 5 year normalized economy
  - i.e. Predicted 2018 load with1999 weather

Extreme Temperature Verification

- Verify load training at extreme temperatures is accurate
- Less data points at temperature extremes for neural-net training



Load Forecast Adjustment

- Average of 30 predicted load shapes adjusted to match LRZ's 50/50 zonal peak load forecast for study year

- Ratio of 1st years Non-Coincident Peak Forecast to Zonal Coincident Peak Forecast applied to future years Non-Coincident Peak Forecast

- Results in 30 Planning Year weather load shapes
  - i.e. 2019-20 PY load if we have 1995 weather

Economic Load Forecast Error

- Use Projected and Actual GDP Growth Rates for Economic Uncertainty
  - Use Congressional Budget Office (CBO) projections for GDP growth (historic)
  - Compare with the actual GDP growth taken from the Bureau of Economic Analysis
  - Translate the GDP forecast error into electric utility forecast error by multiplying by a scalar
    - Rate at which electric load grows in comparison to GDP
  - Calculate the standard deviation of forecast error
  - Using the standard deviation, create a normal distribution of forecast error

Economic Load Uncertainty

- The 2018/19 PY LOLE study showed that the economic load uncertainty modeling resulted in a 0.2 percentage point increase to the MISO Planning Reserve Margin

	Load Forecast Error (LFE) Levels				
	-2.0%	-1.0%	0.0%	1.0%	2.0%
Standard Deviation in LFE	**Probability to assigned to each LFE**				
1.19%	10.4%	23.3%	32.6%	23.3%	10.4%

Advantages in Load Modeling with historical weather

- Multiple load shapes based on weather more accurately capture
  - Variance in load shapes
  - Variance in peak load
  - Seasonal load uncertainty
  - Frequency and duration of severe weather patterns

- Decouple weather and economic uncertainty

Unit Data

- Unit Name
- Unit Physical Local Resource Zone (LRZ)
- Installation Date
- Retirement Date
- Type (Thermal, Curtailable Load, Renewable)
- Unit Summary Type
  - Thermal (Nuclear, Fossil Steam, Combustion Turbine, Hydro, Pumped Storage Hydro)
  - Curtailable Load (Demand Response)
  - Renewable (Intermittent Resources such as Wind, Run-of-River Hydro, Biomass and Energy Efficiency)
- Thermal Units
  - Utilize the GVTC for a peak capacity and each unit's monthly Net Dependable Capacity (NDC) submitted in PowerGADS determines each unit's monthly capacity profile

Forced Outage Rates & Unit Maintenance – Thermal Units Only

- Forced Outage Rates
  - Time to Repair
  - Time to Failure
- Fixed Maintenance – Typically Nuclear Units
  - Begin Date
  - Stop Date
- Planned Outage Rates
  - Percentage of the year in which a unit will be on scheduled maintenance
  - Planned Outage Factor + Maintenance Outage Factor from PowerGADS
- Maintenance scheduled on days with maximum reserves

Curtailable Load Units (Energy Limited)

- SERVM dispatches Demand Response (DR) based on several constraints
  - Days per week
  - Hours per day
  - Hours per year
  - Dispatch price
- Use limitations to model fatigue
  - Minimum Megawatt (MW) – Zero
  - Maximum Megawatt (MW) – Monthly Profile

Demand Side Management (DSM)

- Renewable Units
- Net Hourly Load Modification
  - Maximum Megawatt (MW) – Monthly Profile
  - Positive values decrease load

Non-Firm Support

- Represents benefit of being part of Eastern Interconnect
- 1 MW of non-firm support reduces requirement by 1 MW
- Reliability targets highly sensitive to fluctuations in non-firm support
- LOLE study uses set MW amount of non-firm

Firm Imports

- External resources FRAP'ed or Offered in MECT are included in LOLE modeling
- External purchases are modeled similar to MISO units
- Modeled from external region to MISO
- Firm imports are only modeled in MISO PRM model and not zonal LRR model
- External firm imports impact LOLE based on unit characteristics

Firm Exports/Sales

- Capacity that is ineligible for MISO PRA is excluded from MISO and zonal models
- Only units that have capacity obligations outside of MISO are designated as sold in the LOLE model
- External firm exports impact LOLE based on unit characteristics

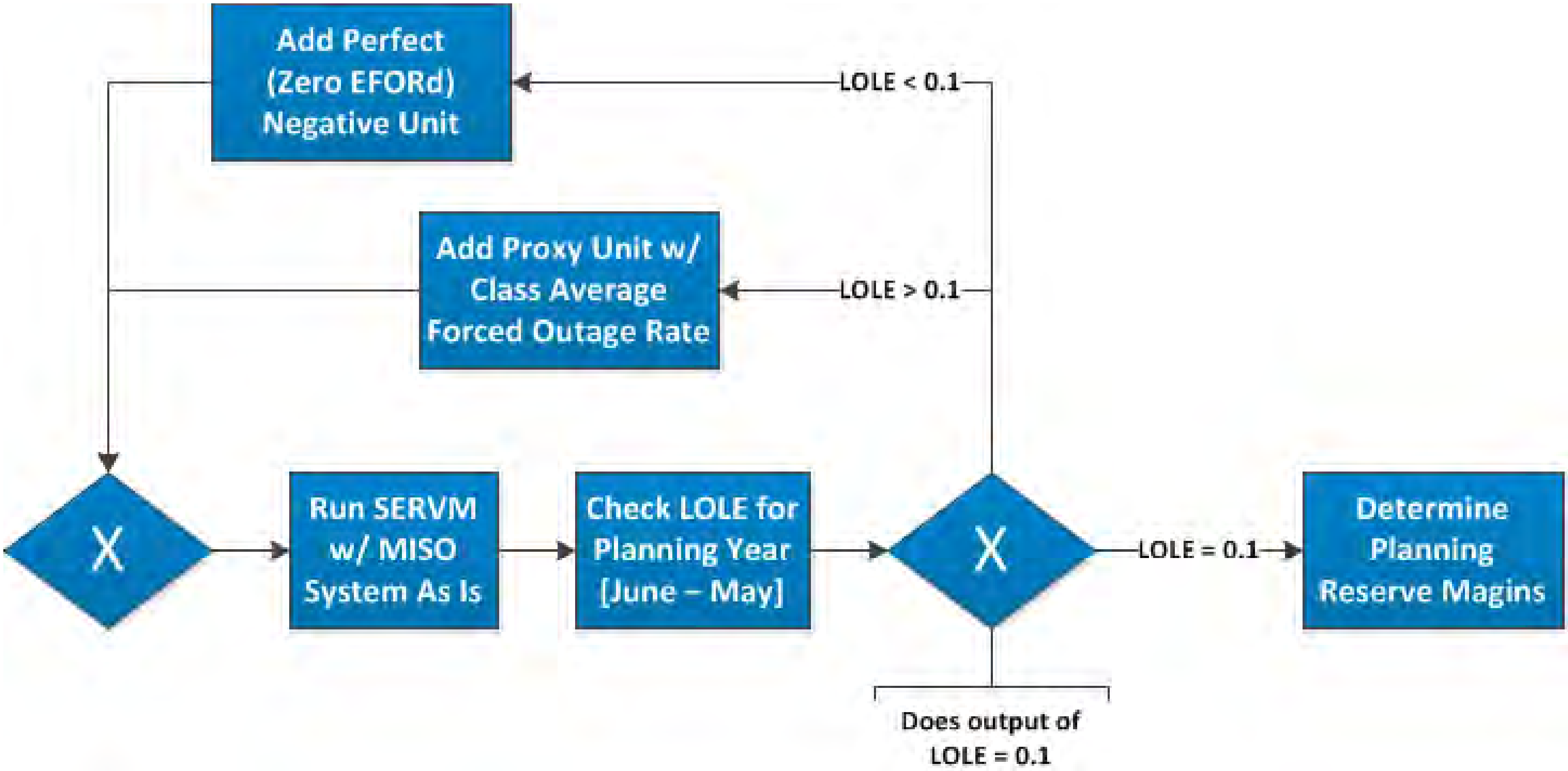
SERVM Simulation Frameworks

30 Weather Years (equal probability) x 5 Economic Uncertainties (Normal Distribution) = 150 Load Scenarios

150 Load Scenarios x 300 unit outage draws = 45,000 8760 hour simulations

** Scenarios are an example of framework and are not fixed

Capacity Adjustment Flowchart



LOLE Study Deliverables to MISO's Planning Resource Action (PRA)

- The LOLE study has four deliverables to the Planning Resource Auction
  - MISO PRM UCAP [%]
  - Local Resource Zones (LRZ) Local Reliability Requirement (LRR) per unit
  - LRZ Capacity Import Limit (CIL)
  - LRZ Capacity Export Limit (CEL)
- LOLE deliverables are applied to updated demand forecasts to calculate PRA requirements

Calculation of MISO PRM [%]

MISO Planning Reserve Margin (PRM)	2018/2019 PY	Formula Key
MISO System Peak Demand (MW)	125,805	[A]
Installed Capacity (ICAP) (MW)	149,901	[B]
Unforced Capacity (UCAP) (MW)	138,505	[C]
Firm External Support ICAP (MW)	4,938	[D]
Firm External Support UCAP (MW)	4,764	[E]
Adjustment to ICAP {1d in 10yr} (MW)	-4,550	[F]
Adjustment to UCAP {1d in 10yr} (MW)	-4,550	[G]
ICAP PRM Requirement (PRMR) (MW)	150,289	[H] = [B]+[D]+[F]
UCAP PRM Requirement (PRMR) (MW)	138,719	[I] = [C]+[E]+[G]
MISO PRM ICAP	19.5%	[J]=[H]-[A]/[A]
MISO PRM UCAP	10.3%	[K]=[I]-[A]/[A]
Post-Processing accounting for non-firm external support		
External Non-Firm Support ICAP (MW)	2,987	[L]
External Non-Firm Support UCAP (MW)	2,331	[M]
With External Support ICAP PRM Requirement (MW)	147,302	[N]=[B]+[D]+[F]-[L]
With External Support UCAP PRM Requirement (MW)	136,388	[O]=[C]+[E]+[G]-[M]
With External Support MISO PRM ICAP	17.1%	[P]=([N]-[A])/[A]
With External Support MISO PRM UCAP	8.4%	[Q]=([O]-[A])/[A]

*MISO Capacity Market procures on UCAP

Calculation of Zonal Requirements and Example PRA Requirements

Local Resource Zone (LRZ)	**LRZ-1 MN/ND**	**LRZ-2 WI**	**LRZ-3 IA**	**LRZ-4 IL**	**LRZ-5 MO**	**LRZ-6 IN**	**LRZ-7 MI**	**LRZ-8 AR**	**LRZ-9 LA/TX**	**LRZ-10 MS**	**Formula Key**
2018-2019 Planning Reserve Margin (PRM) Study											
Installed Capacity (ICAP) (MW)	19,055	15,863	11,145	10,638	8,665	19,458	23,225	11,594	23,514	6,756	[A]
Unforced Capacity (UCAP) (MW)	18,095	14,892	10,613	9,481	7,751	18,165	21,196	10,991	21,674	5,657	[B]
Adjustment to UCAP {1d in 10yr} (MW)	2,326	352	202	2,326	2,411	1,782	3,349	-760	1,595	1,581	[C]
Local Reliability Requirement (LRR) UCAP (MW)	20,422	15,244	10,815	11,807	10,162	19,948	24,545	10,231	23,269	7,237	[D]=[B]+[C]
Peak Demand (MW)	17,789	12,858	9,391	9,709	8,199	17,443	21,296	8,072	20,649	4,859	[E]
LRR UCAP per-unit of LRZ Peak Demand	**114.8%**	**118.6%**	**115.2%**	**121.6%**	**123.9%**	**114.4%**	**115.3%**	**126.7%**	**112.7%**	**148.9%**	[F]=[D]/[E]

Important LOLE Fundamentals Takeaways

- LOLE is the measure of how long, on average, the available generation capacity is likely to fall short of the load demand
  - LOLE is used to study Generation(Resource) Adequacy
  - Probabilistic analysis accurately captures uncertainty risk
- MISO Resource Adequacy criteria for Planning Reserve target is the industry standard LOLE objective:
  - 1-day in 10-years
  - Aligns with NERC standards
- Achieving reliability in the bulk electric systems requires that the amount of resources exceeds customer demand by an adequate margin (Planning Reserve Margin)
  - LOLE models utilize an Equivalized Transportation Model to determine Planning Reserve Margin and Local Reliability Requirements
- All Market Participants are encouraged to participate in the stakeholder process through LOLEWG

Reference Materials

- Past LOLE 101 Documents
  - LOLE 101 (Apil 11th, 2017)
- Loss of Load Expectation Reports
  - 2018 Loss of Load Expectation (LOLE) Study Report
  - Loss of Load Expectation Working Group (LOLEWG)
  - 2018 Wind Capacity Report
  - Resource Adequacy Documents
- Resource Adequacy Documents
  - BPM
    - BPM 011 - Resource Adequacy
  - MISO Tariff: Module E-1
  - NERC Standard BAL-502-RF-03

Appendix

LOLE Terms and Definitions

- **Installed Capacity:** The installed capacity that is physically located within the zone. The ICAP is the output that the generator tested for its max summer output.
- **Unforced Capacity:** The installed capacity less forced outage rates. Capacity Resources are quantified by applying forced outage rates to installed capacity values (ICAP) to calculate the Unforced Capacity value (UCAP) for the resource.
- **Adjustment to UCAP:** The UCAP capacity adjustment within the zone to drive the zone to the "1 day in 10" criteria if the zone was an island. If a zone is more reliable than "1 day in 10" capacity needs to be removed in order to drive the model to the LOLE metric.
- **LRR (UCAP):** Zonal specific reserve margin requirement [MW], capacity above zonal peak load, required to meet "1 day in 10" loss of load expectation requirement if the Local Resource Zone is an island (i.e. completely disconnected from external areas and the rest of MISO).

LOLE Terms and Definitions

- **Peak Demand**: The zone's annual peak demand including transmission losses.
- **Time of Peak Demand (ESTHE):** The date and time of the zones annual peak demand.
- **LRR UCAP per-unit of LRZ Peak Demand**: Zonal specific reserve margin [%], capacity above zonal peak load, required to meet "1 day in 10" loss of load expectation requirement if the Local Resource Zone is an island (i.e. completely disconnected from external areas and the rest of MISO).
- **Capacity Import Limit**: The amount of capacity that a zone can import from outside their zone reliably during peak load before observing a transmission constraint.
- **Capacity Export Limit**: The amount of capacity that a zone can reliably export out of their zone during peak load before observing a transmission constraint.

LOLE Terms and Definitions

- **Forecasted LRZ Load at MISO Peak**: Zone's load coincident with MISO's annual peak load.
- **Firm External Support:** Represents the external resources offered into planning year PRA and are modeled at the individual unit level.
- **External Non-Firm Support:** Represents the benefit of being part of the Eastern Interconnection, where 1 MW increase of no-firm support reduces requirement by 1MW.
- **Local Reliability Requirement**: Zonal specific reserve margin requirement [MW], capacity above zonal peak load, required to meet "1 day in 10" loss of load expectation requirement if the Local Resource Zone is an island (i.e. completely disconnected from external areas and the rest of MISO).

LOLE Terms and Definitions

- **Local Clearing Requirement**: The minimum capacity required to be physically located within a zone to meet the “1 day in 10” Loss of Load Expectation requirement. The LCR is LRR minus the CIL and non-pseudo tied exports.
- **Zone’s System Wide PRMR**: The zones share of the total MISO Planning Reserve Requirement that the zone needs to procure on a UCAP basis [MW]. The difference of the zones system wide PRMR minus the Local Clearing Requirement is the capacity that can be cleared outside of the zone (able to import at peak load) to meet the Planning Reserve Margin Requirement.
- **Planning Reserve Margin (PRM):** The reserve margin, capacity above peak load, the entire MISO footprint needs to procure to meet the “1 day in 10” Loss of Load Expectation requirement. The “1 day in 10” Loss of load requirement is the industry standard risk metric.

PRM and LRR Calculations

$$\text{PRM ICAP} = \frac{[\text{Installed capacity} + \text{ICAP Adjustment to meet 0.1 days/year LOLE} + \text{Firm Contracts}] - \text{MISO Peak Demand}}{\text{MISO Peak Demand}}$$

$$\text{PRM UCAP} = \frac{[\text{Unforced capacity} + \text{UCAP Adjustment to meet 0.1 days/year LOLE} + \text{Firm Contracts}] - \text{MISO Peak Demand}}{\text{MISO Peak Demand}}$$

$$\text{Each LRZ}'\text{s LRR} = \begin{matrix}\text{LRZ Unforced}\\ \text{Capacity}\end{matrix} + \begin{matrix}\text{LRZ UCAP}\\ \text{Adjustment needed}\\ \text{to meet 0.1 d/y LOLE}\end{matrix}$$

$$\text{LRZ per unit LRR} = \frac{\text{LRR}}{\text{LRZ Peak Demand}}$$

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Midcontinent Independent System Operator (MISO)	)))))	Order No. 202-25-3

Exhibit to
Motion to Intervene and Request for Rehearing and Stay of
Public Interest Organizations

Filed June 18, 2025

Exhibit 39

DOE Order No. 202-22-2

Department of Energy
Washington, DC 20585

Order No. 202-22-2

Pursuant to the authority vested in the Secretary of Energy by section 202(c) of the Federal Power Act (FPA), 16 U.S.C. § 824a(c), and section 301(b) of the Department of Energy Organization Act, 42 U.S.C. § 7151(b), and delegated to the Deputy Secretary of Energy by paragraph 1.12(A) of Delegation Order No. S1-DEL-S2-2022 (Mar. 14, 2022), and further delegated by the Deputy Secretary by email correspondence (Sept. 2, 2022), and for the reasons set forth below, I hereby determine that an emergency exists in California due to a shortage of electric energy, a shortage of facilities for the generation of electric energy, and other causes, and that issuance of this Order will meet the emergency and serve the public interest.

Emergency Situation

On September 2, 2022, the Balancing Authority of Northern California (BANC) filed a *Request for Emergency Order Pursuant to Section 202(c) of the Federal Power Act* (Application) with the United States Department of Energy (Department or DOE) "to preserve the reliability of the bulk electric power system in California," and more specifically to allow the BANC Balancing Authority Area (BAA) to request the dispatch of generation within the BANC BAA "that may be necessary for BANC to meet demand in the face of extreme heat." BANC is a joint powers authority whose members include the Sacramento Municipal Utility District and other municipalities, irrigation districts, and public utilities districts. BANC is a registered Balancing Authority with the North American Electric Reliability Corporation and operates as a neighboring BAA to the California Independent System Operator Corporation (CAISO) BAA. On September 4, 2022, BANC filed an *Amended, Supplemented and Clarified Request for Emergency Order Pursuant to Section 202(c) of the Federal Power Act* (Amended Application) in response to questions from DOE.

California has experienced several periods of extreme heat, drought conditions, and threat of wildfires. Such conditions are expected to occur over the next several days and threaten the reliable operation of the bulk electric power system in California. The loads from the forecasted heat wave over the next week are expected to push demand for electric energy by BANC members to at or over historical peaks and higher than normally expected planning targets for this time of year. Amended Application at 2.

On August 31, 2022, California Governor Gavin Newsom issued a proclamation declaring a state of emergency regarding electricity from September 2 through September 7, 2022.[1] In declaring a statutory emergency, the proclamation cited a number of factors and observations, including the following:

- A significant heat wave will bring temperatures "in excess of 100 degrees throughout the State and is forecast to bring record temperatures 10–20 degrees

[1] GSS 9534-1E-20220831133826 (ca.gov)

above normal throughout the State, exceeding 110 degrees in some areas (the 'Extreme Heat Event');"

- The extreme heat will put a significant demand and strain on California's energy grid and is forecast to be a "West-wide event" meaning that energy demand will be high across the region and "California will have limited ability to import energy from out-of-state;"

- The CAISO issued a Heat Bulletin forecasting high electric demand during the extreme heat event that will "stress the energy grid, with peak load for electricity projected to reach its highest level of the year, exceeding 48,000 megawatts on September 5, 2022;" and

- The CAISO is forecasting supply deficiencies of "over 3,000 megawatts during evening hours from September 4, 2022, through September 6, 2022" and advised that emergency interventions would allow energy customers to make contingency plans ahead of the Labor Day holiday weekend.

The proclamation authorizes several measures aimed at mitigating the emergency and avoiding jeopardizing public health or safety, including directing the California Air Resources Board (CARB) to "implement its State-funded Climate Heat Impact Response Program (CHIRP) to mitigate emissions from any operation pursuant to this Proclamation." The proclamation also directs the California Energy Commission (CEC) to "provide information requested by [CARB] to assist with its implementation" of CHIRP.

BANC noted that it "has prepared this request in consultation with the California Energy Commission (CEC), the California Governor's Office, and the CAISO." Application at 2.

Description of Mitigation Measures

In its Application, BANC described actions it has taken in order to alleviate the generation shortfall. Electric utilities within BANC, in coordination with CEC, CAISO, and the California Governor's Office, have implemented conservation and other extraordinary efforts to procure additional supply. BANC members have been able to obtain some purchases from the Pacific Northwest (PNW) bilateral wholesale markets to help offset the additional need, but the physical interties with PNW are near physical limits. BANC members have also been making use of demand-side programs, including commercial interruptible load programs, residential peak shaving programs, and public appeals for conservation. Amended Application at 2.

Request for Order

BANC has requested an emergency order to allow the BANC BAA to dispatch the Covered Resource described below within the BANC BAA that may be necessary for the BANC to meet demand in the face of extreme heat, subject to the terms set forth herein.

The generators for which BANC is seeking this emergency order consist of 24 diesel-fired generator units owned by NTT Global Data Centers Americas (NTT), located at 1312 Striker Ave, Sacramento, CA 95834, known as "CA 2" and more fully described in the Application Exhibit A – List of Covered Resources (NTT Generators or Covered Resource). The Covered Resource plans to participate in the CEC-administered Demand Side Grid Support program that facilitates availability of resources for emergency purposes. Application at 3; Amended Application at 3-4. Therefore, while the Covered Resource has an aggregate installed capacity of 48MW, BANC requests that this emergency order apply only to capacity necessary to supply the load at the NTT facility served by the Covered Resource, up to 26.1 MW (Covered Maximum Output). Amended Application at 3-4.

BANC has requested that the Secretary issue the requested emergency order by Sunday, September 4, 2022, or as soon as possible thereafter, authorizing the Covered Resource to operate at the Covered Maximum Output level between 2:00 p.m. and 10:00 p.m., when directed to do so by BANC, notwithstanding air quality or other permit limitations.

ORDER

Given the emergency nature of the expected load stress and generation shortfall, the responsibility of BANC as the Balancing Authority to balance generation and load in its BAA to ensure maximum reliability on its system, and the ability of BANC to identify and dispatch generation necessary to meet additional load if an order is issued, I have determined that, under the conditions specified below, generation from the Covered Resource is necessary to best meet the emergency and serve the public interest for purposes of FPA section 202(c) up to the Covered Maximum Output. This determination is based on, among other things:

- The expected shortage of electric energy, shortage of facilities for the generation of electric energy, and other causes in the State of California and within the BANC BAA, including as declared in the Governor's August 31 emergency proclamation and as described in the Application and Amended Application, demonstrate the need for the Covered Resource to contribute to the reliability of the BANC BAA.

- The availability of 26.1 MW of reduced load as enabled by generation from the Covered Resource up to the Covered Maximum Output provides significant assistance by freeing up system generating resources to help alleviate the shortage of generation and meet demand in the BANC BAA.

- The Covered Resource is enrolled in CEC's Demand Side Grid Support (DSGS) program. The DSGS program establishes procedures for qualification, operation, and reporting to ensure that enrolled generation such as the Covered Resource provides verifiable load reduction and thereby increase available system capacity during energy emergency events.

- The conditions in CEC's DSGS and those specified below restrict operation of the Covered Resource to those circumstances necessary to avoid load shed.

In line with the emergency proclamation's anticipation of near-term energy shortages, this Order is limited to a 5-day period, from September 4, 2022, through September 8, 2022. Because the additional generation may result in a conflict with environmental standards and requirements, I am authorizing only the necessary additional generation, under the conditions and with reporting requirements as described below.

FPA section 202(c)(2) requires the Secretary of Energy to ensure that any order that may result in a conflict with a requirement of any environmental law be limited to the "hours necessary to meet the emergency and serve the public interest, and, to the maximum extent practicable," be consistent with any applicable environmental law, and minimize any adverse environmental impacts. BANC anticipates that this Order may result in exceedance of National Ambient Air Quality Standards (NAAQS) under the Clean Air Act and other conflicts with environmental law. This Order would permit operation of the Covered Resource and corresponding emissions of volatile organic compounds (VOCs), nitrogen oxides (NOx), sulfur dioxide (SO_2), coarse particles (PM10), and carbon monoxide (CO), in circumstances not contemplated by the units' Title V permit. Namely, under its Title V permits, the Covered Resource is permitted to operate at certain emission rates during maintenance and when electric service from the serving utility is interrupted by an unforeseeable event, but not in order to assist the utility in avoiding service interruptions for other customers. The Order would permit operation under grid emergency conditions; however, under the conditions specified below, it would not permit exceedance of the emission limits otherwise applicable to the units constituting the Covered Resource, including limits on the pounds of VOC, NOx, SO_2, PM10, and CO emitted per year.

Based on my determination of an emergency set forth above, I hereby order:

A. From September 4, 2022, to September 8, 2022, in the event that BANC determines that generation from the Covered Resource is necessary to preserve the reliability of the bulk electric power system in California, I direct BANC to dispatch such unit or units and to order their operation solely under the following conditions: the issuance and continuation of an Energy Emergency Alert Level 2[2] condition or greater between the hours of 14:00 Pacific Time and 22:00 Pacific Time after exhausting all reasonably and practically available resources.

B. Consistent with good utility practice, BANC shall exhaust all reasonably and practically available resources, including other demand response and

[2] For the purposes of this Order, "Energy Emergency Alert Level 2" has the meaning set forth in Section 3.6.3 of the California ISO System Emergency Operating Procedure, Procedure No. 4420, Version 14.0, Effective Date May 1, 2022 (CAISO Emergency Operating Procedure).

identified behind-the-meter generation resources to the extent that such resources provide support to maintain grid reliability, prior to dispatching the Covered Resource.

C. All operation of the Covered Resource must comply with applicable environmental requirements, including but not limited to monitoring, reporting, and recordkeeping requirements, to the maximum extent feasible while operating consistent with the emergency conditions. This Order does not provide relief from any obligation to pay fees or purchase offsets or allowances for emissions that occur during the emergency condition or to use other geographic or temporal flexibilities available to generators. The Covered Resource must comply with the requirements of the CARB Mandatory Reporting Regulation and California's Cap-and-Trade regulation, to the extent applicable. This Order allows operation of the Covered Resource under operating conditions not otherwise permitted by the Covered Resource's Title V permit but does not provide relief from the obligation to operate the Covered Resource within the equipment-specific or cumulative emission limit requirements specified in the Covered Resource's Title V permit.

D. BANC shall provide such additional information regarding the environmental impacts of this Order and its compliance with the conditions of this Order, in each case as requested by the Department from time to time. By October 10, 2022, BANC shall report source-specific data for all dates between September 4, 2022, and September 8, 2022, on which the Covered Resource was operated, including, for each unit, (1) the hours of operation, as well as the hours in which any permit limit was exceeded, and (2) a preliminary description of each permit term that was exceeded and the manner in which such exceedance occurred. BANC shall also submit a final report by November 14, 2022, with any revisions to the information reported on December 12, 2022. The environmental information submitted in the final report shall also include the following information:

i. Emissions data in pounds per hour for each Covered Resource unit, for each hour of the operational scenario, for CO, NOx, PM10, VOC, and SO_2;

ii. Emissions data must include emissions (lbs/hr) calculated consistent with reporting obligations pursuant to operating permits, permitted operating/emission limits, and the actual incremental emissions above the permit limits;

iii. The number and actual hours each day that each Covered Resource unit operated in excess of permit limits or conditions, e.g. "Generator #1; September 5, 2022; 4 hours; 18:00-22:00 PT";

iv. Amount, type and formulation of any fuel used by each Covered Resource;

v. All reporting provided over the last three years to the United States Environmental Protection Agency or Sacramento Metropolitan Air Quality Management District pursuant to operating permit requirements;

vi. Information provided to the CARB in response to the CARB's development and implementation of the plan to mitigate the effects of additional emissions authorized by the August 31, 2022 proclamation;

vii. Additional information requested by DOE as it performs any environmental review relating to the issuance of this Order; and

viii. Information provided by the Covered Resource describing how the requirements in paragraph C above were met by the Covered Resource while operating under the provisions of this Order.

E. BANC shall inform all affected communities where the Covered Resource operates that BANC has been issued this Order, in a manner that ensures that as many members of the community as possible are aware of the Order, and explain clearly what the Order allows BANC to do, including potential impacts to the community where the Covered Resource is located and communities adjacent to the Covered Resource. BANC shall describe the actions taken to comply with this paragraph in the reports delivered to the Department pursuant to paragraph D above.

F. This Order shall not preclude the need for the Covered Resource to comply with applicable state, local, or Federal law or regulations following the expiration of this Order.

G. BANC shall be responsible for the reasonable third-party costs of performing analysis of the environmental and environmental justice impacts of this Order, including any analysis conducted pursuant to the National Environmental Policy Act.

H. This Order shall be effective upon its issuance, and shall expire at 23:59 Pacific Time on September 8, 2022, with the exceptions of paragraphs F and G and the reporting and analysis requirements in paragraphs D and E. Renewal or amendment of this Order, should it be needed, must be requested before this Order expires.

Issued in Washington, D.C. at 16:20 Eastern Time on this 4th day of September, 2022.

Kathleen Hogan
Acting Under Secretary for
Infrastructure

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c)	)	
Emergency Order: Midcontinent	)	Order No. 202-25-3
Independent System Operator	)	
(MISO)	)	
	)	

Exhibit to
Motion to Intervene and Request for Rehearing and Stay of
Public Interest Organizations

Filed June 18, 2025

Exhibit 40

NERC 2024 Reliability Report

NERC

NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

2024 State of Reliability

June 2024

[2024 SOR Infographic](#)

[2024 SOR Overview](#)

[2024 SOR Video](#)

Technical Assessment of 2023 Bulk Power System Performance

Table of Contents

Chapter 4: Grid Performance

Grid performance is evaluated through established reliability metrics and more in-depth analysis of specific aspects of the BPS:

- Reliability Metrics
- Frequency Response Performance
- Generation Performance and Availability
- Transmission Performance and Unavailability

Reliability Metrics

By calculating 2023 reliability metrics[70] and comparing the results to the previous years as well as the five-year average values, the reliability metrics discussed in this chapter can be categorized as either Improving, Stable, Monitor, or Actionable. Measuring and trending the relative state of the BPS in this manner supports NERC's obligation to assess the capability of the BPS. Table 4.1 shows the status of the reliability metrics and includes a reference to the specific metric.

<table>
<tr><th colspan="4">Table 4.1: Reliability Indicators</th></tr>
<tr><th>Metric Name</th><th colspan="3">Metric Performance Status</th></tr>
<tr><td>M-1: Reserve Margin</td><td colspan="3">Actionable</td></tr>
<tr><td>M-2: Transmission-Related Events Resulting in Loss of Load (Excluding Weather)</td><td colspan="3">Improving</td></tr>
<tr><td>M-3: System Voltage Performance</td><td colspan="3">Retired</td></tr>
<tr><td>M-4: Interconnection Frequency Response</td><td>Improving: Texas Interconnection</td><td>Stable: Eastern and Western Interconnections</td><td>Monitor: Québec Interconnection</td></tr>
<tr><td>M-4.1: Inertia and Rate-of-Change-of-Frequency</td><td>Improving: Texas Interconnection</td><td>Stable: Eastern and Western Interconnections</td><td>Monitor: Québec Interconnection</td></tr>
<tr><td>M-5: Activation of Under Frequency Load Shedding</td><td colspan="3">Retired</td></tr>
<tr><td>M-6: Disturbance Control Standard Failures</td><td colspan="3">Metric is Under Review</td></tr>
<tr><td>M-7: Disturbance Control Events Greater than Most Severe Single Contingency</td><td colspan="3">Metric is Under Review</td></tr>
<tr><td>M-8: Interconnection Reliability Operating Limit (IROL) Exceedance</td><td>Improving: Texas and Western Interconnections</td><td></td><td>Monitor: Eastern and Québec Interconnections</td></tr>
<tr><td>M-9: Protection System Misoperations Rate</td><td colspan="3">Stable</td></tr>
<tr><td>M-10: Transmission Constraint Mitigation</td><td colspan="3">Retired</td></tr>
<tr><td>M-11: Energy Emergency Alerts</td><td colspan="3">Improving</td></tr>
<tr><td>M-12: Automatic AC Transmission Outages Initiated by Failed Protection System Equipment</td><td colspan="3">Improving</td></tr>
<tr><td>M-13: Automatic AC Transmission Outages Initiated by Human Error</td><td colspan="3">Improving</td></tr>
<tr><td>M-14: Automatic AC Transmission Outages Initiated by Failed AC Substation Equipment</td><td colspan="3">Improving</td></tr>
</table>

[70] Current Approved Reliability Metrics; Metrics M-3, M-5, and M-10 are retired.

Table 4.1: Reliability Indicators	
Metric Name	**Metric Performance Status**
M-15: Automatic AC Transmission Outages Initiated by Failed AC Circuit Equipment	Improving
M-16: Transmission Element Availability Percentage and Unavailability Percentage	Stable
M-17: Transmission Outage Severity	Stable

Frequency Response Performance

Frequency response arrests and stabilizes frequency during system disturbances. NERC closely monitors the frequency response of each of the four Interconnections and measures the margin at which under-frequency load shedding (UFLS) would be activated. UFLS provides a vital safety net for preserving Interconnection reliability. Measuring the margin allows NERC and the industry to ensure that there is adequate frequency response on the system.

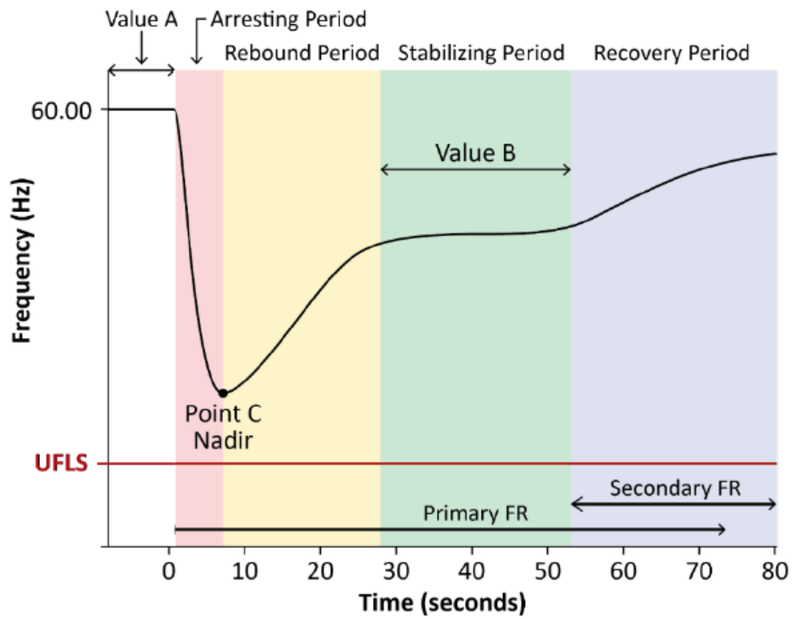


Figure 4.1: Frequency Response Methodology

During the arresting period, the goal is to arrest the frequency decline for credible contingencies before the activation of UFLS. The calculation for Interconnection frequency response obligation (IFRO) under BAL-003 is based on arresting the Point C nadir before the first step of UFLS for resource contingencies at or above the resource loss protection criteria (RLPC)[71] for the Interconnection. Measuring and tracking the margin between the first-step UFLS set point and the Point C nadir is an important indicator of risk for each Interconnection. Figure 4.1 indicates the measurement periods used for analysis of the arresting period of events by looking at the frequency response between Value A and Point C as well as at the margin between Point C and the first-step UFLS set point.

During the stabilizing period, the goal is to stabilize system frequency following a disturbance primarily due to generator governor action. Figure 4.2 indicates the measurement periods used for analysis of the stabilizing period of events by looking at the frequency response between Value A and Value B.

2023 Interconnection Frequency Response

2023 performance and trends frequency response analysis indicate an adequate level of reliability.

- For the stabilizing period, the Interconnection frequency response,[72] the Eastern Interconnection, the Québec Interconnection, and the Western Interconnection showed no statistically significant changes from 2019 through 2023. The Texas Interconnection showed a statistically significant improvement for the stabilizing period from 2019 through 2023.
- For the arresting period, the inertia and rate-of-change-of-frequency (ROCOF),[73] the Eastern and Western Interconnections showed no statistically significant changes from 2019 through 2023. The Texas

[71] BAL-003-2 specifies that the RLPC be based on the two largest potential resource losses in an Interconnection or the largest resource loss due to an N-2 RAS. This value is updated annually through the BAL-003-2 data collection process.
[72] Interconnection Frequency Response, M-4
[73] Inertia and Rate-of-Change-of-Frequency, M-4.1

Interconnection showed a statistically significant improvement. The Québec Interconnection showed a statistically significant decreasing trend.

Of note in 2023, as shown in Table 4.2, the Western Interconnection had two events within the five-year period in which the measured frequency response was less than the IFRO. Both events had a starting frequency well above 60.00 Hz and had a confirmed MW loss under 500 MW. These two factors combined alleviate concerns that the Western Interconnection frequency response is insufficient. Also, of note in 2023 was the decreasing trend in the inertia and ROCOF for the Québec Interconnection. The Québec Interconnection confirmed an overrepresentation of summer events in 2023 compared to other years (2019–2022). Twenty percent of all events in the past five years occurred between May and October 2023 (months that typically have lower inertia), in part due to the wildfire events in the region. The Eastern Interconnection, Québec Interconnection, and Texas Interconnection did not have any events within the five-year period in which the measured frequency response was less than the IFRO for the respective Interconnection.

Table 4.2: 5-Year Statistical Trend

Interconnection	M-4 Interconnection Frequency Response	M4.1 Inertia and Rate-of-Change-of-Frequency	Margin-C-UFLS	Comment
Eastern	neither decreasing nor increasing	neither decreasing nor increasing	neither decreasing nor increasing	No M4 events with FR below IFRO
Texas	increasing	increasing	increasing	No M4 events with FR below IFRO
Québec	neither decreasing nor increasing	decreasing	neither decreasing nor increasing	No M4 events with FR below IFRO
Western	neither decreasing nor increasing	neither decreasing nor increasing	neither decreasing nor increasing	Two M4 events with FR below IFRO

Of note, the Western Interconnection has had the least number of valid events since frequency response evaluation started. This trend in reduction of valid frequency response events is suspected to be due to the retirement of large generating facilities in the Interconnection over the evaluation period and is a positive indicator when considering impacts to Interconnection reliability.

Frequency response for all Interconnections indicates stable and improving performance for the stabilizing period and arresting period as shown in Table 4.3 and Table 4.4.[74]

Table 4.3: 2023 Frequency Response Performance Statistics for Stabilizing Period

	2023 Operating Year Stabilizing Period Performance					
	Number of Events	Mean Frequency Response	Median	Minimum	Maximum	Number of events with FR below the IFRO
Eastern	47	2,685	2,459	1,138	5,176	0
Texas	38	1,410	1,241	682	2,788	0
Québec	65	762	693	260	1,682	0
Western	28	2,049	1,682	912	5,050	2

74 Frequency Response Performance Statistics

Table 4.4: 2023 Frequency Response Performance Statistics for Arresting Period

	Operating Year (OY)							
	Number of Events	Mean Frequency Response	Median	Minimum	Maximum	Mean UFLS Margin	Median UFLS Margin	Min. UFLS Margin
Eastern	47	2,151	1,969	1,059	3,550	0.454	0.453	0.441
Texas	38	727	738	283	1,604	0.611	0.606	0.579
Québec	65	124	120	48	233	1.022	1.065	0.118
Western	28	868	829	544	1,554	0.415	0.421	0.332

Figure 4.2 represents an analysis of the arresting period of frequency response events. The Y-axis shows the percent UFLS margin from 100% (60 Hz) to 0% (first UFLS set point for the Interconnection). The X-axis represents the MW loss for the event, expressed as a percentage of the RLPC for the Interconnection. The Québec Interconnection had two events at or greater than 100% of the RLPC and maintained sufficient UFLS margin. The largest events for the Eastern Interconnection and Texas Interconnection were 45% and 50%, respectively, as measured by percentage of RLPC.

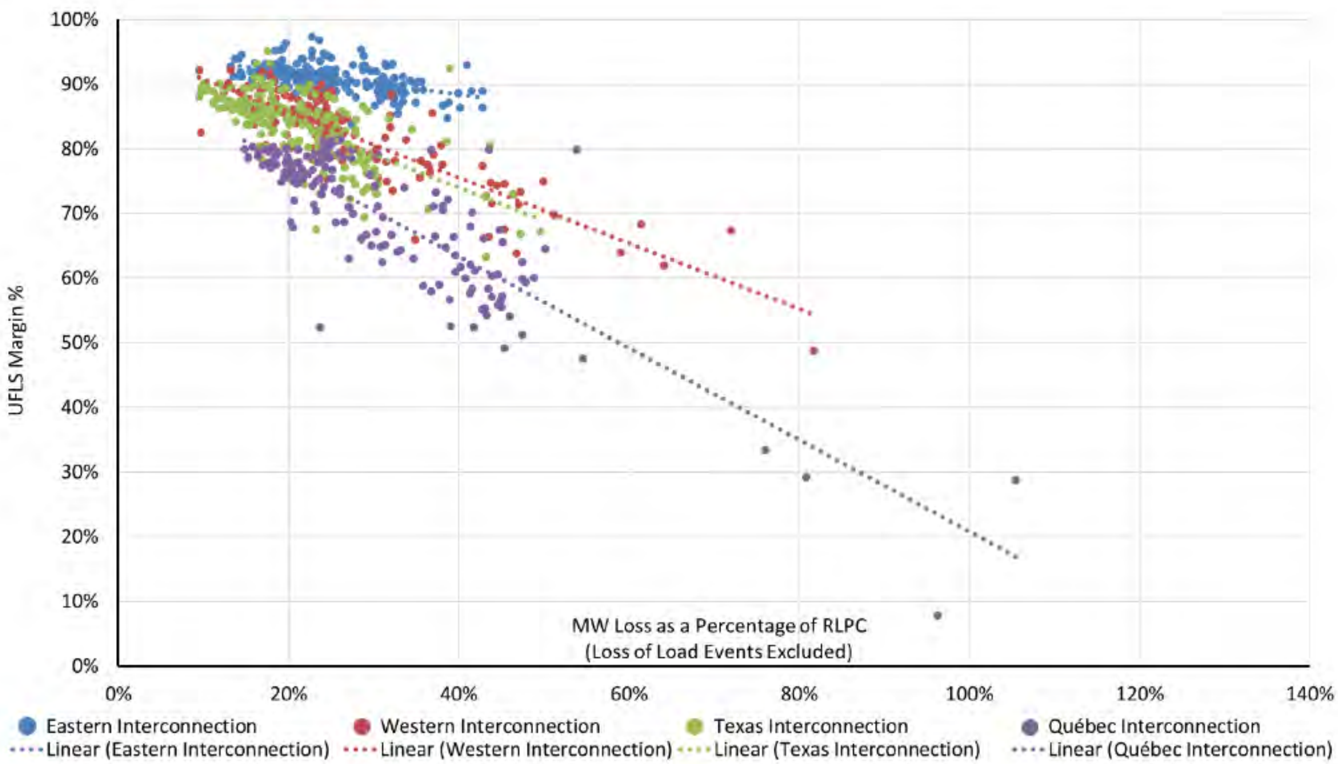


Figure 4.2: Operating Year 2019–2023 Qualified Frequency Disturbances and Remaining UFLS Margin

Interconnection Reliability Operating Limit Exceedances

2023 Performance and Trends

Each RC has a different methodology for determining Interconnection reliability operating limits (IROL)[75] based on the makeup of their area and what constitutes an operating condition that is less than desirable. The following discussion of performance on an Interconnection basis is for clarity, not comparison:

[75] M-8, IROL Exceedance

- **Eastern–Québec Interconnections:** In 2023, there were eight exceedances that lasted more than 10 minutes, less than the five-year average of 19.4 exceedances as shown in Figure 4.3. The 10- to 20-minute range continued to decline from its all-time peak in 2019 with zero exceedances greater than 20 minutes.
- **Western Interconnection:** The trend has been stable with no IROL exceedances reported in 2023.
- **Texas Interconnection:** The trend has been stable with no IROL exceedances reported in 2023.

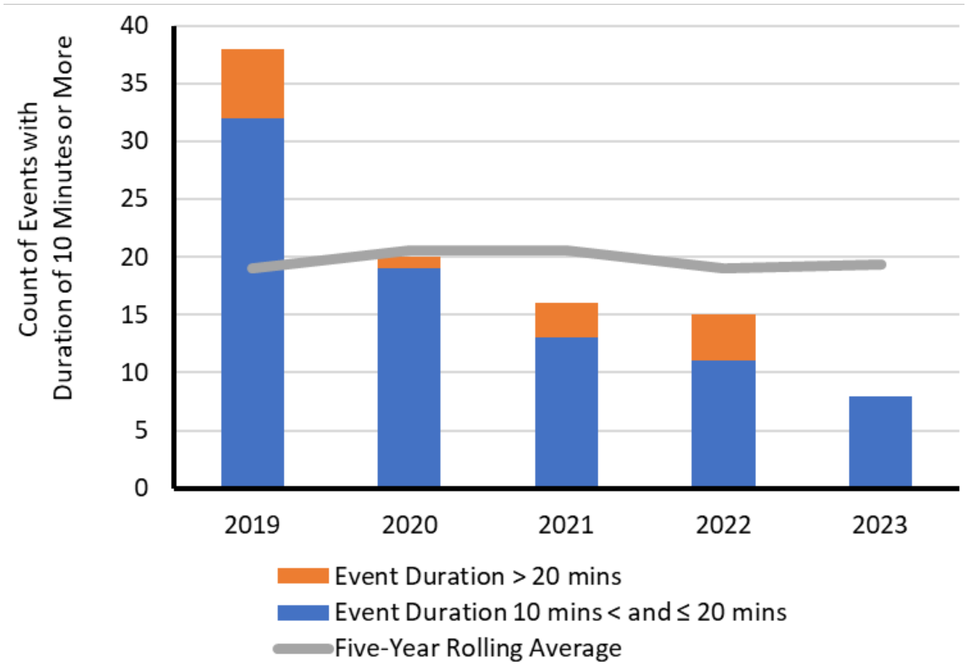


Figure 4.3: IROL Exceedance Counts[76]

Generation Performance and Availability

GADS contains information that can be used to compute reliability measures, such as WEFOR. GADS collects and stores unit operating information by pooling individual unit information, overall generating unit availability, performance, and calculated metrics.

Conventional Generation WEFOR

The horizontal lines in Figure 4.4 show the annual WEFOR compared to the monthly WEFOR columns; the solid horizontal bar shows the WEFOR for all years in the analysis period of 7.4%. While noticeably lower than the two preceding years, the annual WEFOR of 7.8% for 2023 is the third highest since NERC began digitally collecting GADS data in 2013, despite no major outlying winter weather event.

[76] M-8, IROL Exceedance

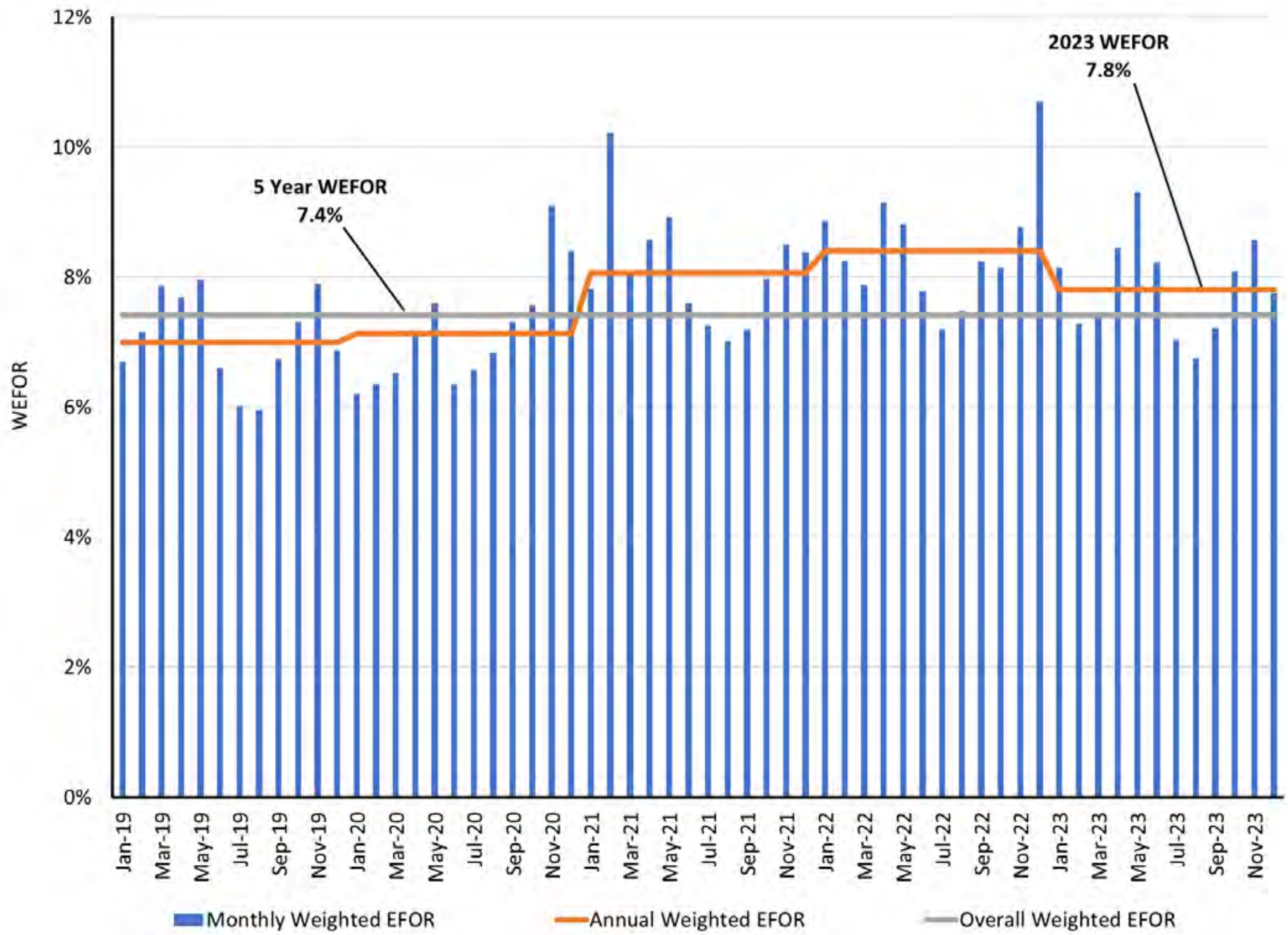


Figure 4.4: Monthly, Annual, and Five-Year WEFOR

To better illustrate 2023's high WEFOR relative to historical norms, Figure 4.5 shows the annual WEFOR by fuel type for the past 10 years. This extended analysis period is presented to illustrate how the abnormally high WEFORs in 2021 and 2022 caused by extreme cold weather conditions obfuscate long-term trends.

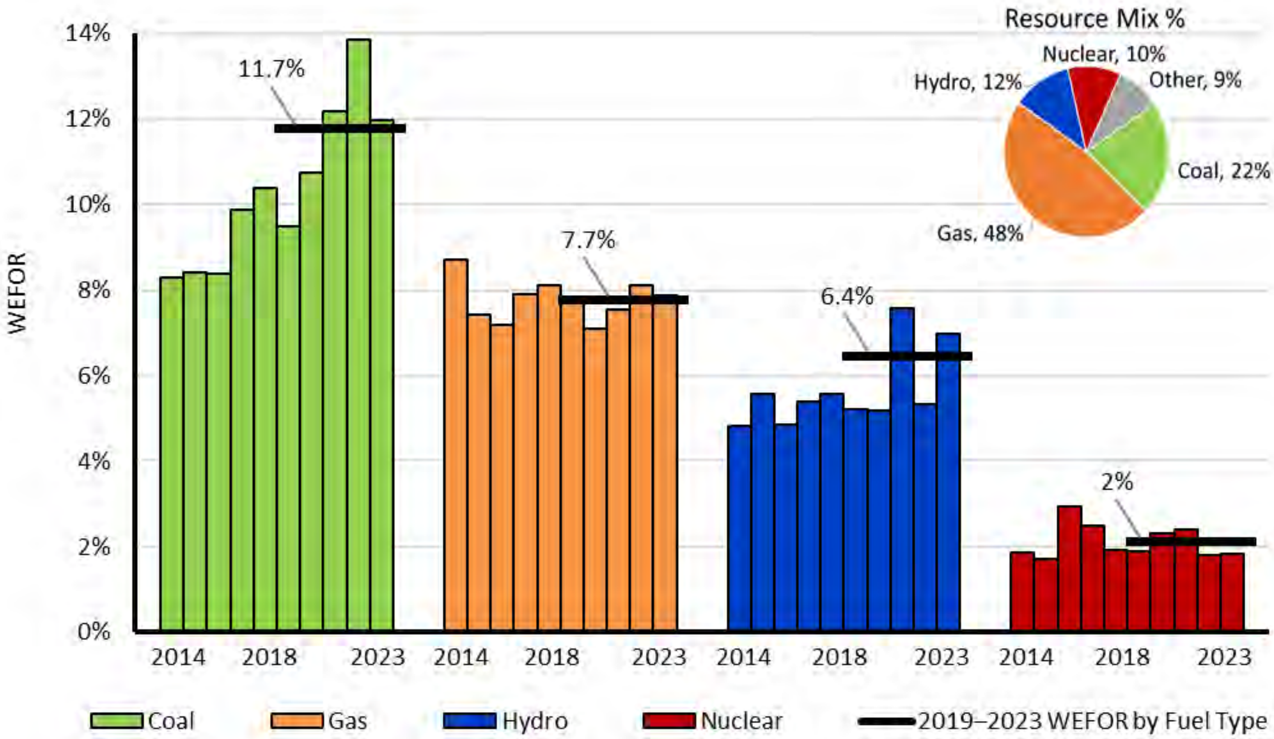


Figure 4.5: 10-Year Annual WEFOR by Fuel Type and 2023 Resource Mix by Net Maximum Capacity

Although coal-fired generation experienced a large decrease in WEFOR in 2023 (12.0% in 2023 versus 13.9% in 2022), it remains above pre-2021 rates. Due to year-over-year variability, coal generation is the primary driver of change in the overall WEFOR despite more energy being produced by both natural gas and nuclear power in 2023 (see Figure 4.6). Further investigation into baseload coal generation indicates that a unit's WEFOR negatively correlates most strongly to capacity factor.[77] Notably, once capacity factor falls below approximately 60%, unweighted average EFORs of units begin increasing more rapidly than those between 60% and 100%. Although forced-outage hours are a definite contributor to lower capacity factor units' increased WEFOR, the disproportionate change appears to be driven more by maintenance/planned outage hours and decreased service hours. This aligns with industry statements indicating that reduced investment in maintenance and abnormal cycling that are being adopted primarily in response to rapid changes in the resource mix are negatively impacting baseload coal unit performance.

Hydro units also experienced an unusually high annual WEFOR (6.9%) for the second time following one in 2021 (7.6%). However, these two relatively high years were both still lower than the associated years' overall WEFOR and do not indicate a trend at this point but warrant continued awareness.

[77] The correlation factor between capacity factor and WEFOR for baseload coal in 2023 was -0.41. While not mathematically indicative of a strong correlation (generally +/-0.7), it is notably stronger than any other aspect that is not a direct component of the WEFOR with the next highest being age (0.18) and planned outage hours (-0.16) given the relatively small sample size and amount of variation between coal units.

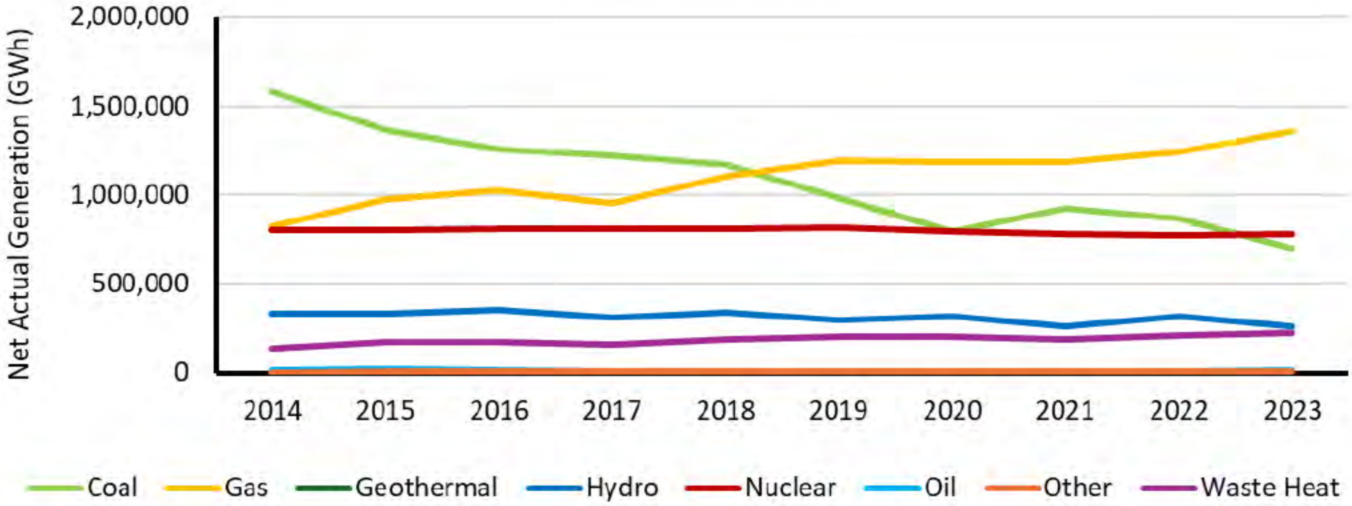


Figure 4.6: 10-Year Annual Conventional Net Actual Generation (GWh) by Fuel Type

Wind Generation Weighted Resource Forced-Outage Rate

NERC began collecting wind performance data with a phased-in approach based on plant size starting with a total installed capacity of 200 MW or greater in 2018 followed by plants with a total installed capacity of 100–199 MW in 2019 and plants with a total installed capacity of 75–99 MW in 2020 (see Figure 4.7). By the end of 2023, data from 137,737 MW of installed capacity, representing 703 wind plants across North America and 13% of nameplate generation, was reported to NERC. Data will continue to be reported separately for the reporting phase groups until sufficient history is available to analyze trends for a five-year rolling period across all wind plants comparable to the analysis for conventional generation. Specific event data collection for wind and solar began in 2024 and will allow for further analysis.

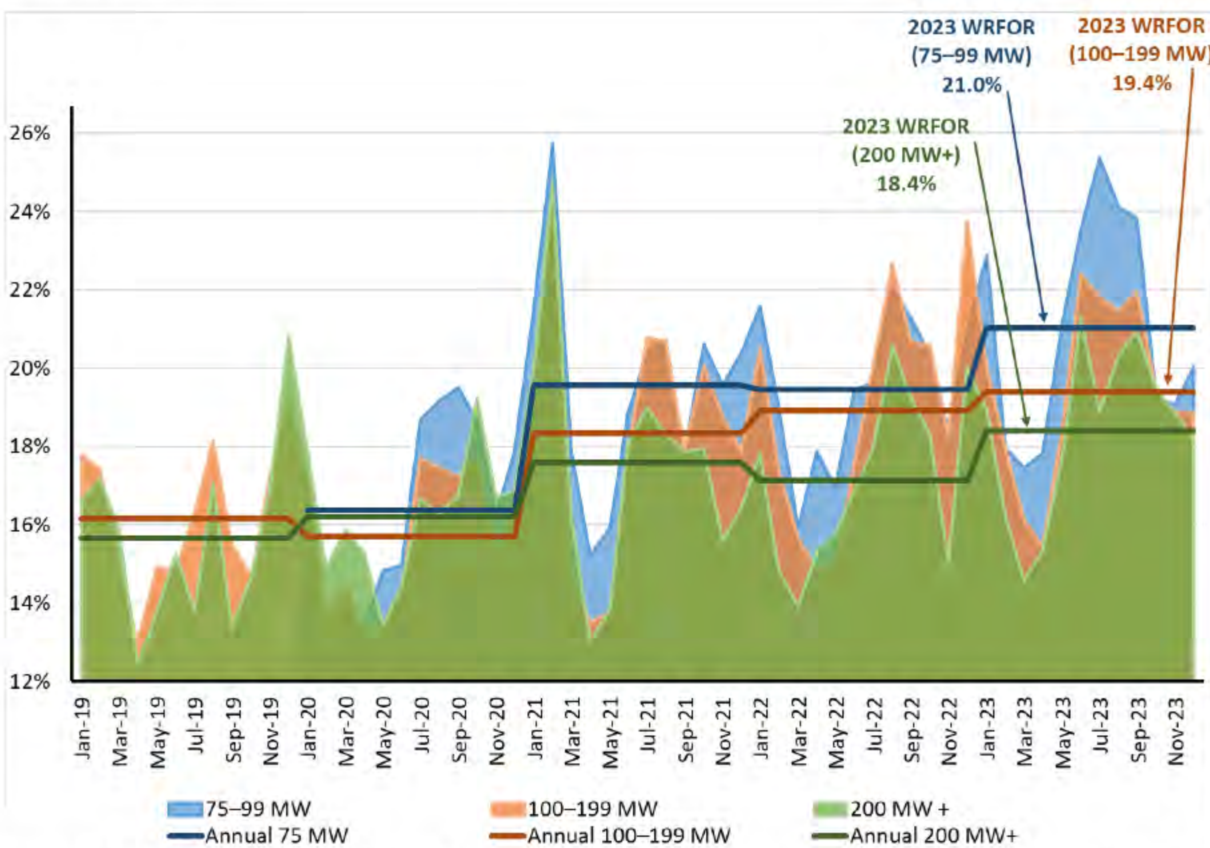


Figure 4.7: Monthly Capacity and Annual Average WRFOR Wind Plant Reporting Group

Transmission Performance and Unavailability

When evaluating transmission reliability, an important concept is that transmission line outages have different impacts on BPS reliability. Some impacts can be very severe, such as those that affect other transmission lines and load loss. Additionally, some outages are longer than others, leaving the transmission system at risk for extended periods of time. Reliability indicators for the transmission system are measured by using qualified event analysis reporting not related to weather and outages reported to TADS. The number of qualified events that include transmission outages that resulted in firm load loss not related to weather is provided in the following subsection.

Transmission-Related Events Resulting in Loss of Load

In 2023, a total of nine distinct non-weather-related transmission events resulted in a loss of firm load that met the ERO EAP reporting criteria (see Figure 4.8). The median firm load loss over the past five years was 97 MW, which is a decrease from 2018–2022's 101 MW. Although, notably, the median load loss was 113 MW in 2023, which is above the five-year median value, no discernible trend in the number of events or amount of loss is identifiable.

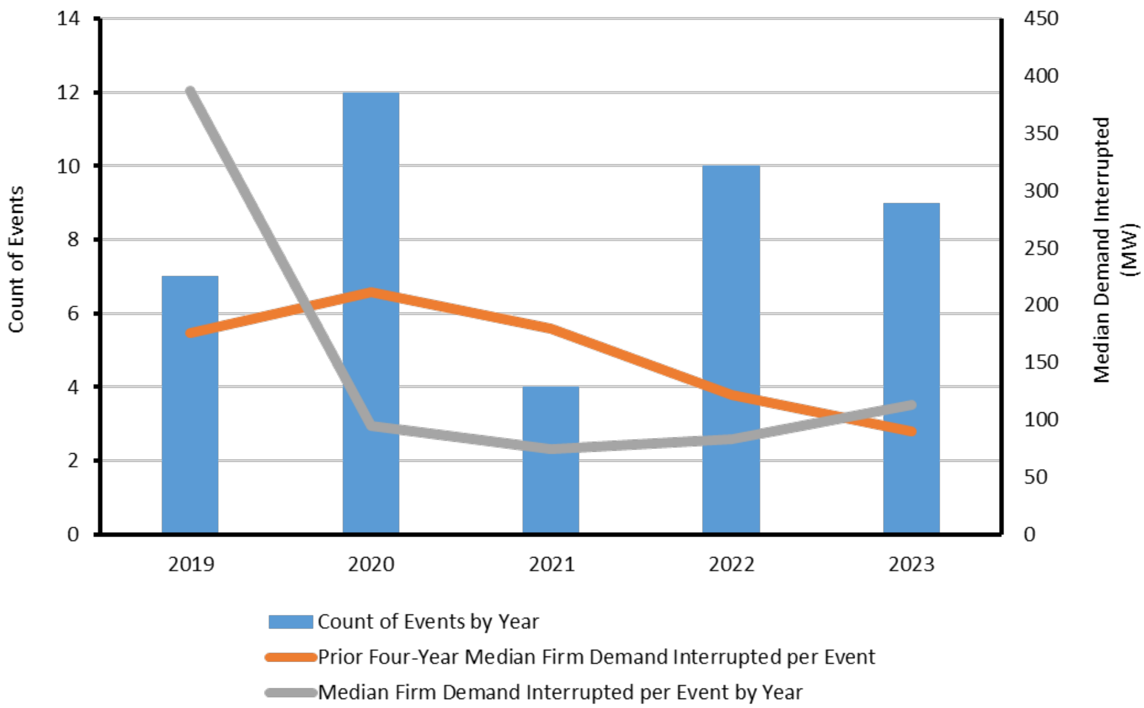


Figure 4.8: Transmission-Related Events Resulting in Loss of Firm Load and Median Amount of Firm Load Loss Excluding Weather-Related Events[78]

TADS Reliability Indicators

A TADS event is an unplanned transmission incident that results in the automatic outage (sustained or momentary) of one or more elements. TADS event information was analyzed for the following indicators in this section:

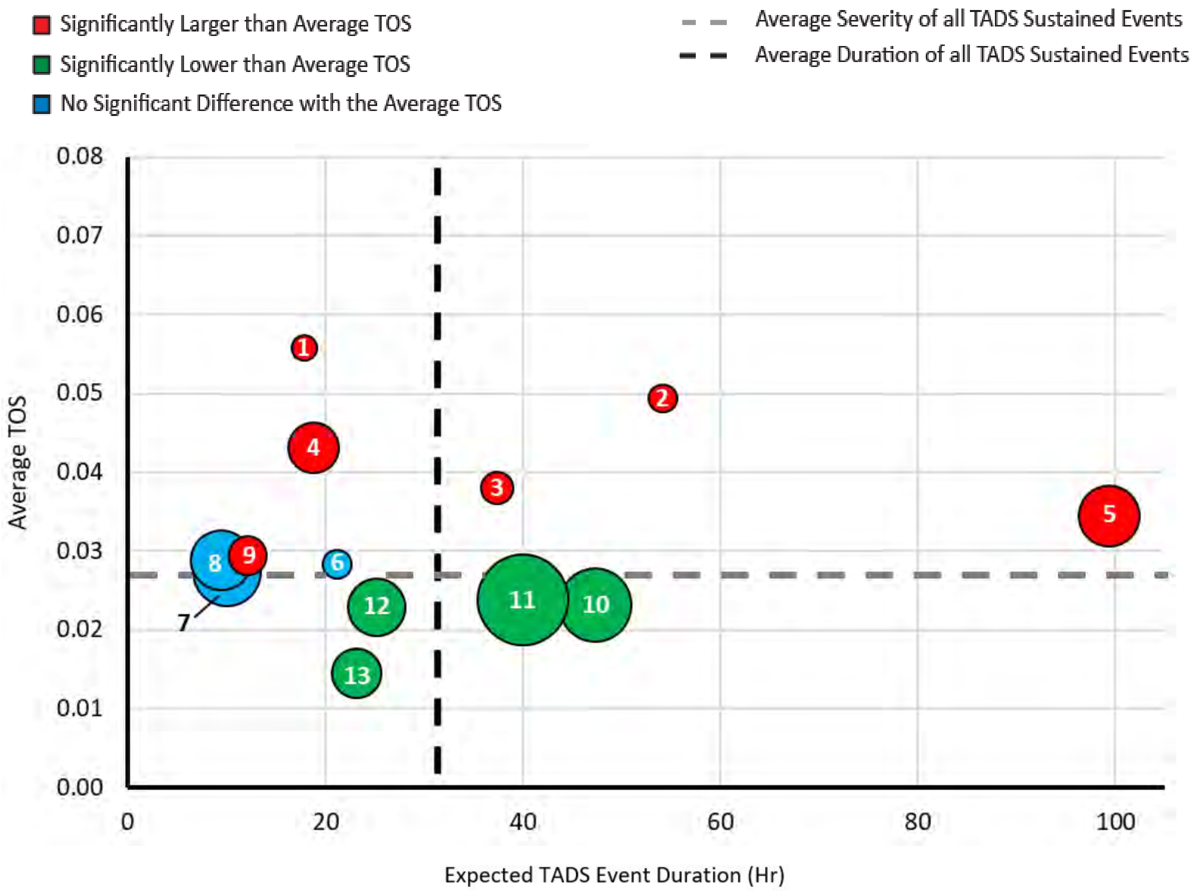
- Transmission Outage Severity
- Automatic AC Transmission Outages
- Transmission Element Unavailability

Transmission Outage Severity

The impact of a TADS event on BPS reliability is called the TOS of the event, which is defined by the number of outages in the event and by the type and voltage class of transmission elements involved in the event. TADS events are categorized by initiating cause codes (ICC). These ICCs facilitate the study of cause-effect relationships between each event's ICC and event severity.

[78] M-2, BPS Transmission Related Events Resulting in Loss of Load (Excluding Weather)

By examining the average TOS, duration, and frequency of occurrence for events with different ICCs (see Figure 4.9), it is possible to determine which ICCs contribute most to reliability performance for the considered period. The average TOS for events with a specific ICC is displayed on the Y-axis. A higher TOS for an ICC indicates that more outages or higher voltage elements were involved in an event. The average duration for events with a specific ICC is displayed on the X-axis; generally, events with a longer duration pose a greater risk to the BPS. The number of ICC occurrences is represented by the bubble size; larger bubbles indicate that an ICC occurs more often. Change in size or position of a bubble with the same number (identifying ICC) may indicate improved or declined performance. Lastly, the bubble colors indicate a statistical significance of a difference in the average TOS of this group and the events from other groups. The number of events per hour, average event duration, and average TOS for each ICC group are shown in Table 4.5.



1. Power System Condition
2. Fire
3. Combined Smaller ICC Groups
4. Misoperation
5. Failed AC Substation Equipment
6. Other
7. Unknown
8. Lightning
9. Human Error
10. Failed AC Circuit Equipment
11. Weather, Excluding Lightning
12. Foreign Interference
13. Vegetation

Figure 4.9: TOS vs. Expected TADS Event Duration

Table 4.5: TOS vs. Expected TADS Event Duration			
TADS Event	Events per Hour	Average TOS	Average Event Duration
Power System Condition	.012	.056	17.9
Fire	.014	.049	54.2
Combined Smaller ICC Groups	.019	.038	37.4
Misoperation	.046	.043	18.8
Failed AC Substation Equipment	.068	.034	99.4
Other	.015	.028	21.2
Unknown	.085	.027	10.0
Lightning	.067	.029	9.5
Human Error	.026	.029	12.2
Failed AC Circuit Equipment	.098	.023	47.3
Weather, Excluding Lightning	.153	.024	40.0
Foreign Interference	.061	.023	25.2
Vegetation	.045	.014	23.2

An analysis of the total TOS by year indicates that 2023 was an outlier from the statistically improving trend identified over the previous five years. Figure 4.10 shows the annual TOS, which is the third highest over the last five years; the shaded area shows the effect of the Québec wildfires on the 2023 TOS.

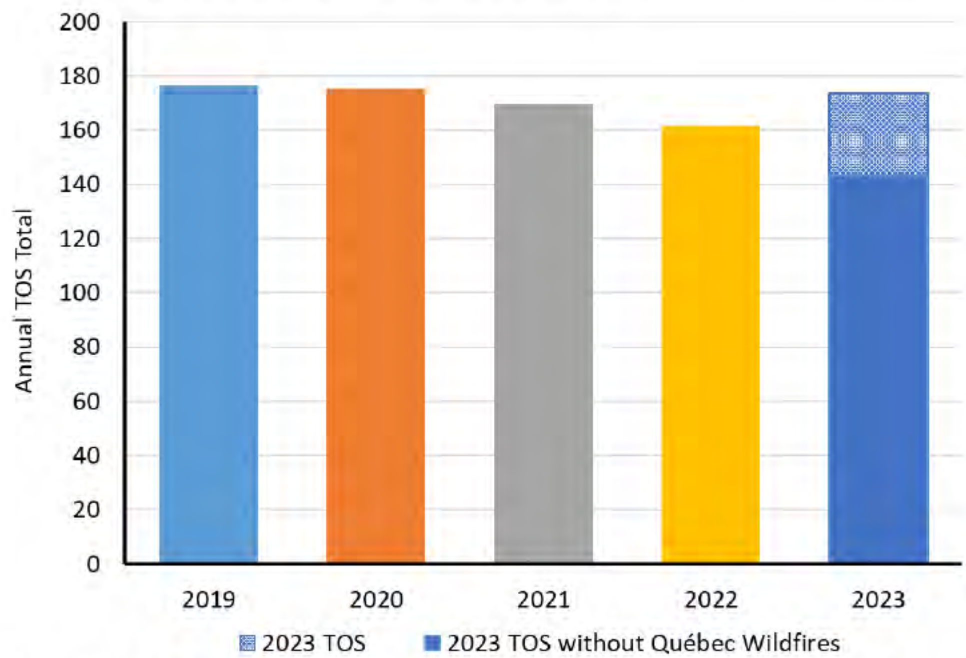


Figure 4.10: TOS of TADS Sustained Events of 100 kV+ AC Circuits and Transformers by Year[79]

Automatic AC Transmission Outages

The average number of outages per circuit due to failed ac substation equipment has continued to improve consistently over the last four years, showing a statistically significant decrease in 2023 compared to 2019–2022 (see Figure 4.11 The number of sustained outages due to failed ac circuit equipment per 100 miles saw a decrease in 2023 (see Figure 4.12).

[79] M-17, Transmission Outage Severity

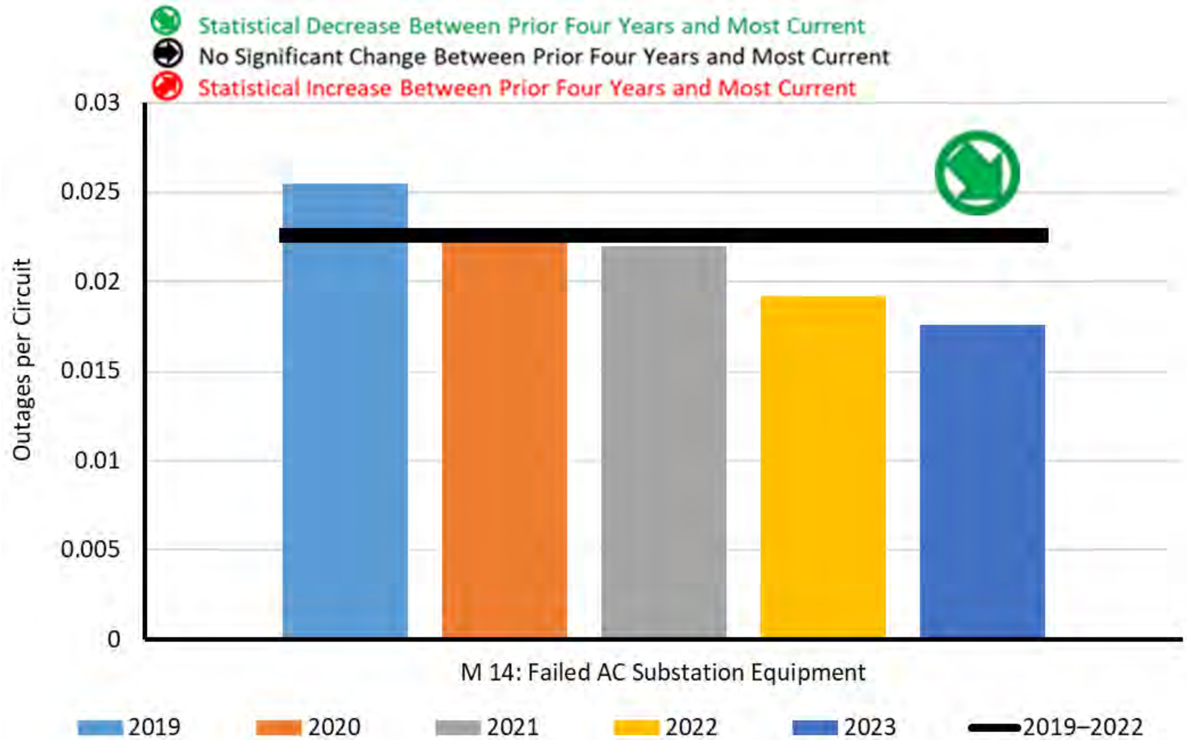


Figure 4.11: Number of Outages per AC Circuit Due to Failed AC Substation Equipment[80]

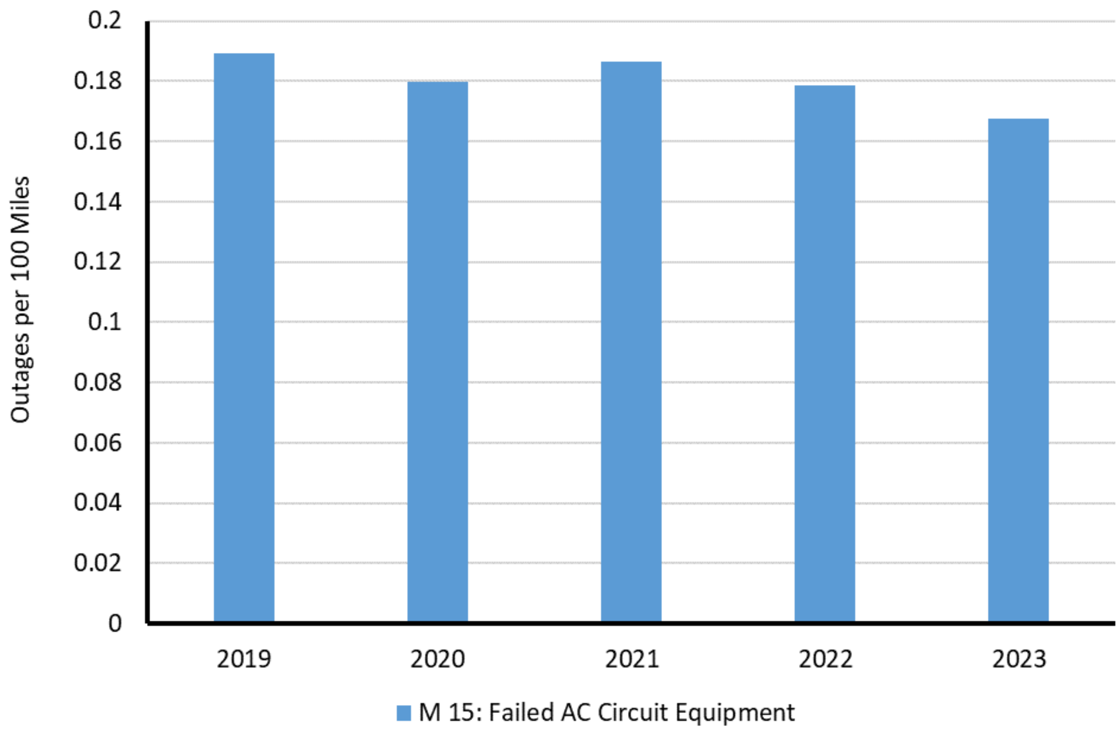


Figure 4.12: Number of Outages per 100 Miles Due to Failed AC Circuit Equipment[81]

[80] M-14, Automatic AC Transmission Outages Initiated by Failed AC Substation Equipment
[81] M-15, Automatic AC Transmission Outages Initiated by Failed AC Circuit Equipment

Automatic AC Transformer Outages

In 2023, the number of automatic ac transformer outages per element caused by failed ac substation equipment was statistically equal to 2019–2022 (see Figure 4.13); the overall average remains stable.

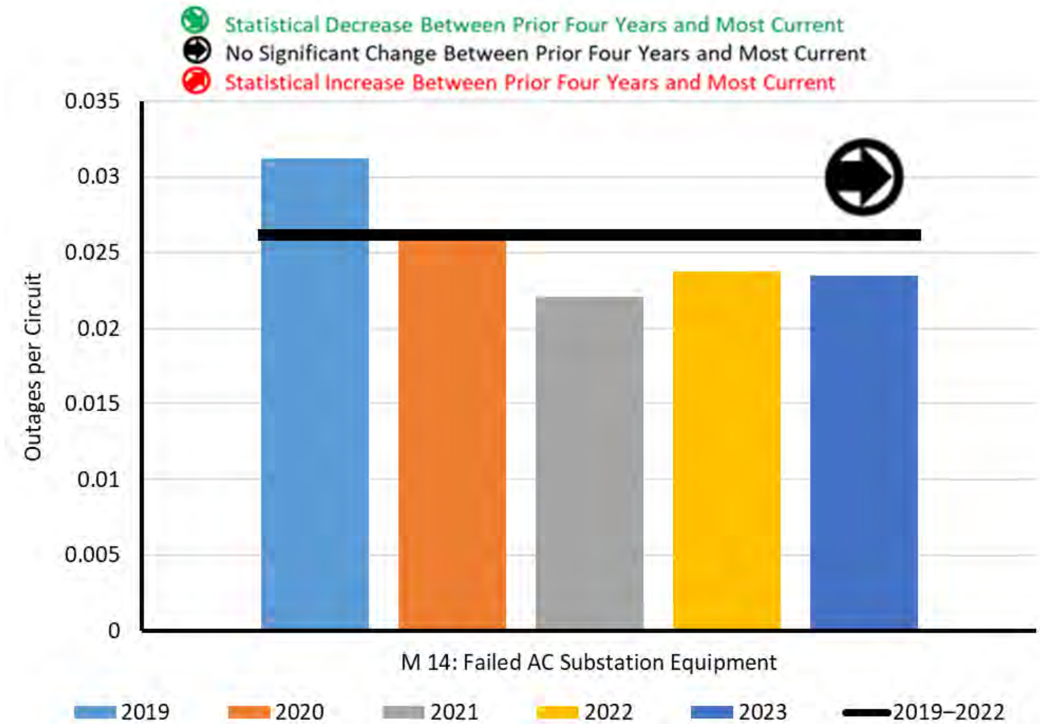


Figure 4.13: Number of Outages per Transformer Due to Failed AC Substation Equipment[82]

Transmission Element Unavailability

In 2023, ac circuits over 200 kV across North America had an unavailability rate of 0.24%, meaning that there is a 0.24% chance that a specific transmission circuit is unavailable due to sustained automatic and operational outages at any given time. Transformers had an unavailability rate of 0.25% in 2023. Figure 4.14 shows that 2023 was the lowest year for ac circuit unavailability of the five-year analysis period. Figure 4.15 shows that 2023 was the second-highest year for transformer unavailability of the five-year analysis period.

[82] M-14, Automatic AC Transmission Outages Initiated by Failed AC Substation Equipment

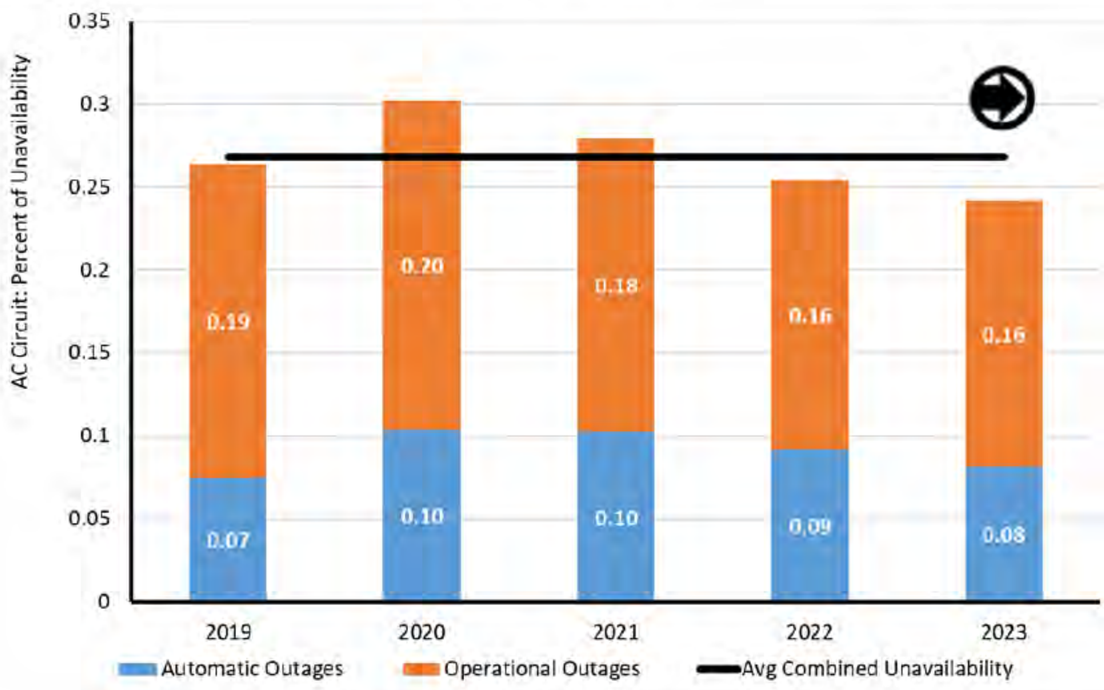


Figure 4.14: AC Circuit Unavailability > 200 kV[83]

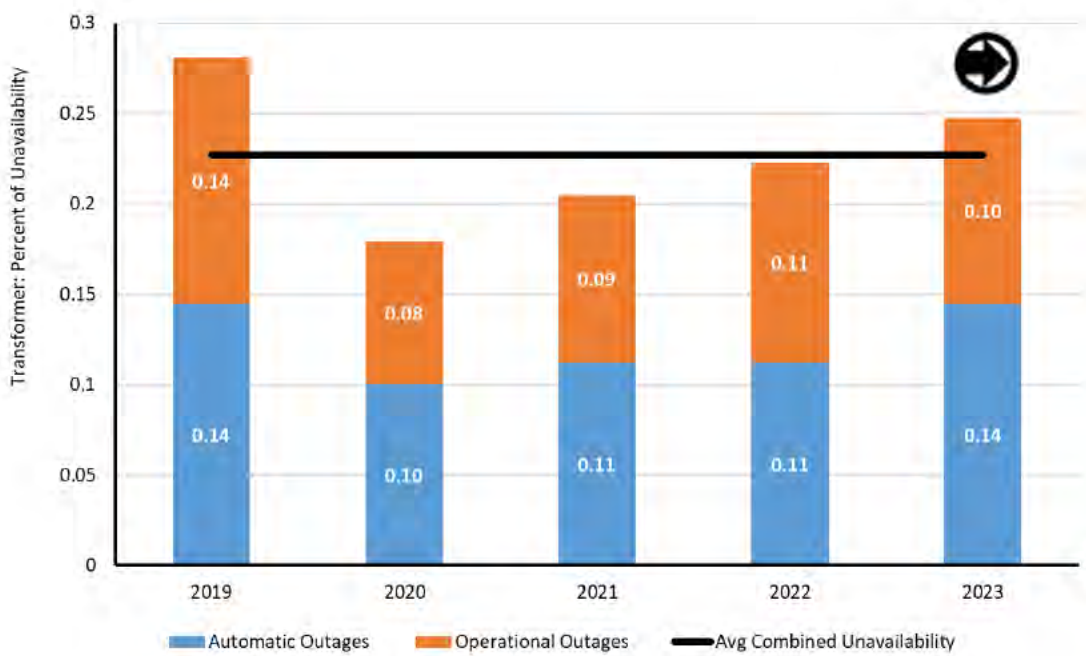


Figure 4.15: Transformer Unavailability[84]

[83] M-16, Element Availability Percentage (APC) & Unavailability Percentage
[84] Ibid.

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Midcontinent Independent System Operator (MISO)	)))))	Order No. 202-25-3

Exhibit to
Motion to Intervene and Request for Rehearing and Stay of
Public Interest Organizations

Filed June 18, 2025

Exhibit 41

NERC 2025 Summer Reliability Assessment

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

2025 Summer Reliability Assessment

May 2025

Table of Contents

Preface

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

Reliability | Resilience | Security

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

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

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

About this Assessment

NERC's *2025 Summer Reliability Assessment* (*SRA*) identifies, assesses, and reports on areas of concern regarding the reliability of the North American BPS for the upcoming summer season. In addition, the *SRA* presents peak electricity demand and supply changes and highlights any unique regional challenges or expected conditions that might affect the reliability of the BPS. The reliability assessment process is a coordinated evaluation between the NERC Reliability Assessment Subcommittee, the Regional Entities, and NERC staff with demand and resource projections obtained from the assessment areas. This report reflects an independent assessment by NERC and the ERO Enterprise and is intended to inform industry leaders, planners, operators, and regulatory bodies so that they are better prepared to take necessary actions to ensure BPS reliability. This report also provides an opportunity for industry to discuss plans and preparations to ensure reliability for the upcoming summer period.

Key Findings

NERC's annual *SRA* covers the upcoming four-month (June–September) summer period. This assessment evaluates generation resource and transmission system adequacy as well as energy sufficiency to meet projected summer peak demands and operating reserves. This includes a deterministic evaluation of data submitted for peak demand hour and peak risk hour as well as results from recently updated probabilistic analyses. Additionally, this assessment identifies potential reliability issues of interest and regional topics of concern. While the scope of this seasonal assessment is focused on the upcoming summer, the key findings are consistent with risks and issues that NERC highlighted in the *2024 Long-Term Reliability Assessment (LTRA*), which covers a 10-year horizon, and other earlier reliability assessments and reports.[1]

Rising electricity demand forecasts, generation growth, and the increasing pace of change in the resource mix feature prominently in the summer risk profile. Since last summer, the aggregate of peak electricity demand for NERC's 23 assessment areas has risen by over 10 GW—more than double the year-to-year increase that occurred between the summers of 2023 and 2024. Over 7.4 GW of generator capacity (nameplate) has retired or become inactive for the upcoming summer, including 2.5 GW of natural-gas-fired and 2.1 GW of coal-fired generators.[2] Meanwhile, growth in solar photovoltaic (PV) and battery storage resources has accelerated with the addition of 30 GW of nameplate solar PV resources and 13 GW of new battery storage. The new solar and battery resource additions are expected to provide over 35 GW in summer on-peak capacity. New wind resources are expected to provide 5 GW on peak. Operators in many parts of the BPS face challenges in meeting higher demand this summer with a resource mix that, in general, has less flexibility and more variability.

The following findings are derived from NERC and the ERO Enterprise's independent evaluation of electricity generation and transmission capacity as well as potential operational concerns that may need to be addressed for Summer 2025.

Resource Adequacy Assessment and Energy Risk Analysis

All areas are assessed as having adequate anticipated resources for normal summer peak load conditions (see **Figure 1**). However, the following areas face risks of electricity supply shortfalls during periods of more extreme summer conditions. This determination of elevated risk is based on analysis of plausible scenarios, including 90/10 demand forecasts and historical high outage rates as well as low wind or solar PV energy conditions:

- **Midcontinent Independent System Operator (MISO):** MISO is expecting to have an existing certain capacity of 142,793 MW in the *2025 SRA*, which is a slight reduction from the 143,866 MW submitted for the *2024 SRA*. The retirement of 1,575 MW of natural gas and coal-fired generation since last summer, combined with a reduction in net firm capacity transfers due to some capacity outside the MISO market opting out of the MISO planning resource auction, is contributing to less dispatchable generation in MISO. With higher demand and less firm resources, MISO is at elevated risk of operating reserve shortfalls during periods of high demand or low resource output. MISO's most recent energy assessment reveals that the period of highest energy shortfall risk has shifted from July to August. This shift is driven by the decline in dispatchable generation and the increasing share that solar and wind resources have in meeting demand. The risk of supply shortfalls increases in late summer as solar output diminishes earlier in the day, leaving variable wind and a more limited amount of dispatchable resources to meet demand.
- **NPCC-New England:** The New England area expects to have sufficient resources to meet the 2025 summer peak demand forecast. As of April 1, the 50/50 peak summer demand is forecast to be 24,803 MW for the weeks beginning June 1, 2025, through September 14, 2025, with a lowest projected net margin of -1,473 MW (6.0%). The lowest projected net margin assumes a net interchange of 1,245 MW, which is capacity-backed; however, ISO New England (ISO-NE) has typically imported around 3,000 MW during summer peak load conditions. ISO-NE anticipates an increase of approximately 500 MW in forced outages from its generating fleet compared to Summer 2024. Based on NPCC's most recent energy assessment, some use of New England's operating procedures for mitigating resource shortages is anticipated during Summer 2025. Cumulative loss of load expectation (LOLE) of <0.031 days/period, loss of load hours (LOLH) of <0.120 hours/period, and expected unserved energy (EUE) of <94 MWh/period were estimated for the expected load with expected summer resources while the reduced resources and highest peak load scenario resulted in an estimated cumulative LOLE risk of 4.369 days/period, with associated LOLH of 19.554 hours/period and EUE of 19,847 MWh/period.
- **MRO-SaskPower:** For the upcoming summer months, no capacity constraints or reliability issues are expected under normal conditions. However, in the event of generator forced outages of more than 350 MW, combined with above-normal peak demand, SaskPower may need to rely on short-term imports from neighboring utilities. Other remedial actions could include quickly activating demand-response programs, adjusting maintenance schedules, and, if necessary, implementing temporary load interruptions. SaskPower's modeling projects

[1] NERC's long-term, seasonal, and special reliability assessments are published on the Reliability Assessments webpage.

[2] Other retirements include 1.2 GW nuclear capacity following the retirement of some units at the Pickering Nuclear Generator Station in Ontario, and 1.6 GW of petroleum, hydro, and other generation. Source: NERC and EIA data.

the probability of experiencing a generation forced outage exceeding 350 MW to be 21.5%. Assuming maximum available imports, the same modeling projects the number of hours with an operating reserve shortfall this summer to be about 0.65 hours with the highest likelihood occurring in June, estimated at 0.43 hours.

- **MRO-SPP:** SPP's Anticipated Reserve Margin (28.5%) is similar to last summer, and resource shortfalls are not expected for the upcoming Summer 2025 season under normal conditions. However, SPP remains at risk for energy shortfalls if above-normal peak demand periods coincide with low wind output and high generator forced outages. Other known operational challenges for the upcoming season include managing wind energy fluctuations; SPP often experiences sharp ramps of its wind generation that can cause transmission system congestion as well as scarcity conditions.
- **Texas RE-ERCOT:** An additional 7 GW of installed solar PV resource capacity and nearly 7.5 GW in new battery storage is helping ERCOT meet rising summer peak demand. ERCOT is projected to have sufficient operating reserves for the August peak load hour given normal summer system conditions. Nevertheless, continued growth in both loads and intermittent renewable resources drives a risk of emergency conditions in the evening hours when solar generation ramps down and loads remain elevated. ERCOT's probabilistic risk assessment of energy emergency alert (EEA) likelihood for the highest risk periods associated with evening hours in the peak month of August is projected to fall to 3%, down from over 15% in 2024. Lower risk is attributed to a nearly doubling of battery energy storage capacity and improved energy availability from new battery storage and operational rules. The South Texas Interconnection reliability operating limit (IROL) continues to present a system constraint, which, under specific unlikely conditions, could ultimately require ERCOT system operators to direct firm load shedding to remain within IROL limits and prevent cascading load loss. For Summer 2025, this risk is being mitigated by updating transmission line dynamic ratings and switching actions to divert power away from the most limiting transmission circuits.
- **WECC-Mexico:** The WECC-Mexico assessment area in Baja California has a peak summer demand of 3,770 MW and is served by a resource mix that is mainly natural-gas-fired generation, with some geothermal, solar, wind, and oil-fired resources (5,636 MW total installed capacity, of which 4,125 MW are gas-fired generators). WECC-Mexico's 14% Anticipated Reserve Margin exceeds the Reference Margin Level for reliability (10%) calculated by WECC. For the upcoming summer, NERC assesses that historically average generator outage rates for peak demand periods can cause a supply shortfall within the WECC-Mexico assessment area and trigger the need for non-firm resources from neighboring areas. Note, in prior SRA reports, the Baja California portion of the BPS was included as part of the WECC-CA/MX assessment area. The *2025 SRA* includes a new assessment area map for the Western Interconnection. The new assessment area boundaries provide reliability risk information in more geographic detail for the United States and Mexico.

Resource additions since last summer have helped lower the risk of energy shortfalls in several areas. Across the U.S. portion of the Western Interconnection, over 6.5 GW of installed solar capacity has been added, along with nearly 7 GW in battery storage. The resources are expected to provide close to 14 GW in on-peak capacity. In British Columbia, new hydroelectric generators were commissioned, contributing to an additional 500 MW in capacity for the summer. The resource additions have alleviated capacity and energy shortfall risks identified in these assessment areas prior to Summer 2024 and provide supplies across the Western Interconnection.

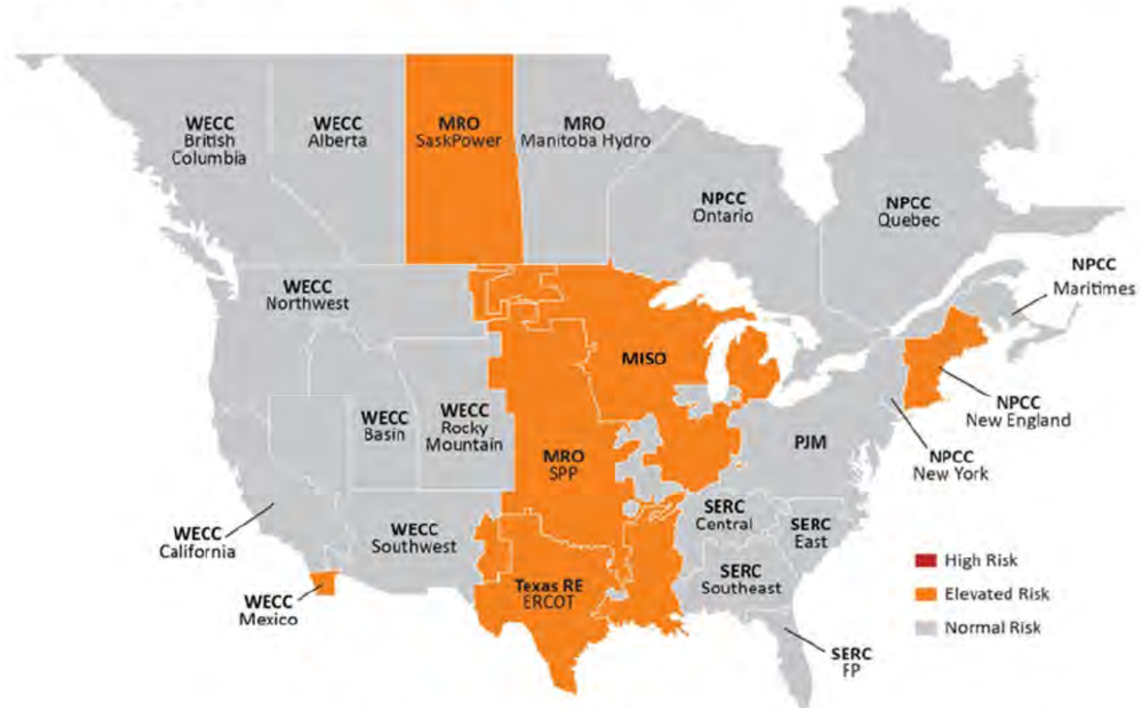


Figure 1: Summer Reliability Risk Area Summary

Seasonal Risk Assessment Summary	
High	Potential for insufficient operating reserves in normal peak conditions
Elevated	Potential for insufficient operating reserves in above-normal conditions
Normal	Sufficient operating reserves expected

Other Reliability Issues

- **Weather services are expecting above-average summer temperatures across much of North America and continued below-average precipitation in the Northwest and Midwest.** In summer-peaking areas, temperature is one of the main drivers of demand and can also contribute to forced outages for generation and other BPS equipment. Average temperatures last summer across the United States and Canada were not as hot as Summer 2023, but Summer 2024 still managed to rank in the top four hottest recorded summers with certain areas breaking records yet again. Few high-level EEAs were issued between June and September 2024, and there were no supply disruptions that resulted from inadequate resources as Balancing Authorities (BA), Transmission Operators (TOP), and Reliability Coordinators (RC) employed a variety of operational mitigations and demand-side management measures. Natural-gas-fired electricity generation broke records last year—highlighting the criticality of natural gas in meeting electric demand. This continuing trend will be key in operator preparations that help to ensure fuel availability for the coming summer. The **Review of 2024 Capacity and Energy Performance** section describes actual demand and resource levels in comparison with NERC's *2024 SRA* and summarizes 2024 resource adequacy events.

- **Load growth is driving higher peak demand forecasts and contributing to resource and transmission adequacy challenges in many areas.** Fifteen of the 23 assessment areas are expecting an increase in peak summer demand from Summer 2024. Aggregated peak demand across all assessment areas has increased by over 10 GW since 2024. This is more than double the increase in peak demand from 2023 to 2024. One of the largest increases is seen in the U.S. West (+5%), where a new peak demand record was set last summer. Extreme heat is reported as a main reliability concern this year among BAs in WECC. With precipitation expected to be lower than average in the Northwest, natural-gas-fired generation and demand-side management could be important in offsetting any lower-than-normal levels of hydroelectric generation availability. SERC Southeast is also projecting a sizable increase in peak demand of more than 2% from NERC's *2024 SRA.* Entities in the assessment area cite economic growth and increased industrial and data mining loads as the main drivers.

- **Aging generation facilities present increased challenges to maintaining generator readiness and resource adequacy.** Forced outage rates for conventional generators and wind resources have trended toward historically high levels in recent years.[3] System operators face increasing risk of resource shortfalls and operating challenges caused by forced generator outages, especially during periods of high demand or when relatively few conventional resources are dispatched to serve load. The threat to BPS reliability can be compounded in areas where aging resources are further depended upon to provide essential reliability services. In the Southwest, for example, a portion of capacity has been in operation for roughly 60 years. Electric utilities in SERC-Central have also described aging generation as a reliability challenge. Historical performance has demonstrated the need for planning assumptions that account for elevated forced outage rates for these generators. Older generators can also require extensive overhauls, such as generator rewinds, that take resources out of service for extended periods of time as discovery work can lead to additional unplanned maintenance.

- **Battery resource additions are helping reduce energy shortfall risks that can arise from resource variability and peaks in demand.** In Texas, California, and across the U.S. West, the influx of battery energy storage systems (BESS) in recent years has markedly improved the ability to manage energy risks during challenging summer periods. These areas can be exposed to energy shortfalls during hours of peak demand and into evening as solar PV output diminishes, but BESS resources that maintain their charge during the day can help meet peak demand and also overcome energy shortfalls on the system that might otherwise occur with solar down-ramps or variability. Natural-gas-fired generation also continues to play an important role in meeting peak demand and flexibly responding to fluctuations output from variable energy resources (VER).

- **Grid operators need to remain vigilant for the potential of inverter-based resources (IBR) to unexpectedly trip during grid disturbances.** While this near-term challenge persists, NERC continues to work diligently with industry to develop long-term solutions to this issue. In April, NERC published the *Aggregated Report on NERC Level 2 Recommendation to Industry: Findings from Inverter-Based Resource Model Quality Deficiencies Alert*.[4] In the report, NERC summarized the deficiencies identified in the Level 2 alert issued in June 2024. The report's findings were as follows:
  - Many grid operators indicated that they did not have the requested data readily available, supporting the previous finding that data acquisition and management was insufficient.
  - Interconnection process requirements are insufficient.
  - Two-thirds of the protection settings used by grid operators are not set to provide the maximum capability. This creates a significant artificial limitation of overall ride-through capability of BPS-connected solar photovoltaic (PV) facilities.
  - 20% of the surveyed facilities use a facility capability with a 0.95 power factor limit, which means that a significant amount of underused reactive capability exists on the BPS.
  - Dynamic model data is inconsistent.

[3] See Key Findings in NERC's [2024 *State of Reliability* report]

[4] *Findings from Inverter-Based Resource Model Quality Deficiencies Alert*

As solar, wind, and battery resources remain the predominant types of resources being added to the BPS, it is imperative for industry, vendors, and manufacturers to take the recommended steps for system modeling and study practices and IBR performance.

- **Operators of natural-gas-fired generators should maintain lines of communication with natural gas system operators to support electric grid reliability.** The 2024 summer season was the fourth hottest on record,[5] and natural-gas-fired generation broke records with a peak monthly average in July of 208 TWh, up 4% from July 2023, per the latest data from the Energy Information Administration (EIA). The EIA projects that rising demand for natural gas exports this year in the wake of ramped up liquefied natural gas (LNG) production combined with lower field production levels could tighten natural gas supplies relative to last summer. Amid year-over-year increases in load projections in most assessment areas, this summer could see another record year for natural-gas-fired generation, thereby stretching supplies even further. Given that late spring and early summer are seasons when natural gas system owners and operators typically perform maintenance requiring system outages, vigilance is needed to ensure the reliability of fuel delivery to natural-gas-fired-generators.[6]
- **Supply chain issues continue to affect lead times for Bulk Electric System (BES) equipment maintenance, replacement, and construction.** While no specific reliability issues for the upcoming summer have been identified, Transmission Owners (TO) and Generator Owners (GO) face delays in parts, materials, and skilled technicians. When summer maintenance preparations or installations are delayed, effects on equipment availability can challenge system operators. Over the long term, supply chain issues and uncertainty continue to affect development. Lead times for transformers remain virtually unchanged, averaging 120 weeks in 2024. Large transformer lead times averaged 80–210 weeks.[7]
- **Wildfire risks in the areas that comprise the Western Interconnection remain ever present.** Wildfire conditions can affect transmission operations by prompting preemptive circuit outages to reduce the risk of fire ignition as well as through fire impacts to transmission infrastructure. Transmission system congestion and reduced import capacity can accompany wildfire conditions. Moreover, fires near wind generation result in curtailment for safety reasons, and solar facilities can be susceptible to range fires. Fire damage to transmission lines interconnected to remote hydro sites in the Pacific Northwest can be particularly problematic with restoration typically taking weeks to months to accomplish.

Recommendations

To reduce the risk of electricity shortfalls on the BPS this summer, NERC recommends the following:

- RCs, BAs, and TOPs in the elevated risk areas identified in the key findings should take the following actions:
  - Review seasonal operating plans and protocols for communicating and resolving potential supply shortfalls in anticipation of potentially extreme demand levels.
  - Consider the potential for higher-than-anticipated forced generator outage rates in operating plans due to plant age, operating patterns, or limited pre-seasonal maintenance availability.
  - Employ conservative generation and transmission outage coordination procedures and operate conservatively commensurate with long-range weather forecasts to ensure adequate resource availability. The review of system performance during the January 2025 cold weather event noted that early declaration of conservative operations in advance of extreme conditions helped reduce grid congestion and enhance transfer capability.[8]
  - Engage state or provincial regulators and policymakers to prepare for efficient implementation of demand-side management mechanisms called for in operating plans.
- GOs with solar PV resources should implement recommendations in the IBR performance issues alert that NERC issued in March 2023.[9]
- State regulators and industry should have protocols in place at the start of summer for managing emergent requests from generators for air-quality restriction waivers. If warranted, U.S. Department Energy (DOE) action to exercise emergency authority under the Federal Power Act (FPA) section 202(c) may be needed to ensure that sufficient generation is available during extreme weather conditions.

[5] US sweltered through its 4th-hottest summer on record – National Oceanic and Atmospheric Administration
[6] Short-Term Energy Outlook - U.S. Energy Information Administration (EIA)
[7] Supply shortages and an inflexible market give rise to high power transformer lead times | Wood Mackenzie
[8] See notable operations practices in Appendix 2 of the *January 2025 Arctic Events System Performance Review | FERC, NERC, and its Regional Entities: A Joint Staff Report*, April 2025.
[9] See NERC Level 2 Alert: Inverter-Based Resource Performance Issues, March, 2023. Owners and operators of BPS-connected IBRs that are currently not registered with NERC should consult NERC's IBR Registration Initiative for information on the registration process.

Summer Temperature and Drought Forecasts

During the summer season, heat drives peak electricity demand as consumers use more electricity to cool their homes and businesses. Summer 2024 was the fourth hottest summer on record for the United States and Canada, and Summer 2025 is expected to bring similar intensity. Assessment area load forecasts account for many years of historical demand data, often up to 30 years, to predict summer peak demand and prepare for more extreme conditions. According to their probabilistic assessments of the coming summer season, late July and early August are the periods most frequently identified among the assessment areas as the expected period of peak demand. Peak demand hours may not coincide with the highest risk hours in the summer as the resource mix shifts during a 24-hour cycle, particularly when there are prolonged periods of above-normal temperatures. Coordinating pre-season preparations and maintenance remains critical to avoiding forced outages where possible and mitigating risks to BPS reliability.

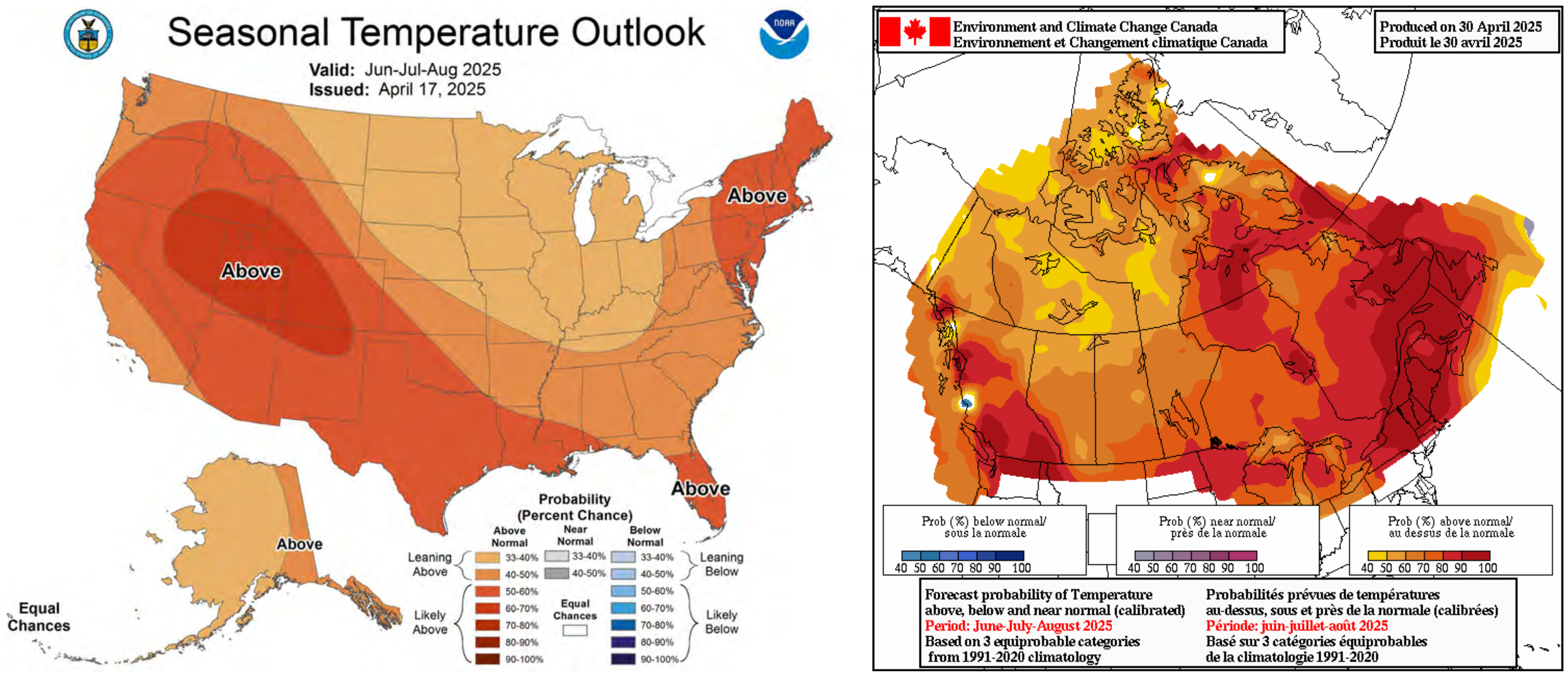


Figure 2: United States and Canada Summer Temperature Outlook[10]

[10] Seasonal forecasts obtained from U.S. National Weather Service and Natural Resources Canada: https://www.cpc.ncep.noaa.gov/products/predictions/long_range/ and https://weather.gc.ca/saisons/prob_e.html

Risk Assessment Discussion

NERC assesses the risk of electricity supply shortfall in each assessment area for the upcoming season by considering Planning Reserve Margins, seasonal risk scenarios, probability-based risk assessments, and other available risk information. NERC provides an independent assessment of the potential for each assessment area to have sufficient operating reserves under normal conditions as well as above-normal demand and low-resource output conditions selected for the assessment. A summary of the assessment approach is provided in Table 1.

Table 1: Seasonal Risk Assessment Summary	
Category	**Criteria**[1]
High Potential for insufficient operating reserves in normal peak conditions	• Planning Reserve Margins do not meet Reference Margin Levels • Probabilistic indices exceed benchmarks (e.g., LOLH of 2.4 hours over the season) • Analysis of the risk hour(s) indicates resources will not be sufficient to meet operating reserves under **normal peak-day demand and outage scenarios**[2]
Elevated Potential for insufficient operating reserves in above-normal conditions	• Probabilistic indices are low but not negligible (e.g., LOLH above 0.1 hours over the season) • Analysis of the risk hour(s) indicates resources will not be sufficient to meet operating reserves under **extreme peak-day demand with normal resource scenarios** (i.e., typical or expected outage and derate scenarios for conditions)[2] • Analysis of the risk hour(s) indicates resources will not be sufficient to meet operating reserves under **normal peak-day demand with reduced resources** (i.e., extreme outage and derate scenarios)[3]
Normal Sufficient operating reserves expected	• Probabilistic indices are negligible • Analysis of the risk hour(s) indicates resources will be sufficient to meet operating reserves under normal and extreme peak-day demand and outage scenarios[4]

Table Notes:
[1]The table provides general criteria. Other factors may influence a higher or lower risk assessment.
[2]**Normal resource scenarios** include planned and typical forced outages as well as outages and derates that are closely correlated to the extreme peak demand.
[3]**Reduced resource scenarios** include planned and typical forced outages and low-likelihood resource scenarios, such as extreme low-wind scenarios, low-hydro scenarios during drought years, or high thermal outages when such a scenario is warranted.
[4]Even in normal risk assessment areas, extreme demand and extreme outage scenarios that are not closely linked may indicate risk of operating reserve shortfall.

Assessment of Planning Reserve Margins and Operational Risk Analysis

Anticipated Reserve Margins, which provide the Planning Reserve Margins for normal peak conditions, as well as reserve margins for seasonal risk scenarios of more extreme conditions are provided in Table 2.

Table 2: Seasonal Risk Scenario On-Peak Reserve Margins			
Assessment Area	**Anticipated Reserve Margin**	**Anticipated Reserve Margin with Typical Outages**	**Anticipated Reserve Margin with Higher Demand, Outages, Derates in Extreme Conditions**
MISO	24.7%	9.3%	-1.9%
MRO-Manitoba	14.6%	11.2%	3.8%
MRO-SaskPower	33.5%	28.3%	22.4%
MRO-SPP	28.5%	18.2%	3.4%
NPCC-Maritimes	42.2%	31.7%	18.6%
NPCC-New England	14.1%	3.9%	4.0%
NPCC-New York	31.6%	12.5%	5.2%
NPCC-Ontario	23.4%	23.4%	3.7%
NPCC-Québec	32.7%	28.2%	19.1%
PJM	24.7%	15.0%	5.3%
SERC-C	19.6%	12.7%	3.2%
SERC-E	29.1%	21.8%	13.0%
SERC-FP	20.2%	14.0%	11.8%
SERC-SE	41.3%	37.7%	12.5%
TRE-ERCOT	43.2%	33.0%	-5.1%
WECC-AB	42.6%	40.3%	20.5%
WECC-Basin	24.3%	15.9%	-27.2%
WECC-BC	24.3%	24.2%	-6.6%
WECC-CA	56.9%	51.0%	4.7%
WECC-Mex	14.1%	1.6%	-16.8%
WECC-NW	32.1%	29.4%	-13.0%
WECC-RM	25.7%	18.2%	-18.9%
WECC-SW	22.3%	14.0%	-13.0%

Seasonal risk scenarios for each assessment area are presented in the Regional Assessments Dashboards section. The on-peak reserve margin and seasonal risk scenario charts in each dashboard provide potential summer peak demand and resource condition information. The reserve margins on the right side of the dashboard pages provide a comparison to the previous year's assessment. The seasonal risk scenario charts present deterministic scenarios for further analysis of different demand and resource levels with adjustments for normal and extreme conditions. The assessment areas determined the adjustments to capacity and peak demand based on methods or assumptions that are summarized in the seasonal risk scenario charts; more information about these dashboard charts is provided in the Data Concepts and Assumptions section.

The seasonal risk scenario charts can be expressed in terms of reserve margins: In Table 2, each assessment area's Anticipated Reserve Margins are shown alongside the reserve margins for a typical generation outage scenario (where applicable) and the extreme demand and resource conditions in their seasonal risk scenario.

Highlighted in orange are the areas identified as having resource adequacy or energy risks for the summer in the Key Findings section. The typical outage reserve margin includes anticipated resources minus the capacity that is likely to be in maintenance or forced outage at peak demand. If the typical maintenance or forced outage margin is the same as the Anticipated Reserve Margin, it is because an assessment area has already factored typical outages into the anticipated resources. The extreme conditions margin includes all components of the scenario and represents the most severe operating conditions of an area's scenario. Note that any reserve margin below zero indicates that the resources fall below demand in the scenario.

In addition to the peak demand and seasonal risk hour scenario charts, the assessment areas provided a resource adequacy risk assessment that was probability-based for the summer season. Results are summarized in Table 3. The risk assessments account for the hour(s) of greatest risk of resource shortfall. For most areas, the hour(s) of risk coincides with the time of forecasted peak demand; however, some areas incur the greatest risk at other times based on the varying demand and resource profiles. Various risk metrics are provided and include LOLE, LOLH, EUE, and the probabilities of an EEA occurrence.

Energy Emergency Alerts

Extreme generation outages, low resource output, and peak loads similar to those experienced in wide-area heat events and the heat domes experienced in western parts of North America during the last three summers are ongoing reliability risks in certain areas for Summer 2025. When forecasted resources in an area fall below expected demand and operating reserve requirements, BAs may need to employ operating mitigations or EEAs to obtain the capacity and energy necessary for reliability. A description of each EEA level is provided below.

Energy Emergency Alert Levels

EEA Level	Description	Circumstances
EEA1	All available generation resources in use	• The BA is experiencing conditions in which all available generation resources are committed to meet firm load, firm transactions, and reserve commitments and is concerned about sustaining its required contingency reserves. • Non-firm wholesale energy sales (other than those that are recallable to meet reserve requirements) have been curtailed.
EEA2	Load management procedures in effect	• The BA is no longer able to provide its expected energy requirements and is an energy-deficient BA. • An energy-deficient BA has implemented its operating plan(s) to mitigate emergencies. • An energy-deficient BA is still able to maintain minimum contingency reserve requirements.
EEA3	Firm load interruption is imminent or in progress	• The energy-deficient BA is unable to meet minimum contingency reserve requirements.

Table 3: Probability-Based Risk Assessment		
Assessment Area	**Type of Assessment**	**Results and Insight from Assessment**
MISO	The Planning Year 2025–2026 LOLE Study Report, an annual LOLE probabilistic study[11]	The values for LOLH and EUE are taken from the assessment report noted, where the annual LOLE is set at 1 day in 10 years, or 0.1 LOLE for the summer season. For Summer 2025, LOLH is 0.252 hrs/year and EUE is 626.2 MWH/year for the Reference Margin Level. Expectations for load-loss and unserved energy are less than these amounts because MISO's resources are above the Reference Margin Level.
MRO-Manitoba	The 2024 LOLE Study	Manitoba Hydro's probability-based resource adequacy risk assessment for the summer (June–September) season is that there is a low risk of resource adequacy issues. The study indicated Annual Probabilistic Indices for the Manitoba Hydro system for 2026 of 5 MWh per year of EUE, considering a range of flow conditions, and that all of this risk would be in the higher load winter season. The increases in Manitoba load since the 2022 LOLE Study were more than offset by a reduction in long-term exports contract with the expiration of a major export sale in April 2025.
MRO-SaskPower	Probability-based capacity adequacy assessment Summer 2025	According to the study, SaskPower's expected number of hours with an operating reserve shortfall between June and September is about 0.65 hours, assuming maximum available imports. June has the highest likelihood of an EEA, estimated at 0.43 hours. For Summer 2025, the projected probability of experiencing a generation forced outage exceeding 350 MW stands at 21.5%. This number represents an approximation of the likelihood, during any given hour of the summer period, of encountering a generation forced outage surpassing the 350 MW threshold.
MRO-SPP	2024 NERC *LTRA* with Probabilistic Assessment (ProbA)	With the current SPP fleet, the ProbA base case Year 2 produced no LOLE.
NPCC	NPCC conducted an all-hour probabilistic assessment that consisted of a base case and several more severe scenarios examining low resources, reduced imports, and higher loads. The highest peak load scenario has a 7% probability of occurring.	NPCC Regional Entity assesses that there will be an adequate supply of electricity across the Regional Entity this summer. Necessary strategies and procedures are in place to deal with operational challenges and emergencies as they may develop. Preliminary results of the probabilistic analysis by assessment area are below. NPCC anticipates releasing the assessment in May.
NPCC-Maritimes		NPCC's assessment results indicate that Maritimes expects minimal LOLE, LOLH, and EUE over the May–September period, with the highest risk occurring in July and August. The assessment projected LOLE at less than 0.089 days per period, LOLH at less than 0.4 hours per period, and EUE at less than 16.5 MWh per period under the reduced resources and highest peak demand scenario.
NPCC-New England		Based on NPCC's assessment, cumulative LOLE (<0.031 days/period), LOLH (<0.120 hours/period), and EUE (<94 MWh/period) risks were estimated over the summer May to September period for the expected load with expected resources scenario. The highest peak load level conditions with reduced resources scenario resulted in an estimated cumulative LOLE risk (4.369 days/period), with associated LOLH (19.554 hours/period) and EUE (19,847 MWh/period) with the highest risk occurring in June, with some in July and August.
NPCC-New York		Negligible cumulative LOLE (<0.018 days/period), LOLH (<0.054 hours/period), and EUE (33 MWh/period) risks were estimated over the summer May–September period for the expected load with expected resources for the summer. For highest peak load level with low likelihood, reduced resource conditions resulted in an estimated cumulative LOLE risk (1.7 days/period), with associated LOLH (6.5 hours/period) and EUE (4,860 MWh/period) with the highest risk occurring in July and August.

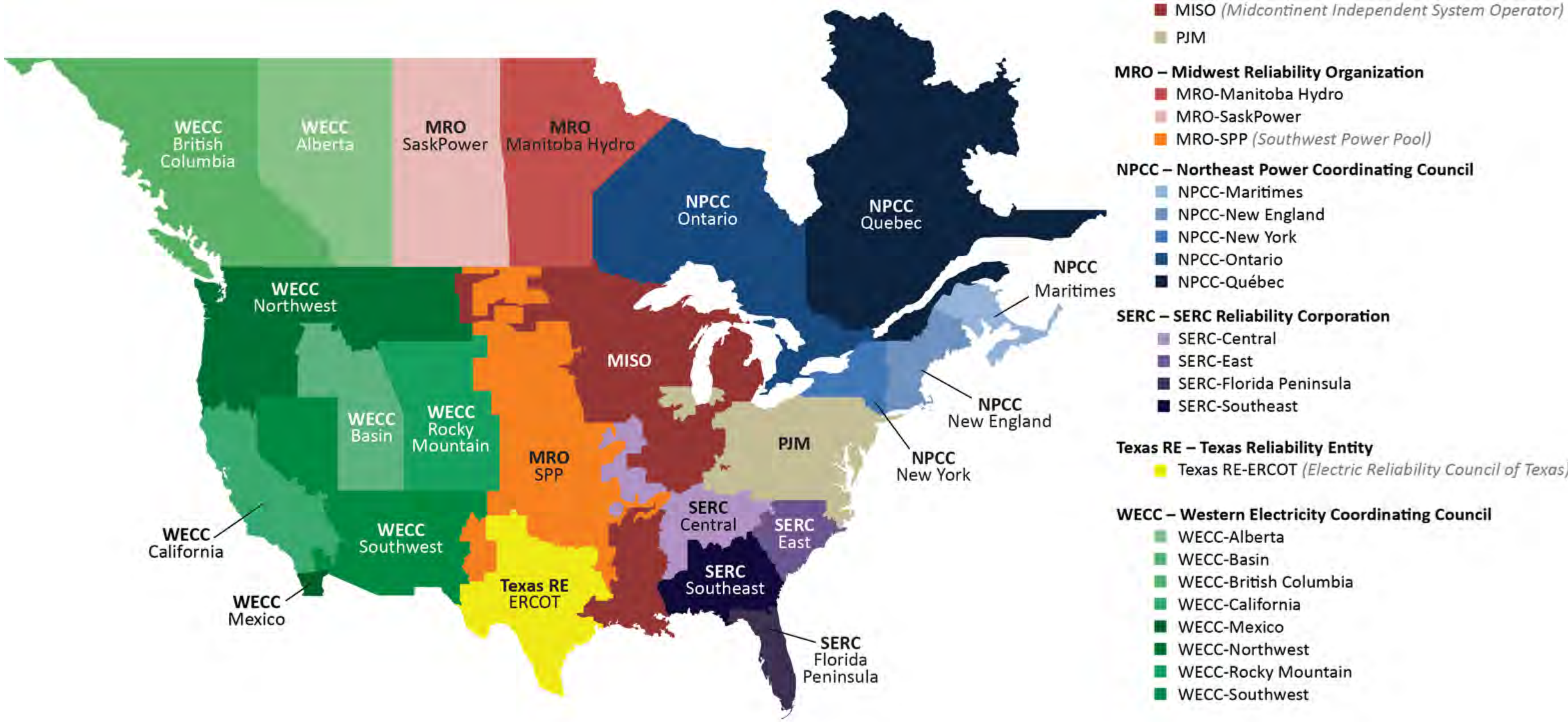
[11] PY 2025–2026 LOLE Study Report

Table 3: Probability-Based Risk Assessment		
Assessment Area	**Type of Assessment**	**Results and Insight from Assessment**
NPCC-Ontario		NPCC's preliminary result of this assessment indicates that the low-likelihood resource case, highest peak load level conditions resulted in a negligible cumulative LOLE (0.081 days/period), with associated cumulative LOLH (0.212 hours/period) and EUE (145.4 MWh/period) with the highest risks occurring predominantly in July, with some in August. Negligible cumulative LOLE, LOLH, and EUE risks were estimated over the May–September summer period for the other scenarios modeled.
NPCC-Québec		The Québec assessment area is not expected to require use of their operating procedures designed to mitigate resource shortages during Summer 2025. Québec did not demonstrate any measurable amounts of cumulative LOLE, LOLH, or EUE risks over the May–September summer period for all the scenarios modeled since the system is winter peaking.
PJM	2023 PJM Reserve Requirement Study (RRS)	PJM is expecting a low risk of resources falling below required operating reserves during Summer 2025. PJM is forecasting around 27% installed reserves (including expected committed demand resources), which is above the target installed reserve margin of 17.7% necessary to meet the 1-day-in-10-years LOLE criterion. The Reserve Requirement Study analyzed a wide range of load scenarios (low, regular, and extreme) as well as multiple scenarios for system-wide unavailable capacity due to forced outages, maintenance outages, and ambient derations. Due to the rather low penetration of limited and variable resources in PJM relative to PJM's peak load, the hour with the most loss-of-load risk remains the hour with the highest forecasted demand.
SERC-Central SERC-East SERC-Florida Peninsula SERC-Southeast	2024 NERC *LTRA* with ProbA. For the ProbA, SERC evaluates 8,760 hourly load and 1,900 sequential Monte Carlo simulations. The results are a probability weighted average of cases, including 38 historic weather-years that are applied to load forecasts for years 2026 and 2028. The model applies a range of economic load forecast errors from -4% to 4% and other noted assumptions.	The 2024 ProbA indicates some resource adequacy risk to SERC with the results for the year 2028 showing slightly higher risk than the year 2026. For the entire SERC footprint, Summer 2026 shows a low risk in summer afternoons into evenings, and for Summer 2028, that risk is still low but extends from summer evenings later into summer nights.
Texas RE-ERCOT	ERCOT probabilistic assessment using the Probabilistic Reserve Risk Model	The simulation indicates some risk of having to declare an EEA for hours ending 20 and 21 for the peak load day in August. These two hours have the highest EEA risk (reflecting corresponding high net load conditions) with probabilities of declaring an EEA 3.05% and 1.54%, respectively. This is categorized by ERCOT as "Low risk" per its criteria of hourly EEA probability that is equal to or less than 10%. For the *2024 SRA*, ERCOT reported EEA declaration probabilities for hours ending 20 and 21 of 18.4% and 9.2%, respectively. The large decrease in EEA probabilities is due to the addition of 7,414 MW of BESS capacity.
WECC	2024 Western Assessment on Resource Adequacy employs a probabilistic energy, area-wide assessment, using Multi Area Variable Resource Integration Convolution (MAVRIC) model	

Table 3: Probability-Based Risk Assessment		
Assessment Area	**Type of Assessment**	**Results and Insight from Assessment**
WECC-AB		Probabilistic analysis performed by WECC found no LOLH or EUE for this summer. All resource margins have increased since last summer with the addition of new capacity, including almost 2,700 MW of new natural gas capacity, 1,200 MW of new wind (+27%), 200 MW of new solar (+13%), and 54 MW of new energy storage systems (+27.5%) on-line. The peak hour has moved earlier, to 3:00 p.m. from 4:00 p.m., still in late July.
WECC-Basin		Probabilistic analysis performed by WECC found no LOLH or EUE for this summer. The reserve margins are not anticipated to fall below the reference margin (14%) for the upcoming summer—existing-certain is forecast at 19% with anticipated and prospective at 24%. The area is expected to peak in early July around 3:00 p.m.
WECC-BC		Probabilistic analysis performed by WECC found no LOLH or EUE for this summer. The reserve margins are not anticipated to fall below the reference margin for the upcoming summer. All reserve margins have increased since 2024 due to increased capacity and energy availability. The peak hour for summer is forecast for early August around 4 p.m.
WECC-CA		Probabilistic analysis performed by WECC found no LOLH or EUE for this summer. The reserve margins are not anticipated to fall below the reference margin for the upcoming summer. Reserve margins have increased since last summer with the increased existing-certain and Tier 1 planned capacity more than offsetting the decrease in available demand response.
WECC-Mex		Probabilistic analysis performed by WECC found no LOLH or EUE for this summer. The peak hour is expected to occur in early August around 4:00 p.m. The reserve margins (14%) are not anticipated to fall below the reference margin (10%) for the upcoming summer. An extreme summer peak load is anticipated to be 4,067 MW. Under extreme conditions, typical forced outages are expected to be 472 MW and derates for thermal generation resources are expected to be 330 MW, requiring imports from neighboring areas. The expected operating reserve requirement on peak is 226 MW.
WECC-RM		Probabilistic analysis performed by WECC found no LOLH or EUE for this summer. The peak hour is expected to occur in late July around 4:00 p.m. Summer 2025 reserve margins (existing-certain 25%, and anticipated and prospective 26%) are not anticipated to fall below the reference margin (17%). An extreme summer peak load may be around 15 GW, and the area has 17.3 GW of existing-certain capacity plus 104 MW of planned new resources. Typical forced outages could be 1,044 MW and derates under extreme conditions of 1,561 MW for thermal and 990 MW for wind. The expected operating reserve requirement on peak is 846 MW.
WECC-NW		Probabilistic analysis performed by WECC found no LOLH or EUE for this summer. Summer 2025 peak hour is expected to occur in early July around 5:00 p.m. Reserve margins (existing-certain 29% and anticipated and prospective 32%) are not anticipated to fall below the reference margin (23%). An extreme summer peak load may be around 32,740 MW. Typical forced outages are forecast to be 777 MW with derates for thermal under extreme conditions to be 1,584 MW and 2,649 MW for wind. The expected operating reserve requirement on peak is 1,750 MW.
WECC-SW		Probabilistic analysis performed by WECC found no LOLH or EUE for this summer. The peak hour is expected to occur in early July around 5:00 p.m. The existing-certain 17% reserve margin does not fall below the reference margin (13%) for the upcoming summer. The anticipated and prospective reserve margin rises to 22%. An extreme summer peak load could approach 40 GW during the riskiest hour, while the region is anticipated to have 40.3 GW of existing-certain energy available and an additional 2 GW of Tier 1 planned resources. Typical forced outages are estimated near 3 GW, and derates for thermal under extreme conditions can shave another 3 GW from available energy. The expected operating reserve requirement is 2,119 MW.

Regional Assessments Dashboards

The following assessment area dashboards and summaries were developed based on data and narrative information collected by NERC from the six Regional Entities on an assessment area basis. Guidelines and definitions are in the **Data Concepts and Assumptions** table. On-peak reserve margin bar charts show the Anticipated Reserve Margin compared to a Reference Margin Level that is established for the areas to meet resource adequacy criteria. Prospective Reserve Margins can give an indication of additional on-peak capacity but are not used for assessing adequacy. The operational risk analysis shown in the following regional assessments dashboard pages provides a deterministic scenario for understanding how various factors that affect resources and demand can combine to impact overall resource adequacy. For each assessment area, there is a risk-period scenario graphic; the left **blue** column shows anticipated resources (from the **Demand and Resource Tables**), and the **orange** column at the right shows the two demand scenarios of the normal peak net internal demand (from the **Demand and Resource Tables**) and the extreme summer peak demand determined by the assessment area. The middle **red** or **green** bars show adjustments that are applied cumulatively to the anticipated resources. Adjustments may include reductions for typical generation outages (maintenance and forced not already accounted for in anticipated resources) and additions that represent the quantified capacity from operational tools (if any) that are available during scarcity conditions but have not been accounted for in the *SRA* reserve margins. Resources throughout the scenario are compared against expected operating reserve requirements that are based on peak load and normal weather. The cumulative effects from extreme events are also factored in through additional resource derates or low-output scenarios. In addition, results from a probability-based resource adequacy assessment are shown in the Highlights section of each dashboard. Methods varied by assessment area and provided further insights into the risk conditions forecasted for the summer period.



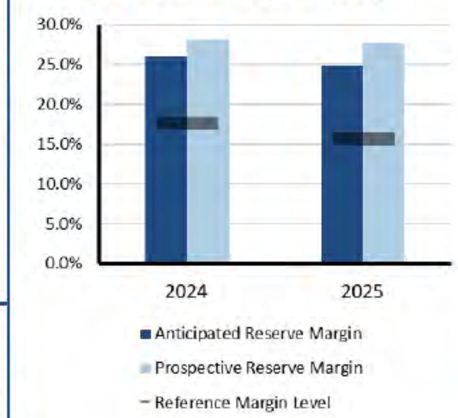
MISO

MISO is a not-for profit, member-based organization that administers wholesale electricity markets that provide customers with valued service; reliable, cost-effective systems and operations; dependable and transparent prices; open access to markets; and planning for long-term efficiency. MISO manages energy, reliability, and operating reserve markets that consist of 36 local BA and 394 market participants, serving approximately 42 million customers. Although parts of MISO fall in three Regional Entities, MRO is responsible for coordinating data and information submitted for NERC's reliability assessments.

Highlights

- Demand forecasts and resource data indicate that MISO is at elevated risk of operating reserve shortfalls during periods of high demand or low resource output.
- The performance of wind and solar generators during periods of high electricity demand is a key factor in determining whether system operators need to employ operating mitigations, such as maximum generation declarations and energy emergencies; MISO has over 31,000 MW of installed wind capacity and 18,245 MW of installed solar capacity; however, the historically based on-peak capacity contribution is 5,616 MW and 9,123 MW, respectively.
- Since last summer, over 1,400 MW of thermal generating capacity has been retired in MISO, and the new generation that has been added is predominantly solar (8,080 MW nameplate/4,140 MW on-peak).
- MISO's most recent energy assessment reveals that the period of highest energy shortfall risk has shifted from July to August.

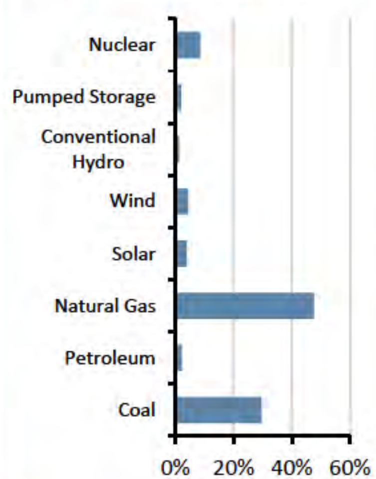
On-Peak Reserve Margin



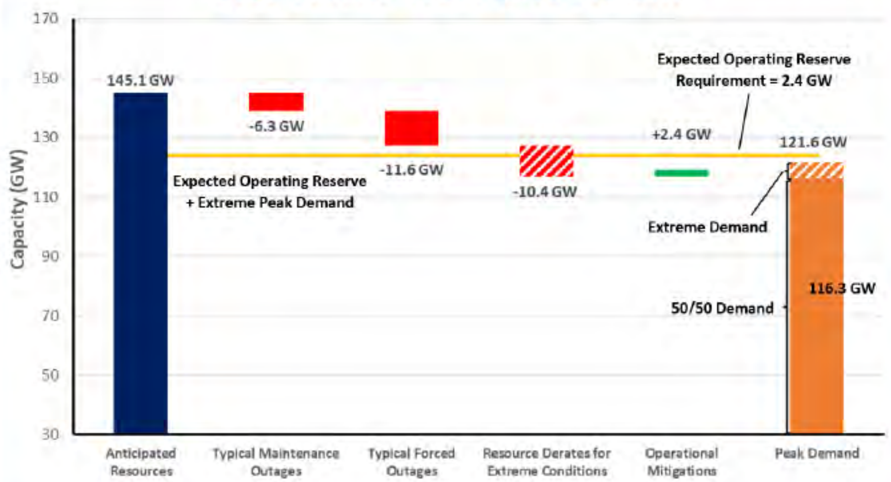
Risk Scenario Summary

Expected resources meet operating reserve requirements under normal peak-demand scenarios. Above-normal summer peak load and extreme generator outage conditions could result in the need to employ operating mitigations (e.g., load-modifying resources and energy transfers from neighboring systems) and EEAs. Emergency declarations that can only be called upon when available generation is at maximum capability are necessary to access load-modifying resources (demand response) when operating reserve shortfalls are projected.

On-Peak Fuel Mix



2025 Summer Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: Net internal demand (50/50) and (90/10) demand forecast using 30 years of historical data

Maintenance Outages: Rolling five-year summer average of maintenance and planned outages

Forced Outages: Five-year average of all outages that were not planned

Extreme Derates: Maximum historical generation outages

Operational Mitigations: A total of 2.4 GW capacity resources available during extreme operating conditions

MRO-Manitoba Hydro

Manitoba Hydro is a provincial Crown corporation and one of the largest integrated electricity and natural gas distribution utilities in Canada. Manitoba Hydro is a leader in providing renewable energy and clean-burning natural gas. Manitoba Hydro provides electricity to approximately 608,500 electric customers in Manitoba and natural gas to approximately 293,000 customers in southern Manitoba. Its service area is the province of Manitoba, which is 251,000 square miles. Manitoba Hydro is winter peaking. Manitoba Hydro is its own Planning Coordinator (PC) and BA. Manitoba Hydro is a coordinating member of MISO, which is the RC for Manitoba Hydro.

Highlights

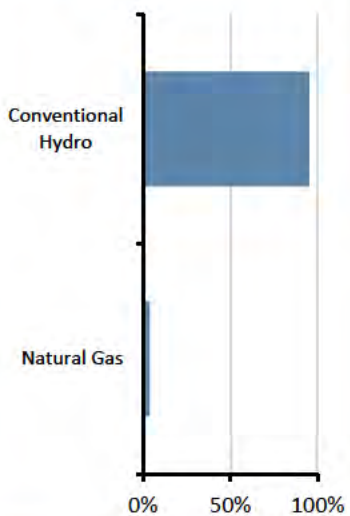
- Manitoba Hydro is not anticipating any operational challenges and/or emerging reliability issues in its assessment area for Summer 2025; the Anticipated Reserve Margin for Summer 2025 exceeds the 12% Reference Margin Level.
- While Manitoba Hydro experienced demand growth in the past year, the growth is less than the recent reduction in firm export contracts.
- Manitoba Hydro water supply conditions are below average but improved from this time last year, and above-average winter snowfall will favorably impact spring runoff.
- Manitoba Hydro expects to reliably supply its internal demand and export obligations even if extreme drought develops throughout the year.

Risk Scenario Summary

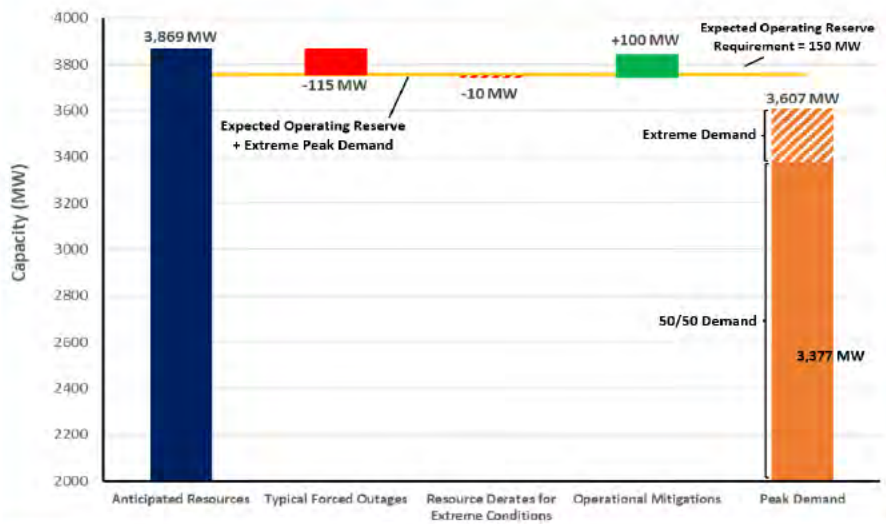
Expected resources meet operating reserve requirements under the assessed scenarios.

On-Peak Reserve Margin

On-Peak Fuel Mix



2025 Summer Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: (50/50) Demand with allowance for extreme demand based on extreme summer weather scenario of 35.4 C (96 F)

Forced Outages: Typical forced outages

Extreme Derates: Summer wind capacity accreditation of 18.1% of nameplate rating based on MISO seasonal analysis

Normal hydro generation expected for this summer.

Operational Mitigations: Utilize Curtailable Rate Program to manage peak demand; utilize operating reserve if additional measures required

MRO-SaskPower

MRO-SaskPower is an assessment area in the Saskatchewan province of Canada. The province has a geographic area of 651,900 square kilometers (251,700 square miles) and a population of approximately 1.1 million. Peak demand is experienced in the winter. The Saskatchewan Power Corporation (SaskPower) is the PC and RC for the province of Saskatchewan and is the principal supplier of electricity in the province. SaskPower is a provincial Crown corporation and, under provincial legislation, is responsible for the reliability oversight of the Saskatchewan BES and its Interconnections.

Highlights

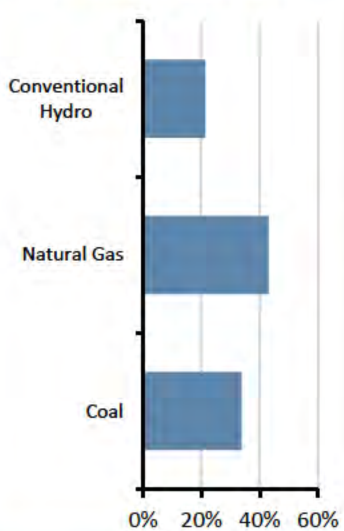
- Although Saskatchewan is mainly a winter-peaking region, summer can also bring high electricity demand due to extreme heat.
- Each year, SaskPower works with Manitoba Hydro on a joint summer operating study with input from the Western Area Power Administration and Basin Electric to develop operational guidelines to address any potential challenges.
- The expected number of hours with an operating reserve shortfall between June and September is about 0.65 hours, assuming maximum available imports. The risk of shortfall increases if major unplanned generator outages coincide with scheduled maintenance during peak demand months (June to September). For Summer 2025, the projected probability of experiencing a generation forced outage exceeding 350 MW stands at 21.5%. This number represents an approximation of the likelihood of encountering a generation forced outage surpassing the 350 MW threshold during any given hour of the summer period.
- If extreme heat coincides with significant generation outages, SaskPower will act by activating demand-response programs, arranging short-term power imports from neighboring utilities, and, if necessary, implementing temporary load interruptions to maintain grid stability.

On-Peak Reserve Margin

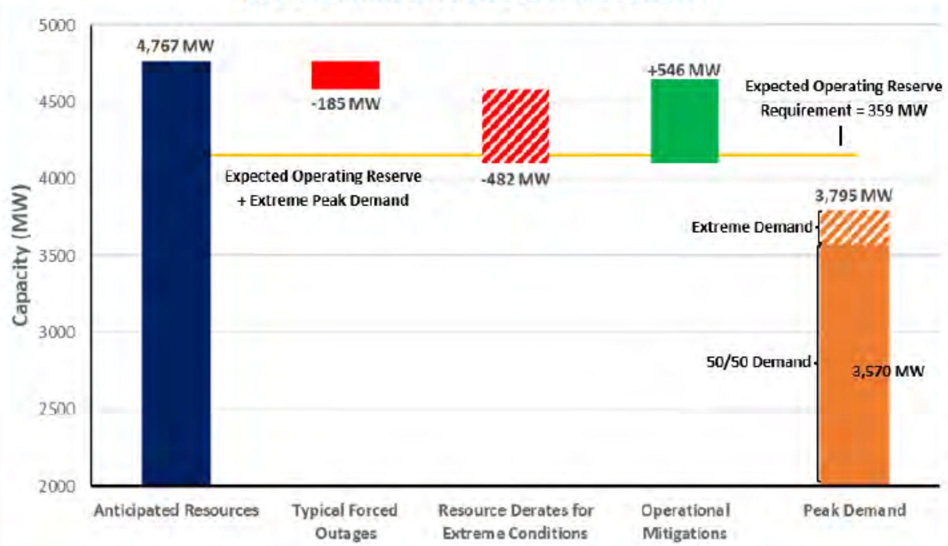
Risk Scenario Summary

Expected resources meet operating reserve requirements under normal peak demand and outage conditions. Above-normal summer peak load and outage conditions are likely to result in the need to employ operating mitigations (e.g., demand response and transfers) and EEAs.

On-Peak Fuel Mix



2025 Summer Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

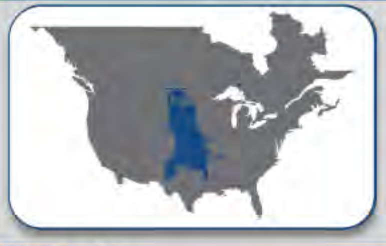
Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: Net internal demand (50/50) and above-normal scenario based on peak demand with lighting and all consumer loads

Forced Outages: Estimated by using SaskPower forced outage model

Extreme Derates: Estimated resources unavailable in extreme conditions

Operational Mitigations: Estimated non-firm imports and standby generators on 2–7-day notice



MRO-SPP

SPP PC's 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 long-term assessment is reported based on the PC footprint, which touches parts of the MRO 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.

Highlights

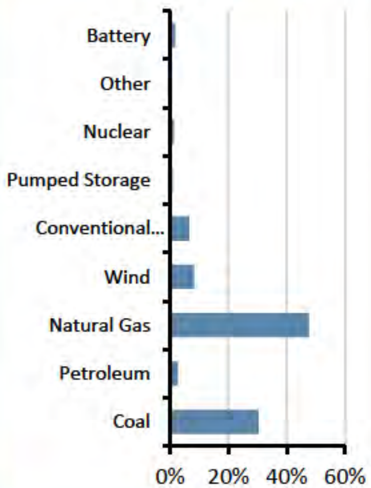
- SPP projects a low likelihood of any emerging reliability issues impacting the area for the 2025 Summer season.
- Generation availability is not expected to be impacted by fuel shortages or river conditions this summer.
- BA generation capacity deficiency risks remain depending on wind generation output levels and unanticipated generation outages in combination with high load periods.
- Using the current operational processes and procedures, SPP will continue to assess the resource needs for the 2025 Summer season and will adjust generation and energy supply portfolios as needed to ensure that real-time energy sufficiency is maintained throughout the summer.

Risk Scenario Summary

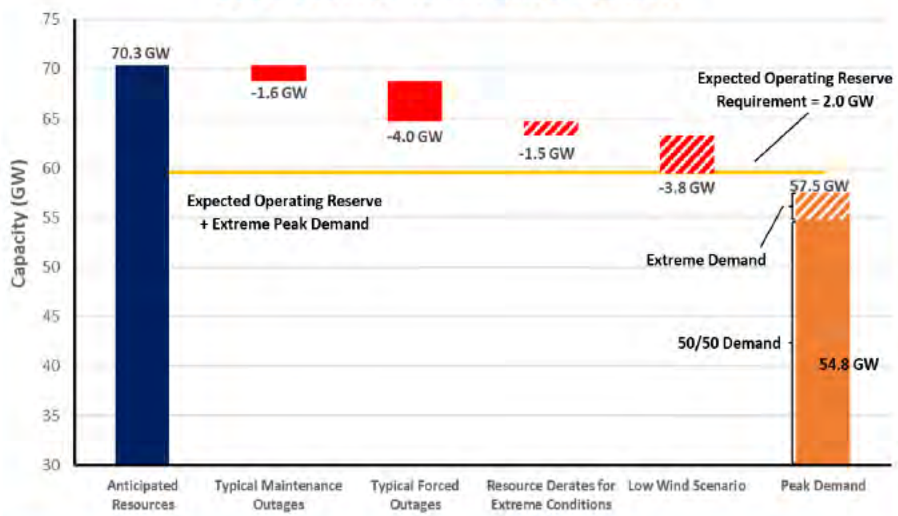
Expected resources are sufficient to meet operating reserve requirements under normal peak-demand and outage scenarios. Above-normal summer peak load, low wind conditions, and higher-than-normal forced outages could result in the need for operating mitigations (e.g., demand response and transfers from neighboring systems) and EEAs.

On-Peak Reserve Margin

On-Peak Fuel Mix



2025 Summer Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: Net internal demand (50/50) and extreme demand is a 5% increase from net internal demand

Maintenance and Forced Outages: Represent five-year historical averages; calculated from SPP's generation assessment process

Extreme Derates: Additional unavailable capacity from operational data at high-demand periods

Low Wind Scenario: Derates reflecting a low-wind day in the summer

NPCC-Maritimes

The Maritimes assessment area is a winter-peaking NPCC area that contains two BAs. It is comprised of the Canadian provinces of New Brunswick, Nova Scotia, and Prince Edward Island and the northern portion of Maine, which is radially connected to the New Brunswick power system. The area covers 58,000 square miles with a total population of 1.9 million.

Highlights

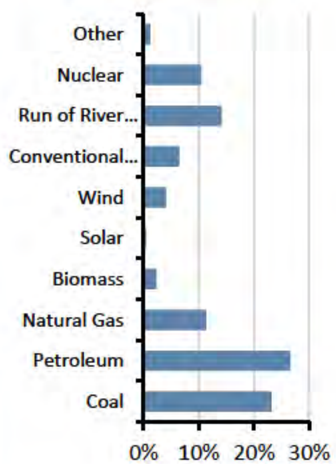
- As Maritimes is a winter-peaking system, no issues are expected for the upcoming summer assessment period with sufficient firm capacity to meet forecast peak demand. If an event were to occur, emergency operations and planning procedures are in place.
- Probabilistic analysis performed by NPCC for the NPCC *Summer Reliability Assessment* found negligible LOLH and EUE for the expected load and resource levels this summer. A scenario with an extreme high load shape produced minimal amounts of cumulative LOLE (<0.089 days/period), LOLH (<0.4 hours/period), or EUE (< 16.5 MWh/period) over the May–September summer period with the highest risk occurring in July and August.
- Dual-fueled units will have sufficient supplies of heavy fuel oil (HFO) on site to sustain operations in the event of natural gas supply interruptions.

On-Peak Reserve Margin

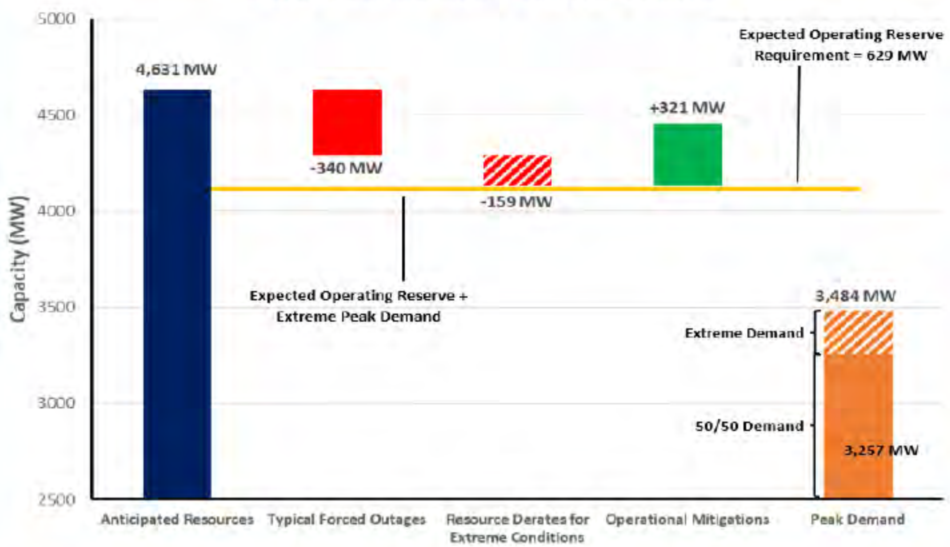
Risk Scenario Summary

Expected resources meet operating reserve requirements under normal peak-demand scenarios. Above-normal summer peak load or extreme outage conditions could necessitate operating mitigations (e.g., demand response and non-firm transfers) and EEAs.

On-Peak Fuel Mix



2025 Summer Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: Net internal demand (50/50) and (above 90/10) extreme demand forecast

Forced Outages: Based on historical operating experience

Extreme Derates: A low-likelihood scenario resulting in an additional 50% derate in the remaining capacity of both natural gas and wind resources under extreme conditions

Operational Mitigations: Imports anticipated from neighbors during emergencies, (e.g. New Brunswick Power System Operator can increase import capability from 200 MW to 550 MW under emergency operations for up to 30 minutes)

NPCC-New England

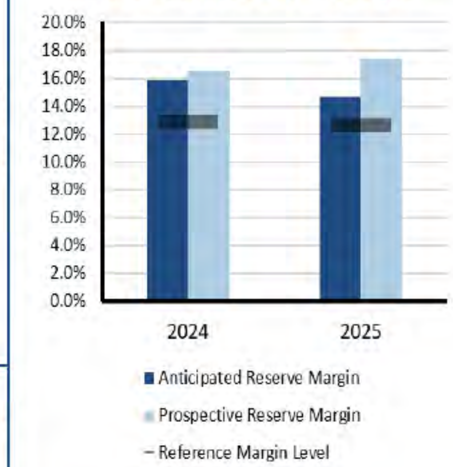
NPCC-New England is an assessment area consisting of the states of Connecticut, Maine, Massachusetts, New Hampshire, Rhode Island, and Vermont that is served by ISO New England (ISO-NE) Inc. ISO-NE is a regional transmission organization that is responsible for the reliable day-to-day operation of New England's bulk power generation and transmission system, administration of the area's wholesale electricity markets, and management of the comprehensive planning of the regional BPS.

The New England BPS serves approximately 14.5 million customers over 68,000 square miles.

Highlights

- ISO-NE forecasts adequate transmission capability and manageable capacity margins to meet the expected peak demand.
- Probabilistic analysis performed by NPCC for the NPCC *Summer Reliability Assessment* identified small amounts of cumulative LOLE, LOLH, and EUE for the expected load with anticipated resources for the summer. A reduced resources and highest peak load level scenario resulted in an estimated cumulative LOLE risk of 4.369 days/period, with associated LOLH (19.554 hours/period) and EUE (19,847 MWh/period). The highest risk occurs in June, with some risk in July and August.
- The NPCC 2025 *Summer Reliability Assessment* will be approved on or about May 12, 2025, and posted on NPCC's website.

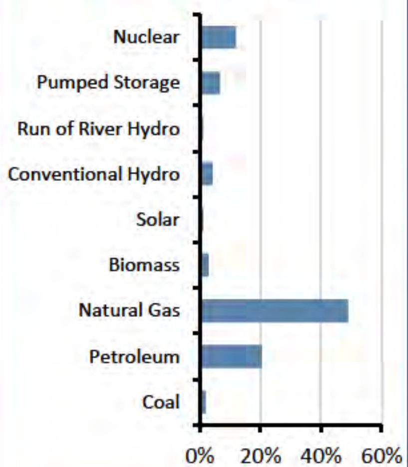
On-Peak Reserve Margin



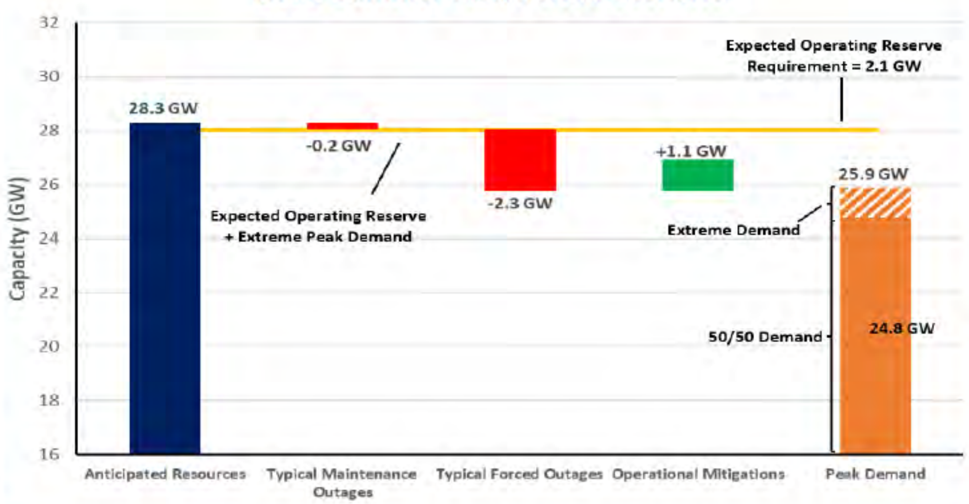
Risk Scenario Summary

Expected resources do not meet operating reserve requirements under normal peak-demand and outage scenarios. Additional non-firm transfers are likely to be needed and available from neighbors. More severe conditions (e.g., above-normal summer peak load and outage conditions) could result in an EEA.

On-Peak Fuel Mix



2025 Summer Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: Peak net internal demand (50/50) and (90/10) extreme demand forecast

Maintenance Outages: Based on historical weekly averages

Typical Forced Outages: Based on seasonal capacity of each resource as determined by ISO-NE

Operational Mitigations: Based on load and capacity relief assumed available from invocation of ISO-NE operating procedures

NPCC-New York

NPCC-New York is an assessment area consisting of the New York ISO (NYISO) service territory. NYISO is responsible for operating New York's BPS, administering wholesale electricity markets, and conducting system planning. NYISO is the only BA within the state of New York. The BPS in New York encompasses over 11,000 miles of transmission lines and 760 power generation units and serves 20.2 million customers. For this *SRA*, the established Reference Margin Level is 15%. Wind, grid-connected solar PV, and run-of-river totals were derated for this calculation. However, New York requires load-serving entities to procure capacity for their loads equal to their peak demand plus an Installed Reserve Margin (IRM). The IRM requirement represents a percentage of capacity above peak load forecast and is approved annually by the New York State Reliability Council. The council approved the 2025–2026 IRM at 24.4%.

Highlights

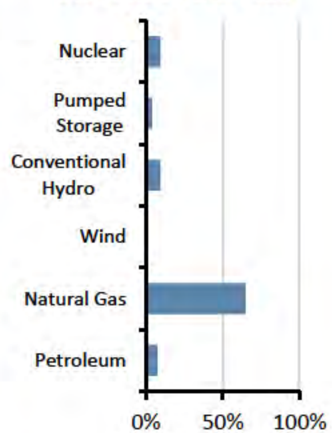
- NYISO is not anticipating any operational issues for the upcoming summer operating period. Adequate reserve margins are anticipated.
- Probabilistic analysis performed by NPCC for the NPCC *Summer Reliability Assessment* found that use of New York's established operating procedures are sufficient to maintain a balance between electricity supply and expected 50/50 demand if needed to mitigate resource shortages during Summer 2025. Negligible cumulative LOLE (<0.018 days/period), LOLH (<0.054 hours/period), and EUE (33 MWh/period) risks were estimated over the summer May to September period for the expected load with expected resources for the summer. The highest peak load level with low likelihood reduced resource conditions resulted in an estimated cumulative LOLE risk (1.7 days/period), with associated LOLH (6.5 hours/period) and EUE (4860 MWh/period) with the highest risk occurring in July and August.
- The NPCC 2025 *Summer Reliability Assessment* will be approved on or about May 12, 2025, and posted on NPCC's website.

On-Peak Reserve Margin

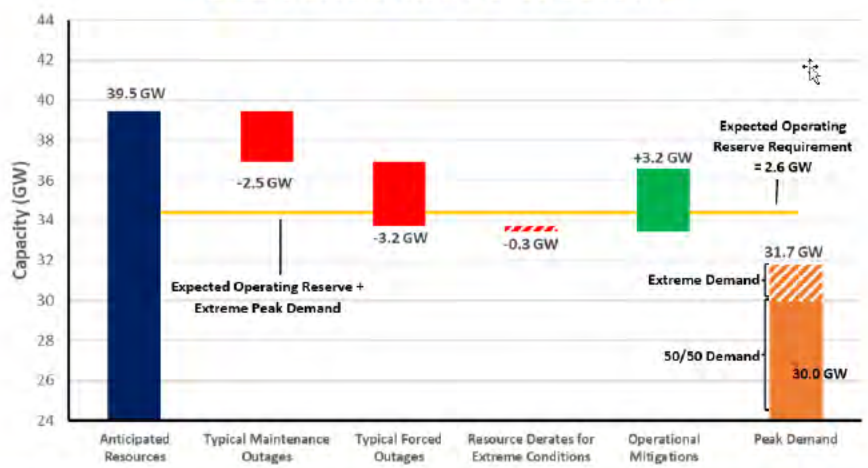
Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed scenarios. Operating mitigations (e.g., demand response and transfers) may be needed to meet above-normal summer peak load and outage conditions.

On-Peak Fuel Mix



2025 Summer Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: Net internal demand (50/50) and (90/10) extreme demand forecast

Maintenance Outages: Based on historical performance and the new NYISO capacity accreditation process

Forced Outages: Based on historical five-year averages

Extreme Derates: Estimated resources unavailable in extreme conditions

Operational Mitigations: A total of 3.2 GW based on operational/emergency procedures in area emergency operations manual

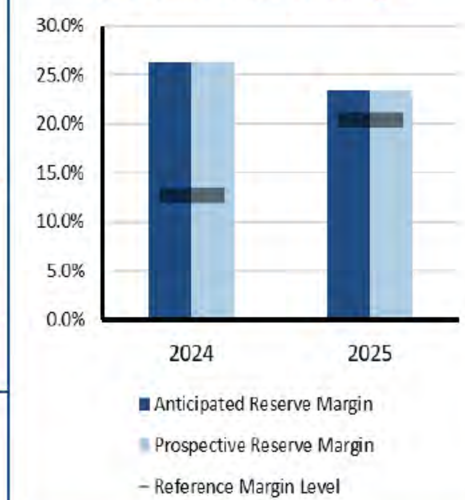
NPCC-Ontario

NPCC-Ontario is an assessment area in the Ontario province of Canada. The Independent Electricity System Operator (IESO) is the BA for the province of Ontario. The province of Ontario covers more than 1 million square kilometers (415,000 square miles) and has a population of m16 million. Ontario is interconnected electrically with Québec, MRO-Manitoba, states in MISO (Minnesota and Michigan), and NPCC-New York.

Highlights

- Overall, Ontario is operating within a period where generation and transmission outages are more challenging to accommodate. The IESO is prepared and expects to have adequate supply for Summer 2025.
- The IESO has been actively coordinating and planning with market participants to maintain reliability.
- This season, the grid will benefit from increased capacity secured through the capacity auction and more planned projects, including new storage, coming into service.
- The IESO is working throughout 2025 to better integrate storage solutions into the electricity markets.
- Starting with this seasonal assessment, demand is forecasted by using probabilistic weather modeling, comparable to the methodology used in the IESO 18-month *Reliability Outlook* as opposed to the previous approach of using weather scenarios."

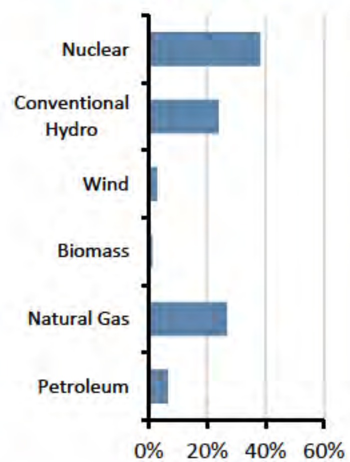
On-Peak Reserve Margin



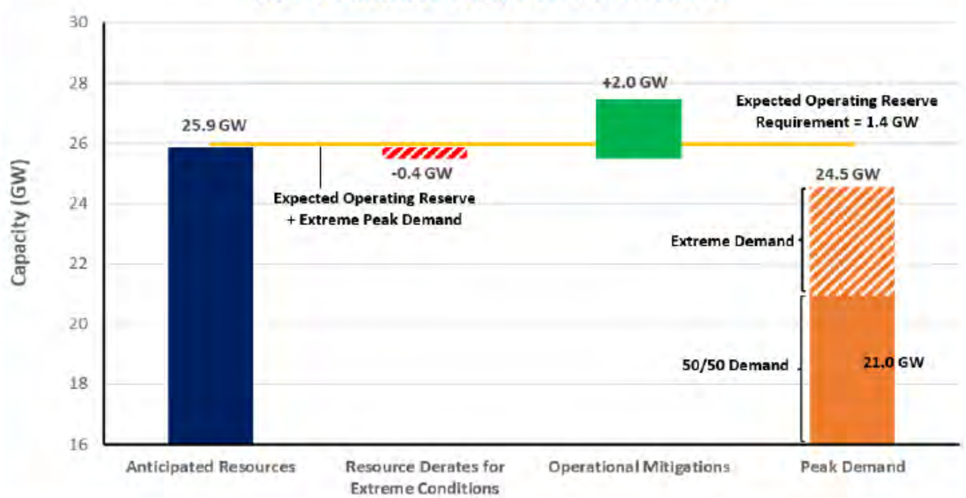
Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed scenarios.

On-Peak Fuel Mix



2025 Summer Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: Net internal demand (50/50 forecast) and highest weather-adjusted daily demand based on 31 years of demand history, and extreme weather represents a 97/3 distribution of probabilistically modelled data

Extreme Derates: Derived from weather-adjusted temperature rating of thermal units and adjustments to expected hydro production for low water conditions

Operational Mitigations: The operational procedures used to mitigate extreme conditions total approximately 2,010 MW for the On-Peak Risk Scenario, consisting of imports, public appeals, and voltage reductions. Public appeals and voltage reductions were not included in the 2024 On-Peak Risk Scenario.

NPCC-Québec

The Québec assessment area (province of Québec) is a winter-peaking NPCC area that covers 595,391 square miles with a population of 8 million. Québec is one of the four Interconnections in North America; it has ties to Ontario, New York, New England, and the Maritimes consisting of either high-voltage direct current ties, radial generation, or load to and from neighboring systems.

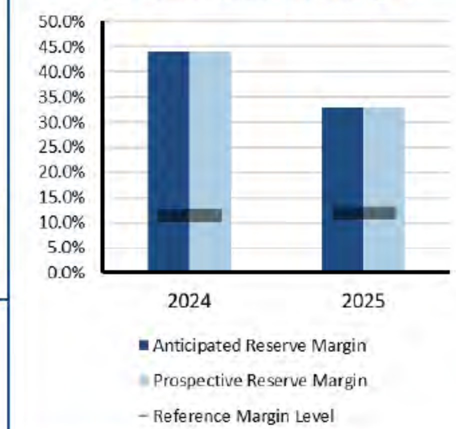
Highlights

- The Québec area forecasted summer peak demand is 23,283 MW during the week beginning August 3, 2025, with a forecasted net margin of 5,698 MW (24.5%).
- Resource adequacy issues are not expected this summer.
- The Québec area expects to be able to assist other areas.
- Modeling was made more precise this year with the inclusion of summer demand-response programs, dispatchable demand-side management (DSM), and weekly modeling of the reserve requirements and bottled generation.

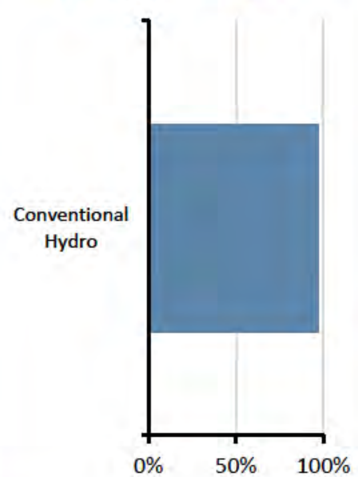
Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed scenarios.

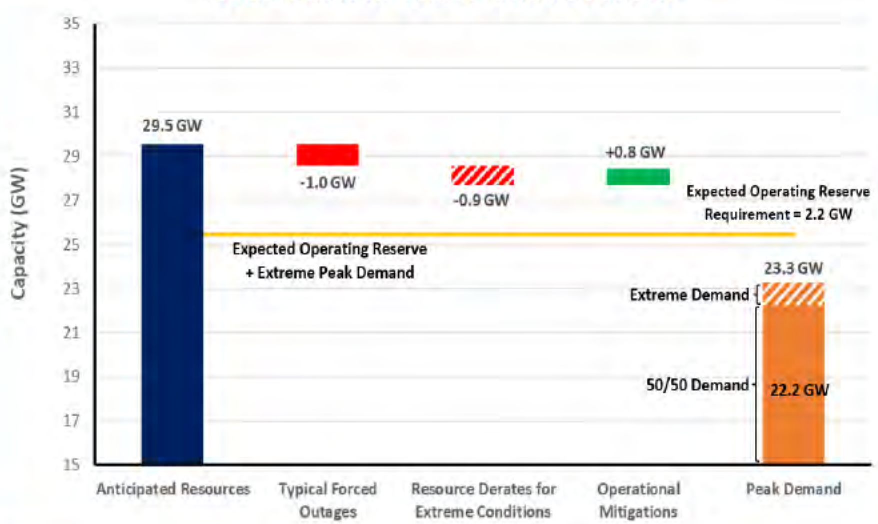
On-Peak Reserve Margin



On-Peak Fuel Mix



2025 Summer Risk Period Scenario

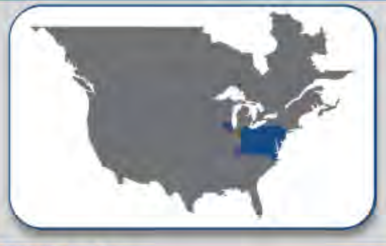


Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenario: Net internal demand (50/50) and (90/10) demand forecast

Operational mitigations: An operational procedure used to mitigate extreme conditions and not already included in margins is the depletion of some operating reserves by 750 MW.



PJM

PJM Interconnection is a regional transmission organization that coordinates the movement of wholesale electricity in all or parts of Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, West Virginia, and the District of Columbia. PJM serves 65 million customers and covers 369,089 square miles. PJM is a BA, PC, Transmission Planner, Resource Planner, Interchange Authority, TOP, Transmission Service Provider, and RC.

Highlights

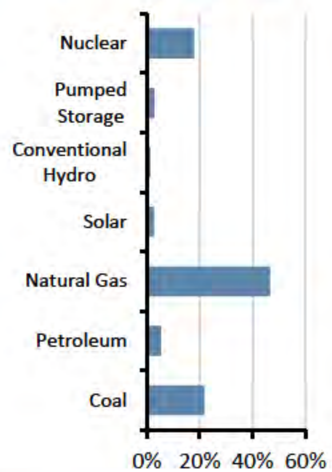
- PJM is forecasting 27% installed reserves (including expected committed demand response), which is above the target installed reserve margin of 17.7% necessary to meet the 1-day-in-10-years LOLE criterion.
- During extreme high temperatures that can cause record demand, PJM anticipates the need for demand-response resources to help reduce load at times this summer.

Risk Scenario Summary

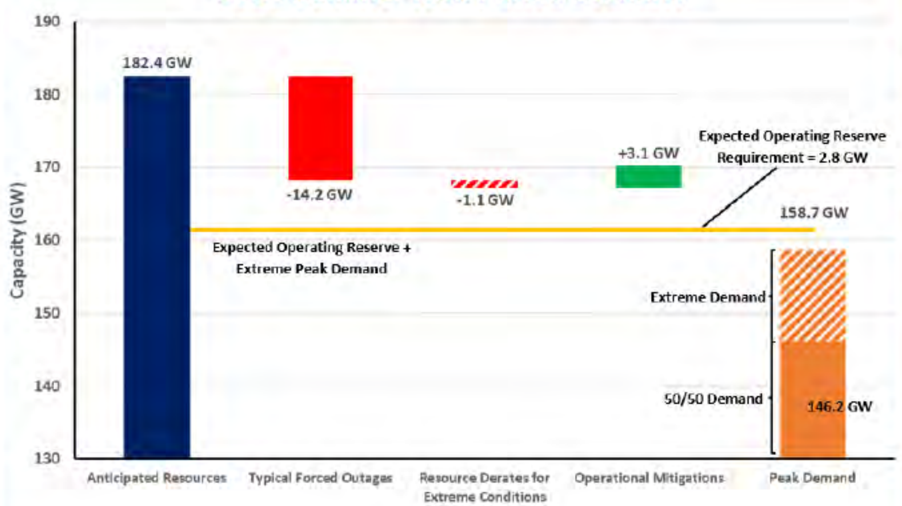
Expected resources meet operating reserve requirements under the assessed scenarios.

On-Peak Reserve Margin

On-Peak Fuel Mix



2025 Summer Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

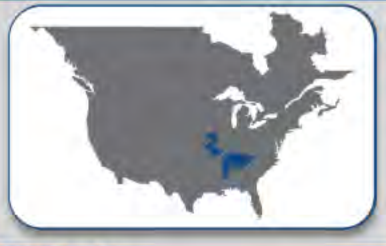
Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: Net internal demand (50/50) and (90/10) demand forecast

Forced Outages: Based on historical data and trending

Extreme Derates: Accounts for reduced thermal capacity contributions due to performance in extreme conditions

Operational Mitigations: A total of 3 GW based on operational/emergency procedures



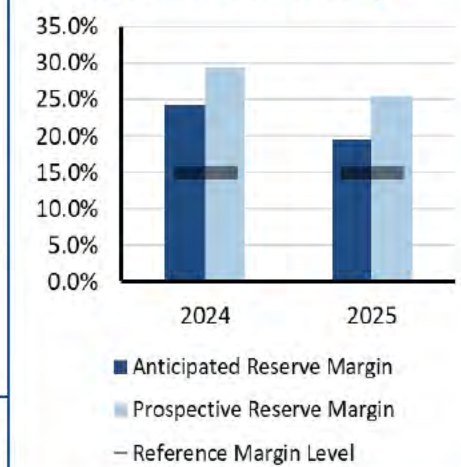
SERC-Central

SERC-Central is an assessment area within the SERC Regional Entity. SERC-Central includes all of Tennessee and portions of Georgia, Alabama, Mississippi, Missouri, and Kentucky. Historically a summer-peaking area, SERC-Central is beginning to have higher peak demand forecasts in winter. SERC is one of the six companies across North America that are responsible for the work under Federal Energy Regulatory Commission (FERC)-approved delegation agreements with NERC. SERC-Central is specifically responsible for the reliability and security of the electric grid across the Southeastern and Central areas of the United States. This area covers approximately 630,000 square miles and serves a population of more than 91 million. The SERC Regional Entity includes 36 BAs, 28 planning entities, and 6 RCs.

Highlights

- SERC-Central saw a sizable increase in its reserves last summer, but coal retirements this summer will result in SERC-Central having lower reserves.
- SERC-Central's anticipated resources meet operating reserve requirements under the expected conditions and under the summer risk period scenario.
- The probabilistic analysis metrics indicate adequate energy resources for the area.
- Entities perform resource studies to ensure resource adequacy to meet the summer peak demand and maintain the reliability of the system.
- Members of SERC-Central actively participate in the SERC working groups to perform coordinated studies and develop mitigating actions for any potential or emerging reliability impacts on transmission and resource adequacy.

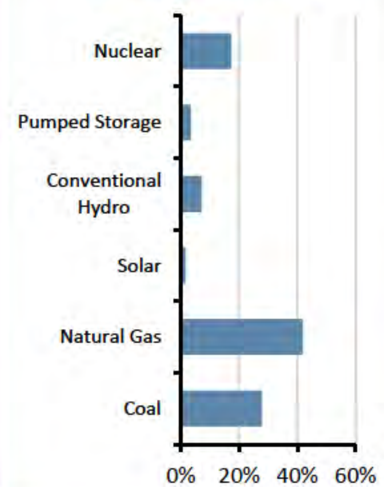
On-Peak Reserve Margin



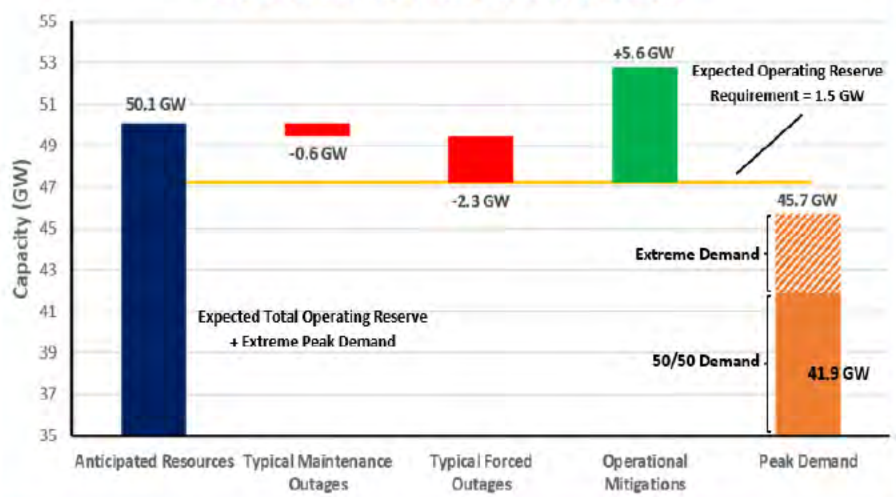
Risk Scenario Summary

Expected resources meet operating reserve requirements under assessed scenarios. More severe conditions (e.g., above-normal summer peak load and outage conditions) result in the need for additional non-firm transfers available from neighbors.

On-Peak Fuel Mix



2025 Summer Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

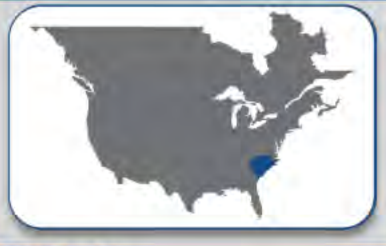
Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: Net internal demand (50/50) and extreme demand forecast based on extreme summer weather (equals or exceeds the (90/10) demand forecast)

Maintenance Outages: Adjusted for higher outages resulting from extreme summer temperatures and aggregated on a SERC subregional level

Forced Outages: Accounts for reduced thermal capacity contributions due to performance in extreme conditions

Operational Mitigations: 5.6 GW based on operational/emergency procedures



SERC-East

SERC-East is an assessment area within the SERC Regional Entity. SERC-East includes North Carolina and South Carolina. Historically a summer-peaking area, SERC-East is beginning to have higher peak demand forecasts in winter. SERC is one of the six companies across North America that are responsible for the work under FERC-approved delegation agreements with NERC. SERC is specifically responsible for the reliability and security of the electric grid across the Southeastern and Central areas of the United States. This area covers approximately 630,000 square miles and serves a population of more than 91 million. The SERC Regional Entity includes 36 BAs, 28 planning entities, and 6 RCs.

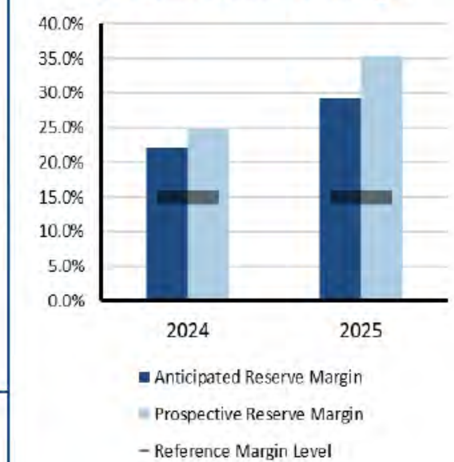
Highlights

- SERC-East's reserves are largely unchanged compared to the reference margin as compared to last summer's assessment.
- SERC-East's anticipated resources meet operating reserve requirements under the expected conditions and under the summer risk period scenario.
- While the last probabilistic analysis indicated that SERC-East could face potential unserved energy in summer, the 2026 and 2028 probabilistic analysis found the SERC-East unserved energy risk has shifted to winter mornings.
- Members of SERC-East actively participate in the SERC working groups to perform coordinated studies and develop mitigating actions for any potential or emerging reliability impacts on transmission and resource adequacy.

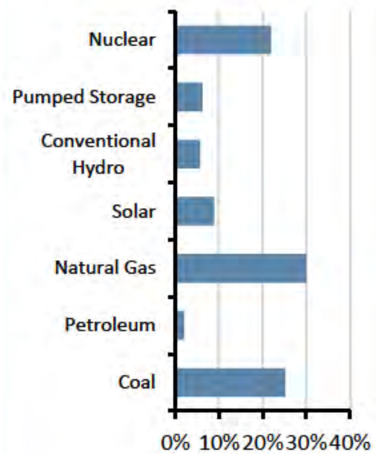
Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed scenarios.

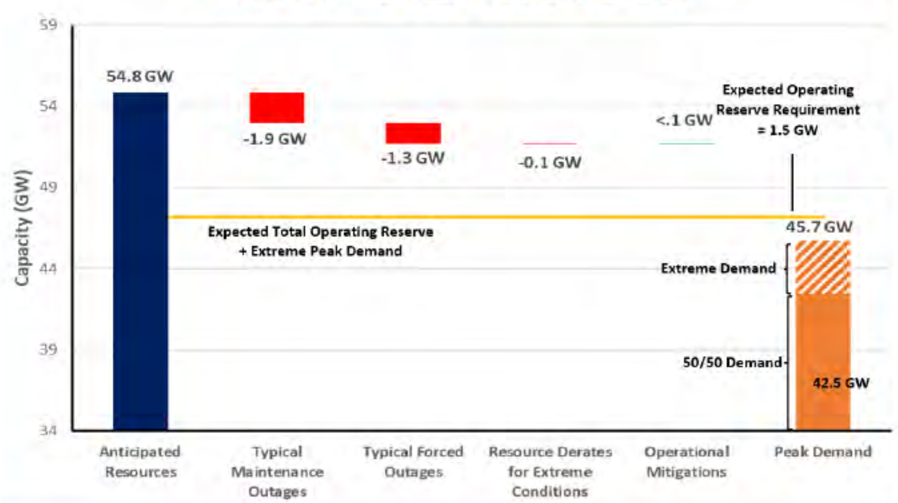
On-Peak Reserve Margin



On-Peak Fuel Mix



2025 Summer Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: Net internal demand (50/50) and extreme demand forecast based on extreme summer weather (equals or exceeds the (90/10) demand forecast)

Maintenance Outages: Adjusted for higher outages resulting from extreme summer temperatures and aggregated on a SERC subregional level

Forced Outages: Accounts for reduced thermal capacity contributions due to performance in extreme conditions

Operational Mitigations: A total of 45 MW based on operational/emergency procedures

SERC-Florida Peninsula

SERC-Florida Peninsula is a summer-peaking assessment area within SERC. SERC is one of the six companies across North America that are responsible for the work under FERC-approved delegation agreements with NERC. SERC is specifically responsible for the reliability and security of the electric grid across the Southeastern and Central areas of the United States. This area covers approximately 630,000 square miles and serves a population of more than 91 million. The SERC Regional Entity includes 36 BAs, 28 planning entities, and 6 RCs.

Highlights

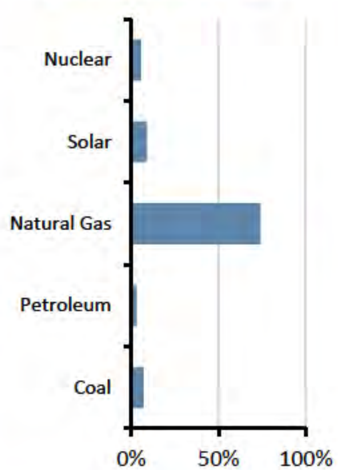
- SERC Florida-Peninsula's anticipated resources meet operating reserve requirements under the expected conditions and under the summer risk period scenario.
- The probabilistic analysis metrics indicate adequate energy resources for the subregion during the summer.
- Members of SERC-Florida Peninsula actively participate in the SERC working groups to perform coordinated studies and develop mitigating actions for any potential or emerging reliability impacts on transmission and resource adequacy.
- Entities have not identified any emerging reliability issues or operational concerns for the upcoming summer season.

On-Peak Reserve Margin

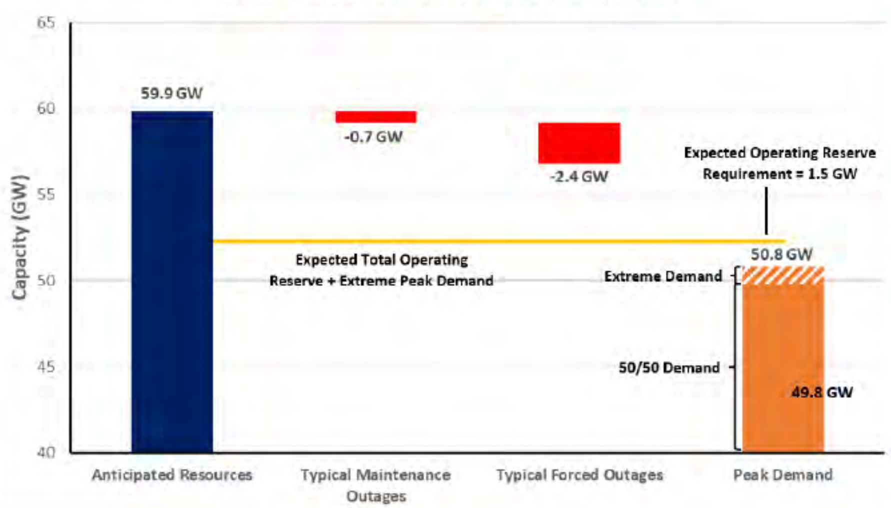
Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed scenarios.

On-Peak Fuel Mix



2025 Summer Risk Period Scenario



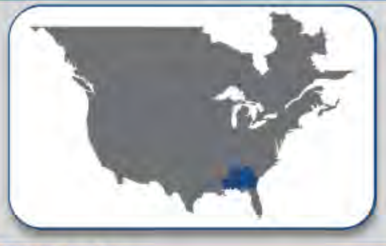
Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: Net internal demand (50/50) and extreme demand forecast based on extreme summer weather (equals or exceeds the (90/10) demand forecast)

Maintenance Outages: Adjusted for higher outages resulting from extreme summer temperatures and aggregated on a SERC subregional level

Forced Outages: Accounts for reduced thermal capacity contributions due to performance in extreme conditions



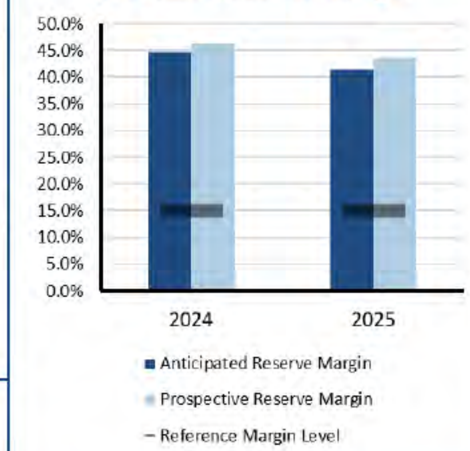
SERC-Southeast

SERC-Southeast is a summer-peaking assessment area within the SERC Regional Entity. SERC-Southeast includes all or portions of Georgia, Alabama, and Mississippi. SERC is one of the six companies across North America that are responsible for the work under FERC-approved delegation agreements with NERC. SERC is specifically responsible for the reliability and security of the electric grid across the Southeastern and Central areas of the United States. This area covers approximately 630,000 square miles and serves a population of more than 91 million. The SERC Regional Entity includes 36 BAs, 28 planning entities, and 6 RCs.

Highlights

- An area within SERC-Southeast notes that natural gas pipeline constraints could impact reliability in summer, but this is not expected to pose a significant summer operational challenge.
- SERC-Southeast's anticipated resources meet operating reserve requirements under the expected conditions and under the summer risk period scenario.
- The probabilistic analysis metrics indicate adequate energy resources for the subregion.
- Members of SERC-Southeast actively participate in the SERC working groups to perform coordinated studies and develop mitigating actions for any potential or emerging reliability impacts on transmission and resource adequacy.

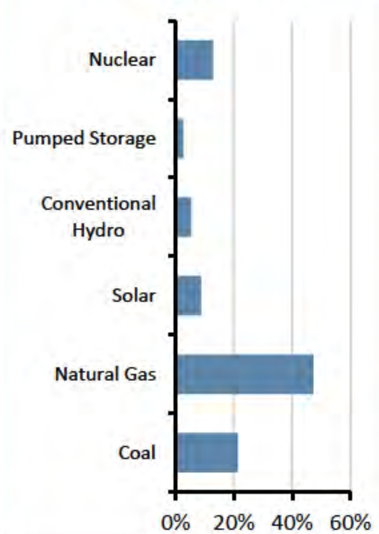
On-Peak Reserve Margin



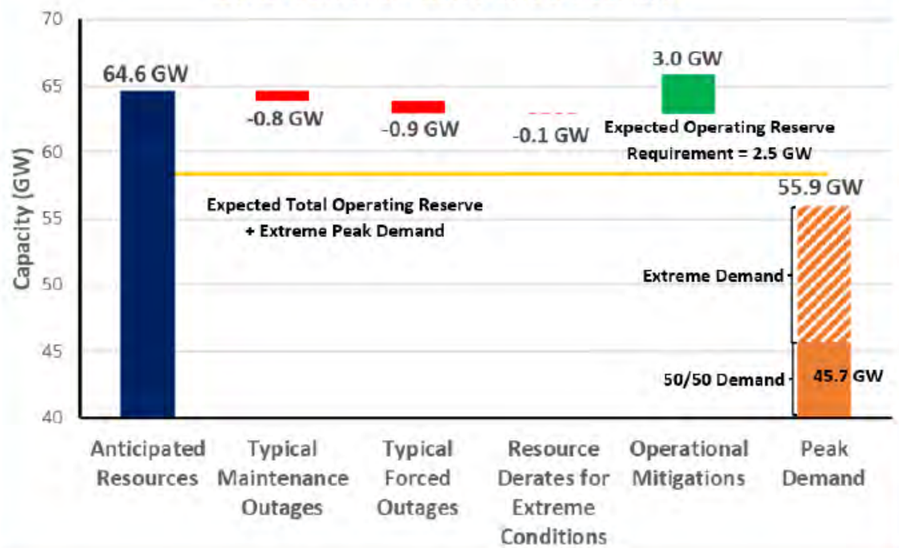
Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed scenarios.

On-Peak Fuel Mix



2025 Summer Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: Net internal demand (50/50) and extreme demand forecast based on extreme summer weather (equals or exceeds the (90/10) demand forecast)

Maintenance Outages: Adjusted for higher outages resulting from extreme summer temperatures and aggregated on a SERC subregional level

Forced Outages: Accounts for reduced thermal capacity contributions due to performance in extreme conditions

Extreme Derates: Estimated resources unavailable in extreme conditions

Operational Mitigations: A total of 3 GW based on operational/emergency procedures

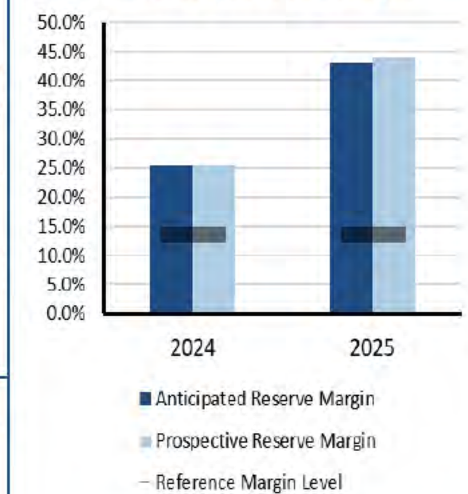
Texas RE-ERCOT

The Electric Reliability Council of Texas (ERCOT) is the independent system operator (ISO) for the ERCOT Interconnection and is located entirely in the state of Texas; it operates as a single BA. It also performs financial settlement for the competitive wholesale bulk-power market and administers retail switching for nearly 8 million premises in competitive choice areas. ERCOT is governed by a board of directors and subject to oversight by the Public Utility Commission of Texas and the Texas Legislature. ERCOT is summer-peaking, and the forecasted summer peak load month is August. It covers approximately 200,000 square miles, connects over 52,700 miles of transmission lines, has over 1,100 generation units, and serves more than 26 million customers. Texas RE is responsible for the Regional Entity functions described in the Energy Policy Act of 2005 for ERCOT. On November 3, 2022, the Public Utility Commission of Texas issued an order directing ERCOT to assume the duties and responsibilities of the reliability monitor for the Texas grid.

Highlights

- ERCOT expects to have sufficient operating reserves for the August peak load hour given normal summer system conditions.
- ERCOT's probabilistic risk assessment indicates a low risk of having to declare EEAs during the expected August (and summer) peak load day; the EEA probability for the highest-risk hour—hour ending 9:00 p.m.—is 3.6%. The likelihood of an EEA is down significantly from the 2024 SRA due to almost a doubling of battery energy storage capacity and improved energy availability reflecting new battery storage and operational rules.
- Continued robust growth in both loads and intermittent renewable resources drives a higher risk of emergency conditions in the evening hours when solar generation ramps down and loads remain elevated.
- The South Texas IROL continues to present a risk of ERCOT directing system-wide firm load shedding to remain within IROL limits. This risk has been mitigated by updating transmission line dynamic ratings and switching actions to divert power away from the most limiting transmission circuits. The South Texas transmission limits are expected to be needed at least until the San Antonio South Reliability Project is placed in service, which is anticipated to be in Summer 2027.
- ERCOT will release its own August 2025 Monthly Outlook for Resource Adequacy on June 6.

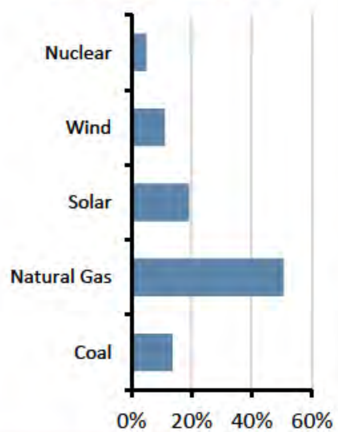
On-Peak Reserve Margin



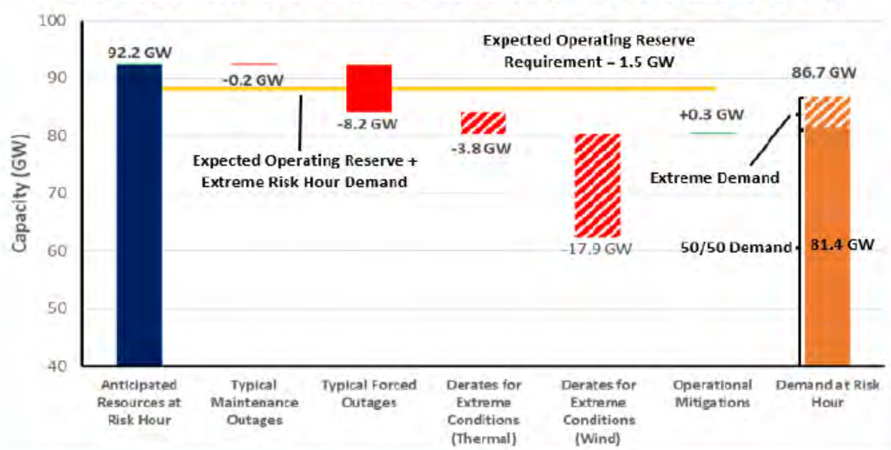
Risk Scenario Summary

Expected resources meet operating reserve requirements for the peak demand hour scenario. However, there is a risk of supply shortages during evening hours (when solar generation ramps down and demand remains high) if there are conventional generation forced outages or extreme low-wind conditions.

On-Peak Fuel Mix



2025 Summer Risk Period Scenario (9:00 p.m. local time)



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at hour ending 9 p.m. local time as solar PV output is diminished and demand remains high

Demand Scenarios: Net internal demand (50/50) and extreme demand (95/5) based on August peak load

Forced Outages: Based on the 95th percentile of historical averages of forced outages for June through September weekdays, hours ending 3:00–8:00 p.m. local time for the last three summer seasons

Extreme Derates: Based on the 90th percentile of thermal forced outages for peak August load day

Low Wind Scenario: Based on the 10th percentile of historical averages of hourly wind for June through September, hours ending 1:00–9:00 p.m. local time

Operational Mitigations: Additional capacity from switchable generation and additional imports

WECC-Alberta

WECC-Alberta is a winter-peaking assessment area in the WECC Regional Entity that consists of the province of Alberta. It has 16,369 miles of transmission. WECC is responsible for coordinating and promoting BES reliability in the Western Interconnection. WECC's 329 members include 40 BAs, representing a wide spectrum of organizations with an interest in the BES. Serving an area of nearly 1.8 million square miles and more than 84.5 million customers, it is geographically the largest and most diverse Regional Entity.

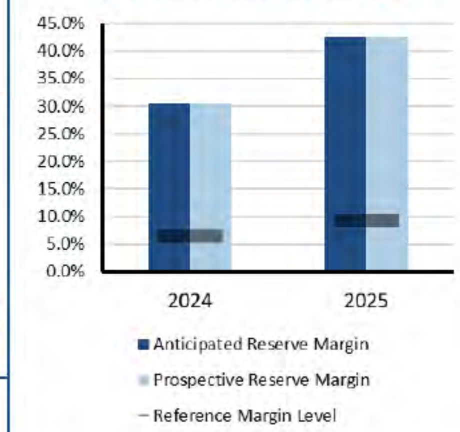
Highlights

- Anticipated and prospective reserve margins are projected to remain above the Reference Margin Level.
- All resource margins have increased by about 50% since last summer with the addition of 23.2% new capacity, including almost 2,700 MW of new natural gas capacity, 1,200 MW of new wind (+27%), 200 MW of new solar (+13%), and 54 MW of new energy storage systems (+27.5%).
- The peak hour has moved earlier, to 3:00 p.m. from 4:00 p.m., still in late July.
- High temperatures, import limitations, and low or declining renewable output during summer evenings can result in grid alerts.
- Wildfires can threaten generating assets and transmission infrastructure requiring invocation of Alberta Electric System Operator (AESO) protocols that include instructing available assets and long lead-time assets to deliver energy up to their maximum capability, calling upon demand response, and maximizing import capability.

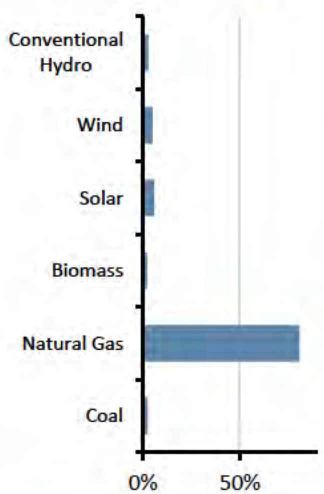
Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed scenarios.

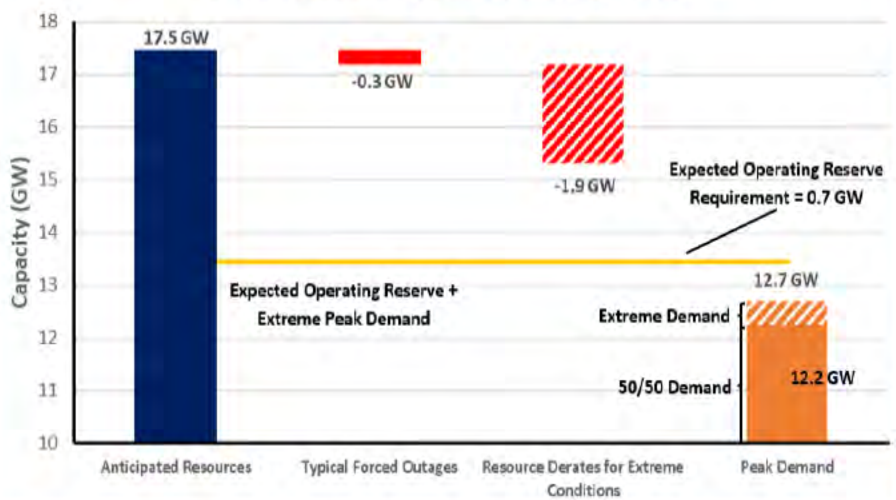
On-Peak Reserve Margin



On-Peak Fuel Mix



2025 Summer Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: Net internal demand (50/50) and (90/10) demand forecast

Typical Forced Outages: Average seasonal outages

Extreme Derates: Using (90/10) point of resource performance distribution

WECC-Basin

WECC-Basin is a summer-peaking assessment area in the WECC Regional Entity that includes Utah, southern Idaho, and a portion of western Wyoming, covering Idaho Power and PacifiCorp's eastern Balancing Authority Area. The population of this area is approximately 5.4 million. It has 15,910 miles of transmission. WECC is responsible for coordinating and promoting BES reliability in the Western Interconnection. WECC's 329 members include 40 BAs, representing a wide spectrum of organizations with an interest in the BES. Serving an area of nearly 1.8 million square miles and more than 84.5 million customers, it is geographically the largest and most diverse Regional Entity. *Note: The 2025 SRA includes a new assessment area map for the U.S. Western Interconnection. The new assessment area boundaries provide more geographic detail of reliability risk information. WECC-Basin is a new assessment area in 2025 that was part of WECC-NW in the 2024 SRA.*

Highlights

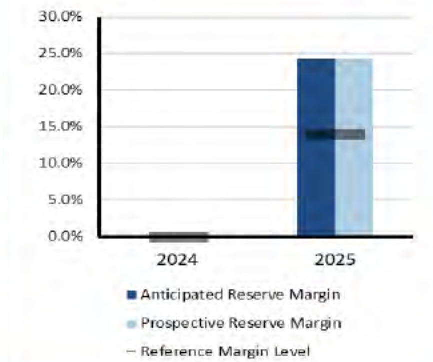
- Total internal expected demand has increased 8% and demand response has increased almost 28% for a net internal demand increase of 7.2%.
- Reserve margins are not anticipated to fall below the reference margin (14%) for the upcoming summer; an early July peak is expected at around 3:00 p.m.
- During periods of contingency reserve shortage, EEAs may be declared in the region to obtain reserves from the Northwest Power Pool.
- Seasonal fluctuations in hydro supply require monitoring and forecasting to have high certainty that these resources will meet anticipated capacity; the Summer 2025 drought outlook for the United States indicates minimal drought conditions in Idaho and some drought areas in Utah this summer.
- Wildfires near wind generation can result in safety curtailments, and fire damage to transmission lines interconnected to hydro sites can present restoration challenges.

Risk Scenario Summary

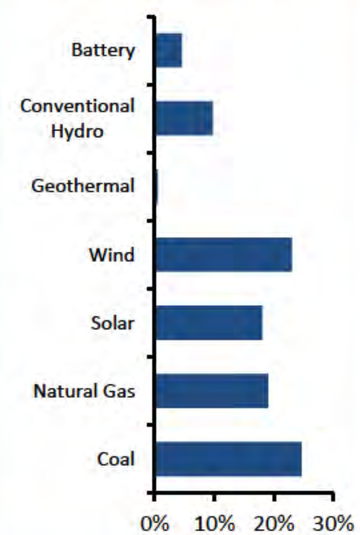
Expected resources meet operating reserve requirements under the assessed scenarios with imports.

On-Peak Reserve Margin

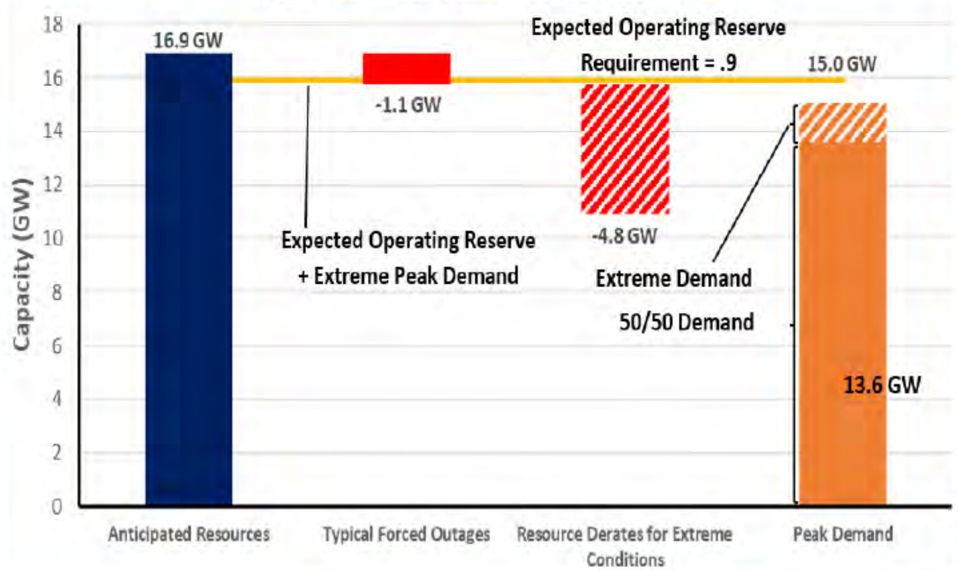
(Note: year comparison not available)



On-Peak Fuel Mix



2025 Summer Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: Net internal demand (50/50) and (90/10) demand forecast

Forced Outages: Average seasonal outages

Extreme Derates: Using (90/10) resource performance distribution at peak hour

WECC-British Columbia

WECC-British Columbia (BC) is a winter-peaking assessment area in the WECC Regional Entity that consists of the province of British Columbia. It has 11,184 miles of transmission. WECC is responsible for coordinating and promoting BES reliability in the Western Interconnection. WECC's 329 members include 40 BAs, representing a wide spectrum of organizations with an interest in the BES. Serving an area of nearly 1.8 million square miles and more than 84.5 million customers, it is geographically the largest and most diverse Regional Entity.

Highlights

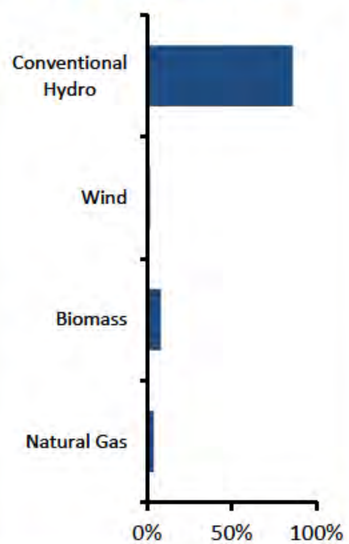
- Existing capacity reserve margin has increased from 19% to 22%, and anticipated and prospective reserve margin from 19% to 24%.
- Reserve margins are not anticipated to fall below the reference margin for the upcoming summer.
- The peak hour is forecast for early August at 4:00 p.m., two hours earlier than last summer's outlook of 6:00 p.m.
- About 60% of hydro owned or contracted energy comes from the Columbia and Peace basins. Heavy precipitation in Fall 2024 mitigated the impact of below-average snowpack the previous winter, resulting in hydro storage tracking close to historical averages as of Spring 2025.
- Wildfires can affect the transmission network and generator availability and have caused energy emergencies on the electric system in the past.

Risk Scenario Summary

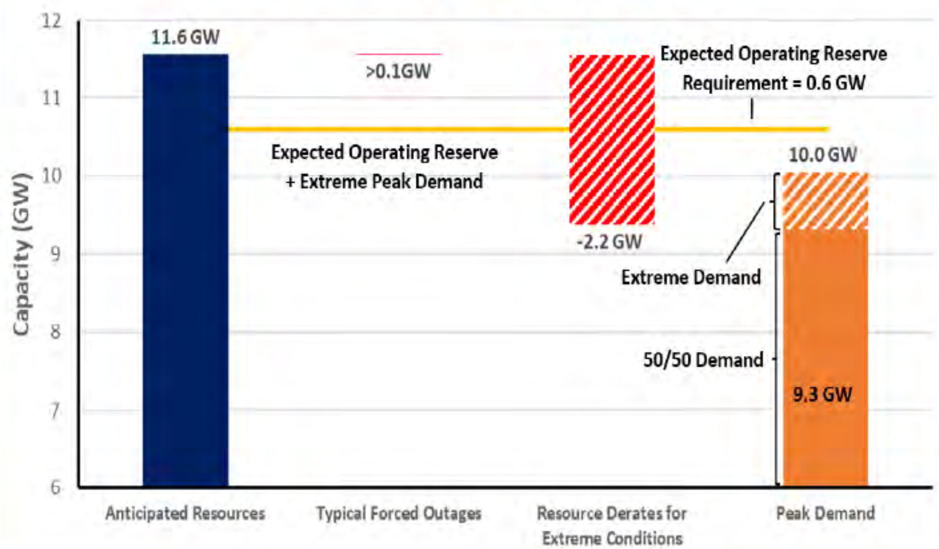
Expected resources meet operating reserve requirements under the assessed scenarios.

On-Peak Reserve Margin

On-Peak Fuel Mix



2025 Summer Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: Net internal demand (50/50) and (90/10) demand forecast

Forced Outages: Average seasonal outages

Extreme Derates: Using (90/10) resource performance distribution at peak hour

WECC-California

WECC-California is a summer-peaking assessment area in the Western Interconnection that includes most of California and a small section of Nevada. The assessment area has a population of over 42.5 million people. The area includes the California ISO, Los Angeles Department of Water and Power, Turlock Irrigation District, and the Balancing Area of Northern California. It has 32,712 miles of transmission. WECC is responsible for coordinating and promoting BES reliability in the Western Interconnection. WECC's 329 members include 40 BAs, representing a wide spectrum of organizations with an interest in the BES. Serving an area of nearly 1.8 million square miles and more than 84.5 million customers, it is geographically the largest and most diverse Regional Entity. *Note: The 2025 SRA includes a new assessment area map for the U.S. Western Interconnection. The new assessment area boundaries provide more geographic detail of reliability risk information. WECC-California is a new assessment area in 2025 that was part of WECC-CA/MX in the 2024 SRA.*

Highlights

- Demand response is down 8.6% since last summer, existing-certain capacity is up 5.8%, and Tier 1 planned capacity is up 41.2% for a net increase in anticipated resources of 9%; anticipated and prospective reserve margins are up by 11.4%. The peak hour is still forecasted for early September around 4:00 p.m.
- Reserve margins are not anticipated to fall below the reference margin for the upcoming summer, and probabilistic assessment of normal and extreme resource/demand scenarios reveal no EUE or LOLH.
- Wildfires can and have threatened both the California Oregon Intertie line, resulting in import capability limitations.
- Prolonged elevated demand during heat waves in combination with thermal resource derates and forced outage rates present significant risk.
- An influx of IBRs and corresponding reduction in system inertia can potentially trigger system reliability issues and require additional regulation, flexible ramp, and future imbalance reserve requirements.
- Increased solar penetrations in this region along with changing load patterns from elevated temperatures and residential demand are shifting the hours with the most challenging resource adequacy needs later into the evening rather than traditional afternoon gross peak load periods.

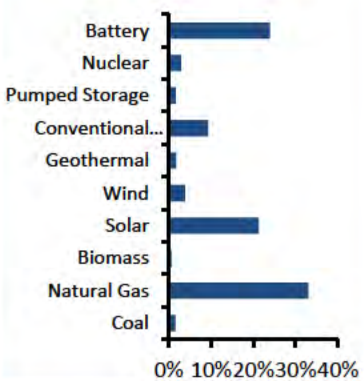
On-Peak Reserve Margin

(Note: year comparison not available)

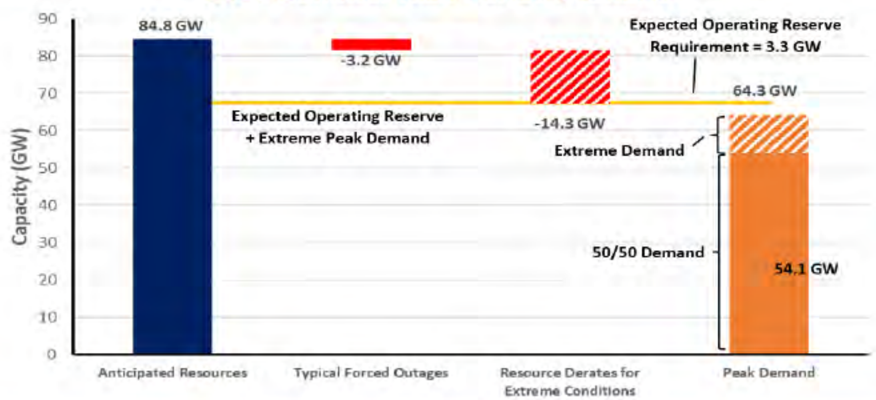
Risk Scenario Summary

Expected resources meet operating reserve requirements under assessed scenarios, and a probabilistic assessment of normal and extreme resource/demand scenarios reveals neither EUE nor LOLH.

On-Peak Fuel Mix



2025 Summer Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: Net internal demand (50/50) at risk hour and (90/10) demand **forecast** at risk hour

Forced Outages: Estimated using market forced outage model

Extreme Derates: On natural gas units based on historical data and manufacturer data for temperature performance and outages

WECC-Mexico

WECC-Mexico is a summer-peaking assessment area in the Western Interconnection that includes the northern portion of the Mexican state of Baja California, which has a population of 3.8 million people and includes CENACE. It has 1,568 miles of transmission. WECC is responsible for coordinating and promoting BES reliability in the Western Interconnection. WECC's 329 members include 40 BAs, representing a wide spectrum of organizations with an interest in the BES. Serving an area of nearly 1.8 million square miles and more than 84.5 million customers, it is geographically the largest and most diverse Regional Entity. *Note: The 2025 SRA includes a new assessment area map for the U.S. Western Interconnection. The new assessment area boundaries provide more geographic detail of reliability risk information. WECC-Mexico is a new assessment area in 2025 that was part of WECC-CA/MX in the 2024 SRA.*

Highlights

- Total and net internal expected (50/50) demand are up 6.8%, existing-certain capacity is up 29.8% or 989 MW, and Tier 1 planned capacity has fallen 100% to zero, leading to a decrease in the anticipated reserve margin from 22.9% down to 14.1%
- The peak hour is expected to occur in early August around 4:00 p.m.
- Operating reserves are a concern in this region during periods of extreme heat and elevated demand. High loading on Path 45 (See: WECC Path Rating Catalog) coupled with outages or derates to large thermal assets in this region can result in the declaration of an EAA and a request for assistance from RC West.

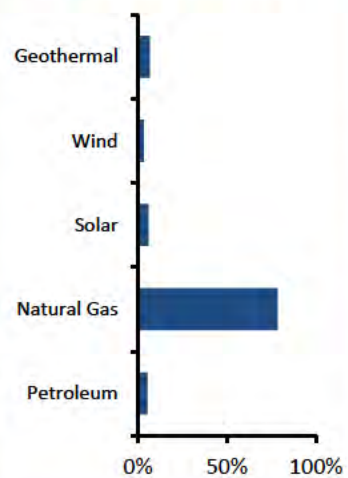
Risk Scenario Summary

Expected resources at normal peak demand and outage conditions require some imports to maintain operating reserves. Thus, above-normal demand, high forced outage conditions, or transmission derates in the neighboring area could place WECC-Mexico in an energy emergency.

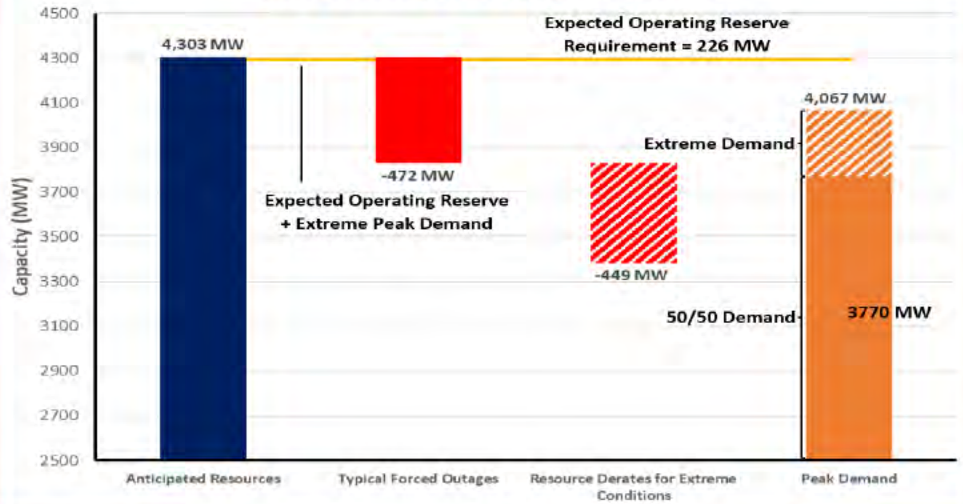
On-Peak Reserve Margin

(Note: year comparison not available)

On-Peak Fuel Mix



2025 Summer Risk Period Scenario



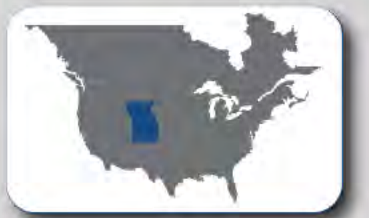
Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: Net internal demand (50/50) and (90/10) demand forecast

Forced Outages: Average seasonal outages

Extreme Derates: Using (90/10) resource performance distribution at peak hour



WECC-Rocky Mountain

WECC-Rocky Mountain is a summer-peaking assessment area in the Western Interconnection that includes Colorado, most of Wyoming, and parts of Nebraska and South Dakota. The population of the area is approximately 6.7 million. It covers the balancing areas of the Public Service Company of Colorado and the Western Area Power Administration's Rocky Mountain Region. It has 18,797 miles of transmission. WECC is responsible for coordinating and promoting BES reliability in the Western Interconnection. WECC's 329 members include 40 BAs, representing a wide spectrum of organizations with an interest in the BES. Serving an area of nearly 1.8 million square miles and more than 84.5 million customers, it is geographically the largest and most diverse Regional Entity. *Note: The 2025 SRA includes a new assessment area map for the U.S. Western Interconnection. The new assessment area boundaries provide more geographic detail of reliability risk information. WECC-Rocky Mountain is a new assessment area in 2025 that was part of WECC-NW in the 2024 SRA.*

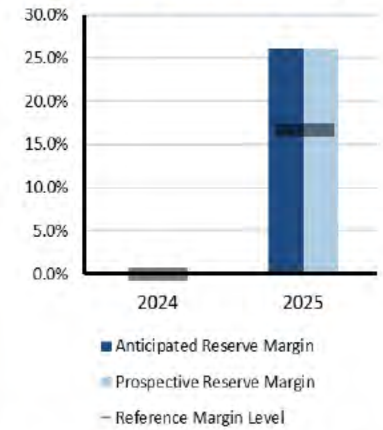
Highlights

- The reserve margins (existing-certain 25% and anticipated and prospective 26%) are not anticipated to fall below the reference margin (17%) for Summer 2025.
- Total and net internal demand (50/50) is up 25% or almost 2,800 MW, leading to a decline in the Anticipated Reserve Margin by almost a third.
- During the summer, there is increased load and decreased market purchase availability. Low wind availability and ramping scarcity events are a concern.
- Environmental and ecological factors have contributed to a rise in wildfire frequency and shortening of the fire return interval in the Rocky Mountain region, which, in addition to having caused generation outages, threatens rural co-ops disproportionately due to the extensive line buildout over remote regions.

Risk Scenario Summary

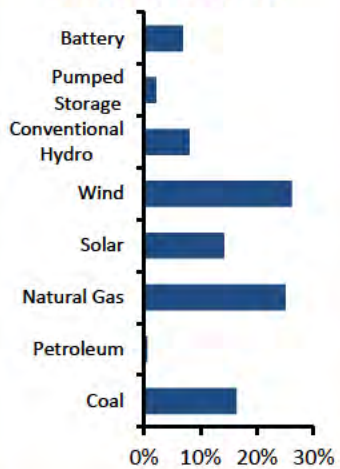
Expected resources meet operating reserve requirements under assessed scenarios with imports.

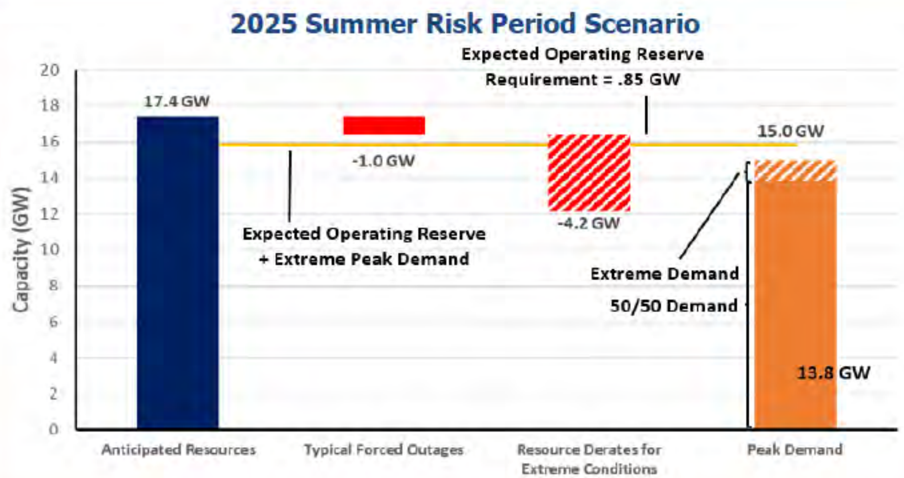
On-Peak Reserve Margin



(Note: year comparison not available)

On-Peak Fuel Mix





Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy occurs at the hour of peak demand

Demand Scenarios: Net internal demand (50/50) at risk hour and (90/10) demand forecast at risk hour

Forced Outages: Average seasonal outages

Extreme Derates: Using (90/10) scenario

WECC-Northwest

WECC-Northwest is a winter-peaking assessment area in the WECC Regional Entity. The area includes Montana, Oregon, and Washington and parts of northern California and northern Idaho. The population of the area is approximately 13.6 million. It has 32,751 miles of transmission. WECC is responsible for coordinating and promoting BES reliability in the Western Interconnection. WECC's 329 members include 40 BAs, representing a wide spectrum of organizations with an interest in the BES. Serving an area of nearly 1.8 million square miles and more than 84.5 million customers, it is geographically the largest and most diverse Regional Entity. *Note: The 2025 SRA includes a new assessment area map for the U.S. Western Interconnection. The new assessment area boundaries provide more geographic detail of reliability risk information. WECC-Northwest is a new assessment area in 2025 that was part of a larger WECC-NW footprint in the 2024 SRA.*

Highlights

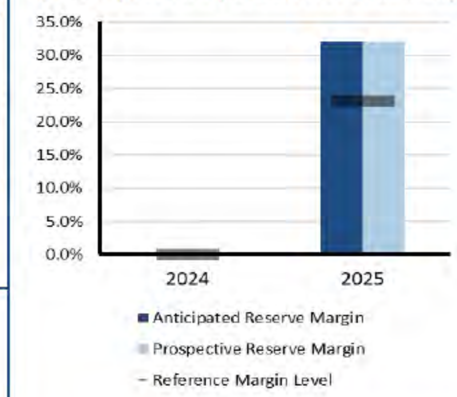
- The reserve margins (existing-certain 29% and anticipated and prospective 32%) are not anticipated to fall below the reference margin (23%) for the upcoming summer. An extreme summer peak load may be around 32,740 MW.
- Typical forced outages are forecast to be 771 MW, with derates for thermal under extreme conditions to be 1,584 MW and 2,649 MW for wind. The expected operating reserve requirement on peak is 1,750 MW.
- Extreme heat corresponds with elevated loads, reduced transmission ratings, and temperature derates of thermal resources, which can strain resource adequacy and grid reliability.
- Seasonal hydro variability is a risk.

Risk Scenario Summary

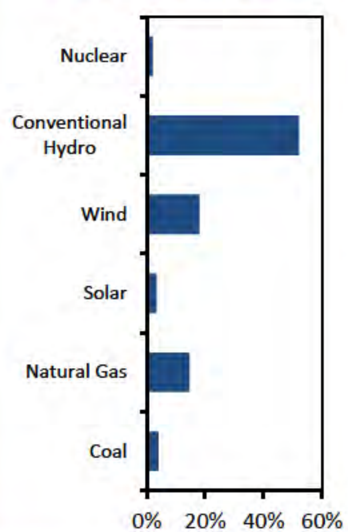
Expected resources meet operating reserve requirements under assessed scenarios with imports.

On-Peak Reserve Margin

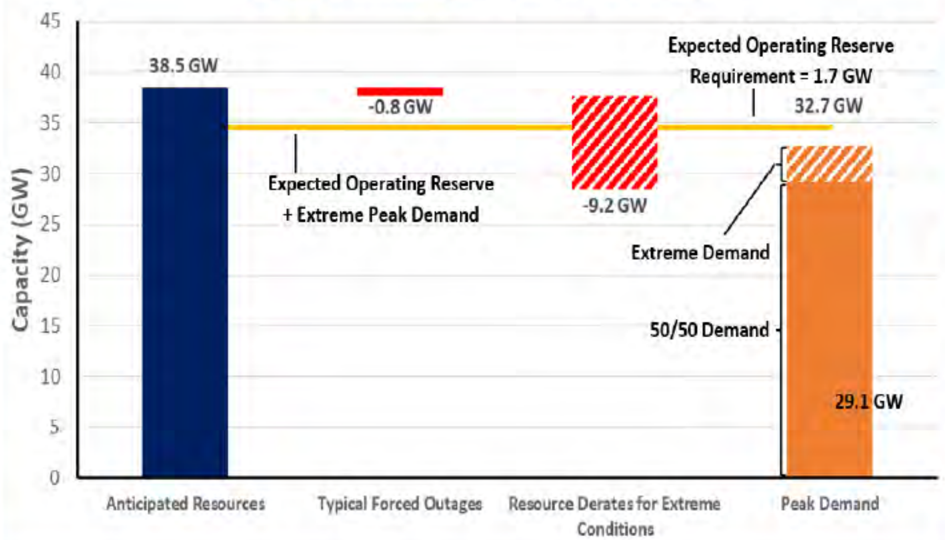
(Note: year comparison not available)



On-Peak Fuel Mix



2025 Summer Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy occurs at the hour of peak demand

Demand Scenarios: Net internal demand (50/50) at risk hour and (90/10) demand forecast at risk hour

Forced Outages: Average seasonal outages

Extreme Derates: Using (90/10) scenario

WECC-Southwest

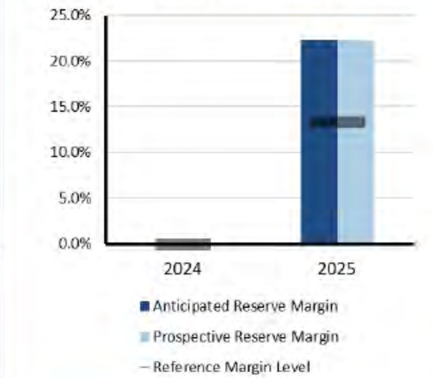
WECC-Southwest is a summer-peaking assessment area in the Western Interconnection that includes all of Arizona and New Mexico, most of Nevada, and small parts of California and Texas. The area has a population of approximately 13.6 million. It has 23,084 miles of transmission. WECC is responsible for coordinating and promoting BES reliability in the Western Interconnection. WECC's 329 members include 40 BAs, representing a wide spectrum of organizations with an interest in the BES. Serving an area of nearly 1.8 million square miles and more than 84.5 million customers, it is geographically the largest and most diverse Regional Entity. *Note: The 2025 SRA includes a new assessment area map for the U.S. Western Interconnection. The new assessment area boundaries provide more geographic detail of reliability risk information. WECC-Southwest is a new, larger assessment area in 2025 that now includes a portion of WECC-NW in the 2024 SRA.*

Highlights

- Anticipated Reserve Margins for the summer are 22%, exceeding the Reference Margin Level for reliability calculated by WECC.
- WECC's probabilistic analysis indicates that the area is not expected to encounter LOLH or EUE under a range of demand and resource conditions.
- The peak hour is expected to occur in early July around 5:00 p.m., when solar generation output begins to diminish.
- Wide-area heat events or wildfires that affect resource and transmission availability across the western interconnection area a reliability concern for the Southwest. Firm imports may be limited at this time if neighboring areas are also experiencing peak loads, limiting energy availability to export to the Southwest.

On-Peak Reserve Margin

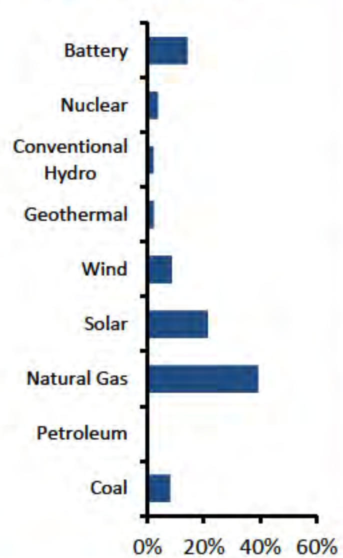
(Note: year comparison not available)



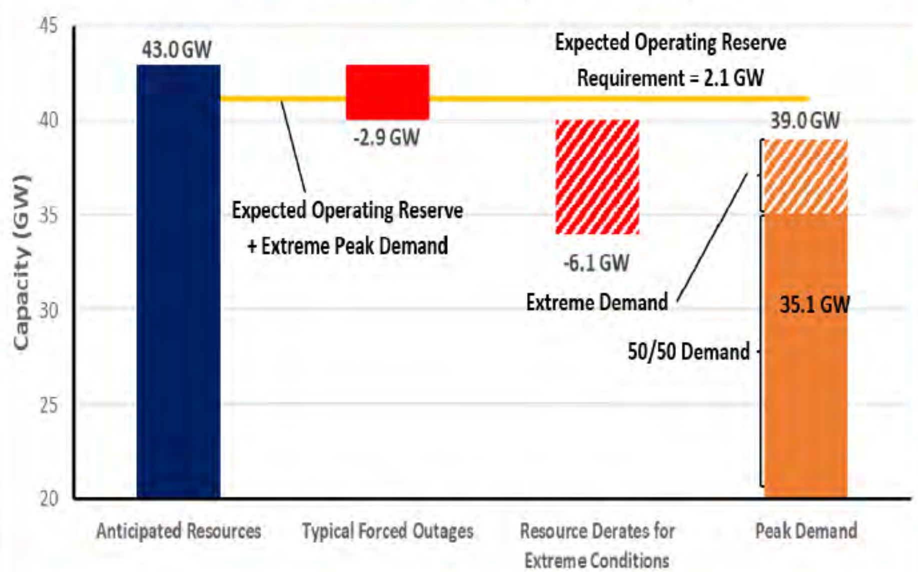
Risk Scenario Summary

Expected resources meet operating reserve requirements under assessed scenarios with imports.

On-Peak Fuel Mix



2025 Summer Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy occurs at the hour of peak demand (5:00 p.m. local)

Demand Scenarios: Net internal demand (50/50) at risk hour and (90/10) demand forecast

Forced Outages: Average seasonal outages

Extreme Derates: Using (90/10) scenario

Data Concepts and Assumptions

The table below explains data concepts and important assumptions used throughout this assessment.

General Assumptions
• Reliability of the interconnected BPS is comprised of both adequacy and operating reliability:
▪ Adequacy is the ability of the electric system to supply the aggregate electric power and energy requirements of the electricity consumers at all times while taking into account scheduled and reasonably expected unscheduled outages of system components.
▪ Operating reliability is the ability of the electric system to withstand sudden disturbances, such as electric short-circuits or unanticipated loss of system components.
• The reserve margin calculation is an important industry planning metric used to examine future resource adequacy.
• All data in this assessment is based on existing federal, state, and provincial laws and regulations.
• Differences in data collection periods for each assessment area should be considered when comparing demand and capacity data between year-to-year seasonal assessments.
• A positive net transfer capability would indicate a net importing assessment area; a negative value would indicate a net exporter.
Demand Assumptions
• Electricity demand projections, or load forecasts, are provided by each assessment area.
• Load forecasts include peak hourly load[12] or total internal demand for the summer and winter of each year.[13]
• Total internal demand projections are based on normal weather (50/50 distribution)[14] and are provided on a coincident[15] basis for most assessment areas.
• Net internal demand is used in all reserve margin calculations, and it is equal to total internal demand then reduced by the amount of controllable and dispatchable demand response projected to be available during the peak hour.
Resource Assumptions
Resource planning methods vary throughout the North American BPS. NERC uses the categories below to provide a consistent approach for collecting and presenting resource adequacy. Because the electrical output of VERs (e.g., wind, solar PV) depends on weather conditions, their contribution to reserve margins and other on-peak resource adequacy analysis is less than their nameplate capacity.
Anticipated Resources: • **Existing-Certain Capacity**: Included in this category are commercially operable generating units or portions of generating units that meet at least one of the following requirements when examining the period of peak demand for the summer season: unit must have a firm capability and have a power purchase agreement with firm transmission that must be in effect for the unit; unit must be classified as a designated network resource; and/or, where energy-only markets exist, unit must be a designated market resource eligible to bid into the market. • **Tier 1 Capacity Additions**: This category includes capacity that either is under construction or has received approved planning requirements. • **Net Firm Capacity Transfers (Imports minus Exports)**: This category includes transfers with firm contracts.
Prospective Resources: Includes all anticipated resources plus the following: **Existing-Other Capacity**: Included in this category are commercially operable generating units or portions of generating units that could be available to serve load for the period of peak demand for the season but do not meet the requirements of existing-certain.

[12] https://www.nerc.com/pa/Stand/Glossary%20of%20Terms/Glossary_of_Terms.pdf used in NERC Reliability Standards

[13] The summer season represents June–September and the winter season represents December–February.

[14] Essentially, this means that there is a 50% probability that actual demand will be higher and a 50% probability that actual demand will be lower than the value provided for a given season/year.

[15] Coincident: This is the sum of two or more peak loads that occur in the same hour. Noncoincident: This is the sum of two or more peak loads on individual systems that do not occur in the same time interval; this is meaningful only when considering loads within a limited period of time, such as a day, a week, a month, a heating or cooling season, and usually for not more than one year. SERC calculates total internal demand on a noncoincidental basis.

Reserve Margin Descriptions

Planning Reserve Margin: This is the primary metric used to measure resource adequacy; it is defined as the difference in resources (anticipated or prospective) and net internal demand then divided by net internal demand and shown as a percentage.

Reference Margin Level: The assumptions and naming convention of this metric vary by assessment area. The RML can be determined using both deterministic and probabilistic (based on a 0.1/year loss-of-load study) approaches. In both cases, this metric is used by system planners to quantify the amount of reserve capacity in the system above the forecasted peak demand that is needed to ensure sufficient supply to meet peak loads. Establishing an RML is necessary to account for long-term factors of uncertainty involved in system planning, such as unexpected generator outages and extreme weather impacts that could lead to increase demand beyond what was projected in the 50/50 load forecasted. In many assessment areas, an RML is established by a state, provincial authority, ISO/Regional Transmission Organization (RTO), or other regulatory body. In some cases, the RML is a requirement. RMLs may be different for the summer and winter seasons. If an RML is not provided by an assessment area, NERC applies 15% for predominantly thermal systems and 10% for predominantly hydro systems.

Seasonal Risk Scenario Chart Description

Each assessment area performed an operational risk analysis that was used to produce the seasonal risk scenario charts in the **Regional Assessments Dashboards**. The chart presents deterministic scenarios for further analysis of different resource and demand levels: The left **blue** column shows anticipated resources, and the two **orange** columns at the right show the two demand scenarios of the normal peak net internal demand and the extreme summer peak demand—both determined by the assessment area. The middle **red** or **green** bars show adjustments that are applied cumulatively to the anticipated resources, such as the following:

- Reductions for typical generation outages (i.e., maintenance and forced outages that are not already accounted for in anticipated resources)
- Reductions that represent additional outage or performance derating by resource type for extreme, low-probability conditions (e.g., drought condition impacts on hydroelectric generation, low-wind scenario affecting wind generation, fuel supply limitations, or extreme temperature conditions that result in reduced thermal generation output)
- Additional capacity resources that represent quantified capacity from operational procedures, if any, that are made available during scarcity conditions

Not all assessment areas have the same categories of adjustments to anticipated resources. Furthermore, each assessment area determined the adjustments to capacity based on methods or assumptions that are summarized below the chart. Methods and assumptions differ by assessment area and may not be comparable.

The chart enables evaluation of resource levels against levels of expected operating reserve requirement and the forecasted demand. Furthermore, the effects from extreme events can also be examined by comparing resource levels after applying extreme scenario derates and/or extreme summer peak demand.

Resource Adequacy

The Anticipated Reserve Margin (ARM), which is based on available resource capacity, is a metric used to evaluate resource adequacy by comparing the projected capability of anticipated resources to serve forecast peak demand.[16] Large year-to-year changes in anticipated resources or forecast peak demand (net internal demand) can greatly impact Planning Reserve Margin calculations. All assessment areas have sufficient ARMs to meet or exceed their RML for the summer 2025 as shown in Figure 4.

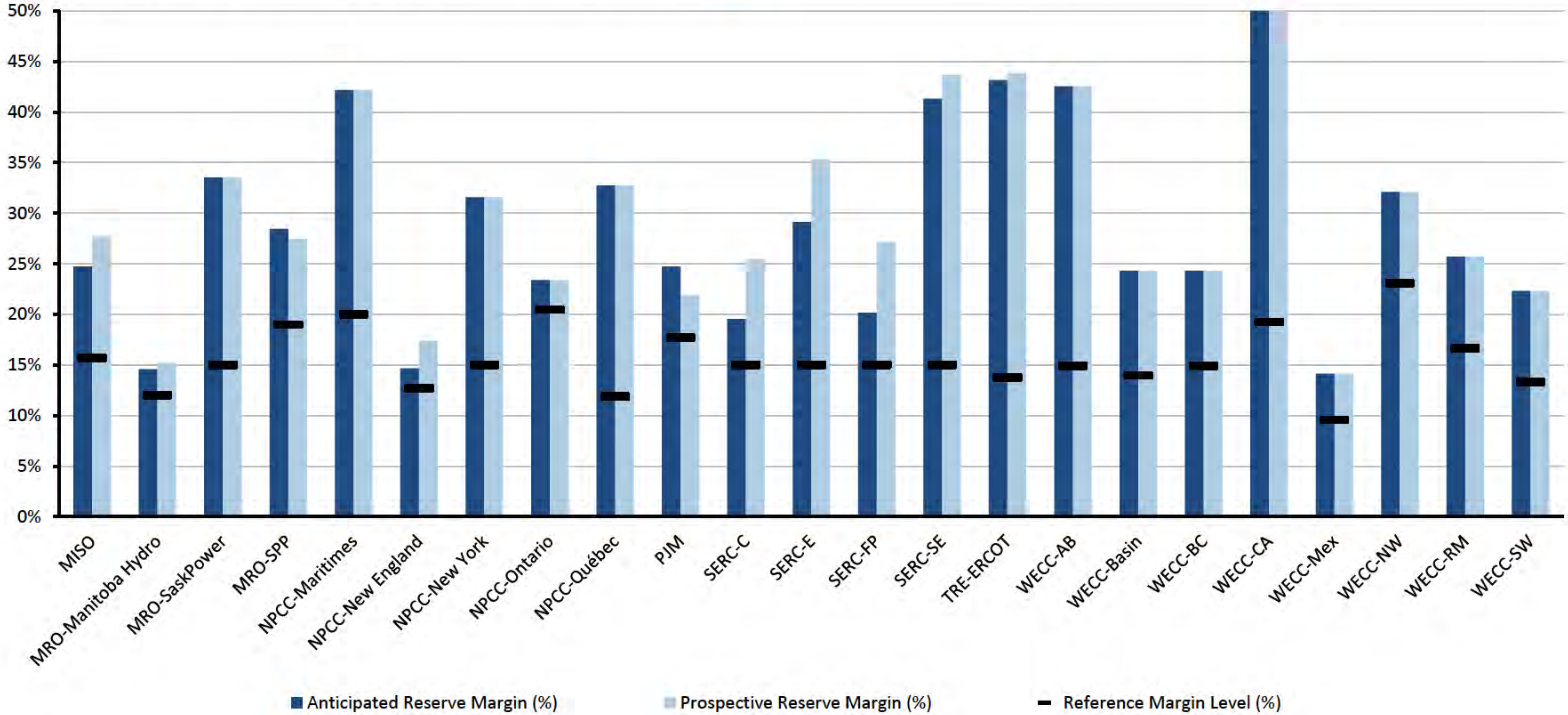


Figure 4: Summer 2025 Anticipated/Prospective Reserve Margins Compared to Reference Margin Level

[16] Generally, anticipated resources include generators and firm capacity transfers that are expected to be available to serve load during electrical peak loads for the season. Prospective resources are those that could be available but do not meet criteria to be counted as anticipated resources. Refer to the Data Concepts and Assumptions section for additional information on Anticipated/Prospective Reserve Margins, anticipated/prospective resources, and RMLs.

Changes from Year to Year

Figure 5 provides the relative change in the forecast ARMs from the 2024 Summer to the 2025 Summer. A significant decline can signal potential operational issues for the upcoming season. Additional details for each assessment area are provided in the Data Concepts and Assumptions and Regional Assessments Dashboards sections.

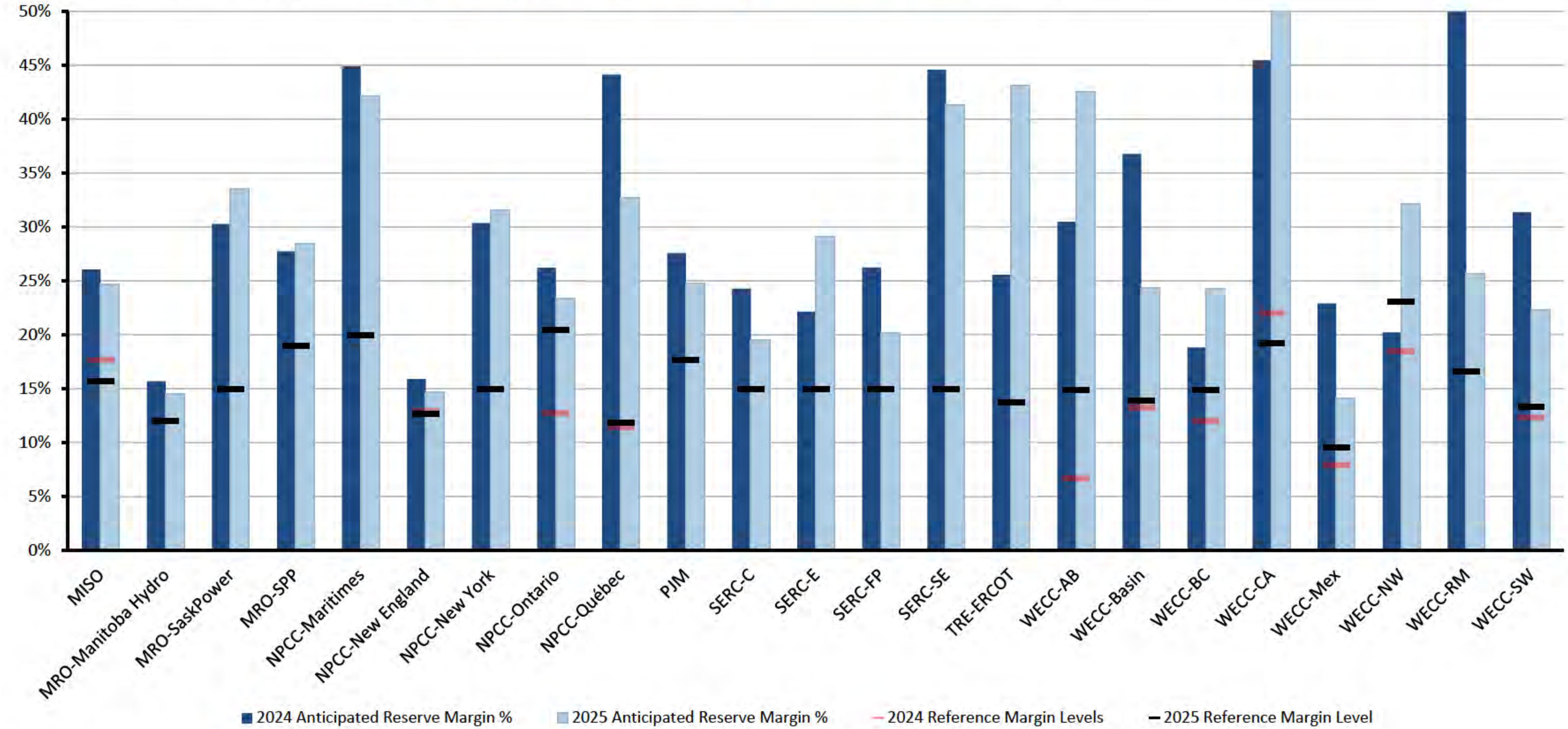


Figure 5: Summer 2024 and Summer 2025 Anticipated Reserve Margins Year-to-Year Change

Note: Yearly trends are not available for new WECC assessment areas in the United States and Baja California, Mexico.

Net Internal Demand

The changes in forecasted net internal demand for each assessment area are shown in Figure 6.[17] Assessment areas develop these forecasts based on historic load and weather information as well as other long-term projections.

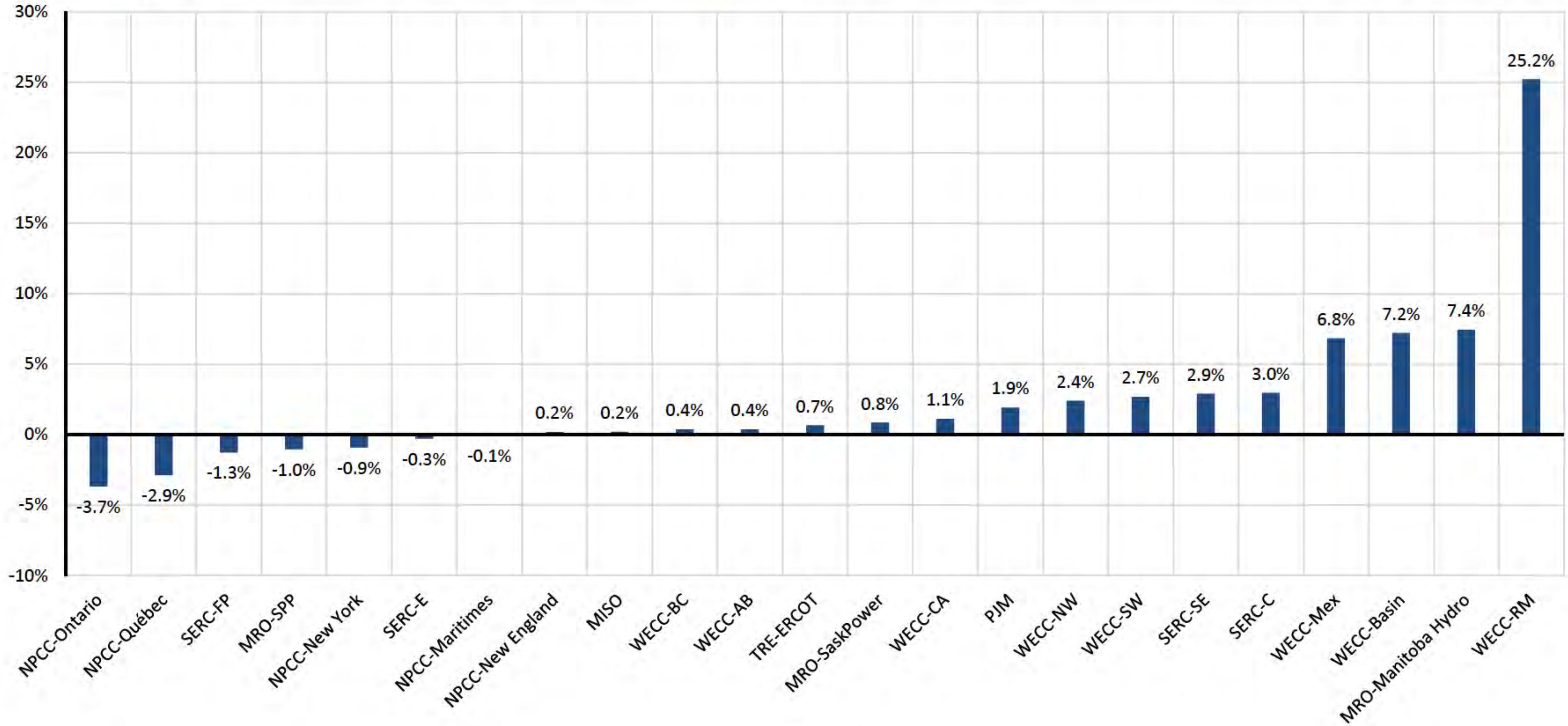


Figure 6: Changes in Net Internal Demand—Summer 2024 Forecast Compared to Summer 2025 Forecast

[17] Changes in modeling and methods are contributing to year-to-year changes in forecasted net internal demand projections in NPCC Maritimes and NPCC Ontario. See assessment area dashboards.

Demand and Resource Tables

Peak demand and supply capacity data—resource adequacy data—for each assessment area are as follows in each table (in alphabetical order).

MISO			
Demand, Resource, and Reserve Margins	**2024 SRA**	**2025 SRA**	**2024 vs. 2025 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	124,830	125,313	0.4%
Demand Response: Available	8,750	9,004	2.9%
Net Internal Demand	116,079	116,309	0.2%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	143,866	142,793	-0.7%
Tier 1 Planned Capacity	0	0	-
Net Firm Capacity Transfers	2,471	2,280	-7.7%
Anticipated Resources	146,337	145,073	-0.9%
Existing-Other Capacity	1,833	1,190	-35.1%
Prospective Resources	148,740	148,543	-0.1%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	26.1%	24.7%	-1.3
Prospective Reserve Margin	28.1%	27.7%	-0.4
Reference Margin Level	17.7%	15.7%	-2.0

MRO-Manitoba Hydro			
Demand, Resource, and Reserve Margins	**2024 SRA**	**2025 SRA**	**2024 vs. 2025 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	3,143	3,377	7.4%
Demand Response: Available	0	0	-
Net Internal Demand	3,143	3,377	7.4%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	5,615	5,583	-0.6%
Tier 1 Planned Capacity	0	0	-
Net Firm Capacity Transfers	-1,978	-1,714	-13.3%
Anticipated Resources	3,637	3,869	6.4%
Existing-Other Capacity	37	21	-42.9%
Prospective Resources	3,674	3,890	5.9%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	15.7%	14.6%	-1.1
Prospective Reserve Margin	16.9%	15.2%	-1.7
Reference Margin Level	12.0%	12.0%	0.0

MRO-SaskPower			
Demand, Resource, and Reserve Margins	**2024 SRA**	**2025 SRA**	**2024 vs. 2025 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	3,590	3,620	0.8%
Demand Response: Available	50	50	0.0%
Net Internal Demand	3,540	3,570	0.8%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	4,323	4,477	3.6%
Tier 1 Planned Capacity	0	0	-
Net Firm Capacity Transfers	290	290	0.0%
Anticipated Resources	4,613	4,767	3.3%
Existing-Other Capacity	0	0	-
Prospective Resources	4,613	4,767	3.3%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	30.3%	33.5%	3.2
Prospective Reserve Margin	30.3%	33.5%	3.2
Reference Margin Level	15.0%	15.0%	0.0

MRO-SPP			
Demand, Resource, and Reserve Margins	**2024 SRA**	**2025 SRA**	**2024 vs. 2025 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	56,316	56,168	-0.3%
Demand Response: Available	979	1,408	43.8%
Net Internal Demand	55,337	54,760	-1.0%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	70,855	70,549	-0.4%
Tier 1 Planned Capacity	0	0	-
Net Firm Capacity Transfers	-157	-201	27.5%
Anticipated Resources	70,698	70,348	-0.5%
Existing-Other Capacity	0	0	-
Prospective Resources	70,151	69,801	-0.5%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	27.8%	28.5%	0.7
Prospective Reserve Margin	26.8%	27.5%	0.7
Reference Margin Level	19.0%	19.0%	0.0

NPCC-Maritimes			
Demand, Resource, and Reserve Margins	**2024 SRA**	**2025 SRA**	**2024 vs. 2025 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	3,586	3,584	-0.1%
Demand Response: Available	327	327	0.0%
Net Internal Demand	3,259	3,257	-0.1%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	4,660	4,348	-6.7%
Tier 1 Planned Capacity	0	220	-
Net Firm Capacity Transfers	63	63	0.0%
Anticipated Resources	4,723	4,631	-1.9%
Existing-Other Capacity	0	0	-
Prospective Resources	4,723	4,631	-1.9%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	44.9%	42.2%	-2.7
Prospective Reserve Margin	44.9%	42.2%	-2.7
Reference Margin Level	20.0%	20.0%	0.0

NPCC-New York			
Demand, Resource, and Reserve Margins	**2024 SRA**	**2025 SRA**	**2024 vs. 2025 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	31,541	31,471	-0.2%
Demand Response: Available	1,281	1,487	16.1%
Net Internal Demand	30,260	29,984	-0.9%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	37,867	37,682	-0.5%
Tier 1 Planned Capacity	0	0	-
Net Firm Capacity Transfers	1,585	1,769	11.6%
Anticipated Resources	39,452	39,451	0.0%
Existing-Other Capacity	0	0	-
Prospective Resources	39,452	39,451	0.0%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	30.4%	31.6%	1.2
Prospective Reserve Margin	30.4%	31.6%	1.2
Reference Margin Level	15.0%	15.0%	0.0

NPCC-New England			
Demand, Resource, and Reserve Margins	**2024 SRA**	**2025 SRA**	**2024 vs. 2025 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	25,294	25,202	-0.4%
Demand Response: Available	661	399	-39.6%
Net Internal Demand	24,633	24,803	0.7%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	27,255	27,054	-0.7%
Tier 1 Planned Capacity	0	0	-
Net Firm Capacity Transfers	1,297	1,245	-4.0%
Anticipated Resources	28,552	28,299	-0.9%
Existing-Other Capacity	138	668	384.1%
Prospective Resources	28,690	28,967	1.0%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	15.9%	14.1%	-1.8
Prospective Reserve Margin	16.5%	16.8%	0.3
Reference Margin Level	12.9%	12.7%	-0.2

NPCC-Ontario			
Demand, Resource, and Reserve Margins	**2024 SRA**	**2025 SRA**	**2024 vs. 2025 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	22,753	21,955	-3.5%
Demand Response: Available	996	998	0.2%
Net Internal Demand	21,757	20,957	-3.7%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	26,856	24,760	-7.8%
Tier 1 Planned Capacity	9	413	4568.6%
Net Firm Capacity Transfers	600	689	14.8%
Anticipated Resources	27,465	25,862	-5.8%
Existing-Other Capacity	0	0	-
Prospective Resources	27,465	25,862	-5.8%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	26.2%	23.4%	-2.8
Prospective Reserve Margin	26.2%	23.4%	-2.8
Reference Margin Level	12.8%	20.5%	7.7

NPCC-Québec			
Demand, Resource, and Reserve Margins	**2024 SRA**	**2025 SRA**	**2024 vs. 2025 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	22,922	23,283	1.6%
Demand Response: Available	0	1,020	-
Net Internal Demand	22,922	22,263	-2.9%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	35,731	32,132	-10.1%
Tier 1 Planned Capacity	0	0	-
Net Firm Capacity Transfers	-2,689	-2,582	-4.0%
Anticipated Resources	33,042	29,550	-10.6%
Existing-Other Capacity	0	0	-
Prospective Resources	33,042	29,550	-10.6%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	44.1%	32.7%	-11.4
Prospective Reserve Margin	44.1%	32.7%	-11.4
Reference Margin Level	11.5%	11.9%	0.4

SERC-Central			
Demand, Resource, and Reserve Margins	**2024 SRA**	**2025 SRA**	**2024 vs. 2025 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	42,636	42,765	0.3%
Demand Response: Available	1,941	864	-55.5%
Net Internal Demand	40,695	41,900	3.0%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	47,674	46,949	-1.5%
Tier 1 Planned Capacity	332	592	78.1%
Net Firm Capacity Transfers	2,578	2,554	-0.9%
Anticipated Resources	50,584	50,095	-1.0%
Existing-Other Capacity	2,075	2,475	19.2%
Prospective Resources	52,659	52,570	-0.2%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	24.3%	19.6%	-4.7
Prospective Reserve Margin	29.4%	25.5%	-3.9
Reference Margin Level	15.0%	15.0%	0.0

PJM			
Demand, Resource, and Reserve Margins	**2024 SRA**	**2025 SRA**	**2024 vs. 2025 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	151,247	154,144	1.9%
Demand Response: Available	7,756	7,898	1.8%
Net Internal Demand	143,491	146,246	1.9%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	183,690	186,638	1.6%
Tier 1 Planned Capacity	0	0	-
Net Firm Capacity Transfers	-607	-4,200	591.9%
Anticipated Resources	183,083	182,438	-0.4%
Existing-Other Capacity	0	0	-
Prospective Resources	182,476	178,238	-2.3%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	27.6%	24.7%	-2.8
Prospective Reserve Margin	27.2%	21.9%	-5.3
Reference Margin Level	17.7%	17.7%	0.0

SERC-East			
Demand, Resource, and Reserve Margins	**2024 SRA**	**2025 SRA**	**2024 vs. 2025 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	43,567	44,015	1.0%
Demand Response: Available	985	1,558	58.2%
Net Internal Demand	42,582	42,457	-0.3%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	51,304	54,665	6.5%
Tier 1 Planned Capacity	122	17	-86.0%
Net Firm Capacity Transfers	593	150	-74.7%
Anticipated Resources	52,019	54,832	5.4%
Existing-Other Capacity	1,131	2,628	132.3%
Prospective Resources	53,150	57,459	8.1%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	22.2%	29.1%	7.0
Prospective Reserve Margin	24.8%	35.3%	10.5
Reference Margin Level	15.0%	15.0%	0.0

SERC-Florida Peninsula			
Demand, Resource, and Reserve Margins	**2024 SRA**	**2025 SRA**	**2024 vs. 2025 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	53,293	52,987	-0.6%
Demand Response: Available	2,824	3,158	11.8%
Net Internal Demand	50,469	49,829	-1.3%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	63,199	59,395	-6.0%
Tier 1 Planned Capacity	34	102	197.8%
Net Firm Capacity Transfers	491	381	-22.4%
Anticipated Resources	63,724	59,878	-6.0%
Existing-Other Capacity	972	3,482	258.2%
Prospective Resources	64,696	63,360	-2.1%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	26.3%	20.2%	-6.1
Prospective Reserve Margin	28.2%	27.2%	-1.0
Reference Margin Level	15.0%	15.0%	0.0

Texas RE-ERCOT			
Demand, Resource, and Reserve Margins	**2024 SRA**	**2025 SRA**	**2024 vs. 2025 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	84,818	85,151	0.4%
Demand Response: Available	3,496	3,292	-5.8%
Net Internal Demand	81,323	81,859	0.7%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	99,541	112,321	12.8%
Tier 1 Planned Capacity	2,578	4,854	88.3%
Net Firm Capacity Transfers	20	20	0.0%
Anticipated Resources	102,139	117,195	14.7%
Existing-Other Capacity	0	0	-
Prospective Resources	102,167	117,770	15.3%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	25.6%	43.2%	17.6
Prospective Reserve Margin	25.6%	43.9%	18.2
Reference Margin Level	13.75%	13.75%	0.0

SERC-Southeast			
Demand, Resource, and Reserve Margins	**2024 SRA**	**2025 SRA**	**2024 vs. 2025 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	46,021	47,049	2.2%
Demand Response: Available	1,599	1,338	-16.3%
Net Internal Demand	44,422	45,711	2.9%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	63,693	64,111	0.7%
Tier 1 Planned Capacity	1,738	0	-100.0%
Net Firm Capacity Transfers	-1,192	489	-141.0%
Anticipated Resources	64,238	64,600	0.6%
Existing-Other Capacity	785	1,077	37.1%
Prospective Resources	65,024	65,676	1.0%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	44.6%	41.3%	-3.3
Prospective Reserve Margin	46.4%	43.7%	-2.7
Reference Margin Level	15.0%	15.0%	0.0

WECC-AB			
Demand, Resource, and Reserve Margins	**2024 SRA**	**2025 SRA**	**2024 vs. 2025 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	12,201	12,246	0.4%
Demand Response: Available	0	0	-
Net Internal Demand	12,201	12,246	0.4%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	13,941	17,176	23.2%
Tier 1 Planned Capacity	1,981	281	-85.8%
Net Firm Capacity Transfers	0	0	-
Anticipated Resources	15,922	17,457	9.6%
Existing-Other Capacity	0	0	-
Prospective Resources	15,922	17,457	9.6%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	30.5%	42.6%	12.1
Prospective Reserve Margin	30.5%	42.6%	12.1
Reference Margin Level	6.7%	9.0%	2.7

WECC-BC			
Demand, Resource, and Reserve Margins	**2024 SRA**	**2025 SRA**	**2024 vs. 2025 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	9,275	9,309	0.4%
Demand Response: Available	0	0	-
Net Internal Demand	9,275	9,309	0.4%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	11,022	11,313	2.6%
Tier 1 Planned Capacity	0	260	-
Net Firm Capacity Transfers	0	0	-
Anticipated Resources	11,022	11,573	5.0%
Existing-Other Capacity	0	0	-
Prospective Resources	11,022	11,573	5.0%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	18.8%	24.3%	5.5
Prospective Reserve Margin	18.8%	24.3%	5.5
Reference Margin Level	12.0%	14.9%	2.9

WECC-California			
Demand, Resource, and Reserve Margins	**2024 SRA**	**2025 SRA**	**2024 vs. 2025 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	54,267	54,797	1.0%
Demand Response: Available	816	746	-8.6%
Net Internal Demand	53,451	54,051	1.1%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	71,564	75,726	5.8%
Tier 1 Planned Capacity	5,998	8,470	41.2%
Net Firm Capacity Transfers	197	598	203.6%
Anticipated Resources	77,759	84,794	9.0%
Existing-Other Capacity	0	0	-
Prospective Resources	77,759	84,794	9.0%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	45.5%	56.9%	11.4
Prospective Reserve Margin	45.5%	56.9%	11.4
Reference Margin Level	22.0%	19.2%	-2.8

WECC-Southwest			
Demand, Resource, and Reserve Margins	**2024 SRA**	**2025 SRA**	**2024 vs. 2025 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	34,629	35,321	2.0%
Demand Response: Available	422	199	-52.9%
Net Internal Demand	34,207	35,122	2.7%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	37,716	40,300	6.9%
Tier 1 Planned Capacity	4,272	1,966	-54.0%
Net Firm Capacity Transfers	2,957	695	-76.5%
Anticipated Resources	44,945	42,961	-4.4%
Existing-Other Capacity	0	0	-
Prospective Resources	44,945	42,961	-4.4%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	31.4%	22.3%	-9.1
Prospective Reserve Margin	31.4%	22.3%	-9.1
Reference Margin Level	12.4%	13.3%	1.0

WECC-Northwest			
Demand, Resource, and Reserve Margins	**2024 SRA**	**2025 SRA**	**2024 vs. 2025 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	28,475	29,157	2.4%
Demand Response: Available	30	30	0.0%
Net Internal Demand	28,445	29,127	2.4%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	33,164	36,388	9.7%
Tier 1 Planned Capacity	201	844	319.9%
Net Firm Capacity Transfers	838	1,249	49.0%
Anticipated Resources	34,203	38,481	12.5%
Existing-Other Capacity	0	0	-
Prospective Resources	34,203	38,481	12.5%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	20.2%	32.1%	11.9
Prospective Reserve Margin	20.2%	32.1%	11.9
Reference Margin Level	18.5%	23.1%	4.6

WECC-Basin			
Demand, Resource, and Reserve Margins	**2024 SRA**	**2025 SRA**	**2024 vs. 2025 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	13,165	14,214	8.0%
Demand Response: Available	485	620	27.8%
Net Internal Demand	12,680	13,594	7.2%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	13,534	14,923	10.3%
Tier 1 Planned Capacity	2,436	704	-71.1%
Net Firm Capacity Transfers	1,376	1,274	-7.4%
Anticipated Resources	17,346	16,901	-2.6%
Existing-Other Capacity	0	0	-
Prospective Resources	17,346	16,901	-2.6%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	36.8%	24.3%	-12.5
Prospective Reserve Margin	36.8%	24.3%	-12.5
Reference Margin Level	13.3%	14.0%	0.7

WECC-Rocky Mountain			
Demand, Resource, and Reserve Margins	**2024 SRA**	**2025 SRA**	**2024 vs. 2025 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	11,313	14,098	24.6%
Demand Response: Available	281	284	1.1%
Net Internal Demand	11,032	13,814	25.2%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	17,345	17,262	-0.5%
Tier 1 Planned Capacity	55	104	89.1%
Net Firm Capacity Transfers	0	0	-
Anticipated Resources	17,400	17,366	-0.2%
Existing-Other Capacity	0	0	-
Prospective Resources	17,400	17,366	-0.2%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	57.7%	25.7%	-32.0
Prospective Reserve Margin	57.7%	25.7%	-32.0
Reference Margin Level	18.0%	16.7%	-1.3

WECC-Mexico			
Demand, Resource, and Reserve Margins	**2024 SRA**	**2025 SRA**	**2024 vs. 2025 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	3,529	3,770	6.8%
Demand Response: Available	0	0	-
Net Internal Demand	3,529	3,770	6.8%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	3,314	4,303	29.8%
Tier 1 Planned Capacity	874	0	-100.0%
Net Firm Capacity Transfers	150	0	-100.0%
Anticipated Resources	4,338	4,303	-0.8%
Existing-Other Capacity	0	0	-
Prospective Resources	4,338	4,303	-0.8%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	22.9%	14.1%	-8.8
Prospective Reserve Margin	22.9%	14.1%	-8.8
Reference Margin Level	7.9%	9.6%	1.6

Variable Energy Resource Contributions

Because the electrical output of VERs (e.g., wind, solar PV) depends on weather conditions, on-peak capacity contributions are less than nameplate capacity. The following table shows the capacity contribution of existing wind and solar PV resources at the peak demand hour for each assessment area. Resource contributions are also aggregated by Interconnection and across the entire BPS. For NERC's analysis of risk periods after peak demand (e.g., U.S. assessment areas in WECC), lower contributions of solar PV resources are used because output is diminished during evening periods.

BPS Variable Energy Resources by Assessment Area												
	Wind			Solar PV			Hydro			Energy Storage Systems (ESS)		
Assessment Area / Interconnection	Nameplate Wind	Expected Wind	Expected Share of Nameplate (%)	Nameplate Solar PV	Expected Solar PV	Expected Share of Nameplate (%)	Nameplate Hydro	Expected Hydro	Expected Share of Nameplate (%)	Nameplate ESS	Expected ESS	Expected Share of Nameplate (%)
MISO	30,992	6,039	19%	18,246	9,123	50%	1,572	1,467	93%	3,159	3,107	98%
MRO-Manitoba Hydro	259	48	19%	-	-	0%	202	60	30%	-	-	0%
MRO-SaskPower	816	310	38%	30	9	29%	848	686	81%	-	-	0%
NPCC-Maritimes	1,230	314	26%	147	-	0%	1,313	1,313	100%	12	6	50%
NPCC-New England	1,546	142	9%	3,266	1,412	43%	575	175	31%	192	110	57%
NPCC-New York	2,586	446	17%	609	243	40%	976	478	49%	32	17	53%
NPCC-Ontario	4,943	742	15%	478	66	14%	8,862	5,320	60%	-	-	0%
NPCC-Québec	4,024	885	22%	10	-	0%	444	444	100%	-	-	0%
PJM	12,465	1,855	15%	13,731	6,244	45%	2,505	2,505	100%	310	288	93%
SERC-Central	1,324	370	28%	1,810	1,053	58%	4,991	3,418	68%	100	100	100%
SERC-East	-	-	0%	7,097	5,022	71%	3,078	3,008	98%	19	8	41%
SERC-Florida Peninsula	-	-	0%	8,295	5,749	54%	-	-	0%	631	631	100%
SERC-Southeast	-	-	0%	8,507	7,728	91%	3,258	3,308	102%	115	105	92%
SPP	35,613	5,556	16%	1,159	492	42%	114	56	49%	182	41	23%
Texas RE-ERCOT	40,102	9,396	23%	31,473	22,962	73%	572	439	77%	15,291	12,190	80%
WECC-AB	5,712	796	14%	2,174	1,480	68%	894	456	51%	250	235	94%
WECC-BC	747	149	20%	2	-	0%	16,918	10,181	60%	-	-	0%
WECC-Basin	4,859	911	19%	2,648	2,231	84%	2,637	2,022	77%	120	118	98%
WECC-CA	7,836	1,207	15%	25,059	14,756	59%	14,565	6,518	45%	11,459	11,115	97%
WECC-Mexico	300	50	17%	350	227	65%	-	-	0%	-	-	0%
WECC-NW	9,199	3,107	34%	1,349	666	49%	33,068	20,145	61%	11	10	91%
WECC-RM	5,681	1,359	24%	2,523	1,669	66%	3,251	2,446	75%	242	235	97%
WECC-SW	4,848	1,091	23%	9,288	4,293	46%	1,316	845	64%	4,187	3,982	95%
EASTERN INTERCONNECTION	91,773	15,822	17%	67,138	37,886	56%	28,294	21,794	77%	4,752	4,413	93%
QUÉBEC INTERCONNECTION	4,024	885	22%	10	-	0%	444	444	100%	-	-	0%
TEXAS INTERCONNECTION	40,102	9,396	23%	31,473	22,962	73%	572	439	77%	15,291	12,190	80%
WECC INTERCONNECTION	39,182	8,670	22%	43,393	25,322	58%	72,649	42,613	59%	16,269	15,695	96%
All INTERCONNECTIONS	175,081	34,774	20%	142,014	86,170	61%	101,959	65,290	64%	36,311	32,298	89%

Review of 2024 Capacity and Energy Performance

The summer of 2024 was the fourth hottest on record for both the contiguous United States[18] and Canada,[19] with some areas experiencing their hottest summer ever. The result was record electricity demand in the United States as well as in Canada, which was particularly pronounced in the Western Interconnection. While peak demand exceeded normal summer forecasts in most areas, only one area experienced demand that met or exceeded a 90/10 demand scenario as defined in the prior year's *SRA*. In addition, Hurricane Helene, the deadliest Atlantic hurricane to strike the US mainland since 2005, made landfall in Florida in September and led to widespread flooding and power outages from Florida to North Carolina. Helene was one of five hurricanes to impact the US last summer, joining other extreme weather incidents such as drought across the West and wildfires in the Southwest. To manage the challenging grid conditions brought about by heat domes and these other extreme weather events, grid operators across North America used various operating mitigations up to, and including, the issuance of EEAs. No disruptions to the BPS occurred due to inadequate resources. The following section describes actual demand and resource levels in comparison with NERC's *2024 SRA* and summarizes 2024 resource adequacy events.

Eastern Interconnection–Canada and Québec Interconnection

During the June heat wave that extended across the eastern half of the United States and Canada, system operators in Ontario and the Maritimes provinces followed conservative operating protocols and issued energy emergencies. A late-summer heat wave resulted in an energy emergency in Maritimes.

Eastern Interconnection–United States

MISO experienced peak electricity demand during late August. Demand was between the normal and 90/10 summer peak forecast levels. Wind and solar resource output at the time of peak demand were near expectations for summer on-peak contributions. Forced outages of thermal units, however, were lower than expected. On the day prior to MISO's peak demand, operators issued advisories to maximize generation. Similar advisories were issued earlier in the summer, coinciding with above-normal temperatures and periods of high generator forced outages.

In SPP, summer electricity demand peaked in mid-July at a level below normal 50/50 forecasts. Above-normal wind performance and sufficient generator availability contributed to sufficient electricity supplies during peak conditions. In late August, however, SPP operators issued an EEA1 due to high load forecasts, generator outages, and forecasts for low wind output. The period coincided with MISO's peak demand period, making excess supplies for import uncertain. Also in August during a period of high demand and low resource availability, operators issued public appeals for conservation when a 345 kV line outage caused a transmission emergency. During other summer periods, SPP operators responded to forecasts for high demand and low resource conditions with resource advisories intended to maximize available generators.

Like SPP, PJM also experienced peak electricity demand in mid-July and issued an EEA in August. Peak demand in July was near 90/10 forecast levels. Generator outages were below normal at the time of peak demand. In late August, PJM operators issued an EEA1 in expectation of extreme demand.

A period of unseasonably high demand in early summer brought on by high temperatures in the Northeast contributed to an EEA1 in NPCC-New England when a large thermal generator encountered a forced outage. Peak demand in New England occurred in mid-July at a near-normal summer peak demand level. At the time of peak demand, generator outages were below historical averages.

Peak demand in the NPCC-New York area occurred in early July at a level below the normal summer peak demand forecast. Generator outages were below historical levels for peak summer conditions.

[18] US sweltered through its 4th-hottest summer on record – National Oceanic and Atmospheric Administration
[19] Climate Trends and Variations Bulletin – Summer 2024 – Government of Canada

Systems in the U.S. Southeast saw successive heat waves beginning prior to the official start to summer and extending to early fall. Operators in the SERC region used conservative operations and resource advisories to maximize generation and transmission network availability and issued EEAs when warranted by conditions. In some instances, EEAs were issued when generator outages threatened supplies needed for high demand. Peak demand in all assessment areas within the SERC region exceeded normal summer peak demand levels and approached 90/10 demand forecasts.

Texas Interconnection–ERCOT

Peak demand in ERCOT was at or near record levels last summer, as load growth and extreme temperatures contributed to escalating summer electricity needs. Demand peaked in August well above the 90/10 demand forecast. At the time of peak demand, wind generation was below expected levels for peak demand periods, while output from solar generation was near forecasted levels. Forced generator outages were well below historical average levels for peak demand, helping to meet the extreme electricity demand. Unlike the prior summer, ERCOT did not issue any conservation appeals to customers to reduce demand during high-demand periods. New solar generation, battery resources, and some thermal generation additions since Summer 2023 boosted electricity supplies, enabling operators to meet demand records without demand-side management.

Western Interconnection

In July, the Western Interconnection set a new peak demand record of 167,988 MW. Operators in United States and Canada employed procedures throughout summer to manage challenging grid conditions from extended extreme heat and wildfires.

Western Interconnection–Canada

In the province of Alberta, the electric system operator issued an EEA3 in early July as high temperatures contributed to elevated demand that coincided with a forced generator outage. A new summer peak demand record was set in Alberta later in July at 12.2 MW (up from 11.5 GW in summer 2023). Alberta’s demand peak was slightly higher than the normal demand peak scenario projected in the spring of last year.

In British Columbia, peak demand reached 9.4 GW (up from 9.2 GW the previous year), also slightly above the normal peak demand that was projected last year.

In both Alberta and British Columbia, peak demand was still below the extreme peak demand scenarios previously projected, which lowered the risk profile of those provinces over Summer 2024.

Western Interconnection–United States

Demand peaked in July in the U.S. Northwest at a level below the normal summer peak demand. During a period of high demand in July, operators at a BA in the U.S. Northwest issued an EEA1 to address forecasted conditions.

The California-Mexico assessment area, which consists of the CAISO, Northern California, and CENACE BAs, experienced system peak electricity demand in early September at a level nearing the 90/10 peak demand forecast. The extreme demand contributed to localized supply concerns and led CAISO to declare a transmission emergency and use conservative operations protocols to posture the system. Despite the extreme demand, operators were able to maintain sufficient supply without resorting to public appeals, as was required in prior summers. New battery resources were instrumental in providing energy to meet high demand during late afternoon and early evenings. Natural-gas-fired generators also performed well and were important to meeting high demand during these same periods. Dry conditions from early summer prompted operators in CA/MX to frequently employ public safety power shutoff (PSPS) procedures beginning in June. Active wildfires led transmission operators to de-energize transmission lines in Northern California and declare transmission emergencies that affected operations across CAISO.

The U.S. Southwest experienced extended heat conditions and demand levels that exceeded 90/10 peak summer forecasts, with peak occurring in early August. Higher-than-expected wind and solar output and low generator outages helped maintain sufficient supplies.

2024 Summer Demand and Generation Summary at Peak Demand							
Assessment Area	Actual Peak Demand[1] (GW)	SRA Peak Demand Scenarios[2] (GW)	Wind – Actual[1] (MW)	Wind – Expected[3] (MW)	Solar – Actual[1] (MW)	Solar – Expected[3] (MW)	Forced Outages Summary[4] (MW)
MISO	118.6	116.1 125.8	4,565	5,599	5,858	4,981	4,412
MRO-Manitoba Hydro	3.6	3.1 3.3	50	48	0	0	290
MRO-SaskPower	3.7	3.5 3.7	170	208	22	6	0
MRO-SPP	54.3	55.3 57.5	10,869	5,876	442	486	6,046
NPCC-Maritimes	3.5	3.3 3.6	428	262	21	-	777
NPCC-New England	24.3	24.6 26.5	174	122	167	1,111	1,496
NPCC-New York	29	30.3 32	130	340	0	53	1,451
NPCC-Ontario	23.9	21.8 23.7	915	720	260	66	1,174
NPCC-Québec	23	22.9 24	2,270	-	0	-	10,500*
PJM	153.1	143.5 156.9	3,366	1,703	2,709	5,694	6,402
SERC-C	42.3	40.7 43.9	312	172	813	996	959
SERC-E	44	42.6 44.7	0	-	3,009	2,405	1,878
SERC-FP	52.4	50.5 53.6	0	-	5,376	5,643	
SERC-SE	44.9	44.4 45.3	0	-	3,507	7,217	1,007
TRE-ERCOT	85.5	81.3 82.3	6,286	9,070	17,566	17,797	3,622
WECC-AB	12.2	12.2 12.7	1,091	666	1,114	786	-**
WECC-BC	9.4	9.3 9.8	257	140	0.94	0	-**

2024 Summer Demand and Generation Summary at Peak Demand							
Assessment Area	Actual Peak Demand[1] (GW)	SRA Peak Demand Scenarios[2] (GW)	Wind – Actual[1] (MW)	Wind – Expected[3] (MW)	Solar – Actual[1] (MW)	Solar – Expected[3] (MW)	Forced Outages Summary[4] (MW)
WECC-CA/MX	58.9	53.2 61.6	1,633	1,124	10,112	13,147	921
WECC-NW	59.7	63 69.7	4,694	2,964	6,339	2,595	3,655
WECC-SW	30.8	26.4 28.8	1,179	542	3,357	1,294	2,042
Highlighting Notes	Actual peak demand in the highlighted areas met or exceeded extreme scenario levels.		Actual wind output in highlighted areas was significantly below seasonal forecast.		Actual solar output in highlighted areas was significantly below seasonal forecast.		Actual forced outages above or below forecast by factor of two

Table Notes:

[1] Actual demand, wind, and solar values for the hour of peak demand in U.S. areas were obtained from EIA From 930 data. For areas in Canada, this data was provided to NERC by system operators and utilities.

[2] See NERC *2024 SRA* demand scenarios for each assessment area (pp. 14–33). Values represent the normal summer peak demand forecast and an extreme peak demand forecast that represents a 90/10, or once-per-decade, peak demand. Some areas use other basis for extreme peak demand.

[3] Expected values of wind and solar resources from the *2024 SRA*.

[4] Values from NERC Generator Availability Data System for the 2024 summer hour of peak demand in each assessment area. Highlighted areas had actual forced outages that were more than twice the value for typical forced outage rates used in the 2024 summer risk period scenarios in the *2024 SRA*.

*Values include both maintenance and forced outages.

**Canadian assessment areas report to the NERC Generator Availability Data System on a voluntary basis, which can contribute to the absence of some values in certain assessment areas.

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c)	)	
Emergency Order: Midcontinent	)	Order No. 202-25-3
Independent System Operator	)	
(MISO)	)	
	)	

Exhibit to
Motion to Intervene and Request for Rehearing and Stay of
Public Interest Organizations

Filed June 18, 2025

Exhibit 42

2019–24 NERC Summer Reliability Assessments

NERC

NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Summer Reliability Assessment

June 2019

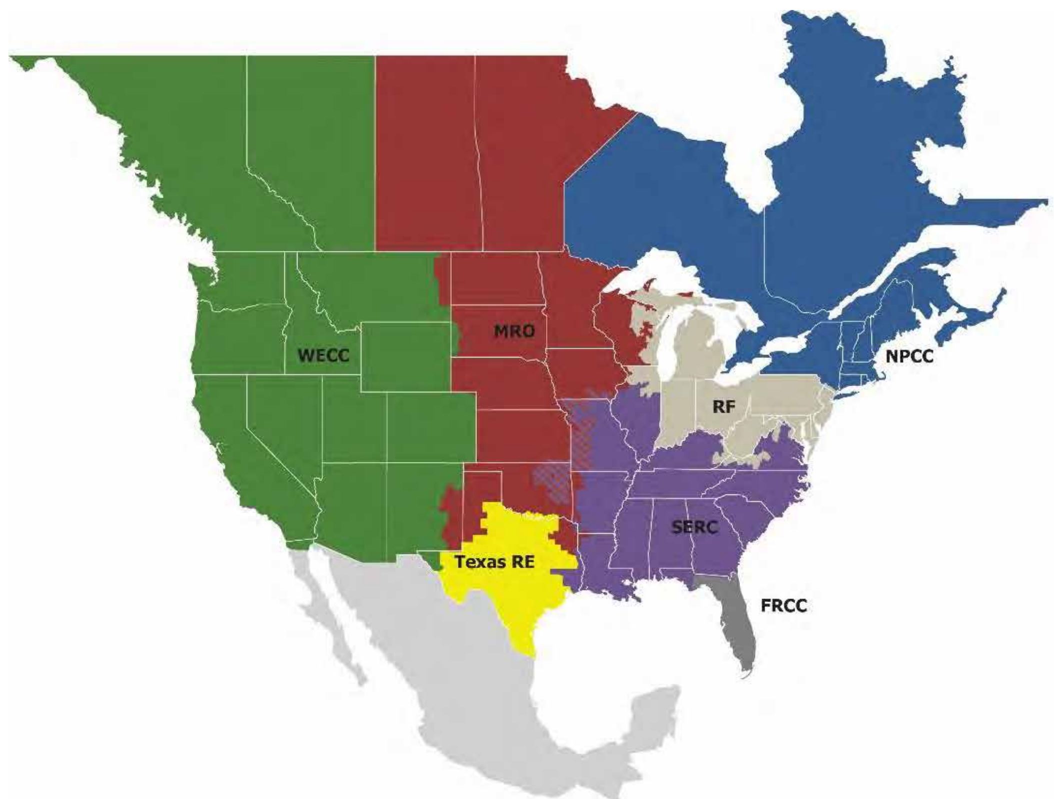
Table of Contents

Preface

The vision for the Electric Reliability Organization (ERO) Enterprise, which is comprised of the North American Electric Reliability Corporation (NERC) and the seven 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. The North American BPS is divided into seven REs with boundaries as shown in the map below. The multicolored area denotes overlap as some load-serving entities participate in one Region while associated Transmission Owners/Operators participate in another. Refer to the **Data Concepts and Assumptions** section for more information. A map and list of the assessment areas can be found in the **Regional Assessment Dashboards** section.

About this Report

NERC's *2019 Summer Reliability Assessment* identifies, assesses, and reports on areas of concern regarding the reliability of the North American BPS for the upcoming summer season. In addition, this assessment presents peak electricity demand and supply changes and highlights any unique regional challenges or expected conditions that might impact the BPS. The reliability assessment process is a coordinated reliability evaluation between the Reliability Assessment Subcommittee (RAS), the Regions, and NERC staff. This report reflects NERC's independent assessment and is intended to inform industry leaders, planners, operators, and regulatory bodies so they are better prepared to take necessary actions to ensure BPS reliability. The report also provides an opportunity for the industry to discuss their plans and preparations to ensure reliability for the upcoming summer period.



Key Findings

NERC's annual *Summer Reliability Assessment* covers the four-month Summer 2019 (June–September) period. This assessment provides an evaluation of whether there is adequate generation and transmission necessary to meet projected summer peak demands. The assessment monitors and identifies potential reliability issues and regional areas of concern that pertain to meeting projected customer demands. The following key findings represent NERC's independent evaluation of electric generation capacity and potential operational concerns that may need to be addressed:

- **ERCOT anticipates Energy Emergency Alerts may be needed to address resource shortfalls during periods of peak demand.** In ERCOT, the Anticipated Reserve Margin remains below the Reference Margin Level of 13.75%. ERCOT's Anticipated Reserve Margin decreased from 10.9% in Summer 2018 to 8.5% for the upcoming summer season. The reduction is caused by higher load growth, a planned generator retirement, and delays in new generation. If resource shortfalls occur, ERCOT anticipates implementing operating mitigations. These measures include importing additional power if available and energy emergency alerts that allow ERCOT to trigger emergency procedures such as voluntary load reduction.
- **Most assessment areas meet or exceed Reference Margin Levels and have sufficient electricity resources for anticipated conditions and more extreme scenarios.** In all areas, with the exception of ERCOT, the Anticipated Reserve Margin meets or surpasses the Reference Margin Level, indicating that planned resources in these areas are adequate to manage loss of load risk under normal conditions.[1] NERC also examined more extreme resource and demand conditions in each assessment area through seasonal risk scenarios. In some assessment areas, extreme summer peak loads and low-probability generator outage scenarios can result in insufficient resources to meet expected operating reserve requirements. In instances where operating reserve requirements are not met, system operators should employ operating procedures and mitigations, which may include demand response, Energy Emergency Alerts that support increased transfers, and other operational mitigations to manage resources and loads.
- **California faces ramping capability concerns.** In the California Independent System Operator (CAISO) area, there is the potential for operational risks at certain times of day as a result of shortages in resources with upward ramping capability. These shortage conditions are more prevalent during late afternoon as solar generation output decreases while system demand is still high. Transfers from neighboring areas may be needed during normal conditions when short on load-following resources capable of ramping up within the CAISO area.
- **Natural-gas-fired electric generation in Southern California will continue to need fuel from natural gas storage facilities for summer reliability.** The natural gas system operator in Southern California assesses that supplies from interstate pipelines alone may not be sufficient to meet the needs of all customers on summer peak load days, leaving electric generators at risk of curtailment. As a result, withdrawals from the Aliso Canyon natural gas storage facility would be necessary to ensure adequate fuel for generators in the Southern California area.
- **Elevated risk for wildfires in Western United States and parts of Canada poses risk to BPS reliability.** Government agencies predict above-normal wildfire risk for summer throughout parts of North America. Operation of the BPS can be impacted in areas where wildfires are active, as well as areas where there is heightened risk of wildfire ignition due to weather and ground conditions. In some areas, pre-season planning includes expanded public safety power shut-off programs in addition to maintenance and operational preparations.

[1] For more information, see the description of the "Reference Margin Level" in the **Data Concepts and Assumptions** section of this report, or refer to NERC's Long-term Reliability Assessment: https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_LTRA_2018_12202018.pdf

Resource Adequacy

NERC uses the Anticipated Reserve Margin to evaluate resource adequacy by comparing the projected capability of anticipated resources to serve forecasted peak load.[2] Large year-to-year changes in anticipated resources or forecasted peak load can greatly impact Planning Reserve Margin calculations. As shown in **Figure 1**, other than Texas RE-ERCOT, all assessment areas have sufficient Anticipated Reserve Margins to meet or exceed their planning Reference Margin Level for the Summer 2019 period. Discussion of significant changes to Anticipated Reserve Margins in the Texas RE-ERCOT and WECC assessment areas are provided in the following sections.

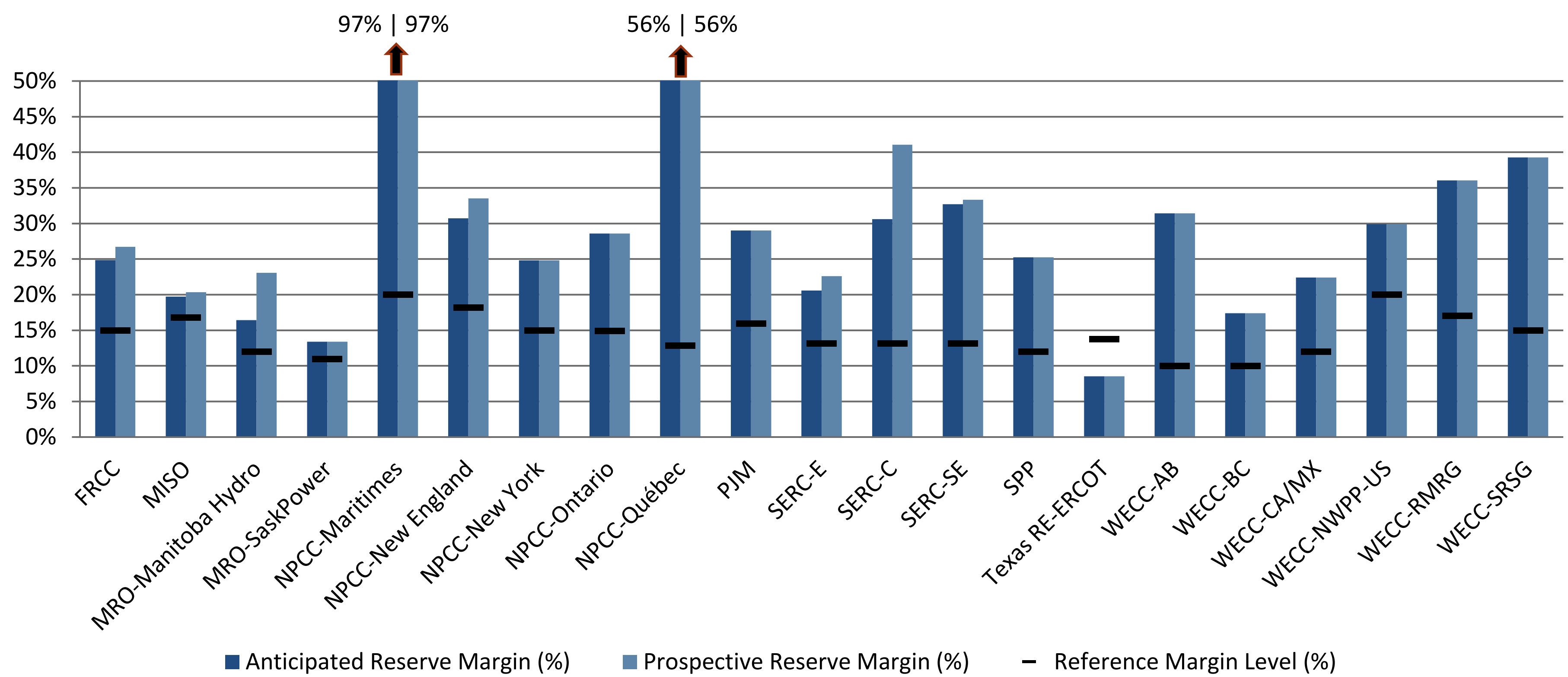


Figure 1: Summer 2019 Anticipated / Prospective Reserve Margins Compared to Reference Margin Level

[2] Refer to the **Data Concepts and Assumptions** section for additional information on Anticipated Reserve Margins, Anticipated Resources, and Reference Margin Levels.

Changes from Year-to-Year

Understanding the changes from year-to-year is an essential step in assessing an area on a seasonal basis. This understanding can be used to further examine potential operational issues that emerge between reporting years. Figure 2 provides the relative change from the Summer 2018 to the Summer 2019 period.

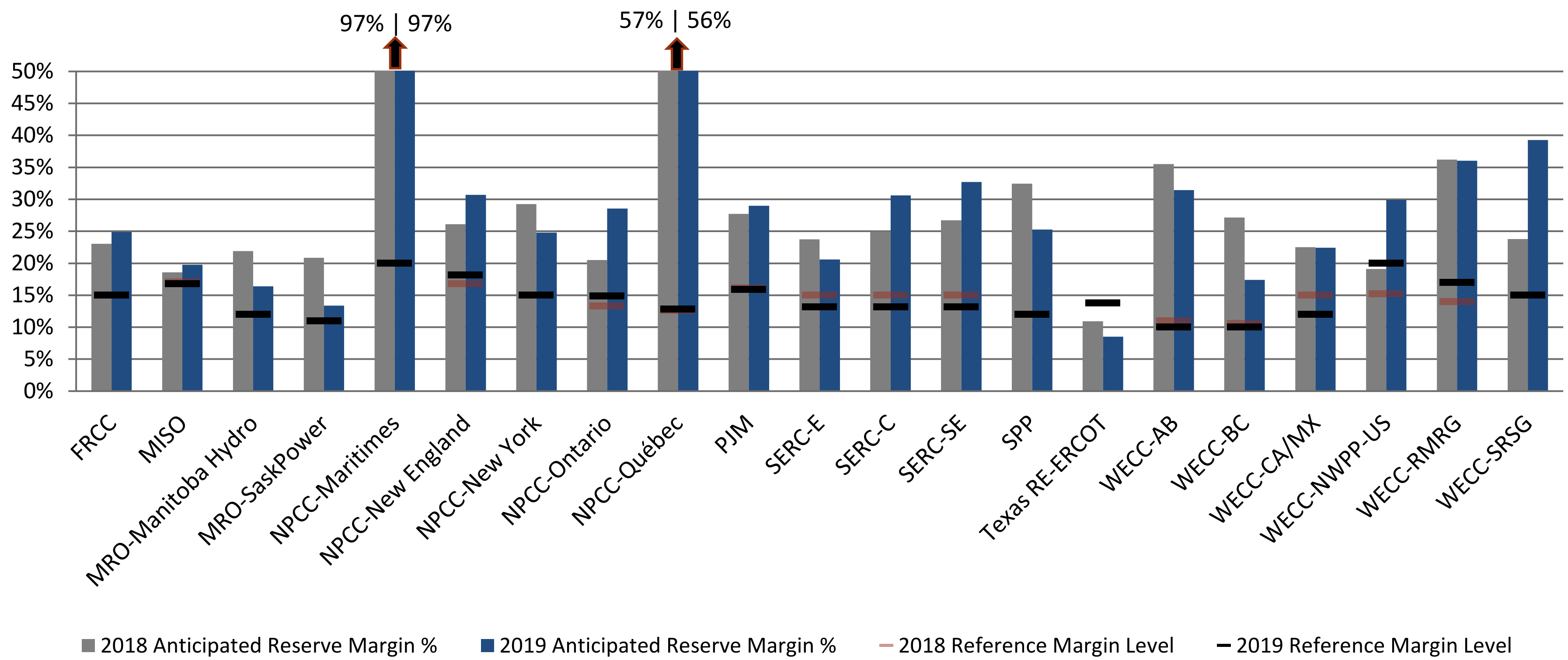


Figure 1: Summer 2018 to Summer 2019 Anticipated Reserve Margins Year-to-Year Change

Risk Highlights for Summer 2019

Tight Reserve Margins in Texas Lead to Operational Challenges

Texas RE-ERCOT enters the Summer 2019 season with a deficit in planning reserves, increasing the likelihood that system operators may need to employ procedures to maintain sufficient operating reserves. In 2018, ERCOT maintained sufficient generation resources through record levels of summer peak demand without resorting to Energy Emergency Alerts. This system performance, due in large part to high levels of generator availability, response to market signals, and unit performance, was notable given the Anticipated Reserve Margin of 10.9%, well-below the Reference Margin Level of 13.75%.[3] For the upcoming summer, growth in anticipated summer peak demand, delays in planned generation projects, and the announced mothballing of a 470 MW coal-fired unit (Gibbons Creek) are expected to push reserve margins still lower, to 8.5%.

Based on ERCOT's summer Seasonal Assessment of Resource Adequacy (SARA) report, released May 8, ERCOT expects that a number of operational tools may be needed this summer to help maintain sufficient operating reserves given the range of resource adequacy scenarios they evaluated.[4] For example, ERCOT system operators can release ancillary services (including load resources that can provide various types of operating reserves based on meeting certain qualification criteria), deploy contracted emergency response service resources, instruct investor-owned utilities to call on their load management and distribution voltage reduction programs, request emergency power across the dc ties, and request support from available switchable generators currently serving non-ERCOT grids.

The SARA report informs ERCOT market participants and operators by deterministically considering the impact of potential variables that may affect the sufficiency of resources for the upcoming season. Historic ranges or expectations for generation maintenance outages, forced outages, and capacity derates during extreme weather conditions are applied deterministically as resource scenarios. The effect of these resource scenarios, along with normal and extreme peak demand scenarios, are examined to determine the potential for scarcity conditions and emergency operating procedure mitigation. **Figure 3** shows a risk assessment developed by NERC using *Summer Reliability Assessment* data and additional data from Texas RE-ERCOT, and the ERCOT 2019 Preliminary SARA report. A description of resource and demand variables is found in **Table 1**.

[3] See ERCOT's 2018 Summer Performance Update: http://www.ercot.com/content/wcm/lists/144927/2018_Summer_Performance_One_Pager_FINAL.pdf
[4] For details see ERCOT's SARA Report: http://www.ercot.com/content/wcm/lists/167022/SARA-FinalSummer2019.xlsx

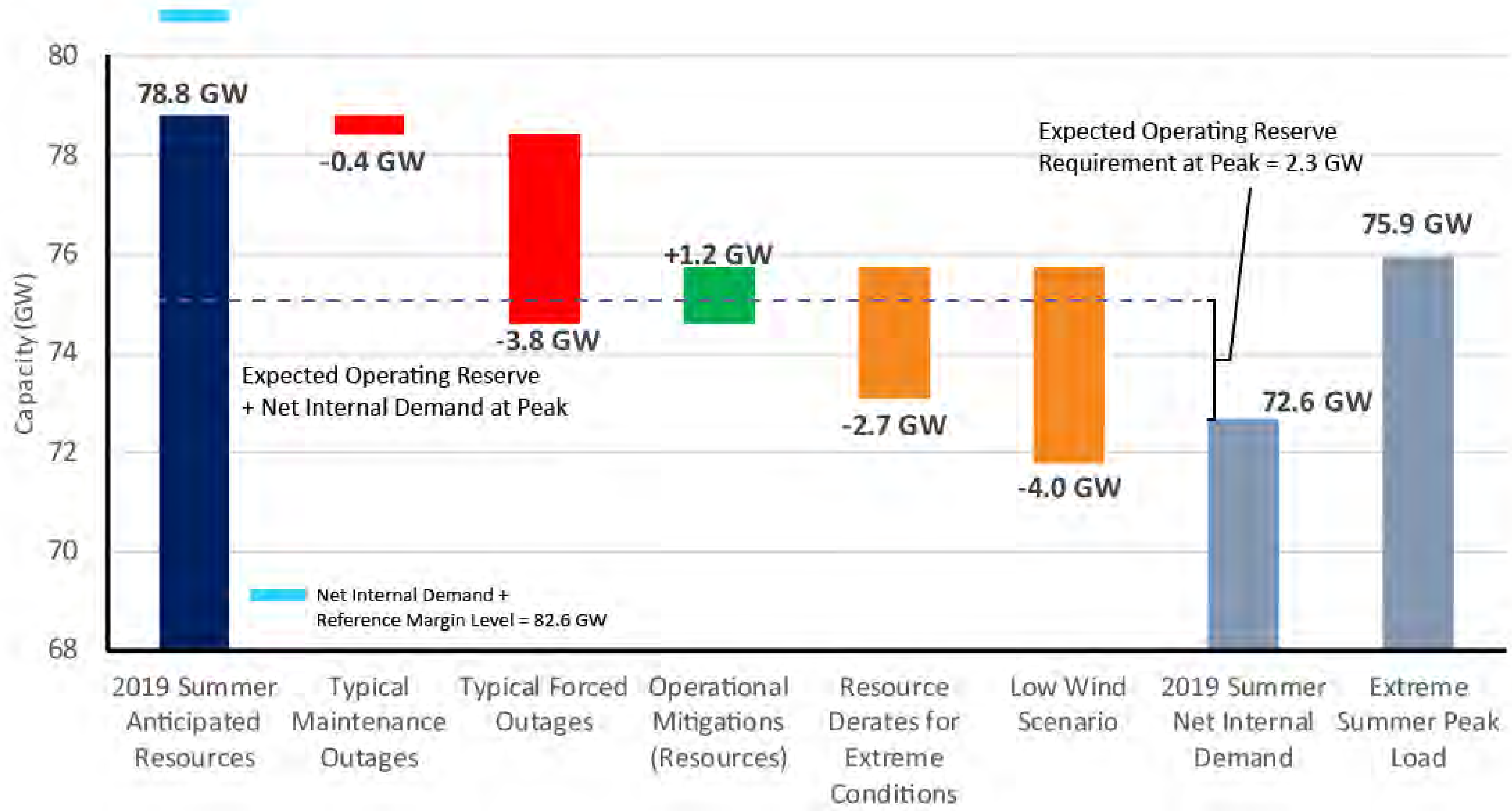


Figure 3: Texas RE-ERCOT Seasonal Risk Assessment

About the Seasonal Risk Assessment The operational risk analysis shown in Figure 3 provides a deterministic scenario for understanding how various factors affecting resources and demand can combine to impact overall resource adequacy. Adjustments are applied cumulatively to summer anticipated capacity, such as the following:

- Reductions for typical generation outages (maintenance and forced, not already accounted for in summer anticipated resources)
- Additions that represent the quantified capacity from operational tools, if any, that are available during scarcity conditions but have not been accounted for in the SRA reserve margins

Resources throughout the scenario are compared against expected operating reserve requirements that are based on peak load and normal weather. The effects from low-probability, extreme events are also factored in, through additional resource derates or extreme resource scenarios, and extreme summer peak load conditions. Because the seasonal risk scenario shows the cumulative impact resulting from the occurrence of multiple low-probability events, the overall likelihood of the scenario is very low. An analysis similar to the Texas RE-ERCOT seasonal risk scenario in Figure 3 can be found for each assessment area in the Regional Assessment Dashboards section of this report.

Table 1: Resource and Demand Variables in the ERCOT Seasonal Risk Assessment	
Resource Scenarios	
Typical Maintenance Outages	Typical maintenance outages refer to an estimate of generation resources that will be out for maintenance during peak load conditions. A value of 381 MW was determined based on the historical average of maintenance outages for June through September weekdays, for the last three summer seasons (2016–2018). Planned maintenance outages are generally accounted for in anticipated summer resources, however, this reduction covers additional generator outages granted by operators on a short-term basis as warranted by system conditions.
Typical Forced Outages	Typical forced outages refer to an estimate of generation resources that will experience forced outage during peak load conditions. A value of 3,845 MW is based on historical average of forced outages for June through September weekdays, for the last three summer seasons (2016–2018).
Operational Mitigations	ERCOT assesses that certain operational mitigations, in addition to operating measures accounted for in SRA data and the preliminary SARA Report, can contribute 1,160 MW of additional resources to support maintaining operating reserve requirements. This value is based on three elements: • Switchable generation resources currently serving the Southwest Power Pool (SPP) market that could become available to ERCOT in the event of an energy emergency (total of 489 MW) • Additional imports from the dc tie with the Mexican grid and from SPP beyond what was designated as long-term firm imports (total of 221 MW) • Distribution service providers implementation of distribution voltage reduction (contributing a total of 450 MW)
High Forced Outage Scenario (Low-likelihood Resource Derates)	A low-likelihood, high forced outage scenario is used to analyze the effect of extreme weather-driven generation outages. A capacity adjustment of 2,665 MW from the preliminary SARA report is based on historical forced outages assuming a 90% confidence interval.
Low-Wind Scenario (Low-likelihood)	The low-wind scenario is used to analyze the impact low-likelihood weather conditions that severely reduce output from wind generation resources. A capacity adjustment of 3,960 MW is based on a low wind output scenario included in ERCOT's preliminary summer SARA report. This capacity amount is calculated as the tenth percentile of wind output associated with the 100 highest net load hours (load minus wind output) for the 2015–2018 summer peak load seasons.
Demand Scenarios	
2019 Net Internal Demand	Net internal demand is equal to total internal demand then reduced by the amount of controllable and dispatchable demand response projected to be available during the peak hour. It is based on historical average weather (i.e., forecasts for a 50/50 distribution).
Extreme Summer Peak Load	A seasonal load adjustment (3,303 MW) is added to 2019 net internal demand based on extreme weather conditions that occurred during Summer 2011. ERCOT compared this value to a statistical extreme load forecast (i.e., a "90/10 load forecast" and found the Summer 2011 peak load to be higher and therefore a more conservative scenario.

ERCOT's tight reserve margins create a potential need to declare an energy emergency alert under many of the peak and extreme conditions studied in the SARA.[5] Once normal operating actions to maintain operating reserves are exhausted, energy emergency alerts can provide system operators with access to additional resources as discussed above that are only available during scarcity conditions. ERCOT also anticipates that higher wholesale market prices during peak demand periods will incentivize power customers to voluntarily reduce load or increase energy output from load-serving generation facilities (such as industrial cogeneration and commercial-sector distributed generation) that can inject power into the ERCOT system. Based on recent ERCOT analysis, the potential amount of this demand and generation response for the upcoming summer is significant but uncertain because the ERCOT market has not experienced summer high prices subsequent to the market design changes implemented in 2012–2014.

Seasonal Risk Assessments for Other Areas

Any area can face resource adequacy risk during peak conditions, even when Planning Reserve Margins exceed Reference Margin Levels. The reasons can be similar: generator scheduled maintenance, forced outages due to normal and more extreme weather conditions and loads, as well as low-likelihood conditions that affect generation resource performance or unit availability including constrained fuel supplies. The **Regional Assessment Dashboards** section in this report includes a seasonal risk scenario for each area that illustrates variables in resources and load, and where appropriate, the potential effects that operating actions can have to mitigate shortfalls in operating reserves.

CAISO Faces Concerns with Ramping Capability, Natural Gas Supply

For Summer 2019, the risk of resource shortfalls in CAISO is lower than last summer. However, there is increased risk of insufficient ramping capability during peak conditions. Conditions for hydroelectric generation are well above normal due to replenishment of reservoirs and mountain snow during the preceding winter, greatly reducing the potential for operating reserve shortfalls. However, the *2019 Summer Loads and Resources Assessment* highlights concerns with shortages in load-following resources capable of ramping up, particularly during late afternoon when solar generation output decreases while system demand is still high.[6] Increasing penetrations of solar resources and the retirements of dispatchable generation units has contributed to a shortage of ramping resources. When faced with such shortages, operators will need to call upon neighbors for imports to maintain system frequency. Should extreme temperatures extend over a large area to the point where neighbors lack surplus energy, load could be at risk from a shortage in ramping capability.

The impacts to electric generation resulting from operating restrictions at the Aliso Canyon natural gas storage facility remain an item of focus for electric reliability within the Western Interconnection. Withdrawals from natural gas storage facilities were at a high level during Winter 2018–2019 due to colder than average winter temperatures, resulting in below average storage levels approaching the Summer 2019 season. The Southern California Gas Company (SoCalGas) forecasts that it will be able to meet the forecasted peak day demand under a "best case" supply assumption even without supply from Aliso Canyon.[7] However, under a worst case supply assumption, supply from Aliso Canyon will be necessary to meet that forecasted peak day demand. Should operating restrictions result in natural gas supply curtailments that affect electric generation in the Southern California area, mitigation procedures that have been in place since 2016 can be used to maintain BPS reliability.

In addition to managing natural gas storage to meet summer demand, SoCalGas also uses summer months to begin increasing storage levels in preparation for peak winter months. Winter storage levels can be impacted in some scenarios that involve reduced natural gas storage receipts due to supply infrastructure servicing.

[5] A description of Energy Emergency Alerts and processes for communicating and coordination during operating emergencies is contained in NERC Reliability Standard *EOP-011-1 – Emergency Operations* available at the following link: https://www.nerc.com/pa/Stand/Reliability%20Standards/EOP-011-1.pdf

[6] See CAISO 2019 Summer Loads and Resources Assessment here: http://www.caiso.com/Documents/2019SummerLoadsandResourcesAssessment.pdf

[7] See Southern California Gas Company (SoCalGas) *2019 Summer Technical Assessment*, April 4, 2019, available at the link below. At the time of drafting the NERC 2019 SRA, the California Public Utilities Commission (CPUC) summer technical assessment for Aliso Canyon had not been released. The CPUC assessment is expected to provide the most current and comprehensive information, including potential impacts to the BPS in Southern California.
http://cpuc.ca.gov/uploadedFiles/CPUCWebsite/Content/News_Room/NewsUpdates/2019/SoCalGas%20Summer%202019%20Technical%20Assessment%20040219.pdf

Mitigation Operating Plans

Should CAISO system operating conditions go into the emergency stages, such as operating reserve shortfalls where non-spinning reserve requirement cannot be maintained or spinning reserve is depleted and operating reserve falls below minimum requirement, the following mitigation operating plan will be implemented to minimize loss of load in the CAISO Balancing Authority area:

- Use the Flex Alert program, signaling that the CAISO expects high peak load condition. This program has been proven to reduce peak load in the CAISO Balancing Authority area.
- Use the CAISO Restricted Maintenance program. This program is intended to reduce potential forced outages, therefore, minimizing forced outage rate during the high peak load condition.
- Perform manual post day-ahead unit commitment and exceptional dispatch of resources under contract to ensure the ability to serve load and meet flexible ramping capability requirements.
- Perform manual exceptional dispatch of intertie resources that have resource adequacy obligation to serve CAISO load.
- Use the CAISO Alert/Warning/Emergency (AWE) program.
- Use the demand response program including the Reliability Demand Response Resources (RDRR) under the “Warning” stage.
- Perform manual exceptional dispatch of physically available resources that are not under capacity contract.

Wildfire Risk and Potential for Impacts to the BPS

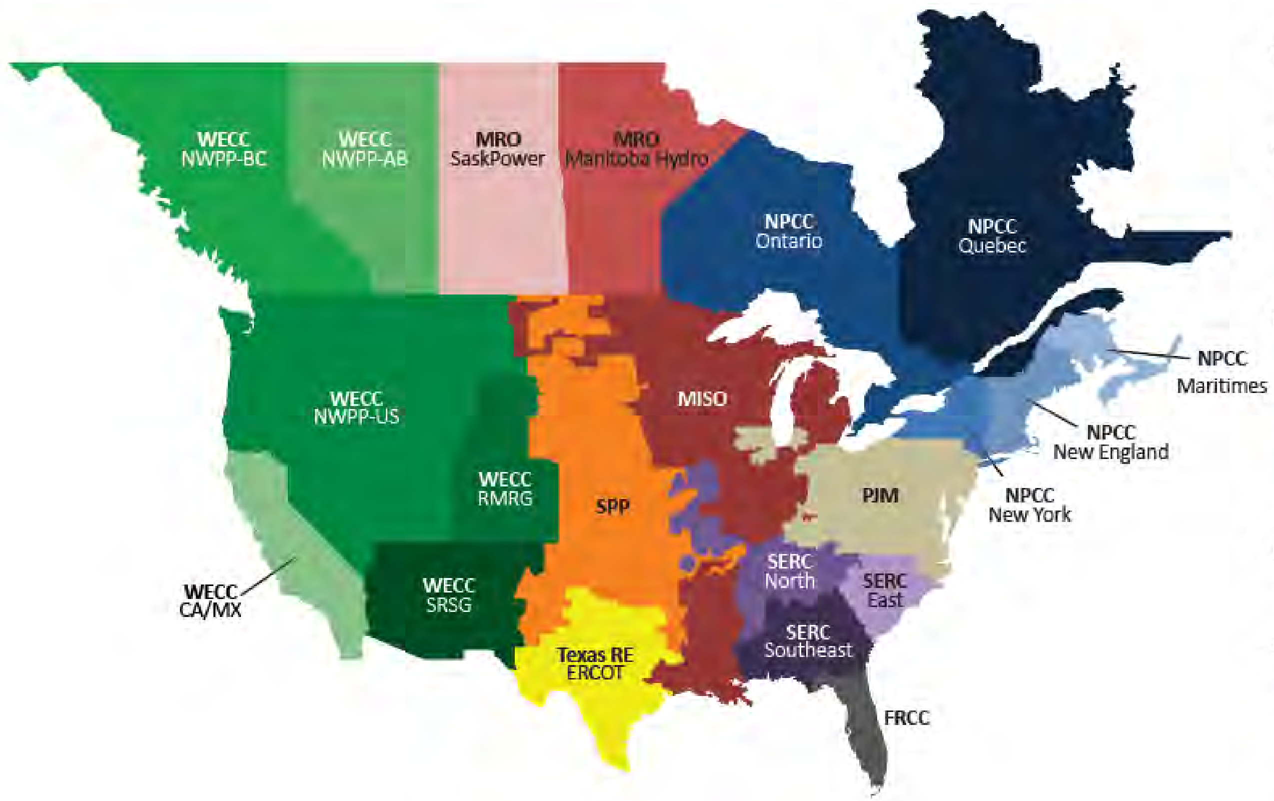
Government agencies predict above-normal wildfire risk for the summer throughout parts of North America. The National Interagency Fire Center, Natural Resources Canada, and National Meteorological Service in Mexico published a three-month seasonal potential wildfire outlook (April-June), which predicts above normal wildfire potential for California and the Pacific Northwest (Western Oregon and Washington), Western Alberta, British Columbia, and Northern Mexico.[8]

Operation of the BPS can be impacted in areas where wildfires are active, as well as areas where there is heightened risk of wildfire ignition due to weather and ground conditions. With the widely dispersed nature of the transmission system in western parts of North America, outages due to wildfires are generally not widespread. Furthermore, utilities are enhancing wildfire prevention planning in California and other areas to address increased risk. In some cases, plans could include expanding power shut-off programs in high fire-risk areas. When conditions warrant implementing these plans, power lines, including transmission-level lines, may be preemptively deenergized in high fire-risk areas to prevent wildfire ignitions. Other activities include implementing enhanced vegetation management, equipment inspections, system hardening, and added situational awareness measures.

[8] See the *North American Seasonal Fire Outlook*, issued May 10, 2019: https://www.predictiveservices.nifc.gov/outlooks/NA_Outlook.pdf

Regional Assessment Dashboards

The following assessment area dashboards and summaries were developed based on data and narrative information collected by NERC from the seven Regional Entities on an assessment area basis.



FRCC – Florida Reliability Coordinating Council
- FRCC

MRO – Midwest Reliability Organization
- MISO
- MRO-Manitoba Hydro
- MRO-SaskPower

NPCC – Northeast Power Coordinating Council
- NPCC-Maritimes
- NPCC-New England
- NPCC-New York
- NPCC-Ontario
- NPCC-Québec

RF – ReliabilityFirst
- PJM

SERC – SERC Reliability Corporation
- SERC-East
- SERC-North
- SERC-Southeast

SPP – Southwest Power Pool
- SPP

Texas RE – Texas Reliability Entity
- Texas RE-ERCOT

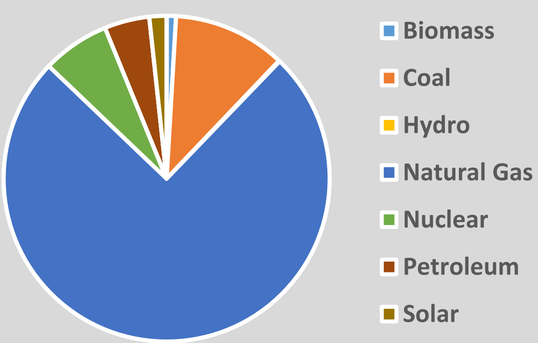
WECC
- WECC-CA/MX
- WECC-NWPP-AB
- WECC-NWPP-BC
- WECC-NWPP-US
- WECC-RMRG
- WECC-SRSG

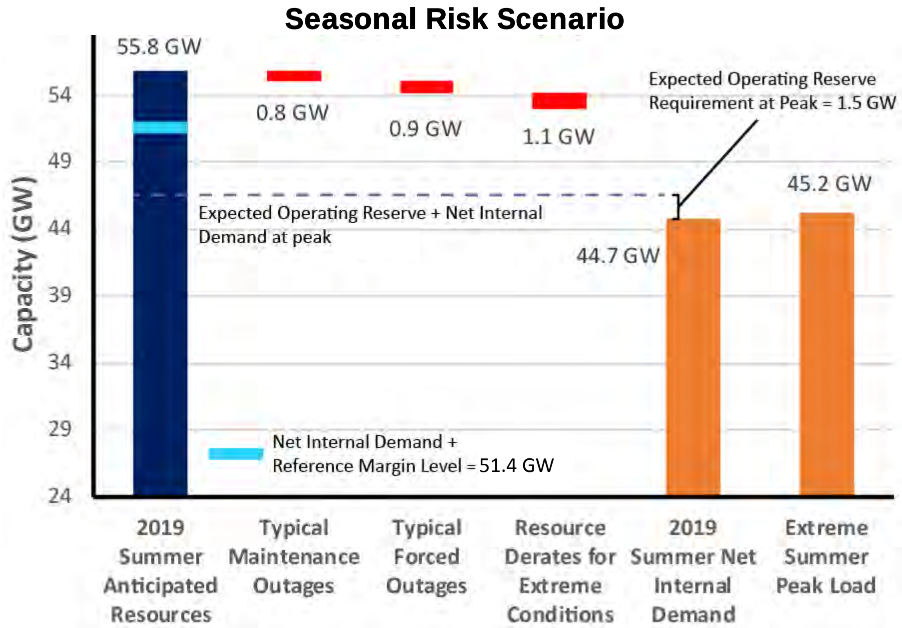
FRCC

The Florida Reliability Coordinating Council's (FRCC) membership includes 32 Regional Entity Division members and 22 Member Services Division members composed of investor-owned utilities, cooperatives, municipal utilities, power marketers, and independent power producers.

FRCC is divided into 10 Balancing Authorities with 36 registered entities (including both members and non-members) performing the functions identified in the NERC Reliability Functional Model and defined in the NERC Reliability Standards. The Region contains a population of more than 16 million people and has a geographic coverage of about 50,000 square miles across Florida.

On-Peak Capacity: Generation Mix





The table and chart above provide potential summer peak demand and resource condition information. The table on the right presents a standard seasonal assessment and comparison to the previous year's assessment. The chart above presents deterministic scenarios for further analysis of different demand and resource levels, with adjustments for normal and extreme conditions. FRCC determined the adjustments to summer capacity and peak demand based on methods or assumptions that are summarized below. See the Seasonal Risk Scenario Chart Description for more information about this chart.

Risk Scenario Summary

Observation:

Resources meet operating reserve requirements under studied scenarios.

Scenario Assumptions

- **Extreme Peak Load:** 90/10 forecast
- **Outages:** Historical average MW during summer season
- **Extreme Derates:** 3% capacity derate applied on all natural gas unit capacity

FRCC Resource Adequacy Data

Demand, Resource, and Reserve Margin	2018 SRA	2019 SRA	2018 vs. 2019 SRA
Demand Projections	**MW**	**MW**	**Net Change**
Total Internal Demand (50/50)	47,495	47,670	0.4%
Demand Response: Available	2,957	2,951	-0.2%
Net Internal Demand	44,538	44,719	0.4%
Resource Projections	**MW**	**MW**	**Net Change**
Existing-Certain Capacity	53,010	52,163	-1.6%
Tier 1 Planned Capacity	321.6	2,221	> 100%
Net Firm Capacity Transfers	1,477	1,456	-1.4%
Anticipated Resources	54,809	55,840	1.9%
Existing-Other Capacity	763.9	834	9.2%
Prospective Resources	55,573	56,674	2.0%
Reserve Margins	**Percent**	**Percent**	**Annual Difference**
Anticipated Reserve Margin	23.1%	24.9%	1.8
Prospective Reserve Margin	24.8%	26.7%	1.9
Reference Margin Level	15.0%	15.0%	0.0

Highlights

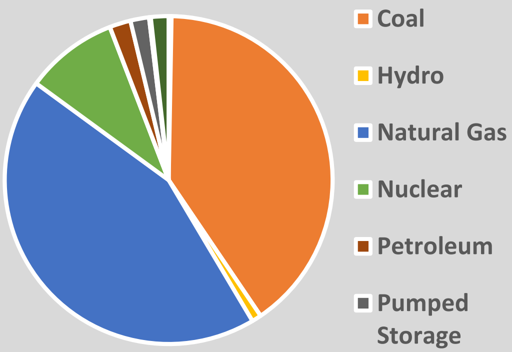
- FRCC has not identified any emerging reliability issues that are expected to impact reliability in the FRCC Region for the upcoming 2019 summer season.
- The BPS within the FRCC Region is expected to perform reliably for the anticipated 2019 summer season condition.
- On July 1, 2019, Regional Entity responsibilities will shift from FRCC to SERC for entities in Florida. FRCC will continue to provide member services and will remain a NERC assessment area.

MISO

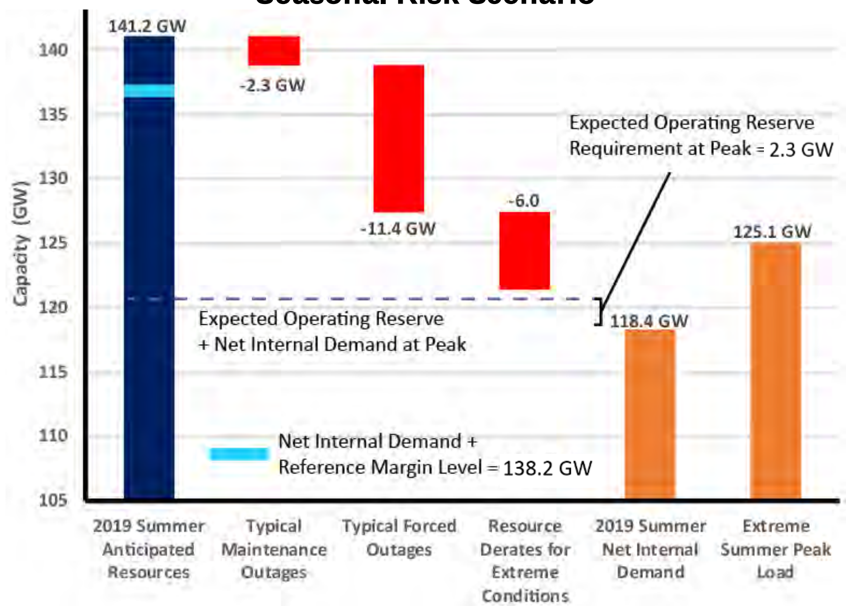
The Midcontinent Independent System Operator, Inc. (MISO) is a not-for-profit, member-based organization administering wholesale electricity markets that provide customers with valued service; reliable, cost-effective systems and operations; dependable and transparent prices; open access to markets; and planning for long-term efficiency.

MISO manages energy, reliability, and operating reserve markets that consist of 36 local Balancing Authorities and 394 market participants, serving approximately 42 million customers. Although parts of MISO fall in three NERC Regions, MRO is responsible for coordinating data and information submitted for NERC's reliability assessments.

On-Peak Capacity: Generation Mix



Seasonal Risk Scenario



The table and chart above provide potential summer peak demand and resource condition information. The table on the right presents a standard seasonal assessment and comparison to the previous year's assessment. The chart above presents deterministic scenarios for further analysis of different demand and resource levels, with adjustments for normal and extreme conditions. MISO determined the adjustments to summer capacity and peak demand based on methods or assumptions that are summarized below. See the Seasonal Risk Scenario Chart Description for more information about this chart.

Risk Scenario Summary

Observation:

Resources meet operating reserve requirements under normal peak load scenario. Extreme summer peak load and outage conditions could result in the need to employ operating mitigation to manage resource shortfall.

Scenario Assumptions

- **Extreme Peak Load:** 90/10 forecast
- **Outages:** Average from highest peak hour over the past five summers
- **Extreme Derates:** Additional outages based on analysis of past five years summer peak outages

MISO Resource Adequacy Data

Demand, Resource, and Reserve Margin	2018 SRA	2019 SRA	2018 vs. 2019 SRA
Demand Projections	**MW**	**MW**	**Net Change**
Total Internal Demand (50/50)	124,704	124,744	0.0%
Demand Response: Available	5,990	6,385	6.6%
Net Internal Demand	118,714	118,359	-0.3%
Resource Projections	**MW**	**MW**	**Net Change**
Existing-Certain Capacity	141,425	139,220	-1.6%
Tier 1 Planned Capacity	0	0	0.0%
Net Firm Capacity Transfers	-8	1,955	-
Anticipated Resources	141,417	141,175	-0.2%
Existing-Other Capacity	1,104	591	-46.5%
Prospective Resources	142,521	141,766	-0.5%
Reserve Margins	**Percent**	**Percent**	**Annual Difference**
Anticipated Reserve Margin	19.1%	19.3%	0.2
Prospective Reserve Margin	20.1%	19.8%	-0.3
Reference Margin Level	17.1%	16.8%	-0.3

Highlights

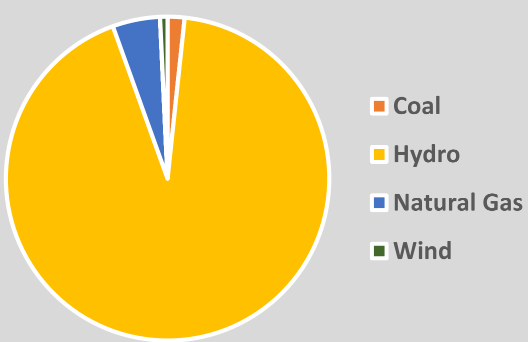
- MISO does not anticipate reliability issues during the upcoming season for typical resource outages and load. MISO studied the summer system reliability under various resource outage and load scenarios. MISO held a summer readiness workshop with its members on April 23, 2019, to prepare for summer operations.
- MISO worked with entities in the SERC Region to develop an operating procedure to address potential issues that may result from high MISO north and south transfers. These transfers between MISO operating areas can cause entities in other Regions to experience loop flows that can impact system operations.
- MISO's Load Modifying Resource (LMR) FERC filing is expected to provide MISO's operators with greater access to the existing capabilities of LMRs. Enhancements include requiring LMR units to operate to their existing capability and added processes to schedule LMRs in anticipation of emergency conditions.

MRO-Manitoba Hydro

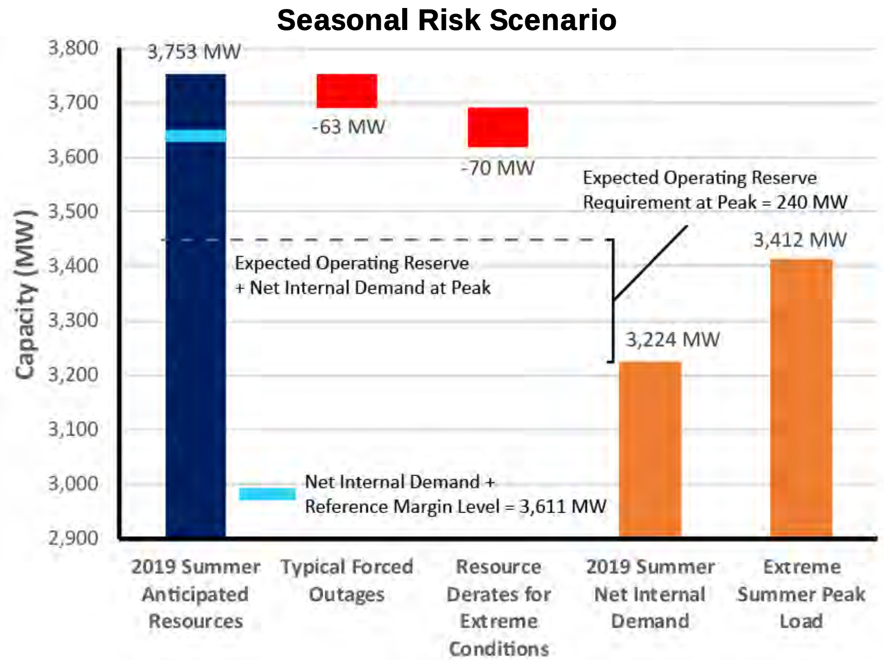
Manitoba Hydro is a provincial crown corporation that provides electricity to about 573,000 customers throughout Manitoba and natural gas service to about 279,000 customers in various communities throughout Southern Manitoba. The Province of Manitoba has a population of about 1.3 million people in an area of 250,946 square miles.

Manitoba Hydro is winter peaking. No change in the footprint area is expected during the assessment period. Manitoba Hydro is its own Planning Coordinator and Balancing Authority. Manitoba Hydro is a coordinating member of MISO. MISO is the Reliability Coordinator for Manitoba Hydro.

On-peak Capacity: Generation Mix



Seasonal Risk Scenario



The table and chart above provide potential summer peak demand and resource condition information. The table on the right presents a standard seasonal assessment and comparison to the previous year's assessment. The chart above presents deterministic scenarios for further analysis of different demand and resource levels, with adjustments for normal and extreme conditions. MRO-Manitoba determined the adjustments to summer capacity and peak demand based on methods or assumptions that are summarized below. See the Seasonal Risk Scenario Chart Description for more information about this chart.

Risk Scenario Summary

Observation:
Resources meet operating reserve requirements under studied scenarios.

Scenario Assumptions

- **Extreme Peak Load:** All-time highest peak load
- **Outages:** Based on historical operating experience
- **Extreme Derates:** Thermal units derated for extreme temperature where appropriate

MRO-Manitoba Hydro Resource Adequacy Data

Demand, Resource, and Reserve Margin	2018 SRA	2019 SRA	2018 vs. 2019 SRA
Demand Projections	**MW**	**MW**	**Net Change**
Total Internal Demand (50/50)	3,237	3,224	-0.4%
Demand Response: Available	0	0	0.0%
Net Internal Demand	3,237	3,224	-0.4%
Resource Projections	**MW**	**MW**	**Net Change**
Existing-Certain Capacity	5,288	5,161	-2.4%
Tier 1 Planned Capacity	0	0	0.0%
Net Firm Capacity Transfers	-1,342	-1,408	4.9%
Anticipated Resources	3,946	3,753	-4.9%
Existing-Other Capacity	122.3	215	75.4%
Prospective Resources	4,068	3,968	-2.5%
Reserve Margins	**Percent**	**Percent**	**Annual Difference**
Anticipated Reserve Margin	21.9%	16.4%	-5.5
Prospective Reserve Margin	25.7%	23.1%	-2.6
Reference Margin Level	12.0%	12.0%	0.0

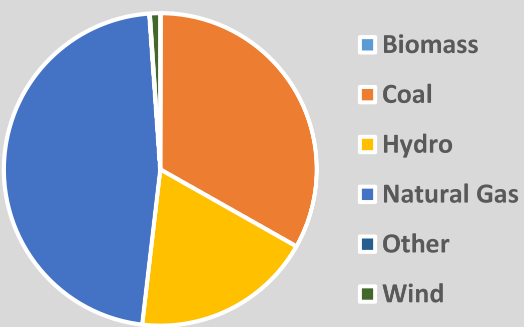
Highlights

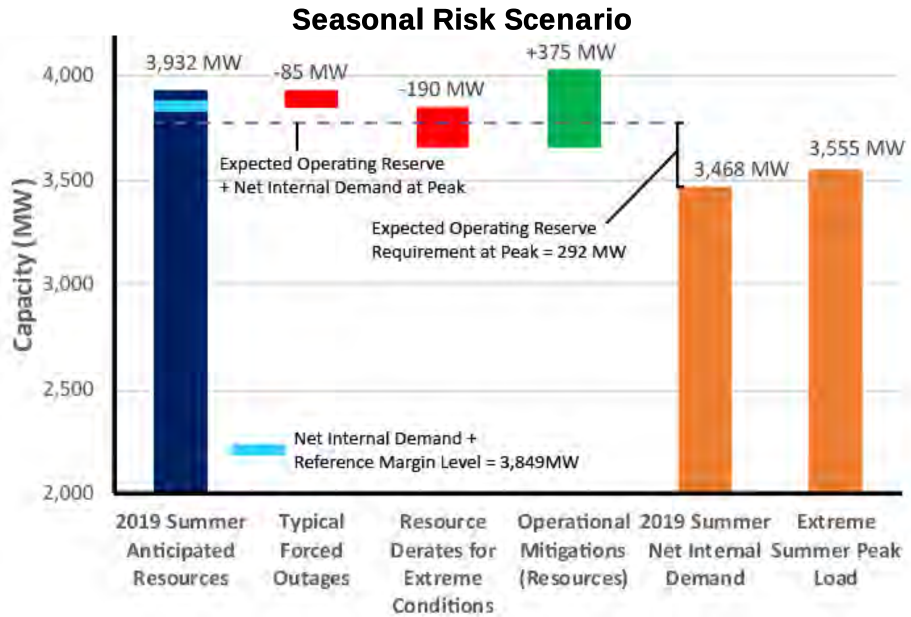
- There are no emerging reliability issues for the upcoming season in the Manitoba Hydro assessment area.
- Manitoba Hydro completed and commissioned the third HVdc line and placed it into service in July 2018. This addition significantly increased the system reliability by introducing an additional corridor for transmission of power generated by the bulk of Manitoba Hydro's generation in northern Manitoba to Southern Manitoba where the majority of the load is located.
- Reservoirs are at adequate storage levels and capable of supplying through design drought conditions.

MRO-SaskPower

Saskatchewan is a province of Canada and comprises a geographic area of 651,900 square kilometers (251,700 square miles) with approximately 1.1 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 and is the principal supplier of electricity in the province. 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.

On-Peak Capacity: Generation Mix





The table and chart above provide potential summer peak demand and resource condition information. The table on the right presents a standard seasonal assessment and comparison to the previous year's assessment. The chart above presents deterministic scenarios for further analysis of different demand and resource levels, with adjustments for normal and extreme conditions. MRO-SaskPower determined the adjustments to summer capacity and peak demand based on methods or assumptions that are summarized below. See the Seasonal Risk Scenario Chart Description for more information about this chart.

Risk Scenario Summary

Observation:

Resources meet operating reserve requirements under typical scenarios. Operating mitigations would be needed to meet reserve requirements in extreme outages and peak loads.

Scenario Assumptions

- **Extreme Peak Load:** Peak load with peak lighting and industrial demand
- **Maintenance Outages:** Estimated based on average maintenance outages in Summer 2018
- **Forced Outages:** Estimated using SaskPower model
- **Extreme Derates:** Derate on natural gas units based on historic data and manufacturer data

MRO-SaskPower Resource Adequacy Data

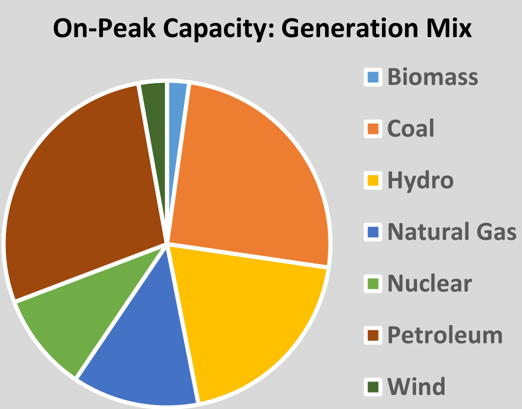
Demand, Resource, and Reserve Margin	2018 SRA	2019 SRA	2018 vs. 2019 SRA
Demand Projections	**MW**	**MW**	**Net Change**
Total Internal Demand (50/50)	3,426	3,553	3.7%
Demand Response: Available	85	85	0.0%
Net Internal Demand	3,341	3,468	3.8%
Resource Projections	**MW**	**MW**	**Net Change**
Existing-Certain Capacity	4,013	3,907	-2.6%
Tier 1 Planned Capacity	0	0	0.0%
Net Firm Capacity Transfers	25	25	0.0%
Anticipated Resources	4,038	3,932	-2.6%
Existing-Other Capacity	0	0	0.0%
Prospective Resources	4,038	3,932	-2.6%
Reserve Margins	**Percent**	**Percent**	**Annual Difference**
Anticipated Reserve Margin	20.8%	13.4%	-7.4
Prospective Reserve Margin	20.8%	13.4%	-7.4
Reference Margin Level	11.0%	11.0%	0.0

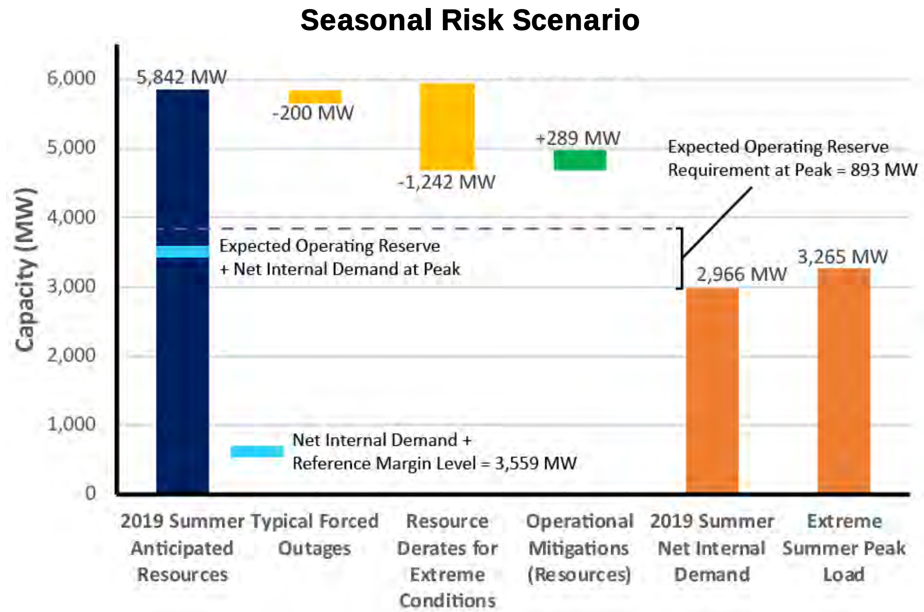
Highlights

- No reliability issues are expected for the upcoming summer season. Saskatchewan experiences peak load in winter. Reserve margin is expected to be higher than the reference reserve margin for the upcoming summer
- SaskPower conducts an annual summer season joint operating study with Manitoba Hydro, with inputs from Basin Electric Power Cooperative (North Dakota), and prepares operating guidelines for identified issues.
- In case of extreme load conditions combined with large generation forced outages, SaskPower would use available demand response programs, short term power transfers from neighboring utilities, and short term load interruptions.

NPCC-Maritimes

The Maritimes assessment area is a winter-peaking NPCC subregion that contains two Balancing Authorities. It is comprised of the Canadian provinces of New Brunswick, Nova Scotia, and Prince Edward Island, and the northern portion of Maine, which is radially connected to the New Brunswick power system. The area covers 58,000 square miles with a total population of 1.9 million people.





NPCC-Maritimes Resource Adequacy Data			
Demand, Resource, and Reserve Margin	**2018 SRA**	**2019 SRA**	**2018 vs. 2019 SRA**
Demand Projections	**MW**	**MW**	**Net Change**
Total Internal Demand (50/50)	3,235	3,255	0.6%
Demand Response: Available	300	289	-3.7%
Net Internal Demand	2,935	2,966	1.1%
Resource Projections	**MW**	**MW**	**Net Change**
Existing-Certain Capacity	5,828	5,842	0.2%
Tier 1 Planned Capacity	0	0	0.0%
Net Firm Capacity Transfers	0	0	0.0%
Anticipated Resources	5,828	5,842	0.2%
Existing-Other Capacity	0	0	0.0%
Prospective Resources	5,828	5,842	0.2%
Reserve Margins	**Percent**	**Percent**	**Annual Difference**
Anticipated Reserve Margin	98.6%	97.0%	-1.6
Prospective Reserve Margin	98.6%	97.0%	-1.6
Reference Margin Level	20.0%	20.0%	0.0

The table and chart above provide potential summer peak demand and resource condition information. The table on the right presents a standard seasonal assessment and comparison to the previous year's assessment. The chart above presents deterministic scenarios for further analysis of different demand and resource levels, with adjustments for normal and extreme conditions. NPCC-Maritimes determined the adjustments to summer capacity and peak demand based on methods or assumptions that are summarized below. See the Seasonal Risk Scenario Chart Description for more information about this chart.

Risk Scenario Summary

Observation:

Resources meet operating reserve requirements under studied scenarios.

Scenario Assumptions

- **Extreme Peak Load:** 90/10 forecast
- **Outages:** Based on historical operating experience
- **Extreme Derates:** An extreme, low-likelihood scenario is used whereby thermal units are derated for extreme temperature and all wind unit capacity is unavailable

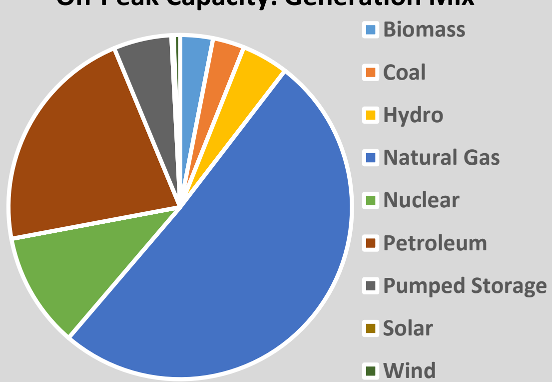
Highlights

- The Maritimes area has not identified any operational issues that are expected to impact system reliability. If an event were to occur, there are emergency operations and planning procedures in place. All of the area's declared firm capacity is expected to be operational for the summer operating period.
- As part of the planning process, dual-fueled units will have sufficient supplies of heavy fuel oil (HFO) on-site to enable sustained operation in the event of natural gas supply interruptions.

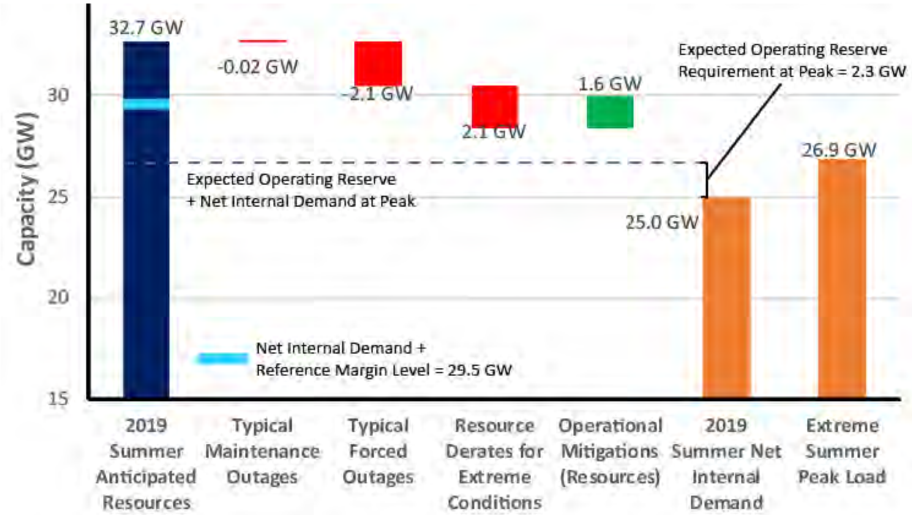
NPCC-New England

ISO New England (ISO-NE) Inc. is a Regional Transmission Organization that serves 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, and it also administers the area's wholesale electricity markets and manages the comprehensive planning of the regional BPS. The New England regional electric power system serves approximately 14.5 million people over 68,000 square miles.

On-Peak Capacity: Generation Mix



Seasonal Risk Scenario



The table and chart above provide potential summer peak demand and resource condition information. The table on the right presents a standard seasonal assessment and comparison to the previous year's assessment. The chart above presents deterministic scenarios for further analysis of different demand and resource levels, with adjustments for normal and extreme conditions. NPCC-New England determined the adjustments to summer capacity and peak demand based on methods or assumptions that are summarized below. See the Seasonal Risk Scenario Chart Description for more information about this chart.

Risk Scenario Summary

Observation:

Resources meet operating reserve requirements under studied scenarios.

Scenario Assumptions

- **Extreme Peak Load:** 90/10 Forecast
- **Outages:** Near-zero MW due to summer peaking area
- **Extreme Derates:** Based on historical forced outages and any additional reductions for fuel-supply risk
- **Operating Mitigations:** Based on ISO-NE operating procedures

NPCC-New England Resource Adequacy Data			
Demand, Resource, and Reserve Margin	**2018 SRA**	**2019 SRA**	**2018 vs. 2019 SRA**
Demand Projections	**MW**	**MW**	**Net Change**
Total Internal Demand (50/50)	25,729	25,323	-1.6%
Demand Response: Available	408	340	-16.7%
Net Internal Demand	25,321	24,983	-1.3%
Resource Projections	**MW**	**MW**	**Net Change**
Existing-Certain Capacity	30,460	30,144	-1.0%
Tier 1 Planned Capacity	0	1,185	-
Net Firm Capacity Transfers	1,468	1,328	-9.5%
Anticipated Resources	31,928	32,657	2.3%
Existing-Other Capacity	421	704	67.2%
Prospective Resources	32,349	33,361	3.1%
Reserve Margins	**Percent**	**Percent**	**Annual Difference**
Anticipated Reserve Margin	26.1%	30.7%	4.6
Prospective Reserve Margin	27.8%	33.5%	5.7
Reference Margin Level	16.8%	18.3%	1.5

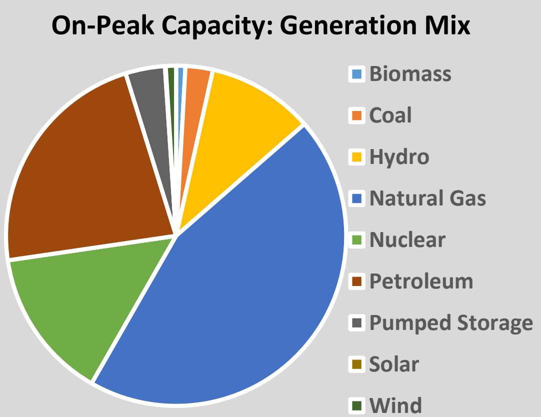
Highlights

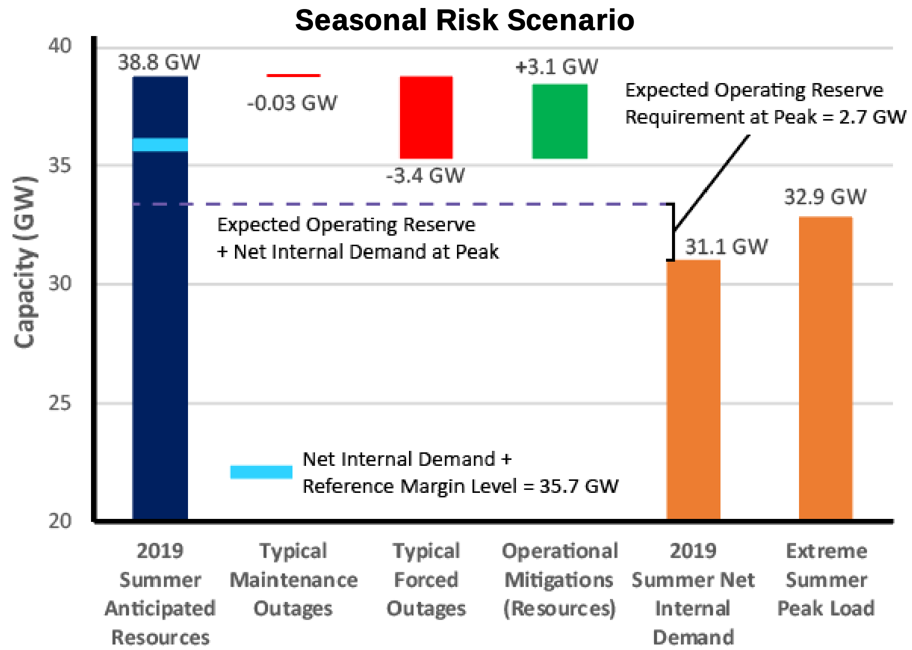
- The New England area expects to have sufficient resources to meet the 2019 summer peak demand forecast of 25,323 MW, with a corresponding projected net margin of 7,674 MW after accounting for demand response resources. This net margin is a 1,067 MW increase from the 2018 Anticipated Reserve Margin forecast. The increase can be largely attributed to new generation becoming available prior to the 2019 summer and a decrease in forecasted net demand.
- The upcoming retirement of the 674 MW Pilgrim nuclear unit is offset by additions in excess of 1,000 MW of combined cycle and combustion gas turbine generating units.
- The 2019 summer demand forecast is 406 MW (1.6%) lower than the 2018 summer forecast and takes into account the demand reductions associated with energy efficiency and behind-the-meter photovoltaic (BTM-PV) systems.
- The 18.3% Reference Margin Level is based on New England's net installed capacity requirement for the 2019–2020 commitment period, which was approved by FERC.

NPCC-New York

The New York Independent System Operator (NYISO) is the only Balancing Authority (NYBA) within the state of New York. NYISO is a single-state ISO that was formed as the successor to the New York Power Pool—a consortium of the eight IOUs—in 1999. NYISO manages the New York State transmission grid that encompasses approximately 11,000 miles of transmission lines, more than 47,000 square miles, and serving the electric needs of 19.5 million people. New York experienced its all-time peak load of 33,956 MW in the Summer 2013.

The NERC Reference Margin Level is 15%. Wind, grid-connected solar, and run-of-river totals were derated for this calculation. However, New York requires load serving entities to procure capacity for their loads equal to their peak demand plus an Installed Reserve Margin (IRM). The IRM requirement represents a percentage of capacity above peak load forecast and is approved annually by the New York State Reliability Council (NYSRC). NYSRC approved the 2019–2020 IRM at 17%.





The table and chart above provide potential summer peak demand and resource condition information. The table on the right presents a standard seasonal assessment and comparison to the previous year's assessment. The chart above presents deterministic scenarios for further analysis of different demand and resource levels, with adjustments for normal and extreme conditions. NPCC-New York determined the adjustments to summer capacity and peak demand based on methods or assumptions that are summarized below. See the Seasonal Risk Scenario Chart Description for more information about this chart.

Risk Scenario Summary

Observation:

Resources meet operating reserve requirements under studied scenarios.

Scenario Assumptions

- **Extreme Peak Load:** 90/10 forecast
- **Extreme Derates:** Near-zero MW due to summer peaking area
- **Forced Outages:** Based on five-year average performance
- **Operational Mitigation:** Based on operational/emergency procedures in NYISO Emergency Operations Manual

NPCC-New York Resource Adequacy Data

Demand, Resource, and Reserve Margin	2018 SRA	2019 SRA	2018 vs. 2019 SRA
Demand Projections	**MW**	**MW**	**Net Change**
Total Internal Demand (50/50)	32,904	32,382	-1.6%
Demand Response: Available	1,219	1,309	7.4%
Net Internal Demand	31,685	31,073	-1.9%
Resource Projections	**MW**	**MW**	**Net Change**
Existing-Certain Capacity	39,066	37,304	-4.5%
Tier 1 Planned Capacity	260	27	-89.6%
Net Firm Capacity Transfers	1,625	1,452	-10.7%
Anticipated Resources	40,950	38,783	-5.3%
Existing-Other Capacity	0	0	0.0%
Prospective Resources	40,950	38,783	-5.3%
Reserve Margins	**Percent**	**Percent**	**Annual Difference**
Anticipated Reserve Margin	29.2%	24.8%	-4.4
Prospective Reserve Margin	29.2%	24.8%	-4.4
Reference Margin Level	18.2%	15.0%	-3.2

Highlights

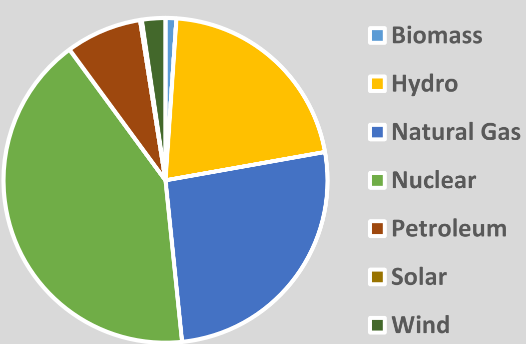
- NYISO is not anticipating any operational issues in the New York control area for the upcoming summer operating period. Adequate capacity margins are anticipated and existing operating procedures are sufficient to handle any issues that may occur.
- High capacity factors on certain New York City peaking units could result in possible violations of their daily NOx emission limits if they were to fully respond to the NYISO dispatch signals. Significant run-time on peaking units, indicating the potential for a violation, could be the result of long duration hot weather events or loss of significant generation or transmission assets in New York City.

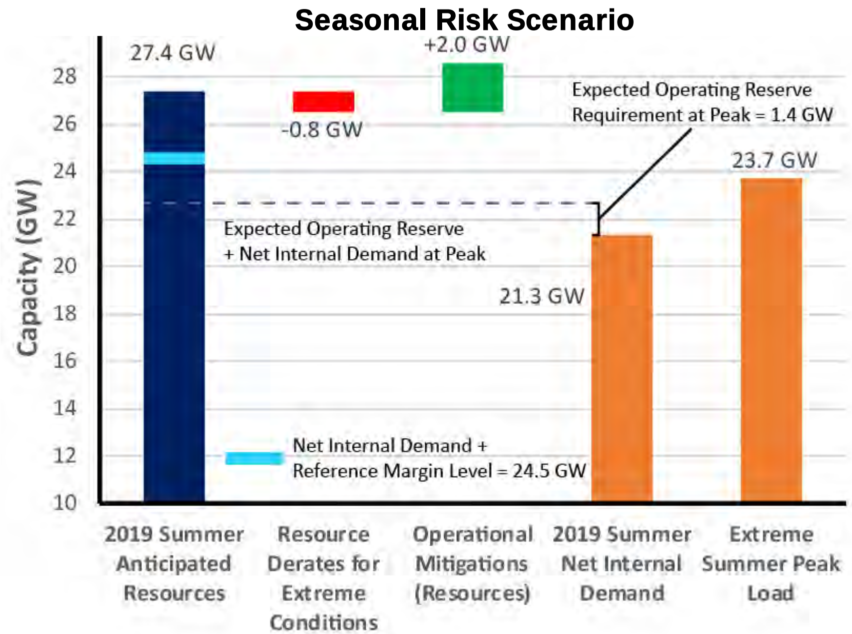
NPCC-Ontario

The Independent Electricity System Operator (IESO) is the Balancing Authority and Reliability Coordinator for the province of Ontario. In addition to administering the area's wholesale electricity markets, the IESO plans for Ontario's future energy needs. Ontario covers more than 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.

Ontario IESO treats demand response as a resource for its own assessments, while in the NERC assessment demand response is used as a load-modifier. As a result, the total internal demand, reserve margin, and Reference Margin Level values differ in IESO's reports when compared to NERC reports.

On-Peak Capacity: Generation Mix





NPCC-Ontario Resource Adequacy Data			
Demand, Resource, and Reserve Margin	**2018 SRA**	**2019 SRA**	**2018 vs. 2019 SRA**
Demand Projections	**MW**	**MW**	**Net Change**
Total Internal Demand (50/50)	22,002	22,105	0.5%
Demand Response: Available	630	790	25.4%
Net Internal Demand	21,372	21,315	-0.3%
Resource Projections	**MW**	**MW**	**Net Change**
Existing-Certain Capacity	25,731	26,581	3.3%
Tier 1 Planned Capacity	23	924	>100%
Net Firm Capacity Transfers	0	-102	-
Anticipated Resources	25,754	27,403	6.4%
Existing-Other Capacity	0	0	0.0%
Prospective Resources	25,754	27,403	6.4%
Reserve Margins	**Percent**	**Percent**	**Annual Difference**
Anticipated Reserve Margin	20.5%	28.6%	8.1
Prospective Reserve Margin	20.5%	28.6%	8.1
Reference Margin Level	13.3%	14.9%	1.6

The table and chart above provide potential summer peak demand and resource condition information. The table on the right presents a standard seasonal assessment and comparison to the previous year's assessment. The chart above presents deterministic scenarios for further analysis of different demand and resource levels, with adjustments for normal and extreme conditions. NPCC-Ontario determined the adjustments to summer capacity and peak demand based on methods or assumptions that are summarized below. See the Seasonal Risk Scenario Chart Description for more information about this chart.

Risk Scenario Summary

Observation:

Resources meet operating reserve requirements under studied scenarios.

Scenario Assumptions

- **Extreme Peak Load:** Based on severe historic weather conditions
- **Extreme Derates:** Based on thermal unit derating curves, and historical hydro performance in low-water year
- **Operational Mitigation:** 2,000 MW imports assessed as available from neighbors

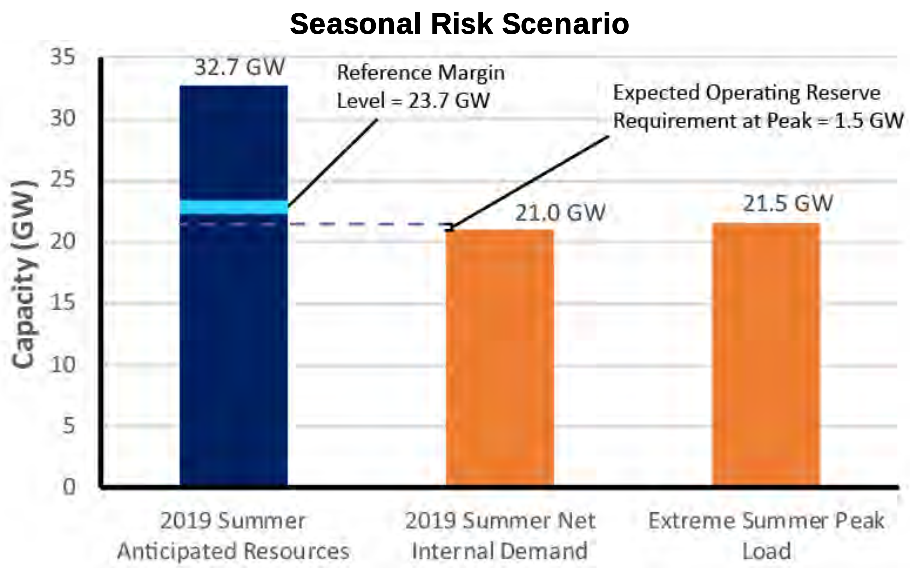
Highlights

- There are sufficient resources to maintain the reliability of Ontario's electricity system under normal weather conditions for Summer 2019.
- The IESO recently revised its outage approval methods and will evaluate outages using its extreme weather scenario with only firm resources and up to 2,000 MW of imports.
- Driven by the need to enhance planning transparency and help market participants make more informed decisions and investments, the IESO has renewed its approach to planning with a particular emphasis on its commitment to regular sharing of information with stakeholders. As a first step in delivering on this commitment, and helping generators and transmitters plan for and schedule outages, the IESO now extends its 18-month outage planning horizon to five years twice yearly.

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 million.

Québec is one of the four NERC Interconnections in North America, with ties to Ontario, New York, New England, and the Maritimes, consisting of either HVDC ties, radial generation, or load to and from neighboring systems.



NPCC- Québec Resource Adequacy Data			
Demand, Resource, and Reserve Margin	**2018 SRA**	**2019 SRA**	**2018 vs. 2019 SRA**
Demand Projections	**MW**	**MW**	**Net Change**
Total Internal Demand (50/50)	20,534	21,005	2.3%
Demand Response: Available	0	0	0.0%
Net Internal Demand	20,534	21,005	2.3%
Resource Projections	**MW**	**MW**	**Net Change**
Existing-Certain Capacity	34,014	34,303	0.8%
Tier 1 Planned Capacity	0	28	-
Net Firm Capacity Transfers	-1,829	-1,663	-9.1%
Anticipated Resources	32,185	32,667	1.5%
Existing-Other Capacity	0	0	0.0%
Prospective Resources	32,185	32,667	1.5%
Reserve Margins	**Percent**	**Percent**	**Annual Difference**
Anticipated Reserve Margin	56.7%	55.5%	-1.2
Prospective Reserve Margin	56.7%	55.5%	-1.2
Reference Margin Level	12.6%	12.8%	0.2

The table and chart above provide potential summer peak demand and resource condition information. The table on the right presents a standard seasonal assessment and comparison to the previous year's assessment. The chart above presents deterministic scenarios for further analysis of different demand and resource levels, with adjustments for normal and extreme conditions. NPCC-Québec determined the adjustments to peak demand based on methods or assumptions that are summarized below. See the Seasonal Risk Scenario Chart Description for more information about this chart.

Risk Scenario Summary

Observation:
Resources meet operating reserve requirements under studied scenarios.

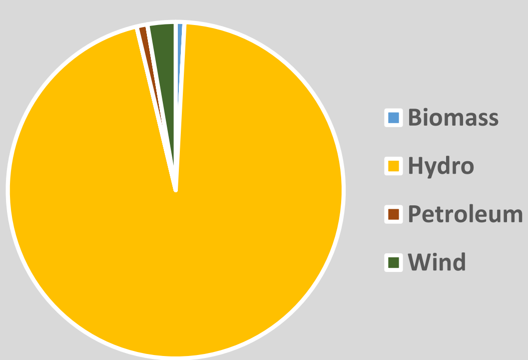
Scenario Assumptions

- **Extreme Peak Load:** 90/10 forecast
- **Anticipated Resources:** Includes planned generator outages, deratings, bottling, historic hydroelectric reduction and 100% reduction in installed wind generation capacity

Highlights

- No issues are anticipated for the summer operating period since the system is winter peaking.
- A new 735 kV line is expected to be commissioned in May 2019 to meet NERC Reliability Standards and will provide more flexibility to operators.
- The Québec area expects to be able to provide assistance to neighboring areas if needed, up to the transfer capability available.

On-Peak Capacity: Generation Mix

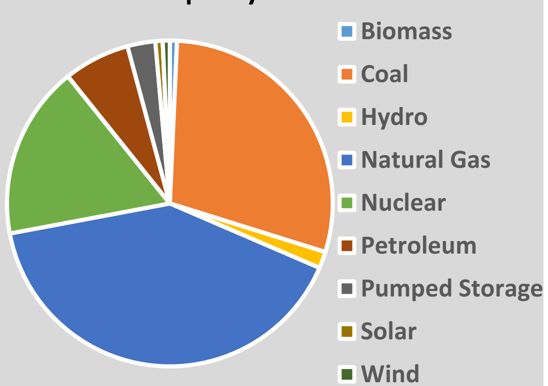


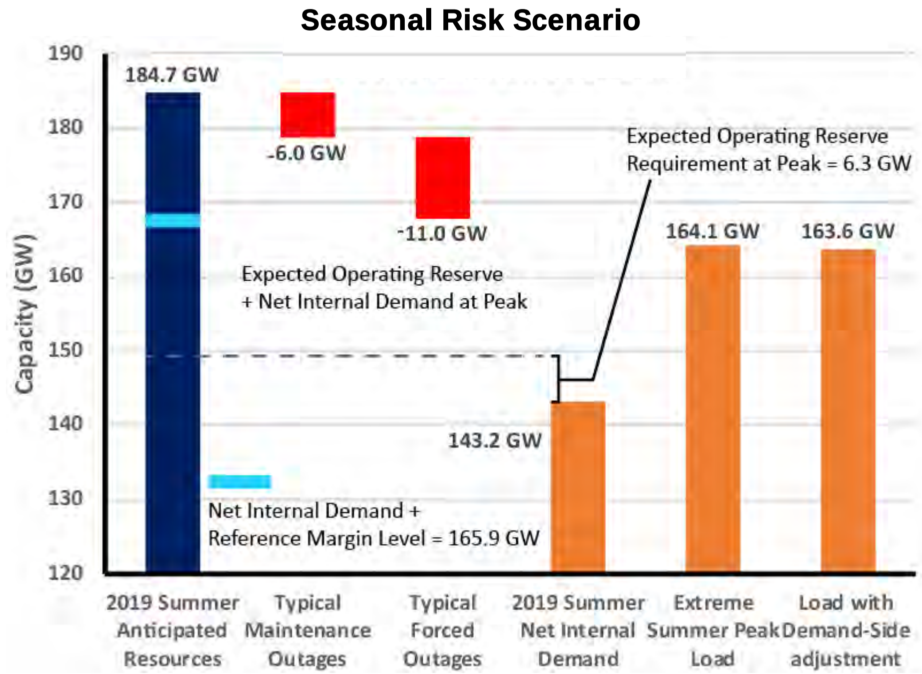
PJM

PJM Interconnection is a Regional Transmission Organization that coordinates the movement of wholesale electricity in all or parts of Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, West Virginia, and the District of Columbia.

PJM serves 65 million people and covers 369,089 square miles. PJM is a Balancing Authority, Planning Coordinator, Transmission Planner, Resource Planner, Interchange Authority, Transmission Operator, Transmission Service Provider, and Reliability Coordinator.

On-Peak Capacity: Generation Mix





PJM Resource Adequacy Data			
Demand, Resource, and Reserve Margin	**2018 SRA**	**2019 SRA**	**2018 vs. 2019 SRA**
Demand Projections	**MW**	**MW**	**Net Change**
Total Internal Demand (50/50)	152,108	151,358	-0.5%
Demand Response: Available	9,095	8,154	-10.3%
Net Internal Demand	143,013	143,204	0.1%
Resource Projections	**MW**	**MW**	**Net Change**
Existing-Certain Capacity	185,440	181,013	-2.4%
Tier 1 Planned Capacity	0	2,200	-
Net Firm Capacity Transfers	4,419	1,535	-65.3%
Anticipated Resources	189,859	184,748	-2.7%
Existing-Other Capacity	0	0	0
Prospective Resources	189,859	184,748	-2.7%
Reserve Margins	**Percent**	**Percent**	**Annual Difference**
Anticipated Reserve Margin	32.8%	29.0%	-3.8
Prospective Reserve Margin	32.8%	29.0%	-3.8
Reference Margin Level	16.1%	15.9%	-0.2

The table and chart above provide potential summer peak demand and resource condition information. The table on the right presents a standard seasonal assessment and comparison to the previous year's assessment. The chart above presents deterministic scenarios for further analysis of different demand and resource levels, with adjustments for normal and extreme conditions. PJM determined the adjustments to summer capacity and peak demand based on methods or assumptions that are summarized below. See the Seasonal Risk Scenario Chart Description for more information about this chart.

Risk Scenario Summary

Observation:

Resources meet operating reserve requirements under studied scenarios.

Scenario Assumptions

- **Extreme Peak Load:** 90/10 Forecast
- **Outages:** Approximate values based on review of previous summer peak periods

Highlights

- The PJM reserve margin for this summer is 29.0% with a requirement of 15.9%. With this level of capacity, PJM has not identified any emerging reliability issues regarding resource adequacy.
- Ohio Valley Electric Cooperative (OVEC) moved from MISO into PJM in December 2018. OVEC has two large generating plants that have moved from having significant transfers into PJM to now being part of the PJM market dispatch.

SERC

SERC's assessment areas are traditionally summer-peaking and cover approximately 72,000 circuit miles and serve a population estimated at 23 million.

For NERC's assessment, the Region is divided into three assessment areas: SERC- E, SERC-C, and SERC-SE. The assessment areas include 12 Balancing Authorities: Cube Hydro Carolinas LLC, Associated Electric Cooperative, Inc. (AECI), Duke Energy Carolinas (DEC), Duke Energy Progress (DEP), Electric Energy, Inc. (EEI), LG&E and KU Services Company (as agent for Louisville Gas and Electric and Kentucky Utilities (LG&E/ KU)), PowerSouth Energy Cooperative (PowerSouth), South Carolina Electric & Gas Company (SCE&G), South Carolina Public Service Authority (SCPSA), Southern Company Services, Inc. (SOCO), Southeastern Power Administration (SPA), and Tennessee Valley Authority (TVA).

SERC Resource Adequacy Data

Demand, Resource, and Reserve Margins	SERC-E	SERC-C	SERC-SE	2018 SRA SERC Total	2019 SRA SERC Total	2018 vs. 2019 SRA
Demand Projections	**Megawatts**	**Megawatts**	**Megawatts**	**Megawatts**	**Megawatts**	**Net Change (%)**
Total Internal Demand (50/50)	43,704	40,781	47,311	131,994	131,796	-0.2%
Demand Response: Available	1,054	1,964	2,293	4,640	5,311	14.5%
Net Internal Demand	42,650	38,817	45,018	127,354	126,485	-0.7%
Resource Projections	**Megawatts**	**Megawatts**	**Megawatts**	**Megawatts**	**Megawatts**	**Net Change (%)**
Existing-Certain Capacity	50,976	50,391	61,182	161,532	162,549	0.6%
Tier 1 Planned Capacity	0	0	458	1,875	458	-75.6%
Net Firm Capacity Transfers	455	301	-1,905	-3,133	-1,150	-63.3%
Anticipated Resources	51,431	50,692	59,734	160,274	161,857	1.0%
Existing-Other Capacity	852	4,060	289	2,361	5,200	120.2%
Prospective Resources	52,282	54,752	60,023	162,635	167,057	2.7%
Planning Reserve Margins	**Percent**	**Percent**	**Percent**	**Percent**	**Percent**	**Annual Difference**
Anticipated Reserve Margin	20.6%	30.6%	32.7%	25.9%	28.0%	2.1
Prospective Reserve Margin	22.6%	41.1%	33.3%	27.7%	32.1%	4.4
Reference Margin Level	13.15%	13.15%	13.15%	15.00%	13.15%	-1.85

Highlights

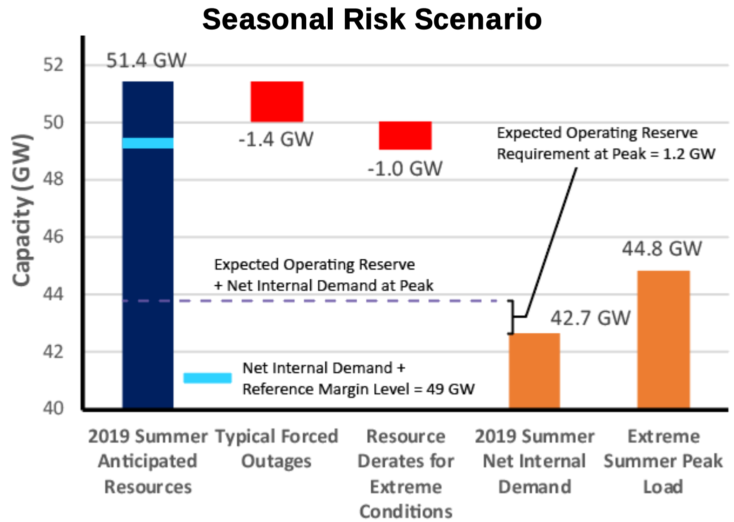
- To date, there are no significant reliability risks expected for the 2019 summer season in the SERC Region.
- SERC continues to prepare for the integration of entities within FRCC. Both FRCC and the SERC Region are coordinating activities to ensure a successful transition of the new registered entities into the SERC Region's reliability programs and processes. For more information, visit the FRCC RE Integration webpage.[9]
- To align with SERC's subregional naming convention in its regional studies and assessments, the SERC North Assessment Area was changed to SERC Central Assessment Area in NERC Reliability Assessments.
- SERC Southeast entities have experienced loop flows from a high regional transfers between MISO North and MISO South. As a result, the impacted utilities along with MISO developed an operating procedure to address potential reliability issues that could result from high MISO regional transfers.

Charts

The charts on the next page provide potential summer peak demand and resource condition information. The table above presents a standard seasonal assessment and comparison to the previous year's assessment. The waterfall charts on the next page present deterministic scenarios for further analysis of different demand and resource levels with adjustments for normal and extreme conditions. SERC determined the adjustments to summer capacity and peak demand based on methods or assumptions that are summarized on the next page. See the **Seasonal Risk Scenario Chart Description** for more information about the charts.

[9] See http://www.serc1.org/outreach/frcc-re-integration

SERC-E



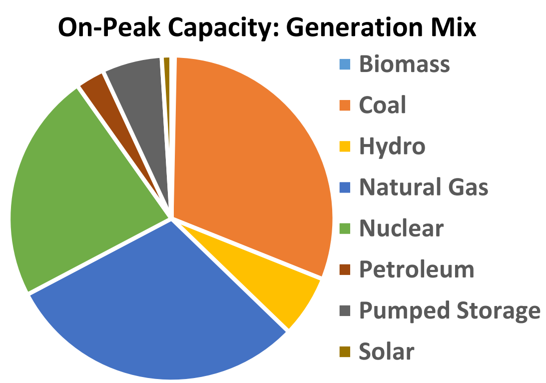
Risk Scenario Summary

Observation:

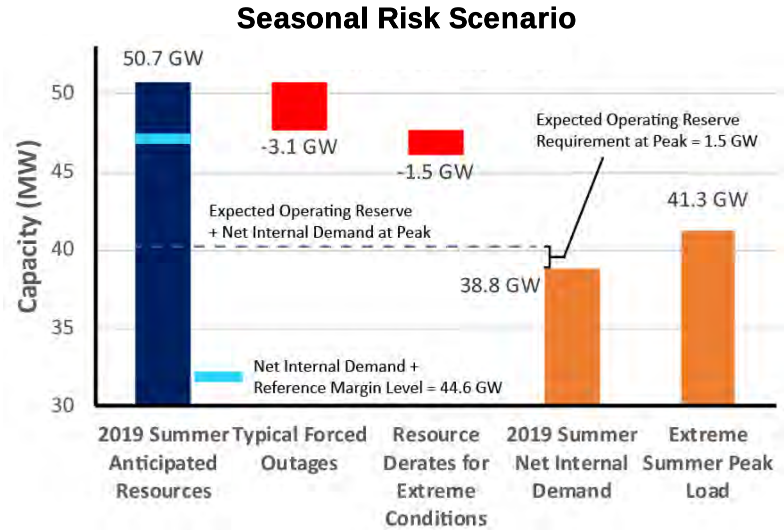
Resources meet operating reserve requirements under studied scenarios

Scenario Assumptions

- **Extreme Peak Load:** Based on 2018 SERC Probabilistic Assessment, equal to or exceeding a 90/10 statistical level
- **Outages:** Based on historical data
- **Extreme Derates:** Based on 2018 SERC Probabilistic Assessment, equal to or exceeding a 90/10 statistic



SERC-C



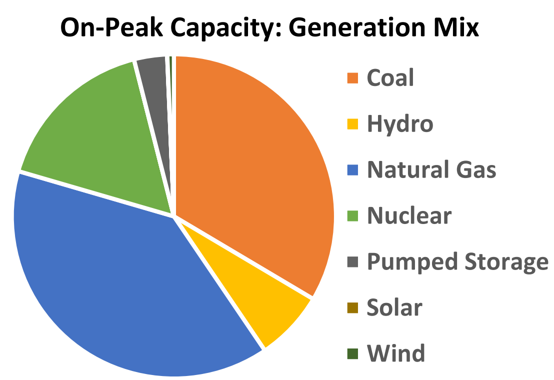
Risk Scenario Summary

Observation:

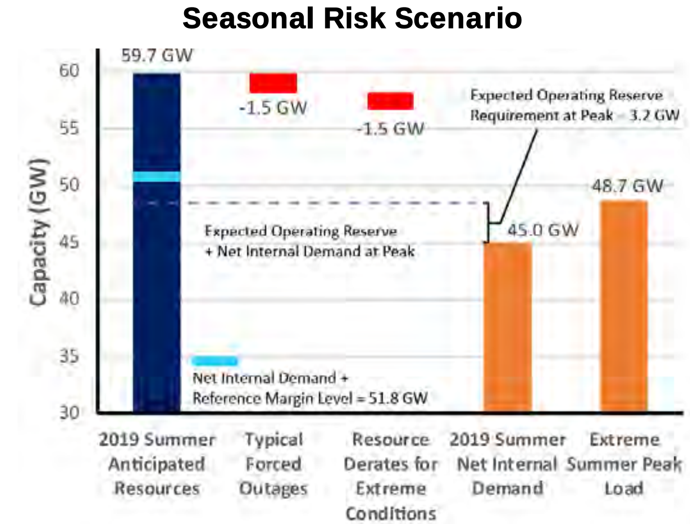
Resources meet operating reserve requirements under studied scenarios

Scenario Assumptions

- **Extreme Peak Load:** Based on 2018 SERC Probabilistic Assessment, equal to or exceeding a 90/10 statistical level
- **Outages:** Based on historical data
- **Extreme Derates:** Based on 2018 SERC Probabilistic Assessment, equal to or exceeding a 90/10 statistic



SERC-SE



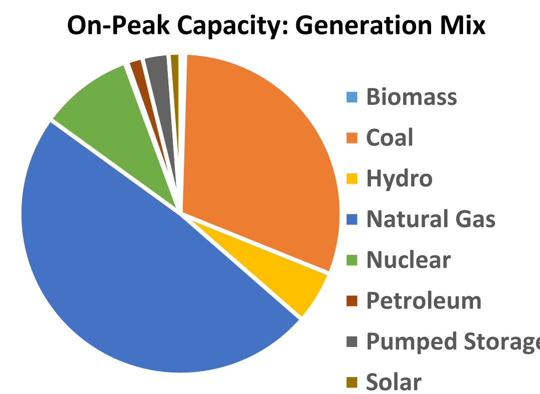
Risk Scenario Summary

Observation:

Resources meet operating reserve requirements under studied scenarios

Scenario Assumptions

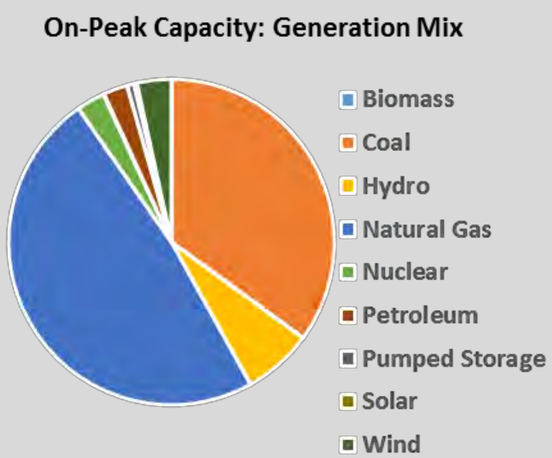
- **Extreme Peak Load:** Based on 2018 SERC Probabilistic Assessment, equal to or exceeding a 90/10 statistical level
- **Outages:** Based on historical data
- **Extreme Derates:** Based on 2018 SERC Probabilistic Assessment, equal to or exceeding a 90/10 statistic

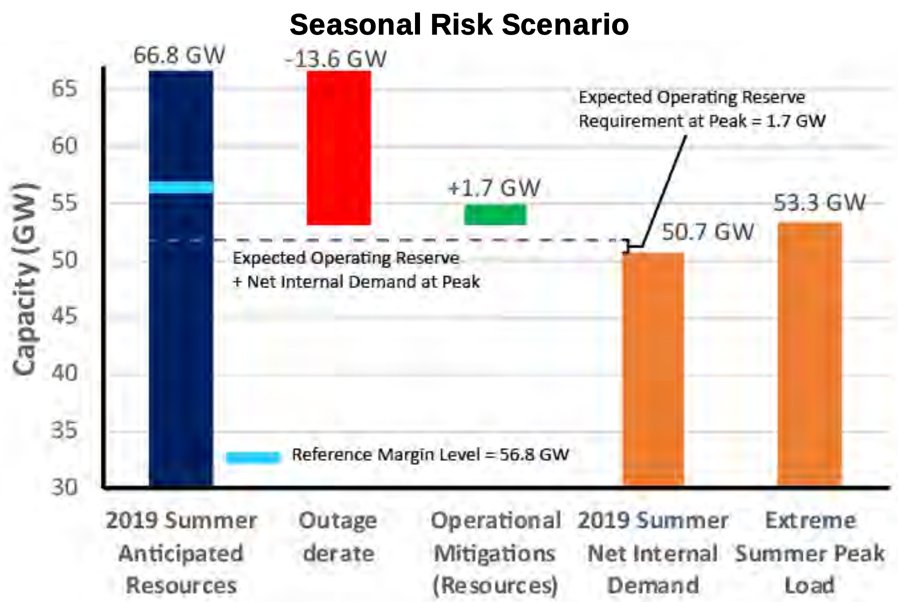


SPP

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 long-term assessment is reported based on the Planning Coordinator footprint, which touches parts of the Midwest Reliability Organization Regional Entity, and WECC. 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 people.





The table and chart above provide potential summer peak demand and resource condition information. The table on the right presents a standard seasonal assessment and comparison to the previous year's assessment. The chart above presents deterministic scenarios for further analysis of different demand and resource levels, with adjustments for normal and extreme conditions. SPP determined the adjustments to summer capacity and peak demand based on methods or assumptions that are summarized below. See the Seasonal Risk Scenario Chart Description for more information about this chart.

Risk Scenario Summary

Observation: Resources meet operating reserve requirements under studied scenarios.

Scenario Assumptions

- **Extreme Peak Load:** 90/10 Forecast
- **Outages:** A derate for forced outages and performance in extreme weather based on historical data

SPP Resource Adequacy Data			
Demand, Resource, and Reserve Margin	**2018 SRA**	**2019 SRA**	**2018 vs. 2019 SRA**
Demand Projections	**MW**	**MW**	**Net Change**
Total Internal Demand (50/50)	52,554	51,520	-2.0%*
Demand Response: Available	867	835	-3.8%
Net Internal Demand	51,687	50,685	-1.9%
Resource Projections	**MW**	**MW**	**Net Change**
Existing-Certain Capacity	67,649	67,960	0.5%
Tier 1 Planned Capacity	779.85	64	-91.8%
Net Firm Capacity Transfers	19	-1,244	-
Anticipated Resources	68,447	66,780	-2.4%
Existing-Other Capacity	0	0	0.0%
Prospective Resources	68,447	66,780	-2.4%
Reserve Margins	**Percent**	**Percent**	**Annual Difference**
Anticipated Reserve Margin	32.4%	31.8%	-0.6
Prospective Reserve Margin	32.4%	31.8%	-0.6
Reference Margin Level	12.0%	12.0%	0.0

* In 2018, Total Internal Demand was calculated on a non-coincident peak basis, resulting in higher demand calculations compared to coincident peak basis used for the 2019 SRA.

Highlights

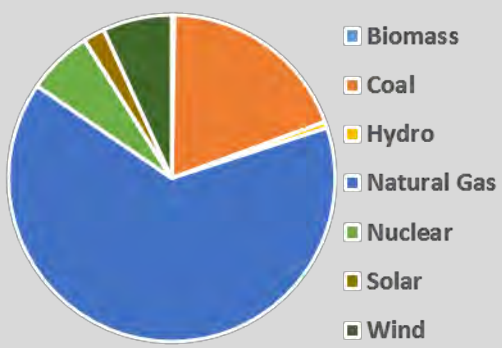
- SPP does not anticipate any emerging reliability issues impacting the area for the 2019 summer season.
- SPP has experienced mid-range forecast error uncertainty in wind forecasts as the penetration of wind generation increases. This is not an issue if the error is short lived, but if the error continues throughout the day it can lead to short-term supply scarcity. Within SPP, a team is developing mitigation to ensure appropriate ramp product is available on a daily basis.

Texas RE-ERCOT

The Electric Reliability Council of Texas (ERCOT) is the ISO for the ERCOT Interconnection and is located entirely in the state of Texas; it operates as a single Balancing Authority. It also performs financial settlement for the competitive wholesale bulk-power market and administers retail switching for nearly 8 million premises in competitive choice areas. ERCOT is governed by a board of directors and subject to oversight by the Public Utility Commission of Texas and the Texas Legislature.

ERCOT is a summer-peaking Region that covers approximately 200,000 square miles, connects over 46,500 miles of transmission lines, has 650 generation units, and serves more than 25 million customers. Texas RE is responsible for the regional RE functions described in the Energy Policy Act of 2005 for the ERCOT Region.

On-Peak Capacity: Generation Mix



Texas RE-ERCOT Resource Adequacy Data			
Demand, Resource, and Reserve Margin	**2018 SRA**	**2019 SRA**	**2018 vs. 2019 SRA**
Demand Projections	**MW**	**MW**	**Net Change**
Total Internal Demand (50/50)	72,756	74,853	2.9%
Demand Response: Available	2,301	2,227	-3.2%
Net Internal Demand	70,455	72,626	3.1%
Resource Projections	**MW**	**MW**	**Net Change**
Existing-Certain Capacity	76,654	77,482	1.1%
Tier 1 Planned Capacity	738.95	607	-17.9%
Net Firm Capacity Transfers	753	721	-4.2%
Anticipated Resources	78,146	78,810	0.9%
Existing-Other Capacity	0	0	0.0%
Prospective Resources	78,146	78,810	0.9%
Reserve Margins	**Percent**	**Percent**	**Annual Difference**
Anticipated Reserve Margin	10.9%	8.5%	-2.4
Prospective Reserve Margin	10.9%	8.5%	-2.4
Reference Margin Level	13.75%	13.75%	0.0

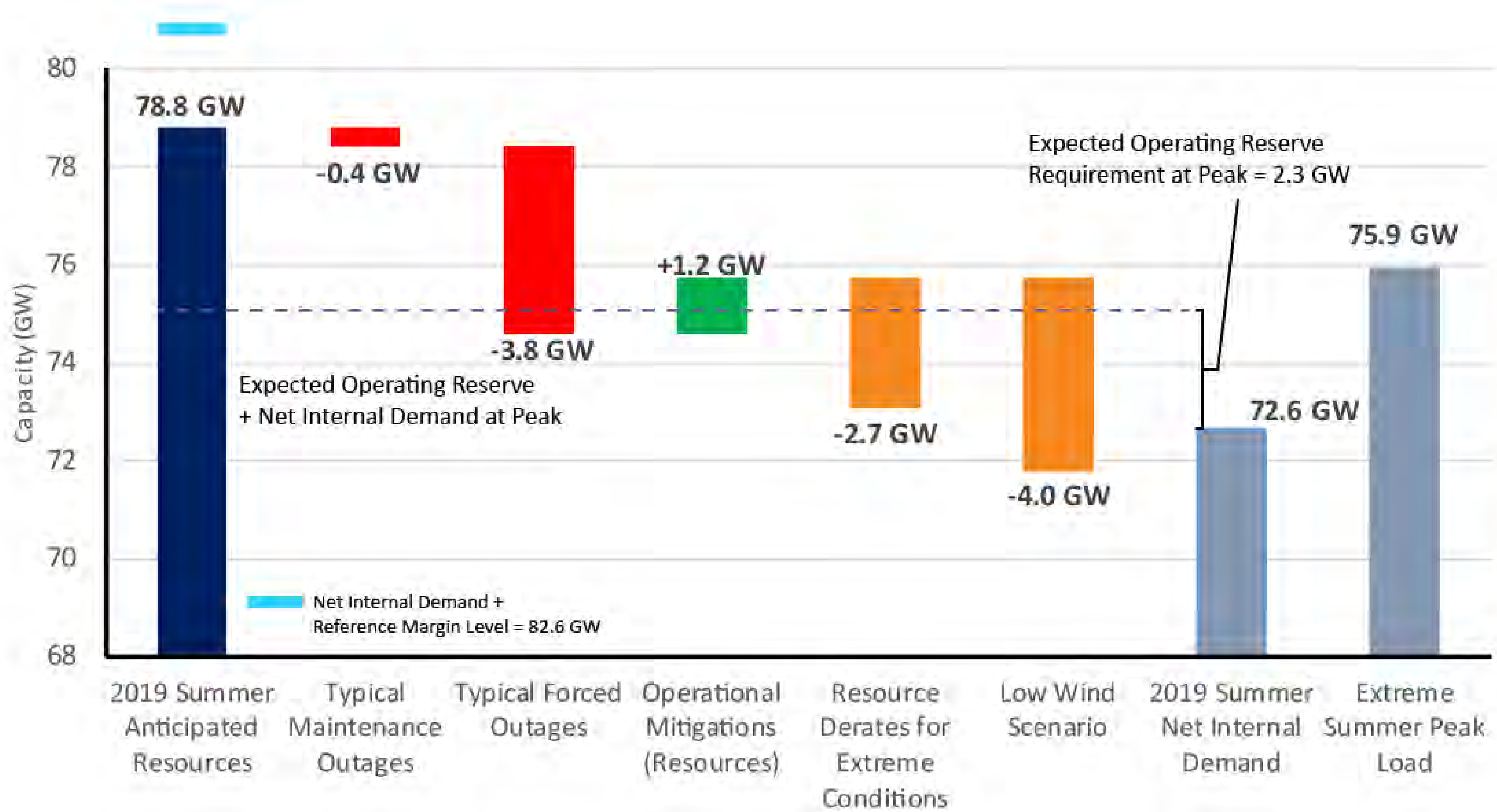
Highlights

- Despite growth in anticipated resources relative to last summer, even higher expected summer peak demand, combined with delays in planned generation projects and the announced mothballing of a 470 MW coal-fired unit, are expected to result in a tighter reserve margin for the upcoming summer.
- Notable transmission improvements include a new 250 MVAr STATCOM expected to be in-service prior to summer in the Far West Texas region to support the rapid growth of oil and gas production load in the Permian Basin. Additionally, a new 345 kV line in Central Texas will be energized in the spring to support the San Antonio area.
- There are no known transmission reliability, fuel supply, or essential reliability service procurement issues projected for the upcoming season. However, delays or cancellations of planned transmission expansion projects, if they occur, may contribute to potential localized reliability concerns.

Charts

The chart on the next page provide potential summer peak demand and resource condition information. The table above presents a standard seasonal assessment and comparison to the previous year's assessment. The waterfall charts on the next page present deterministic scenarios for further analysis of different demand and resource levels with adjustments for normal and extreme conditions. ERCOT determined the adjustments to summer capacity and peak demand based on methods or assumptions that are summarized on the next page. See the Seasonal Risk Scenario Chart Description for more information about the chart.

Seasonal Risk Scenario



The table on page 26 and the chart above provide potential summer peak demand and resource condition information. The table presents a standard seasonal assessment and comparison to the previous year's assessment. The chart presents deterministic scenarios for further analysis of different demand and resource levels, with adjustments for normal and extreme conditions.

Risk Scenario Summary

Observation:

Operating Mitigations and Energy Emergency Alerts may be needed under peak and extreme conditions studied.

Scenario Assumptions (see Table 1 on Page 9 for detailed discussion)

- **Extreme Peak Load:** Based on 2011 historic summer peak load
- **Outages:** A derate for maintenance and forced outages based on the past three year summer periods
- **Operational Mitigations.** Additional resources (e.g., switchable generation resources, additional imports, and voltage reduction) to support maintaining operating reserves, not already counted in SRA reserve margins.

WECC

WECC is responsible for coordinating and promoting BES reliability in the Western Interconnection. WECC's 329 members, which include 38 Balancing Authorities, represent a wide spectrum of organizations with an interest in the BES. Serving an area of nearly 1.8 million square miles and more than 82 million people, it is geographically the largest and most diverse of the NERC Regional Entities. WECC's service territory extends from Canada to Mexico. It includes the provinces of Alberta and British Columbia in Canada, the northern portion of Baja California in Mexico, and all or portions of the 14 western states in between. The WECC assessment area is divided into six subregions: Rocky Mountain Reserve Group (RMRG), Southwest Reserve Sharing Group (SRSG), California/Mexico (CA/MX), the Northwest Power Pool (NWPP), and the Canadian areas of Alberta (WECC AB) and British Columbia (WECC BC). These subregional divisions are used for this study, as they are structured around reserve sharing groups that have similar annual demand patterns and similar operating practices.

WECC Resource Adequacy Data									
Demand, Resource, and Reserve Margins	**WECC AB**	**WECC BC**	**CA/MX**	**NWPP-US**	**RMRG**	**SRSG**	**2018**	**2019**	**2018 vs. 2019 SRA**
Demand Projections	**MW**	**MW**	**MW**	**MW**	**MW**	**MW**	**Total MW**	**Total MW**	**Net Change (%)**
Total Internal Demand (50/50)	11,111	8,432	52,929	47,619	12,636	23,415	154,256	156,142	1.2%
Demand Response: Available	0	0	957	614	225	368	3,569	2,164	-39.4%
Net Internal Demand	11,111	8,432	51,972	47,006	12,411	23,047	150,687	153,979	2.2%
Resource Projections	**MW**	**MW**	**MW**	**MW**	**MW**	**MW**	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	14,560	9,746	61,806	60,056	16,627	31,413	184,981	194,208	5.0%
Tier 1 Planned Capacity	43	152	1,818	1,007	257	684	1,098	3,961	>100%
Net Firm Capacity Transfers	0	0	0	0	0	0	0	0	0.0%
Anticipated Resources	14,603	9,898	63,624	61,063	16,884	32,097	186,079	198,169	6.5%
Existing-Other Capacity	0	0	0	0	0	0	0	0	0.0%
Prospective Resources	14,603	9,898	63,624	61,063	16,884	32,097	186,079	198,169	6.5%
Planning Reserve Margins	**Percent**	**Percent**	**Percent**	**Percent**	**Percent**	**Percent**	**Percent**	**Percent**	**Annual Difference**
Anticipated Reserve Margin	31.4%	17.4%	22.4%	29.9%	36.0%	39.3%	23.5%	28.7%	5.2
Prospective Reserve Margin	31.4%	17.4%	22.4%	29.9%	36.0%	39.3%	23.5%	28.7%	5.2
Reference Margin Level	10.0%	10.0%	12.0%	20.0%	17.0%	15.0%	15.4%	15.4%	0.0

Highlights

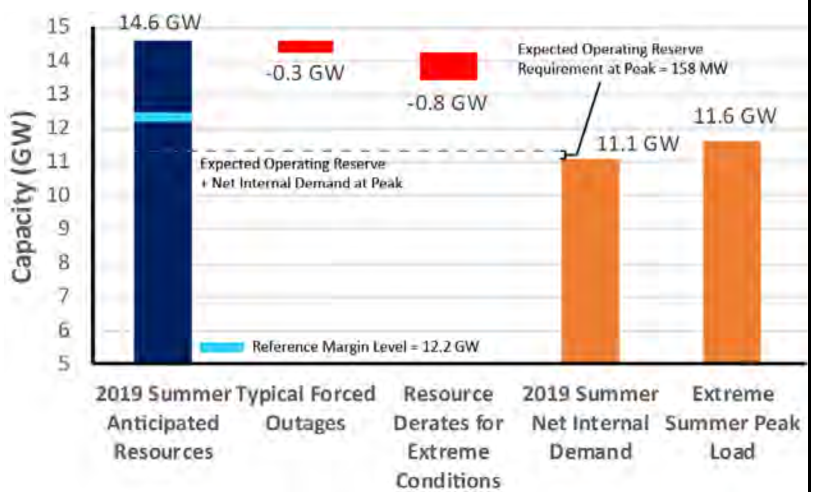
- The existing and Anticipated Reserve Margins for WECC, its subregions, and all zones within are expected to exceed their respective NERC Reference Margin Levels for the upcoming season.
- WECC and NERC are monitoring the transition of Reliability Coordinator (RC) responsibilities in the Western Interconnection as Peak RC winds down toward disestablishment at the end of 2019. NERC-certified RCs are scheduled to assume responsibilities in California (July 1) and British Columbia (September 2). All other areas will complete transition prior to December 31. Certification site visits, shadow-operating periods with Peak RC, and WECC-sponsored RC transition activities are being implemented to manage reliability risks.
- Inventories of the Aliso Canyon natural gas storage facility remain an item of focus for reliability within the Western Interconnection. This condition is being closely monitored by the CAISO, SoCal Gas, and WECC's Situational Awareness group.
- Above-average snowpack levels and the anticipated abundance of hydroelectric generation in California may be used to displace generation from natural-gas-fired units, freeing up more natural gas for Southern California if fuel availability becomes an issue.
- Localized short-term operational issues may occur due to wildfires, if seasonal wildfire predictions are accurate. Due to the widely dispersed nature of the transmission system, outages due to wildfires are generally not widespread.

Charts

The charts on the next page provide potential summer peak demand and resource condition information. The table above presents a standard seasonal assessment and comparison to the previous year's assessment. The waterfall charts on the next page present deterministic scenarios for further analysis of different demand and resource levels with adjustments for normal and extreme conditions. WECC entities determined the adjustments to summer capacity and peak demand based on methods or assumptions that are summarized on the next page. See the **Seasonal Risk Scenario Chart Description** for more information about the charts.

WECC-Alberta

Seasonal Risk Scenario



Risk Scenario Summary

Observation:

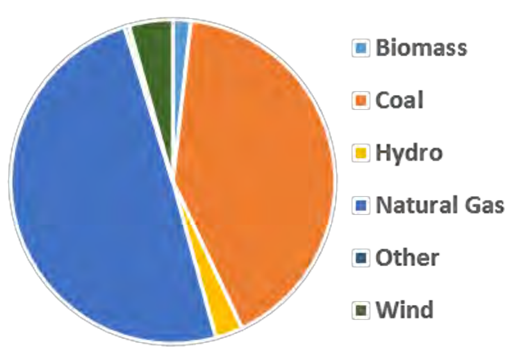
Resources meet operating reserve requirements under studied scenarios.

Scenario Assumptions

- **Extreme Peak Load:** Based on 90/10 demand forecast
- **Forced Outages:** Based on historical data

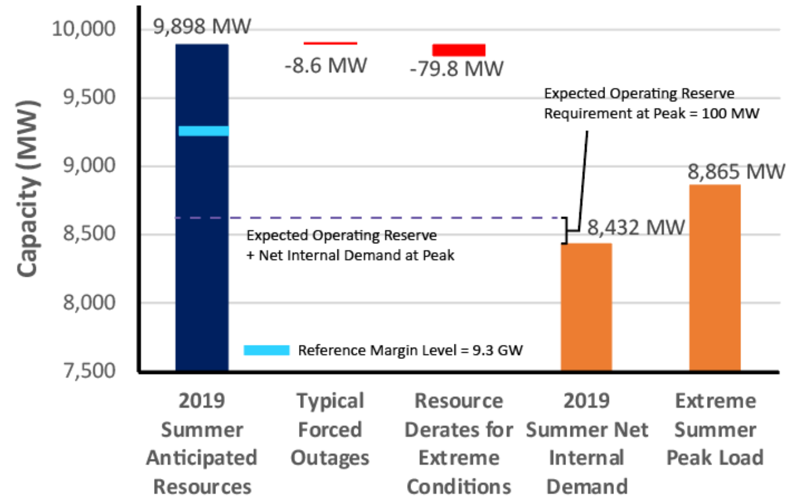
Extreme Derates: Derates for thermal, wind, and solar were developed using the tenth percentile availability curves for the respective resources for the assessment area peak hour

On-Peak Capacity: Generation Mix



WECC-British Columbia

Seasonal Risk Scenario



Risk Scenario Summary

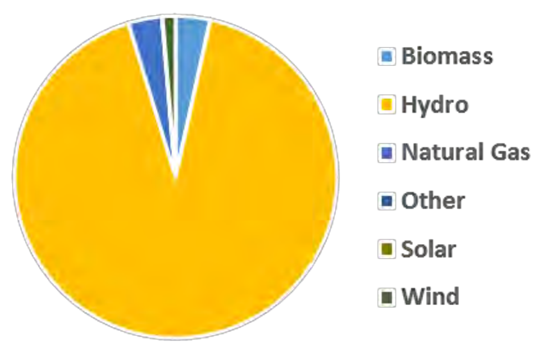
Observation:

Resources meet operating reserve requirements under studied scenarios.

Scenario Assumptions

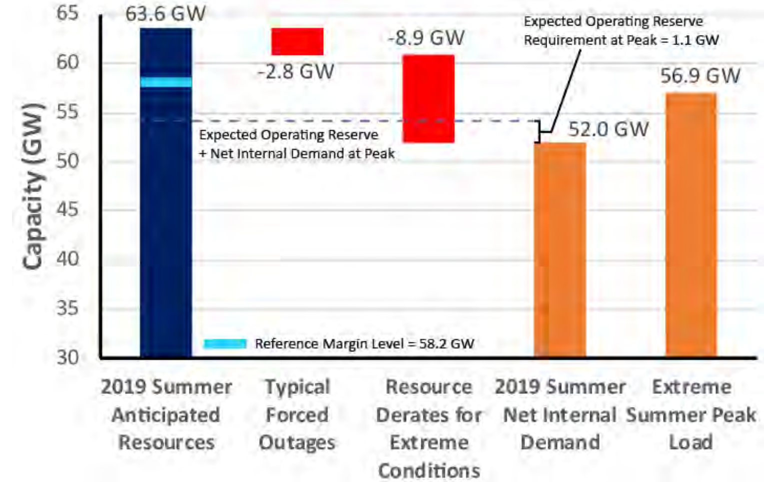
- **Extreme Peak Load:** Based on 90/10 demand forecast
- **Forced Outages:** Based on historical data
- **Extreme Derates:** Derates for thermal, wind, and solar were developed using the tenth percentile availability curves for the respective resources for the assessment area peak hour

On-Peak Capacity: Generation Mix



WECC-California / Mexico

Seasonal Risk Scenario



Risk Scenario Summary

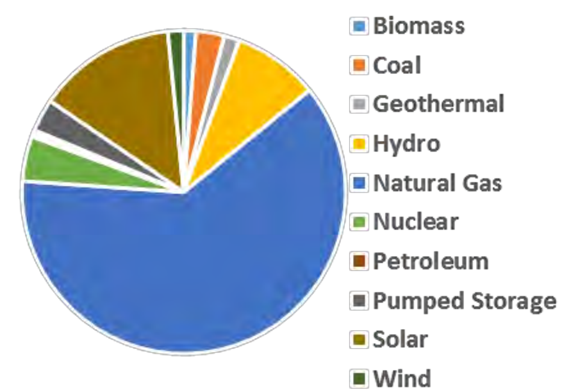
Observation:

Resources meet operating reserve requirements for typical outage conditions, peak load, and extreme peak loads. Extreme outages may result in insufficient resources at peak load.

Scenario Assumptions

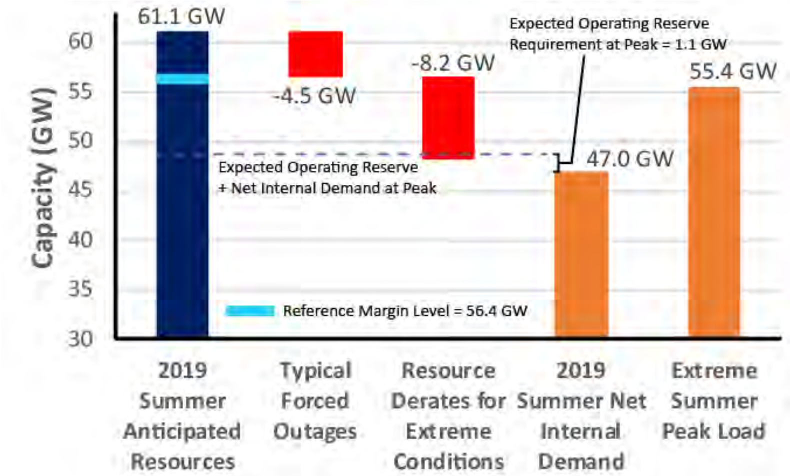
- **Extreme Peak Load:** Based on 90/10 demand forecast
- **Forced Outages:** Based on historical data
- **Extreme Derates:** Derates for thermal, wind, and solar were developed using the tenth percentile availability curves for the respective resources for the assessment area peak hour

On-Peak Capacity: Generation Mix



WECC-Northwest Power Pool

Seasonal Risk Scenario



Risk Scenario Summary

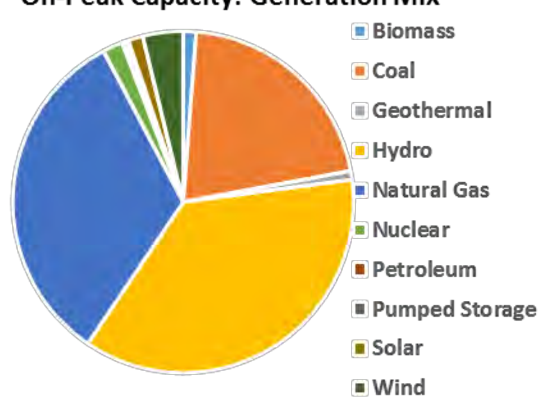
Observation:

Resources meet operating reserve requirements for typical outage conditions, peak load, and extreme peak loads. Extreme outages may result in insufficient resources at peak load.

Scenario Assumptions

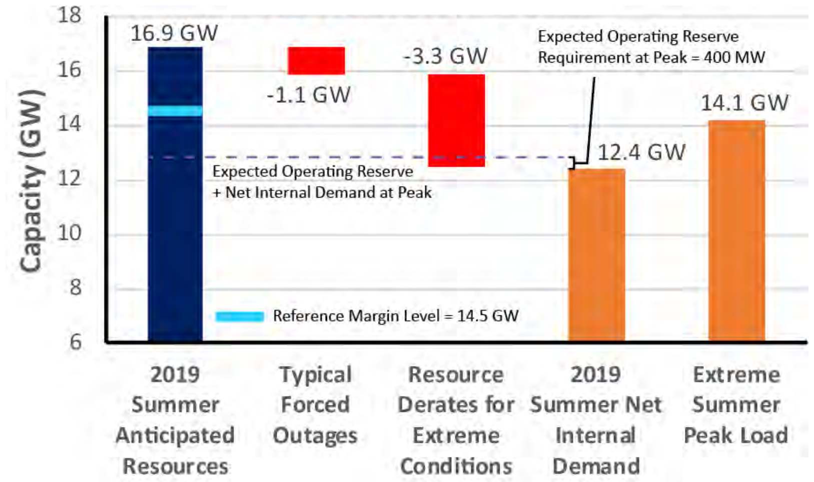
- **Extreme Peak Load:** Based on 90/10 demand forecast
- **Forced Outages:** Based on historical data
- **Extreme Derates:** Derates for thermal, wind, and solar were developed using the tenth percentile availability curves for the respective resources for the assessment area peak hour

On-Peak Capacity: Generation Mix



WECC-Rocky Mountain Reserve Sharing Group

Seasonal Risk Scenario



Risk Scenario Summary

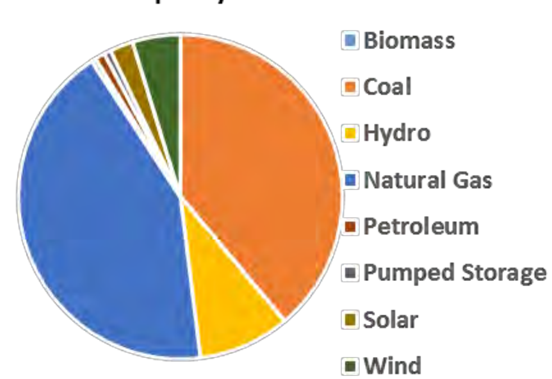
Observation:

Resources meet operating reserve requirements for typical outage conditions, peak load, and extreme peak loads. Extreme outages may result in insufficient resources at peak load.

Scenario Assumptions

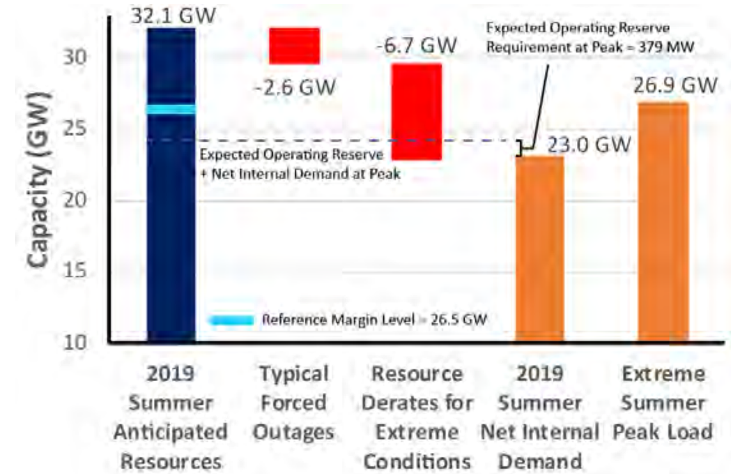
- **Extreme Peak Load:** Based on 90/10 demand forecast
- **Forced Outages:** Based on historical data
- **Extreme Derates:** Derates for thermal, wind, and solar were developed using the tenth percentile availability curves for the respective resources for the assessment area peak hour

On-Peak Capacity: Generation Mix



WECC-Southwest Reserve Sharing Group

Seasonal Risk Scenario



Risk Scenario Summary

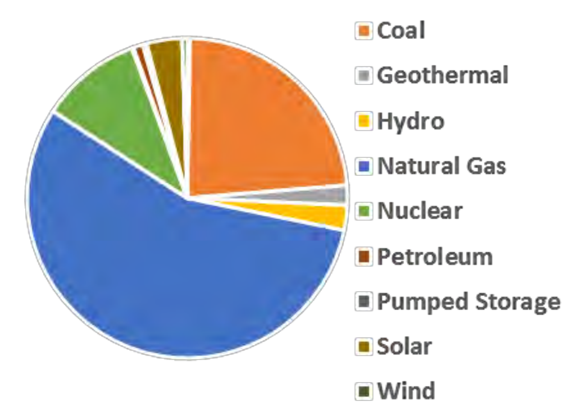
Observation:

Resources meet operating reserve requirements for typical outage conditions, peak load, and extreme peak loads. Extreme outages may result in insufficient resources at peak load.

Scenario Assumptions

- **Extreme Peak Load:** Based on 90/10 demand forecast
- **Forced Outages:** Based on historical data
- **Extreme Derates:** Derates for thermal, wind, and solar were developed using the tenth percentile availability curves for the respective resources for the assessment area peak hour

On-Peak Capacity: Generation Mix



Data Concepts and Assumptions

The table below explains data concepts and important assumptions used throughout this assessment.

General Assumptions

- Reliability of the interconnected BPS is comprised of both adequacy and operating reliability.
  - Adequacy is the ability of the electric system to supply the aggregate electric power and energy requirements of the electricity consumers at all times while taking into account scheduled and reasonably expected unscheduled outages of system components.
  - Operating reliability is the ability of the electric system to withstand sudden disturbances such as electric short-circuits or unanticipated loss of system components.
- The reserve margin calculation is an important industry planning metric used to examine future resource adequacy.
- All data in this assessment is based on existing federal, state, and provincial laws and regulations.
- Differences in data collection periods for each assessment area should be considered when comparing demand and capacity data between year-to-year seasonal assessments.
- *2018 Long-Term Reliability Assessment* data has been used for most of this 2019 assessment period, augmented by updated load and capacity data.
- A positive net transfer capability would indicate a net importing assessment area; a negative value would indicate a net exporter.

Demand Assumptions

- Electricity demand projections, or load forecasts, are provided by each assessment area.
- Load forecasts include peak hourly load[10], or total internal demand, for the summer and winter of each year.[11]
- Total internal demand projections are based on normal weather (50/50 distribution[12]) and are provided on a coincident[13] basis for most assessment areas.
- Net internal demand is used in all reserve margin calculations, and it is equal to total internal demand then reduced by the amount of controllable and dispatchable demand response projected to be available during the peak hour.

Resource Assumptions

Resource planning methods vary throughout the North American BPS. NERC uses the following categories to provide a consistent approach for collecting and presenting resource adequacy:

Anticipated Resources:

- **Existing-Certain Capacity**: included in this category are commercially operable generating units, or portions of generating units, that meet at least one of the following requirements when examining the period of peak demand for the summer season: unit must have a firm capability and have a power purchase agreement (PPA) with firm transmission that must be in effect for the unit; unit must be classified as a designated network resource; and/or where energy-only markets exist, unit must be a designated market resource eligible to bid into the market.
- **Tier 1 Capacity Additions**: includes capacity that either is under construction or has received approved planning requirements.
- **Net Firm Capacity Transfers (Imports minus Exports)**: transfers with firm contracts.

Prospective Resources: Includes all anticipated resources, plus the following:

Existing-Other Capacity: included in this category are commercially operable generating units, or portions of generating units, that could be available to serve load for the period of peak demand for the summer or summer season but do not meet the requirements of existing-certain.

Reserve Margin Definitions

Reserve Margins: the primary metric used to measure resource adequacy; it is defined as the difference in resources (anticipated or prospective) and net internal demand then divided by net internal demand, shown as a percentage:

[10] *Glossary of Terms* Used in NERC Reliability Standards

[11] The summer season represents June–September and the winter season represents December–February.

[12] Essentially, this means that there is a 50% probability that actual demand will be higher and a 50% probability that actual demand will be lower than the value provided for a given season/year.

[13] Coincident: The sum of two or more peak loads that occur in the same hour. Noncoincident: The sum of two or more peak loads on individual systems that do not occur in the same time interval. Meaningful only when considering loads within a limited period of time, such as a day, a week, a month, a heating or cooling season, and usually for not more than one year. SERC and FRCC calculate total internal demand on a noncoincidental basis

Seasonal Risk Scenario Chart Description

Each assessment area performed an operational risk analysis that was used to produce the seasonal risk scenario charts in the **Regional Assessment Dashboards**. The chart presents deterministic scenarios for further analysis of different resource and demand levels. The left blue column shows Summer Anticipated Resources (from the Resource Adequacy Data table). The two orange columns at the right show two demand scenarios: normal peak net internal demand from the Resource Adequacy Data table and an extreme summer peak demand, both determined by the assessment area. The middle red or green bars show adjustments that are applied cumulatively to the Summer Anticipated Resources, such as the following:

- Reductions for typical generation outages (maintenance and forced, not already accounted for in Summer Anticipated Resources)
- Reductions that represent additional outage or performance derating by resource type for extreme, low-probability conditions (e.g., drought condition impacts on hydroelectric generation, low-wind scenario affecting wind generation, fuel supply limitations, or extreme temperature conditions resulting in reduced thermal generation output)
- Additional capacity resources that represent quantified capacity from operational procedures, if any, that are made available during scarcity conditions

Not all assessment areas have the same categories of adjustments to anticipated resources. Furthermore, each assessment area determined the adjustments to summer capacity based on methods or assumptions that are summarized below the chart. Methods and assumptions differ by assessment area and may not be comparable.

The chart enables evaluation of resource levels against levels of expected operating reserve requirement and the forecasted demand. Further, the effects from low-probability, extreme events can also be examined by comparing resource levels after applying extreme-scenario derates and/or extreme summer peak demand. Because such extreme scenario analysis depicts the cumulative impact resulting from the occurrence of multiple low-probability events, the overall likelihood of the scenario is very low.

2020 Summer Reliability Assessment

June 2020

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 Region while associated Transmission Owners/Operators participate in another.

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

About this Report

NERC's *2020 Summer Reliability Assessment* (SRA) identifies, assesses, and reports on areas of concern regarding the reliability of the North American BPS for the upcoming summer season. In addition, the SRA presents peak electricity demand and supply changes and highlights any unique regional challenges or expected conditions that might impact the BPS. The reliability assessment process is a coordinated reliability evaluation between the Reliability Assessment Subcommittee (RAS), the Regions, and NERC staff. This report reflects NERC's independent assessment and is intended to inform industry leaders, planners, operators, and regulatory bodies so they are better prepared to take necessary actions to ensure BPS reliability. This report also provides an opportunity for the industry to discuss plans and preparations to ensure reliability for the upcoming summer period.

In April 2020, NERC published its *Special Report Pandemic Preparedness and Operational Assessment: Spring 2020* to advise electricity stakeholders about elevated risk to electric reliability as a result of the global health crisis.[1] NERC continues to assess risks to the reliability and security of the BPS from the global health crisis and reports on industry actions and preparedness in this SRA.

[1] https://www.nerc.com/pa/rrm/bpsa/Alerts%20DL/NERC_Pandemic_Preparedness_and_Op_Assessment_Spring_2020.pdf

Findings

NERC's annual SRA covers the Summer 2020 (June–September) period. This assessment provides an evaluation of resource and transmission system adequacy necessary to meet projected summer peak demands. In addition to assessing resource adequacy, the SRA monitors and identifies potential reliability issues of interest and regional topics of concern. In 2020, there is heightened uncertainty in demand projections stemming from the progression of the coronavirus (COVID-19) pandemic and the response of governments, society, and the electricity industry. The following key findings represent NERC's independent evaluation of electric generation and transmission capacity as well as potential operational concerns that may need to be addressed for the upcoming summer:

- **Sufficient capacity resources are expected to be in-service for the upcoming summer.** In all areas, with the exception of ERCOT, the Anticipated Reserve Margin meets or surpasses the Reference Margin Level, indicating that planned resources in these areas are adequate to manage risk of a capacity deficiency under normal conditions.[2] Assessment areas are prepared to meet potential peak demand with or without pandemic-related demand reductions. Should pandemic related restrictions continue through the summer, peak demand is expected to be lower than forecast.
  - **Texas RE-ERCOT**. Projections for increased peak demand in ERCOT indicate the potential for energy emergency alerts (EEAs) during summer peak periods. Prior to the arrival of COVID-19 and the resulting mitigations that have impacted electricity demand, ERCOT planners were expecting similarly tight operating conditions to those faced in Summer 2019. The ERCOT Anticipated Reserve Margin has risen from 8.5% in Summer 2019 to 12.9% for the upcoming summer. The increase in reserve margin is driven by the addition of over 1.9 GW of on-peak resource capacity. ERCOT's forecast of peak demand for Summer 2020 is also forecasted to grow in 2020, but higher-growth projections have been tempered in recent months by COVID-19 economic impacts. The potential for EEAs and operating mitigation at peak load remains.
- **Maintenance and preparations for summer operations impacted by pandemic.** As summer peak operating season approaches each year, generator and transmission owners and operators engage in extensive preparations, including preventive maintenance, supply stocking, and training programs. However, many normal efforts have been impinged by the global pandemic. To avoid the risk of failing to complete maintenance on-time, some owners and operators have deferred or cancelled preseason maintenance in response to pandemic-related issues. Monitoring the progress of ongoing efforts to prepare staff and equipment for summer will be important to ensuring the availability of anticipated resources to meet electricity demand. Furthermore, system operators must be prepared to address demand forecast uncertainty and potentially challenging operating conditions as a result of low demand on the system.
- **Protecting critical electric industry workforce during the COVID-19 pandemic remains a priority for reliability and resilience.** System and generation plant operators have implemented operating postures and personnel restrictions prescribed by their pandemic plans in order to protect essential personnel and support reliable operations. Many of these measures will need to be maintained for the foreseeable future. There is a continuing risk that control centers or plants could be temporarily shut down if a significant number of operators or plant employees test positive for COVID-19 despite preparedness efforts. When relaxations can be implemented, operators will likely need to stay postured to return to heightened protections in response to dynamic public health conditions.
- **Late-summer wildfire season in western United States and Canada poses risk to BPS reliability.** Government agencies warn of the potential for above-normal wildfire risk beginning as early as June in parts of the Western United States as well as Central and Western Canada.[3] Operation of the BPS can be impacted in areas where wildfires are active as well as areas where there is heightened risk of wildfire ignition due to weather and ground conditions.

[2] For more information, see the description of the "Reference Margin Level" in the **Data Concepts and Assumptions** section of this report or refer to NERC's *Long-term Reliability Assessment*: https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_LTRA_2019.pdf

[3] See North American Seasonal Fire Assessment and Outlook, April 2020: https://www.predictiveservices.nifc.gov/outlooks/NA_Outlook.pdf

Resource Adequacy

The Anticipated Reserve Margin, which is based on available resource capacity, is a metric used to evaluate resource adequacy by comparing the projected capability of anticipated resources to serve forecasted peak demand.[4] Large year-to-year changes in anticipated resources or forecasted peak demand (net internal demand) can greatly impact Planning Reserve Margin calculations. Other than in ERCOT, all assessment areas have sufficient Anticipated Reserve Margins to meet or exceed their Reference Margin Level for Summer 2020 as shown in the **Figure 1**.

Although the pandemic introduces significant uncertainty into demand and some risk to generation resource availability, as discussed in the following section, the projections below provide indication that adequate resources are available to meet peak demand.

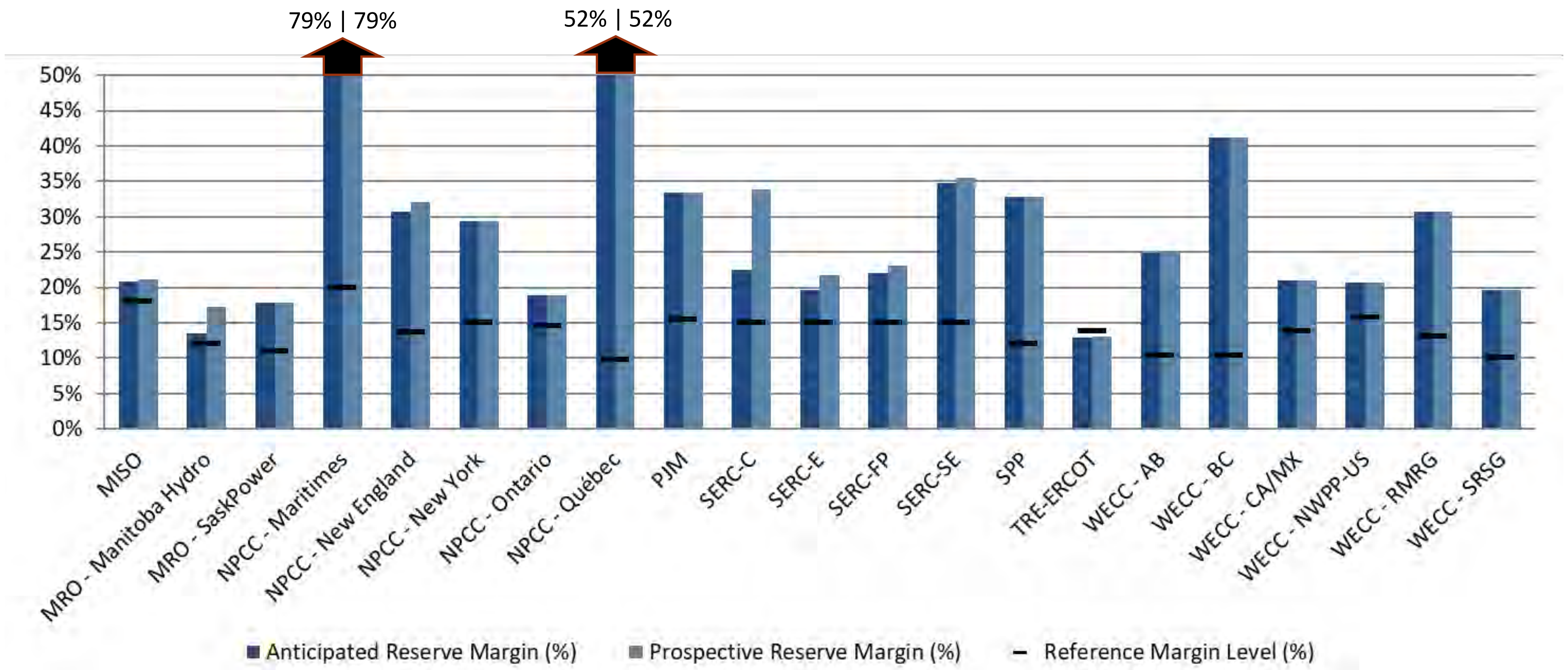


Figure 1: Summer 2020 Anticipated/Prospective Reserve Margins Compared to Reference Margin Level

[4] Generally, anticipated resources include generators and firm capacity transfers that are expected to be available to serve load during electrical peak loads for the season. Prospective Resources are those that could be available but do not meet criteria to be counted as Anticipated Resources. Refer to the **Data Concepts and Assumptions** section for additional information on Anticipated/Prospective Reserve Margins, Anticipated/Prospective Resources, and Reference Margin Levels.

Changes from Year-to-Year

Understanding the changes from year-to-year is an essential step in assessing an area on a seasonal basis. Figure 2 provides the relative change from the Summer 2019 to the Summer 2020 period. The Regional Assessment Dashboards provide details of the demand and resource components that make up the anticipated reserve margins for each assessment area. In the following areas, anticipated reserve margin changed by more than five percentage points: none of the changes result in a resource adequacy concern for the upcoming summer.

- **NPCC Maritimes:** The retirements of one coal-fired generator and two biomass generators contributed to lower anticipated reserve margins.
- **NPCC Ontario:** Anticipated Reserve Margins decrease due to nuclear unit refurbishments and reductions in the contribution of demand response and hydro.
- **WECC BC and WECC SRSG:** Reserve margin changes are attributed to revised variable generation capacity factors and changes in peak-hour demand.
- **WECC NWPP-US:** Forecasted summer peak demand increased by 6,300 MW (13.5%) while resource levels were relatively stable, resulting in lower reserve margins.

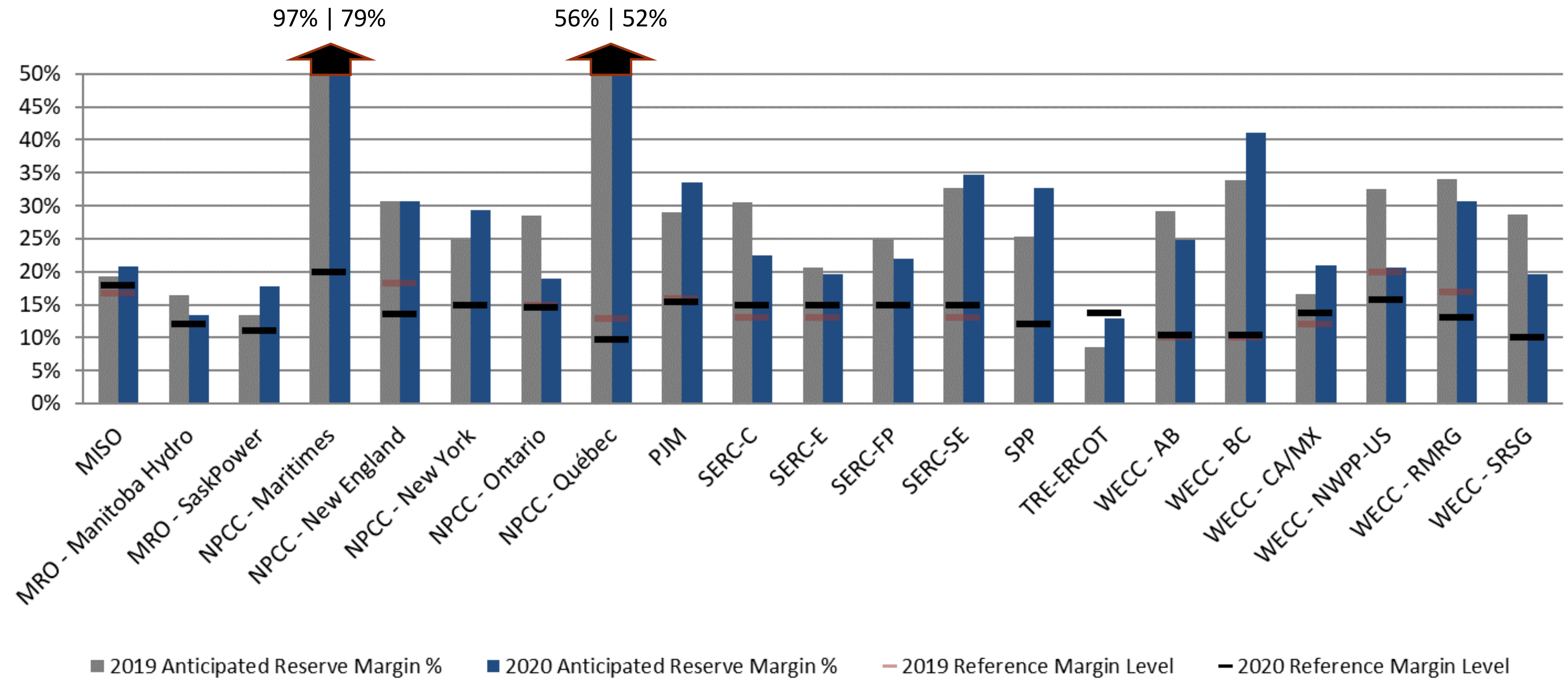


Figure 2: Summer 2019 to Summer 2020 Anticipated Reserve Margins Year-to-Year Change

Internal Demand

The changes in forecasted Net Internal Demand for each assessment area are shown in Figure 3.[5] Assessment areas develop these forecasts based on historic load and weather information as well as other long-term projections.

Most assessment area demand projections in this assessment have not been decreased to account for COVID-19 mitigation measures. Although government and societal responses to halt the spread of the coronavirus (i.e., shelter-in-place orders, minimal travel, and restrictions on public gatherings) have resulted in near-term decreased electricity demand, impact projections for summer are difficult to forecast. ERCOT is an exception, where planners reduced the pre-seasonal peak demand forecast by 1,496 MW but still anticipate potentially record-setting peak demand. The demand projections used in Figure 3 and elsewhere throughout this report are likely higher than would be expected with pandemic mitigation completely factored in.

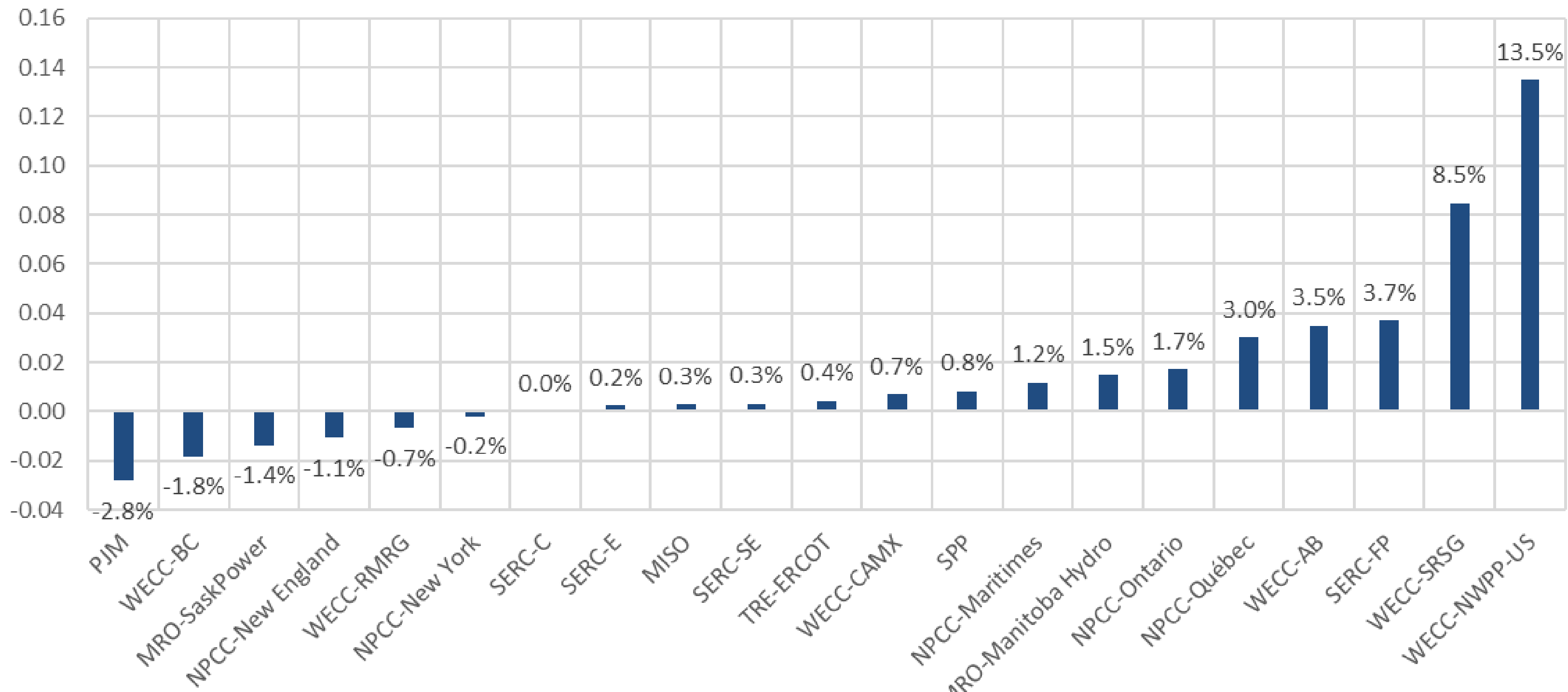


Figure 3: Change in Net Internal Demand: 2020 Summer Forecast Compared to 2019 Summer Forecast

[5] Changes in modeling and methods may also contribute to year-to-year changes in forecasted net internal demand projections.

Pandemic Preparedness and Operational Assessment—Summer 2020

The global health crisis has elevated the electric reliability risk profile due to potential workforce disruptions, supply chain interruptions, and increased cyber security threats. In April, NERC released its *Pandemic Preparedness and Operational Assessment – Spring 2020* (special report) to advise electricity stakeholders of the reliability considerations and assess the operational preparedness of the BPS owners and operators during pandemic conditions in April and May 2020. In its special report, NERC did not identify any specific threat or degradation to the reliable operation of the BPS for the spring time frame. The ERO continues to assess risks and conditions and is pursuing all available avenues to continue coordination with federal, state, and provincial regulators as well as work with industry to identify reliability implications and lessons learned.

Increased Reliability Risk Profile by Operating Period

Spring 2020	Summer 2020	Long-Term
• No specific reliability issue identified • Potential workforce disruptions • Supply chain interruption • Increased cyber security threat and monitoring • Different system conditions including lower demands and higher voltages. • System operators under sequester • Noncritical staff are remote	• Continued potential for workforce disruptions; support service disruption • Potential equipment and fuel supply chain disruptions • Deferred generation maintenance and other factors impacting unit availability • Generation in-service dates	• Potential changes to generation and transmission in-service dates • Increased remote operation of non-critical staff • Changes to pandemic preparedness and operating plans based on lessons learned Note: a more granular assessment will be Included in NERC's 2020 Long-Term Reliability Assessment

Since the start of the widening coronavirus infection in North America in February 2020, registered entities have taken steps from pandemic plans and industry advisories to maintain the reliability and security of the BPS. In March 2020, the Electricity Subsector Coordinating Council (ESCC) issued the first version of the *ESCC Resource Guide*[6] as a resource for electric power industry leaders to guide informed localized decisions in response to the COVID-19 global health emergency; it is updated on a regular basis as new approaches, planning considerations, and issues develop. The guide highlights data points, stakeholders, and options to consider in making decisions about operational status while protecting the health and safety of employees, customers, and communities. Sharing experiences and expertise helps users of the guide to make independent, localized decisions aimed at reducing negative impacts to the continent's power supply during the COVID-19 global pandemic. In addition to immediate measures designed to protect critical operations, personnel, and functions, entities are working to minimize risk to resource and BPS equipment availability, assure fuel supplies, and prepare operating personnel for peak season.

Maintenance Preparations for Summer Impacted

Since electricity demand is lower in a typical spring season than peak summer and winter periods, Transmission and Generator Owners normally have the opportunity to schedule maintenance and address training needs. Pandemic response and mitigation plans at national, state, provincial, and local levels can impact maintenance efforts by disrupting the flow of personnel and supply chains. Some delays to transmission projects due to disrupted travel of specialized contractors has been reported. To avoid the risk of failing to complete maintenance on time, some owners and operators have deferred or cancelled preseason maintenance in response to pandemic-related issues as can be seen by the MISO area example in **Figure 4**.

[6] https://www.electricitysubsector.org/

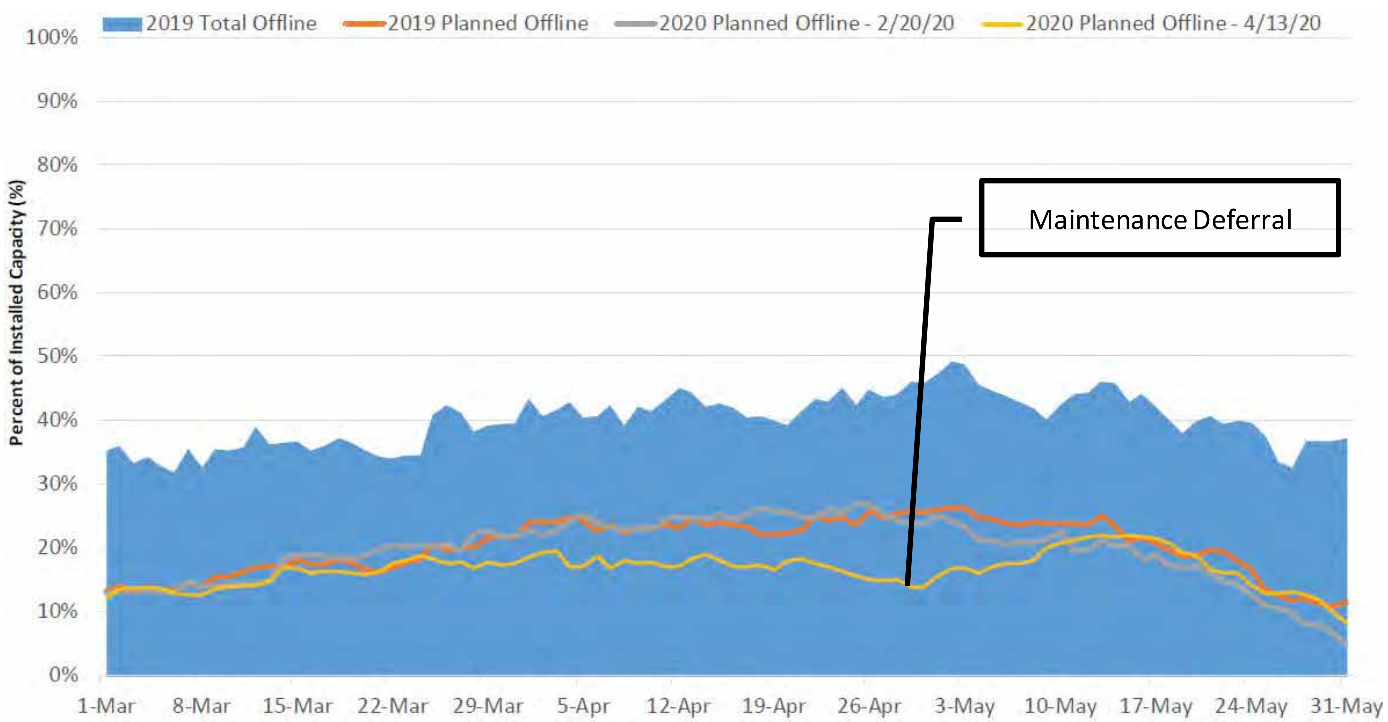


Figure 4: Generation Capacity Planned to be Off-line in MISO through May 31, 2020 (Scheduled February 20 and April 13, 2020).

In ERCOT, planners observed a higher-than-normal volume of generator maintenance outages in late March/early April possibly due to Generator Owners accelerating maintenance schedules to get ahead of potential supply chain or personnel delays. Planners and operators continue to manage schedules of equipment outages into the summer season to ensure sufficient resource availability and transmission system readiness. Maintenance that would have been performed prior to summer but is deferred can increase the risk of forced outages.

Operators in areas where a large portion of generators have deferred maintenance could experience higher-than-expected forced outages that could lead to generation supply deficiencies during periods of peak demand. NERC is implementing codes for its Generator Availability Data System (GADS) that will support collection of data on outages with pandemic causes for use in analyzing reliability impacts in later months.[7]

Electricity supply risk can be compounded by risks to the generator and to their supply of fuel. Natural-gas-fired generators can be at risk to fuel supply infrastructure disruption from mechanical or other issues; planners and operators in areas with impacted preseason maintenance are implementing measures to mitigate such risks. For example, in ISO-NE, the Electric/Gas Operations Committee has been conducting weekly meetings to determine and assess pandemic impacts to pipelines. The ISO has also increased surveying of generator owners and operators to assess outage risks.

[7] Information about GADS: https://www.nerc.com/pa/RAPA/gads/Pages/GeneratingAvailabilityDataSystem-(GADS).aspx

Demand Impacts Vary and Cause Forecast Uncertainty

The pandemic is negatively impacting electricity demand in many parts of North America just as it has elsewhere around the world. Prior to summer, when government stay-at-home orders and societal response were at their highest, some areas reported as much as 15% drop off in peak demand. However, these observed demand impacts varied across North America and in some areas were negligible. Throughout the pandemic, many independent system operators and regional transmission operators have periodically reported on demand impacts.[8] In most areas, weather continues to be the predominant factor in electricity demand. Diminished peak demand resulting from pandemic does not pose any meaningful risk to reliability for the summer season.

Many areas are experiencing variations in hourly load shapes as a result of changing societal behaviors and mechanisms implemented to halt the spread of the coronavirus. In general, these areas are seeing below-normal ramp in demand in morning hours and lower evening demand as can be seen in **Figure 5**. Changes to pre-pandemic patterns can affect accuracy of day-ahead demand forecasts that are relied upon to ensure resources are available for each hour of the day. In recent years, demand and resource forecasting has become more complex—and more critical—as the generation resource mix has changed to include higher levels of variable generation, and load shape has changed with increasing solar photovoltaic (PV) resources. When operating entities began observing discrepancies between predicted and actual demand as a result of pandemic behavior, many instituted measures designed to improve the accuracy of forecasts made available to system operators. In MISO and other ISOs, support teams have increased the frequency of short-term demand forecast simulations.

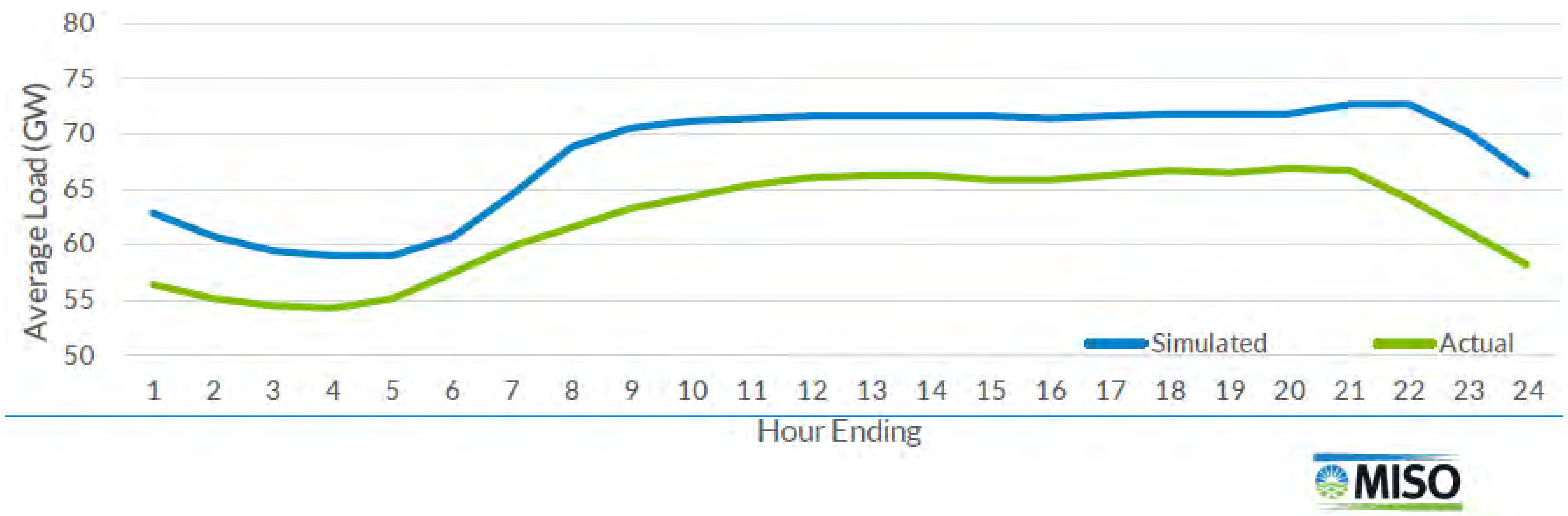


Figure 5: Average Simulated and Actual Load in MISO Area for April 4–10, 2020

[8] For example, see reports from ERCOT and CAISO: http://www.caiso.com/Documents/COVID-19-Impacts-ISOLoadForecast-Presentation.pdf
http://www.ercot.com/content/wcm/lists/200201/ERCOT_COVID-19_Analysis_FINAL.pdf

Potential Demand and Resource Challenges for System Operators

Where pandemic restrictions persist through the summer, system operators could encounter difficult system characteristics, such as increased impact of DERs on load profiles, distribution reverse power flows, higher than usual operating voltages, and minimum demands at all-time lows. Operating challenges such as these need to be addressed in real-time and often by using complex tools for studying dynamic system conditions.

The effect of distributed energy resources (DERs) on system performance can become more pronounced as synchronous generation can be replaced on the system during periods of lower minimum demand; operators could face challenges in maintaining sufficient amounts of frequency-responsive reserves necessary to regulate or arrest changes in frequency. Typically, DER effects on the system are more pronounced in the spring when milder temperatures reduce air conditioning load and increase efficiency in solar PV modules. With potentially lower demand on the system as a result of the pandemic, these conditions could extend into early summer. In areas with higher DER penetration (e.g., California and North Carolina), minimum loads and reverse power flows from the distribution system can cause some challenges for system operators.

Operators in some areas may also have to contend with how a reduction in industrial and commercial loads could affect operating strategies and emergency plans. The potential lack of industrial and commercial load could alter underfrequency or undervoltage load shedding plans that rely on tripping these loads as well as demand response programs that may be relied on to support emergency operations.

Operating Reliability Considerations

- Increased uncertainty in demand projections and daily use
- Potential for increased forced outages due to deferred maintenance, staff unavailability, or limited supplies and/or fuel
- Higher than usual operating voltages
- Light load conditions
- Reverse power flow and increased penetration levels of DERs
- Potential for reduced effectiveness in underfrequency/voltage load shedding schemes as industrial and commercial load may not be online

Utility Crews and Operators Must Stay Postured for Reliability, Security, and Resilience

As the coronavirus crisis unfolds in the lead up to summer, the industry is preparing to operate with a significantly smaller workforce, an encumbered supply chain, and limited support services for an extended and unknown period of time. Vigilance to cyber security threats intensifies as risks are elevated due to a greater reliance on remote working arrangements. The business continuity and pandemic plans developed by the different operating entities are designed to protect the people working for them and to ensure critical electricity operations and infrastructure are supported properly throughout an emergency.

Protecting critical electric industry workforce during the COVID-19 pandemic remains a priority for reliability and resilience. System and Generator Operators have implemented operating postures and personnel restrictions prescribed by their pandemic plans in order to protect essential personnel and support reliable operations. Many of these measures will need to be maintained for the foreseeable future. There is a continuing risk that control centers or plants could be temporarily shut down if a significant number of operators or plant employees test positive for COVID-19 despite preparedness efforts, including employee sequestration. As of April, many entities had begun developing return to work plans; however, the majority of entities indicated that they expected to maintain protective protocols for operating personnel through summer and beyond. When relaxations can be implemented, operators will likely need to stay postured to return to heightened protections if warranted by public health conditions.

An important component of BPS resilience and recovery from hurricanes and major storms is the effective mutual assistance rendered by organizations from outside the storm-affected areas. The comprehensive plans in place to rapidly deploy support teams and equipment take on even greater complexity for the 2020 North American hurricane season (May–November) due to the need to safeguard personnel from coronavirus infection. In April, the ESCC updated its *Resource Guide* to provide lessons learned from the experience of the utilities, electric cooperatives, and investor-owned electric companies affected by a series of storms in late March and early April of this year. Lessons learned include considerations for maintaining social distancing at all times, planning for personnel protection equipment needs, and increased need for local logistical and coordination personnel to support a decentralized response.[9]

[9] See *ESCC Resource Guide*, Version 7, April 27, 2020, p. 47–48.

Cyber Security Risk and Information Sharing

Electricity and other critical infrastructure sectors face elevated cyber security risks arising from the COVID-19 pandemic in addition to ongoing risks. Opportunistic actors are attempting to find and exploit new vulnerabilities that arise as entities shift work processes and locations to maintain business continuity. The Electricity Infrastructure Sharing and Analysis Center (E-ISAC) continues to exchange information with its members and has posted communications and guidance from the ESCC and from government partners, and other advisories on its Portal; members are encouraged to check in regularly to receive updates. The E-ISAC also continues to provide information regarding emerging cyber threats; these include attacks on conferencing and remote access infrastructure, disinformation, and spear phishing campaigns attempting to harvest credentials and other information. Members are encouraged to actively share information regarding threats and other malicious activities with the E-ISAC to enable broader communication with other sector participants and government partners.

Operational Risks Highlighted for Summer 2020

Seasonal Operational Risk Assessments of Resource and Demand Scenarios

Areas can face energy shortfalls despite having Planning Reserve Margins that exceed Reference Margin Levels. Operating resources may be insufficient during periods of peak demand for reasons that could include generator scheduled maintenance, forced outages due to normal and more extreme weather conditions and loads, and low-likelihood conditions that affect generation resource performance or unit availability, including constrained fuel supplies. The **Regional Assessment Dashboards** section in this report includes a seasonal risk scenario for each area that illustrates potential variation in resource and load as well as the potential effects that operating actions can have to mitigate shortfalls in operating reserves when insufficiencies occur. **Figure 6** shows an example seasonal risk assessment for the Southwest Power Pool (SPP) area that NERC developed using SRA data. A description of resource and demand variables is found in **Table 1**.

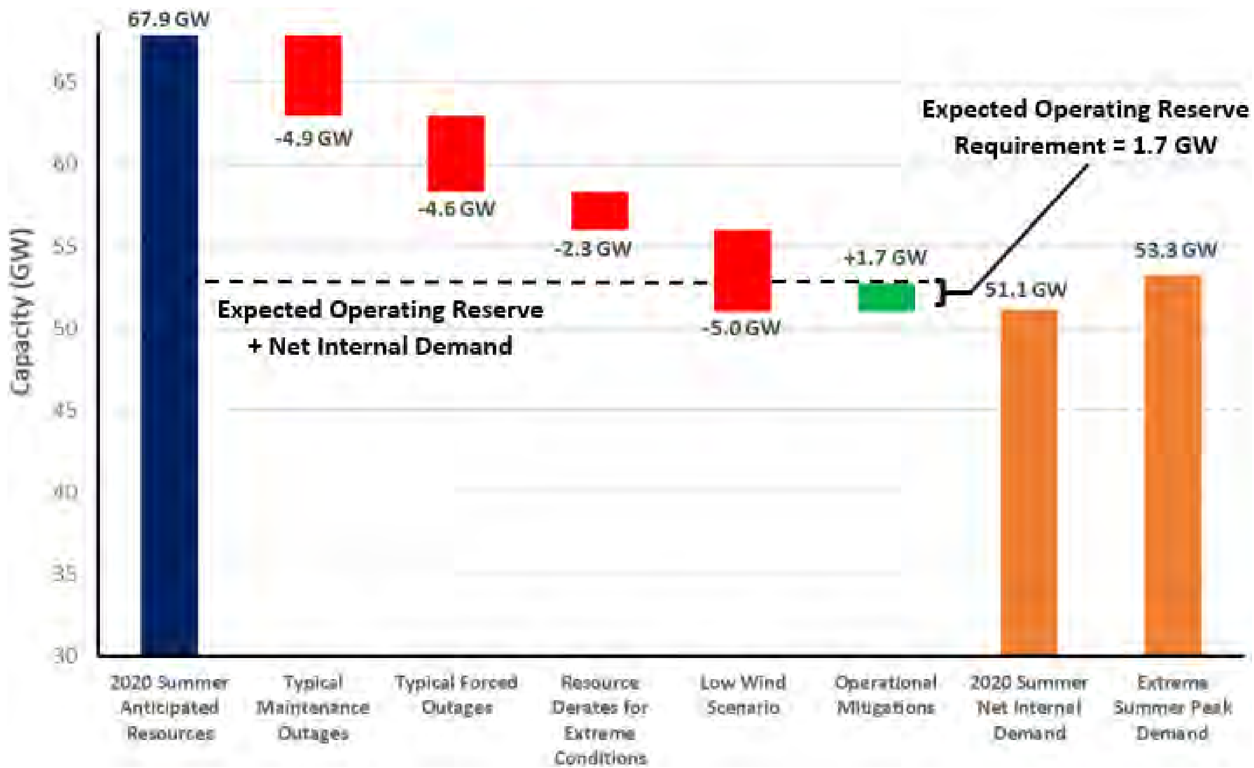


Figure 6: SPP Assessment Area Seasonal Risk Assessment

About the Seasonal Risk Assessment

The operational risk analysis shown in Figure 6 provides a deterministic scenario for understanding how various factors affecting resources and demand can combine to impact overall resource adequacy. Adjustments are applied cumulatively to anticipated capacity, such as reductions for typical generation outages (maintenance and forced not already accounted for in anticipated resources) and additions that represent the quantified capacity from operational tools, if any, that are available during scarcity conditions but have not been accounted for in the SRA reserve margins.

Resources throughout the scenario are compared against expected operating reserve requirements that are based on peak load and normal weather. The effects from low-probability, extreme events are also factored in through additional resource derates or extreme resource scenarios and extreme summer peak load conditions. Because the seasonal risk scenario shows the cumulative impact resulting from the occurrence of multiple low-probability events, the overall likelihood of the scenario is very low. An analysis similar to the SPP seasonal risk scenario in Figure 6 can be found for each assessment area in the Regional Assessment Dashboards section of this report.

The seasonal risk assessment for the SPP assessment area shows that resources are available to meet peak summer demand, including normally hot and humid summer conditions. However, extreme heat and summer conditions, such as those associated with record-setting temperatures, could increase demand and reduce generator performance enough to cause operating emergencies. A low-output wind generation event, though rare, could lead to operating actions, including conservative operations plans and EEA declarations, to manage resources and demand. Despite anticipated resources in excess of Reference Margin Levels as shown in Figure 1, operators in SPP and other areas of North America can face resource constraints during extreme summer weather.

During the past two summers, system operators in SPP needed to take operating actions, including issuing one EEA in August 2019, to address resource shortfalls. In some instances, operators were responding to higher than expected planned and forced outages coupled with real time forecasting errors for load and wind. SPP has established operational mitigation teams and developed enhanced processes and procedures to support operators in maintaining real time reliability.

Table 1: Resource and Demand Variables in the SPP Seasonal Risk Assessment	
Resource Scenarios	
Typical Maintenance Outages	Typical maintenance outages refer to an estimate of generation resources that will be out for maintenance during peak demand conditions. SPP calculated a value of 4,926 MW based on historical averages.
Typical Forced Outages	Typical forced outages refer to an estimate of generation resources that will experience forced outage during peak load conditions. SPP calculated a value of 4,638 MW based on historical averages.
Resource Derates for Extreme Conditions (Low-likelihood)	An estimated capacity derate due to extreme conditions is calculated and used for a low-likelihood resource scenario. The derate accounts for reduced capacity contributions due to generator performance in extreme conditions. SPP calculated a capacity derate of 2,276 MW for thermal generation due to extreme conditions.
Low-Wind Scenario (Low-likelihood)	The low-wind scenario is used to analyze the impact of low-likelihood weather conditions that severely reduce output from wind generation resources. A capacity adjustment of 5,017 MW is based on a low wind generator output historical event observed by system operators during summer peak conditions.
Operational Mitigations	SPP estimates that certain operational mitigations can contribute 1,700 MW of additional resources to support maintaining operating reserve requirements.
Demand Scenarios	
2020 Summer Net Internal Demand	Net internal demand is equal to total internal demand then reduced by the amount of controllable and dispatchable demand response projected to be available during the peak hour. It is based on historical average weather (i.e., forecasts for a 50/50 distribution).
Extreme Summer Peak Load	A seasonal load adjustment (2,313 MW) is added to 2020 Net Internal Demand to account for extreme weather conditions. The adjustment is based on a 90/10 statistical extreme load forecast.

Seasonal Risk Assessments for Other Areas

Seasonal risk scenarios for each assessment area are presented in the **Regional Assessment Dashboards** section of this report. Potential extreme generation resource outages and peak loads that can accompany extreme hot or humid weather may result in reliability risks in MISO, SPP, and ERCOT as well as the Canadian provinces of Manitoba, Saskatchewan, and the Maritimes. Parts of the system within the WECC area, including California ISO, could also experience resource shortfalls in low-likelihood resource derate scenarios. Under studied conditions for these areas, grid operators would need to employ operating mitigations or EEAs to obtain resources necessary to meet extreme peak demands.

Wildfire Risk Potential and BPS Impacts

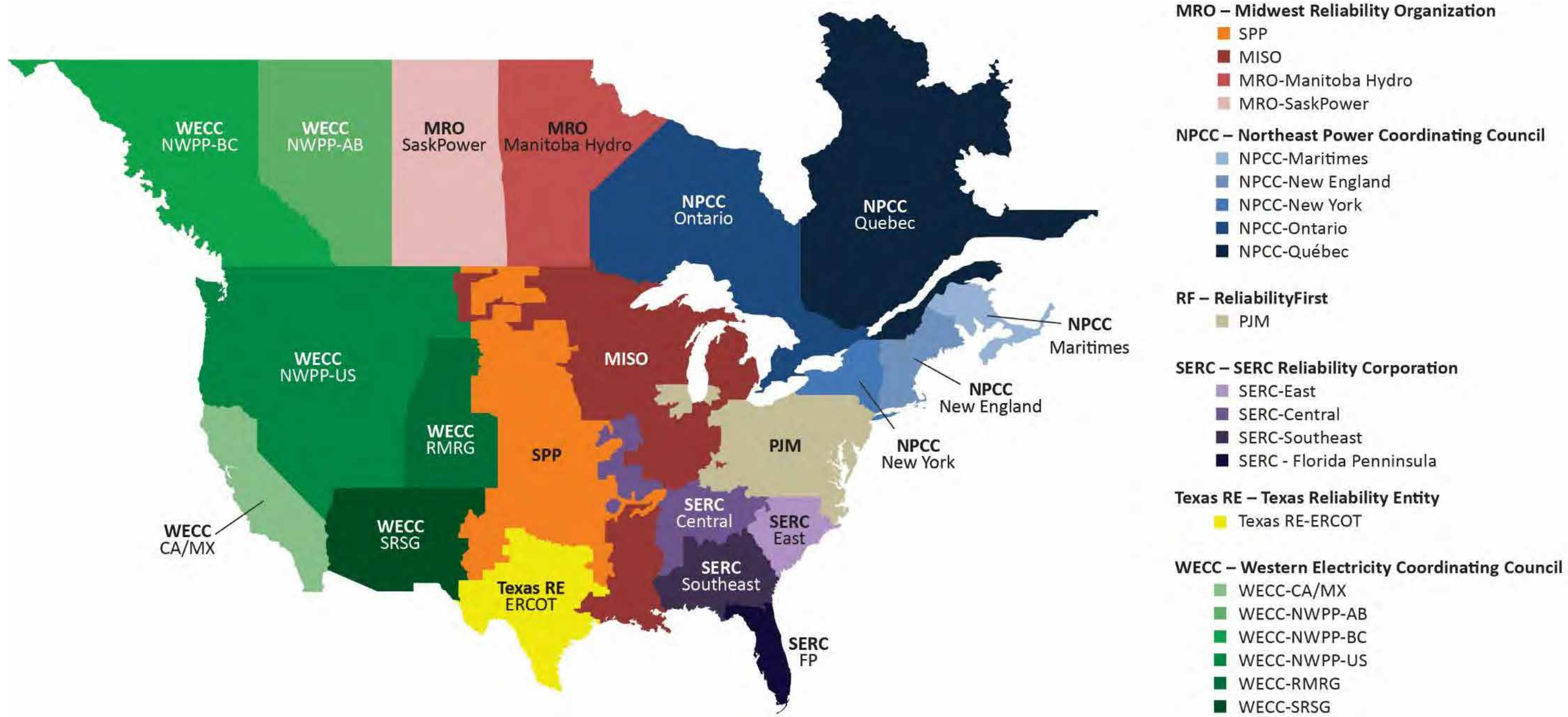
Government agencies predict normal to below-normal wildfire risk at the start of summer for the West Coast of the United States and the southwestern states. However, the latest three-month *Seasonal Fire Assessment and Outlook* published by the National Interagency Fire Center, Natural Resources Canada, and National Meteorological Service in Mexico warns that the trend toward warmer, drier weather could lead to above normal wildland fire potential in Northern California, Oregon, and Washington beginning in June.[10] Across most of western Canada, weather patterns and forecasts also suggest increased potential for wildland fires.

Operation of the BPS can be impacted in areas where wildfires are active as well as areas where there is heightened risk of wildfire ignition due to weather and ground conditions. Wildfire prevention planning in California and other areas include power shut-off programs in high fire-risk areas. When conditions warrant implementing these plans, power lines, including transmission-level lines, may be preemptively de-energized in high fire-risk areas to prevent wildfire ignitions. Other wildfire risk mitigation activities include implementing enhanced vegetation management, equipment inspections, system hardening, and added situational awareness measures.

[10] See *North American Seasonal Fire Assessment and Outlook*, May 2020: https://www.predictiveservices.nifc.gov/outlooks/NA_Outlook.pdf

Regional Assessment Dashboards

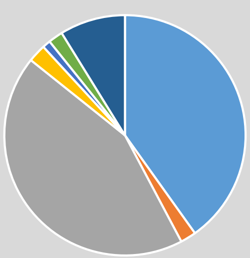
The following assessment area dashboards and summaries were developed based on data and narrative information collected by NERC from the Regional Entities on an assessment area basis.

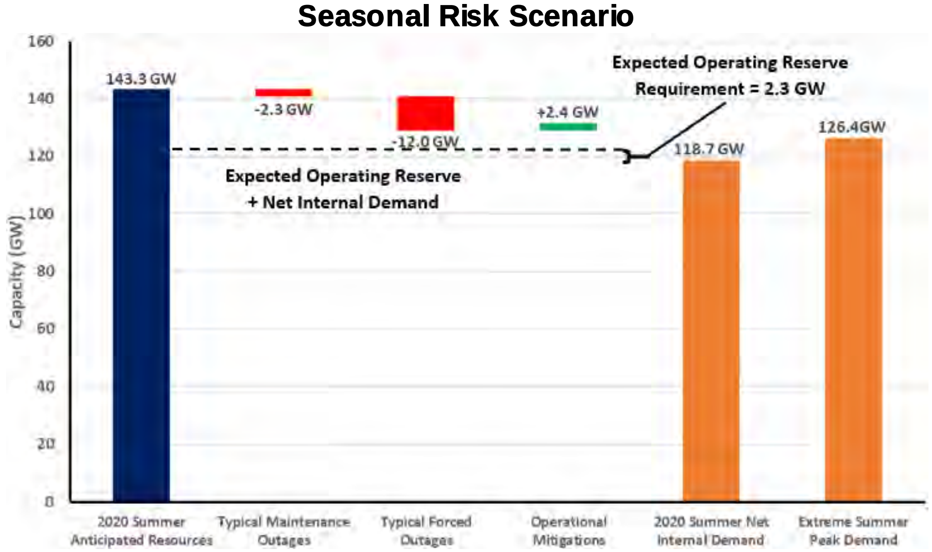


MISO

The Midcontinent Independent System Operator, Inc. (MISO) is a not-for-profit, member-based organization administering wholesale electricity markets that provide customers with valued service; reliable, cost-effective systems and operations; dependable and transparent prices; open access to markets; and planning for long-term efficiency.

MISO manages energy, reliability, and operating reserve markets that consist of 36 local Balancing Authorities and 394 market participants that serves approximately 42 million customers. Although parts of MISO fall in three NERC Regions, MRO is responsible for coordinating data and information submitted for NERC's reliability assessments.





MISO Resource Adequacy Data			
Demand, Resource, and Reserve Margin	2019 SRA	2020 SRA	2019 vs. 2020 SRA
Demand Projections	MW	MW	Net Change
Total Internal Demand (50/50)	124,744	124,866	0.1%
Demand Response: Available	6,385	6,172	-3.3%
Net Internal Demand	118,359	118,694	0.3%
Resource Projections	MW	MW	Net Change
Existing-Certain Capacity	139,220	140,636	1.0%
Tier 1 Planned Capacity	0	0	-
Net Firm Capacity Transfers	1,955	2,795	42.9%
Anticipated Resources	141,175	143,430	1.6%
Existing-Other Capacity	591	290	-50.9%
Prospective Resources	141,766	143,720	1.4%
Reserve Margins	Percent	Percent	Annual Difference
Anticipated Reserve Margin	19.3%	20.8%	1.5
Prospective Reserve Margin	19.8%	21.1%	1.3
Reference Margin Level	16.8%	18.0%	1.2

The table and chart above provide potential summer peak demand and resource condition information. The table on the right presents a standard seasonal assessment and comparison to the previous year's assessment. The chart above presents deterministic scenarios for further analysis of different demand and resource levels, with adjustments for normal and extreme conditions. MISO determined the adjustments to summer capacity and peak demand based on methods or assumptions that are summarized below. See the Data Concepts and Assumptions for more information about this table and chart.

Risk Scenario Summary

Observation:
Resources meet operating reserve requirements under normal demand and outage scenarios. Extreme summer peak demand or outages could result in a need to employ operating procedures to mitigate resource shortfall.

Scenario Assumptions

- **Extreme Peak Load:** 90/10 forecast
- **Outages:** Average from highest peak hour over the past five summers

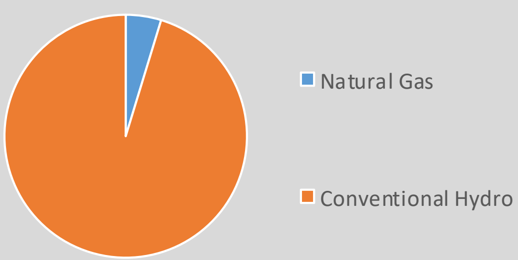
Highlights

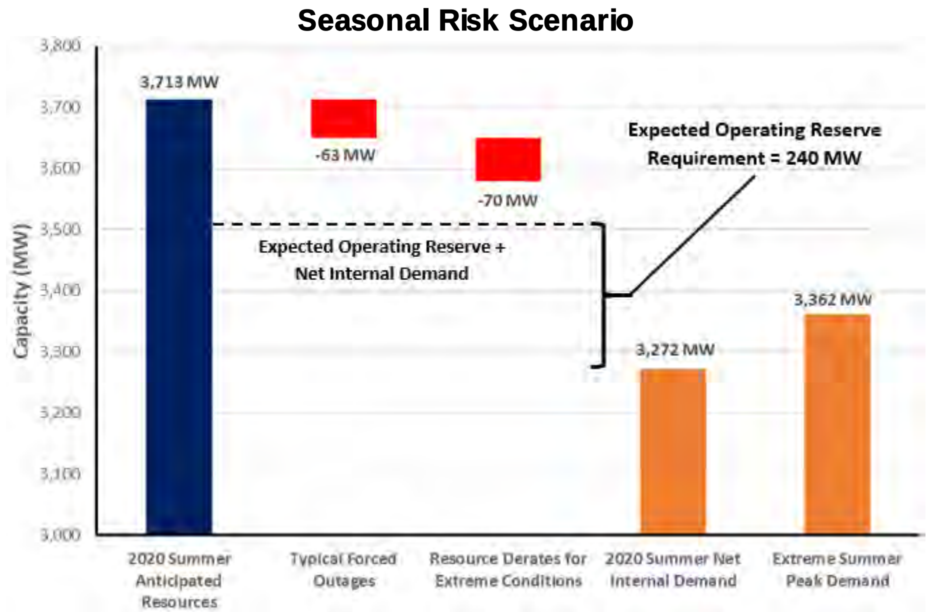
- Summer scenarios with high resource outages and high demand may require use of load modifying resources during peak periods as load modifying resources become an increasingly important segment of MISO's resource portfolio.
- Though MISO remains resource adequate for the 2020 summer, some areas may be resource and import constrained presenting local operating challenges.
- Near-term impacts of COVID-19 have resulted in generally lower loads and shifted morning and evening peaks to later hours. It is unclear how observed trends will change through the summer months.

MRO-Manitoba Hydro

Manitoba Hydro is a provincial crown corporation that provides electricity to about 580,000 customers throughout Manitoba and natural gas service to about 282,000 customers in various communities throughout Southern Manitoba. The Province of Manitoba has a population of about 1.3 million people in an area of 250,946 square miles.

Manitoba Hydro is winter peaking. No change in the footprint area is expected during the assessment period. Manitoba Hydro is its own Planning Coordinator and Balancing Authority. Manitoba Hydro is a coordinating member of MISO. MISO is the Reliability Coordinator for Manitoba Hydro.





MRO-Manitoba Hydro Resource Adequacy Data			
Demand, Resource, and Reserve Margin	**2019 SRA**	**2020 SRA**	**2019 vs. 2020 SRA**
Demand Projections	**MW**	**MW**	**Net Change**
Total Internal Demand (50/50)	3,224	3,272	1.5%
Demand Response: Available	0	0	-
Net Internal Demand	3,224	3,272	1.5%
Resource Projections	**MW**	**MW**	**Net Change**
Existing-Certain Capacity	5,161	5,239	1.5%
Tier 1 Planned Capacity	0	0	-
Net Firm Capacity Transfers	-1,408	-1,526	8.4%
Anticipated Resources	3,753	3,713	-1.1%
Existing-Other Capacity	215	125	-41.6%
Prospective Resources	3,968	3,838	-3.3%
Reserve Margins	**Percent**	**Percent**	**Annual Difference**
Anticipated Reserve Margin	16.4%	13.5%	-2.9
Prospective Reserve Margin	23.1%	17.3%	-5.8
Reference Margin Level	12.0%	12.0%	0.0

The table and chart above provide potential summer peak demand and resource condition information. The table on the right presents a standard seasonal assessment and comparison to the previous year's assessment. The chart above presents deterministic scenarios for further analysis of different demand and resource levels with adjustments for normal and extreme conditions. MRO-Manitoba determined the adjustments to capacity and peak demand based on methods or assumptions that are summarized below. See the Data Concepts and Assumptions for more information about this table and chart.

Risk Scenario Summary

Resources meet operating reserve requirements under normal demand and outage scenarios.

Scenario Assumptions

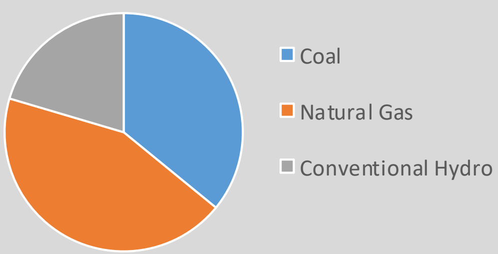
- **Extreme Peak Demand:** All-time highest peak load
- **Outages:** Based on historical operating experience
- **Extreme Derates:** Thermal units derated for extreme temperature where appropriate.

Highlights

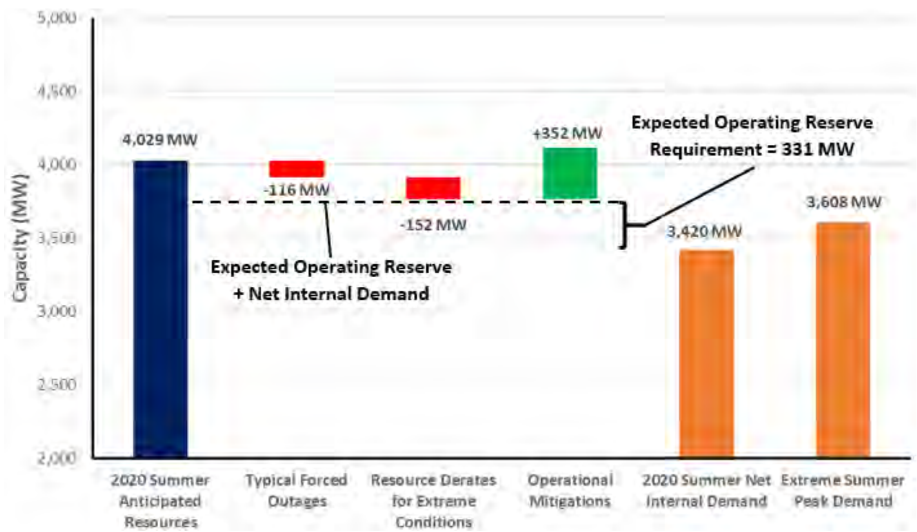
- Manitoba Hydro has implemented measures to minimize coronavirus impact risk to operations. While the COVID-19 Pandemic is expected to be present over the summer assessment period, an impact on BPS reliability is not anticipated.
- Reservoir storage levels are above average and more than adequate to withstand the design-basis drought conditions.

MRO-SaskPower

Saskatchewan is a province of Canada and comprises a geographic area of 651,900 square kilometers (251,700 square miles) with approximately 1.1 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 and is the principal supplier of electricity in the province. SaskPower is a provincial crown corporation, under provincial legislation, and is responsible for the reliability oversight of the Saskatchewan Bulk Electric System (BES) and its interconnections.



Seasonal Risk Scenario



The table and chart above provide potential summer peak demand and resource condition information. The table on the right presents a standard seasonal assessment and comparison to the previous year's assessment. The chart above presents deterministic scenarios for further analysis of different demand and resource levels with adjustments for normal and extreme conditions. MRO-SaskPower determined the adjustments to capacity and peak demand based on methods or assumptions that are summarized below. See the **Data Concepts and Assumptions** for more information about this table and chart.

Risk Scenario Summary

Resources meet operating reserve requirements under normal scenarios. Extreme summer peak load and outage conditions could result in the need to employ operating mitigations (i.e., demand response, transfers, and short-term load interruption.)

Scenario Assumptions

- **Extreme Peak Load:** Peak demand with lighting and all large consumer loads
- **Maintenance Outages:** Estimated based on average maintenance outages for June, July, August, and September for 2019
- **Forced Outages:** Estimated using SaskPower forced outage model
- **Extreme Derates:** Derate on natural gas units based on historic data and manufacturer data

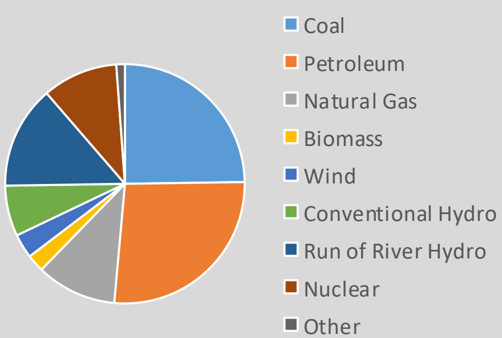
MRO-SaskPower Resource Adequacy Data			
Demand, Resource, and Reserve Margin	**2019 SRA**	**2020 SRA**	**2019 vs. 2020 SRA**
Demand Projections	**MW**	**MW**	**Net Change**
Total Internal Demand (50/50)	3,553	3,480	-2.1%
Demand Response: Available	85	60	-29.4%
Net Internal Demand	3,468	3,420	-1.4%
Resource Projections	**MW**	**MW**	**Net Change**
Existing-Certain Capacity	3,907	3,904	-0.1%
Tier 1 Planned Capacity	0	0	-
Net Firm Capacity Transfers	25	125	400.0%
Anticipated Resources	3,932	4,029	2.5%
Existing-Other Capacity	0	0	-
Prospective Resources	3,932	4,029	2.5%
Reserve Margins	**Percent**	**Percent**	**Annual Difference**
Anticipated Reserve Margin	13.4%	17.8%	4.4
Prospective Reserve Margin	13.4%	17.8%	4.4
Reference Margin Level	11.0%	11.0%	0.0

Highlights

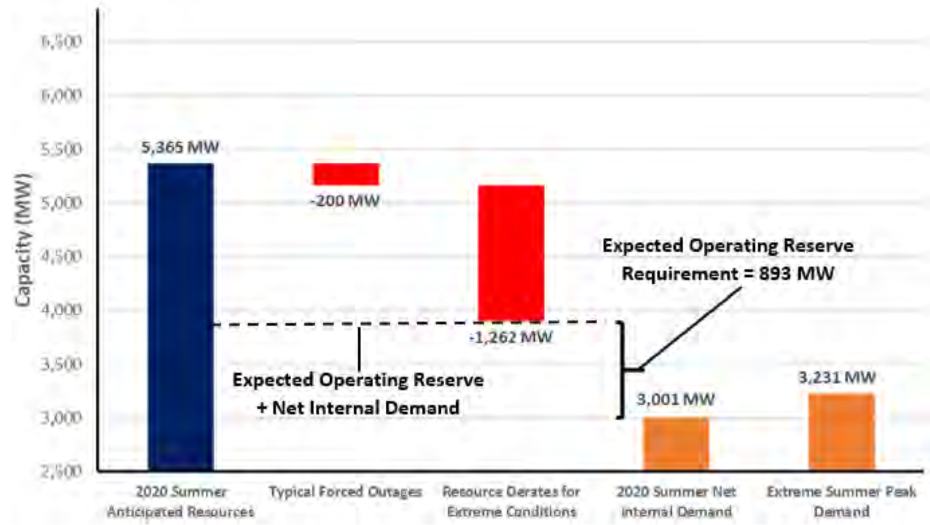
- Saskatchewan experiences high load in summer as a result of extreme hot weather.
- SaskPower conducts an annual summer joint operating study with Manitoba Hydro with inputs from Basin Electric (North Dakota) and prepares operating guidelines for any identified issues.
- The risk of operating reserve shortage during peak load times or EEAs could increase if large generation forced outage occurs during peak load times in the end of August to early October 2020 when 641 MW of SaskPower's natural gas generating station is off-line for overhaul maintenance.

NPCC-Maritimes

The Maritimes assessment area is a winter-peaking NPCC subregion that contains two Balancing Authorities. It is comprised of the Canadian provinces of New Brunswick, Nova Scotia, and Prince Edward Island, and the northern portion of Maine that is radially connected to the New Brunswick power system. The area covers 58,000 square miles with a total population of 1.9 million.



Seasonal Risk Scenario



The table and chart above provide potential summer peak demand and resource condition information. The table on the right presents a standard seasonal assessment and comparison to the previous year's assessment. The chart above presents deterministic scenarios for further analysis of different demand and resource levels with adjustments for normal and extreme conditions. NPCC-Maritimes determined the adjustments to capacity and peak demand based on methods or assumptions that are summarized below. See the Data Concepts and Assumptions for more information about this table and chart.

Risk Scenario Summary

Resources meet operating requirements under normal peak load scenario. Extreme summer peak load and outage conditions could result in the need to employ operating mitigation to manage resource shortfall.

Scenario Assumptions

- **Extreme Peak Load:** 90/10 forecast
- **Outages:** Based on historical operating experience
- **Extreme Derates:** An extreme, low-likelihood scenario is used whereby thermal units are derated for extreme temperature and all wind unit capacity is unavailable

NPCC-Maritimes Resource Adequacy Data

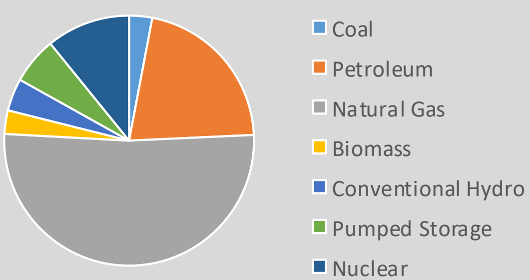
Demand, Resource, and Reserve Margin	2019 SRA	2020 SRA	2019 vs. 2020 SRA
Demand Projections	**MW**	**MW**	**Net Change**
Total Internal Demand (50/50)	3,255	3,370	3.5%
Demand Response: Available	289	369	27.7%
Net Internal Demand	2,966	3,001	1.2%
Resource Projections	**MW**	**MW**	**Net Change**
Existing-Certain Capacity	5,842	5,312	-9.1%
Tier 1 Planned Capacity	0	0	0.0%
Net Firm Capacity Transfers	0	53	0.0%
Anticipated Resources	5,842	5,365	-8.2%
Existing-Other Capacity	0	0	0.0%
Prospective Resources	5,842	5,365	-8.2%
Reserve Margins	**Percent**	**Percent**	**Annual Difference**
Anticipated Reserve Margin	97.0%	78.8%	-18.2
Prospective Reserve Margin	97.0%	78.8%	-18.2
Reference Margin Level	20.0%	20.0%	0.0

Highlights

- The Maritimes area has not identified any operational issues that are expected to impact system reliability. If an event was to occur, there are emergency operations procedures in place. All of the area's declared firm capacity is expected to be operational for the summer operating period.
- As part of the planning process, dual-fueled units will have sufficient supplies of heavy fuel oil (HFO) on-site to enable sustained operation in the event of natural gas supply interruptions.
- The effects of the COVID-19 pandemic on load patterns, energy use, and peak demands will continue to be evaluated as the pandemic evolves.
- The Maritimes are evaluating contingency plans for transmission, distribution and generation planned work, planned maintenance and forced outages to proceed conservatively while mitigating short term and longer term reliability risks.

NPCC-New England

ISO New England (ISO-NE) Inc. is a regional transmission organization that serves 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, and it also administers the area's wholesale electricity markets and manages the comprehensive planning of the regional BPS. The New England regional electric power system serves approximately 14.5 million people over 68,000 square miles.



NPCC-New England Resource Adequacy Data			
Demand, Resource, and Reserve Margin	**2019 SRA**	**2020 SRA**	**2019 vs. 2020 SRA**
Demand Projections	**MW**	**MW**	**Net Change**
Total Internal Demand (50/50)	25,323	25,158	-0.7%
Demand Response: Available	340	443	30.3%
Net Internal Demand	24,983	24,715	-1.1%
Resource Projections	**MW**	**MW**	**Net Change**
Existing-Certain Capacity	30,144	30,791	2.1%
Tier 1 Planned Capacity	1,185	0	-100.0%
Net Firm Capacity Transfers	1,328	1,510	13.7%
Anticipated Resources	32,657	32,301	-1.1%
Existing-Other Capacity	704	324	-54.0%
Prospective Resources	33,361	32,625	-2.2%
Reserve Margins	**Percent**	**Percent**	**Annual Difference**
Anticipated Reserve Margin	30.7%	30.7%	0.0
Prospective Reserve Margin	33.5%	32.0%	-1.5
Reference Margin Level	18.3%	18.3%	0.0

The table and chart above provide potential summer peak demand and resource condition information. The table on the right presents a standard seasonal assessment and comparison to the previous year's assessment. The chart above presents deterministic scenarios for further analysis of different demand and resource levels with adjustments for normal and extreme conditions. NPCC-New England determined the adjustments to capacity and peak demand based on methods or assumptions that are summarized below. See the Data Concepts and Assumptions for more information about this table and chart.

Risk Scenario Summary

Resources meet operating reserve requirements under studied scenarios.

Scenario Assumptions

- **Extreme Peak Load:** 90/10 Forecast
- **Outages:** Based on weekly averages
- **Operating Mitigations:** Based on ISO-NE operating procedures

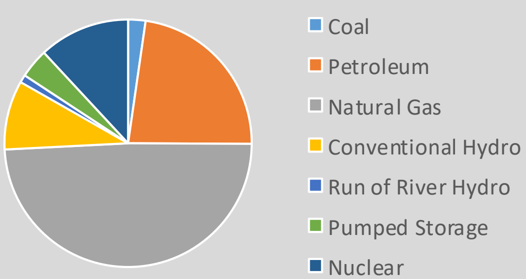
Highlights

- The New England Area expects to have sufficient resources to meet the 2020 summer peak demand forecast of 25,158 MW for the week beginning July 5, 2020, with a projected net margin of 3,197MW (12.7%). The 2020 summer demand forecast is 165 MW (0.7%) less than the 2019 summer forecast of 25,323 MW and takes into account the demand reductions associated with energy efficiency, load management, behind-the-meter photovoltaic (BTM-PV) systems, and distributed generation.
- With residents and businesses across New England changing their behavior in response to the COVID-19 pandemic, ISO New England is seeinga decline in system demand of approximately 3–5% compared to what would normally be expected under weather conditions in the area. These percentages may change over time.
- In addition to overall declines in consumer demand, these societal changes are also affecting demand patterns across the region. Though the pandemic is affecting energy use, weather conditions remain the primary drivers of system demand. ISO-NE will continuously monitor these ever-changing trends in load patterns and make the appropriate adjustments to calculate an accurate load forecast. The area's power system continues to remain reliable.

NPCC-New York

The New York Independent System Operator (NYISO) is the only Balancing Authority within the state of New York. NYISO is a single-state ISO that was formed as the successor to the New York Power Pool—a consortium of the eight IOUs—in 1999. NYISO manages the New York State transmission grid that encompasses approximately 11,000 miles of transmission lines, more than 47,000 square miles, and serving the electric needs of 19.5 million people. New York experienced its all-time peak load of 33,956 MW in the summer of 2013.

The NERC Reference Margin Level is 15%. Wind, grid-connected solar, and run-of-river totals were derated for this calculation. However, New York requires load serving entities to procure capacity for their loads equal to their peak demand plus an IRM. The IRM requirement represents a percentage of capacity above peak load forecast and is approved annually by the New York State Reliability Council (NYSRC). NYSRC approved the 2020–2021 IRM at 18.9%.



NPCC-New York Resource Adequacy Data			
Demand, Resource, and Reserve Margin	**2019 SRA**	**2020 SRA**	**2019 vs. 2020 SRA**
Demand Projections	**MW**	**MW**	**Net Change**
Total Internal Demand (50/50)	32,382	32,296	-0.3%
Demand Response: Available	1,309	1,282	-2.1%
Net Internal Demand	31,073	31,014	-0.2%
Resource Projections	**MW**	**MW**	**Net Change**
Existing-Certain Capacity	37,304	38,475	3.1%
Tier 1 Planned Capacity	27	101	274.8%
Net Firm Capacity Transfers	1,452	1,562	7.6%
Anticipated Resources	38,783	40,138	3.5%
Existing-Other Capacity	0	0	0.0%
Prospective Resources	38,783	40,138	3.5%
Reserve Margins	**Percent**	**Percent**	**Annual Difference**
Anticipated Reserve Margin	24.8%	29.4%	4.6
Prospective Reserve Margin	24.8%	29.4%	4.6
Reference Margin Level	15.0%	15.0%	0.0

The table and chart above provide potential seasonal peak demand and resource condition information. The table on the right presents a standard seasonal assessment and comparison to the previous year's assessment. The chart above presents deterministic scenarios for further analysis of different demand and resource levels with adjustments for normal and extreme conditions. NPCC-New York determined the adjustments to capacity and peak demand based on methods or assumptions that are summarized below. See the Data Concepts and Assumptions for more information about this table and chart.

Risk Scenario Summary

Resources meet operating reserve requirements under studied scenarios.

Scenario Assumptions

- **Extreme Peak Demand:** 90/10 load forecast with demand response adjustments
- **Extreme Derates:** Near-zero MW due to summer peaking area
- **Typical Outages:** Based on scheduled maintenance and GADS forced outage data
- **Operational Mitigation:** 3.1 GW based on operational/emergency procedures in NYISO *Emergency Operations Manual*

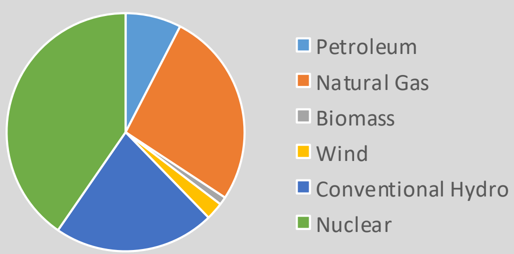
Highlights

- NYISO is not anticipating any operational issues in the New York control area for the upcoming summer. Adequate capacity margins are anticipated and existing operating procedures are sufficient to handle any issues that may occur.
- New York requires load serving entities to procure capacity for their loads equal to their peak demand plus an Installed Reserve Margin (IRM). The IRM requirement represents a percentage of capacity above peak load forecast and is determined and approved annually by the New York State Reliability Council (NYSRC). NYSRC approved a 2020–2021 IRM of 18.9%. The IRM meets the NPCC and NYSRC criterion of a loss of load expectation of no greater than 0.1 days per year. Its calculation is based on a study that accounts for the forced outage rates of thermal generators, the peak load forecast, the load forecast uncertainty, the actual hourly production data for wind and solar over the most recent five-year calendar period, long term capacity imports and exports, demand response programs derated to account for historic availability, various emergency operation procedures, and assistance from neighboring control areas. Historically since 2000, the IRM has ranged between 15.0% and 18.9%.

NPCC-Ontario

The Independent Electricity System Operator (IESO) is the Balancing Authority and Reliability Coordinator for the province of Ontario. In addition to administering the area's wholesale electricity markets, the IESO plans for Ontario's future energy needs. Ontario covers more than 415,000 square miles and has a population of more than 14 million. Ontario is interconnected electrically with Québec, MRO-Manitoba, states in MISO (Minnesota and Michigan), and NPCC-New York.

Ontario IESO treats demand response as a resource for its own assessments while in the NERC assessment demand response is used as a load-modifier. As a result, the total internal demand, reserve margin, and Reference Margin Level values differ in IESO's reports when compared to NERC reports.



NPCC-Ontario Resource Adequacy Data			
Demand, Resource, and Reserve Margin	**2019 SRA**	**2020 SRA**	**2019 vs. 2020 SRA**
Demand Projections	**MW**	**MW**	**Net Change**
Total Internal Demand (50/50)	22,105	22,195	0.4%
Demand Response: Available	790	518	-34.5%
Net Internal Demand	21,315	21,677	1.7%
Resource Projections	**MW**	**MW**	**Net Change**
Existing-Certain Capacity	26,581	25,719	-3.2%
Tier 1 Planned Capacity	924	49	-94.7%
Net Firm Capacity Transfers	-102	0	-100.0%
Anticipated Resources	27,403	25,768	-6.0%
Existing-Other Capacity	0	0	0.0%
Prospective Resources	27,403	25,768	-6.0%
Reserve Margins	**Percent**	**Percent**	**Annual Difference**
Anticipated Reserve Margin	28.6%	18.9%	-9.7
Prospective Reserve Margin	28.6%	18.9%	-9.7
Reference Margin Level	14.9%	14.6%	-0.3

The table and chart above provide potential summer peak demand and resource condition information. The table on the right presents a standard seasonal assessment and comparison to the previous year's assessment. The chart above presents deterministic scenarios for further analysis of different demand and resource levels with adjustments for normal and extreme conditions. NPCC-Ontario determined the adjustments to capacity and peak demand based on methods or assumptions that are summarized below. See the Data Concepts and Assumptions for more information about this table and chart.

Risk Scenario Summary

Resources meet operating reserve requirements under studied scenarios.

Scenario Assumptions

- **Extreme Peak Load:** Determined from the most severe historical weather
- **Extreme Derates:** Based on thermal unit derating curves and historical hydro performance for a low-water year
- **Operational Mitigation:** 2,000 MW imports assessed as available from neighbors

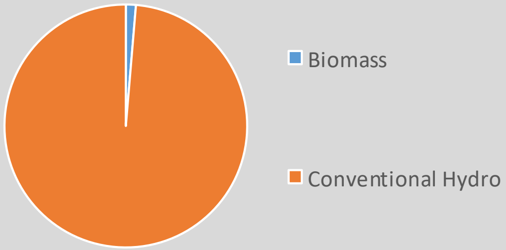
Highlights

- The IESO expects to have sufficient generation supply for Summer 2020. Likewise, Ontario's transmission system is expected to continue to reliably supply province-wide demand throughout the summer season.
- Napanee Generating Station, a 994 MW natural-gas-fired plant, was added to Ontario's generation fleet in March 2020. The Darlington Nuclear Unit G2 (936 MW) is expected to return to service following refurbishment prior to summer.
- The year-on-year reduction in anticipated/prospective reserve margin is due to a greater number of nuclear units on refurbishment outage as well as reductions in demand response and hydroelectric contributions.
- The ongoing transmission outage of the phase angle regulator on the L33 circuit at the New York-St Lawrence interconnection continues to impact import and export capacity between Ontario and New York. The issue is being jointly managed by all involved parties.

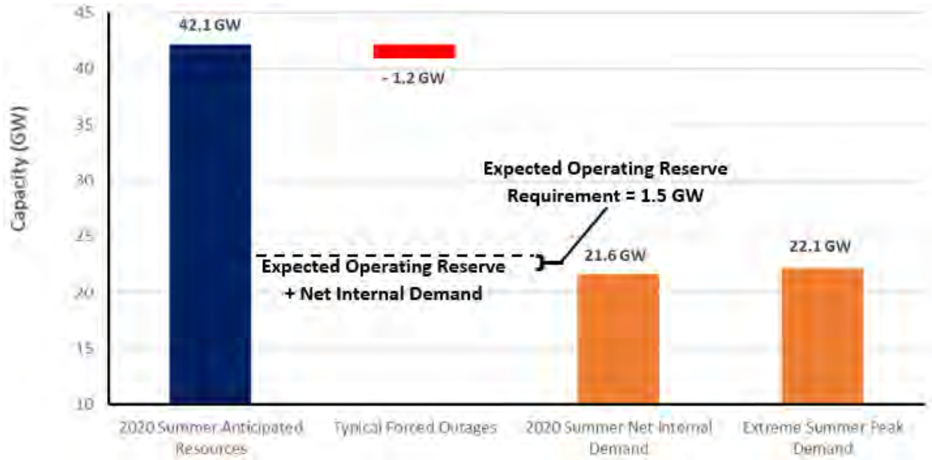
NPCC-Québec

The Québec assessment area (Province of Québec) is a winter-peaking NPCC subregion that covers 595,391 square miles with a population of 8 million.

Québec is one of the four NERC Interconnections in North America; with ties to Ontario, New York, New England, and the Maritimes; consisting of either HVDC ties, radial generation, or load to and from neighboring systems.



Seasonal Risk Scenario



NPCC- Québec Resource Adequacy Data			
Demand, Resource, and Reserve Margin	**2019 SRA**	**2020 SRA**	**2019 vs. 2020 SRA**
Demand Projections	**MW**	**MW**	**Net Change**
Total Internal Demand (50/50)	21,005	21,635	3.0%
Demand Response: Available	0	0	0.0%
Net Internal Demand	21,005	21,635	3.0%
Resource Projections	**MW**	**MW**	**Net Change**
Existing-Certain Capacity	34,303	34,771	1.4%
Tier 1 Planned Capacity	28	14	-49.1%
Net Firm Capacity Transfers	-1,663	-1,963	18.0%
Anticipated Resources	32,667	32,822	0.5%
Existing-Other Capacity	0	0	0.0%
Prospective Resources	32,667	32,822	0.5%
Reserve Margins	**Percent**	**Percent**	**Annual Difference**
Anticipated Reserve Margin	55.5%	51.7%	-3.8
Prospective Reserve Margin	55.5%	51.7%	-3.8
Reference Margin Level	12.8%	9.8%	-3.0

The table and chart above provide potential seasonal peak demand and resource condition information. The table on the right presents a standard seasonal assessment and comparison to the previous year's assessment. The chart above presents deterministic scenarios for further analysis of different demand and resource levels with adjustments for normal and extreme conditions. NPCC-Québec determined the adjustments to peak demand based on methods or assumptions that are summarized below. See the Data Concepts and Assumptions for more information about this table and chart.

Risk Scenario Summary

Resources meet operating reserve requirements under studied scenarios.

Scenario Assumptions

- **Extreme Peak Load:** 90/10 forecast
- **Forced Outages:** Hydro resources operate in extreme conditions without increased outage rates

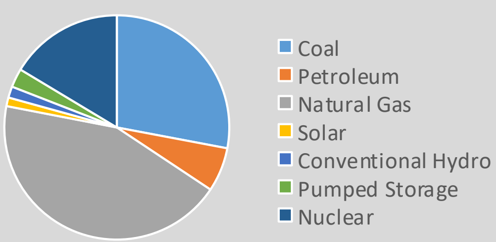
Highlights

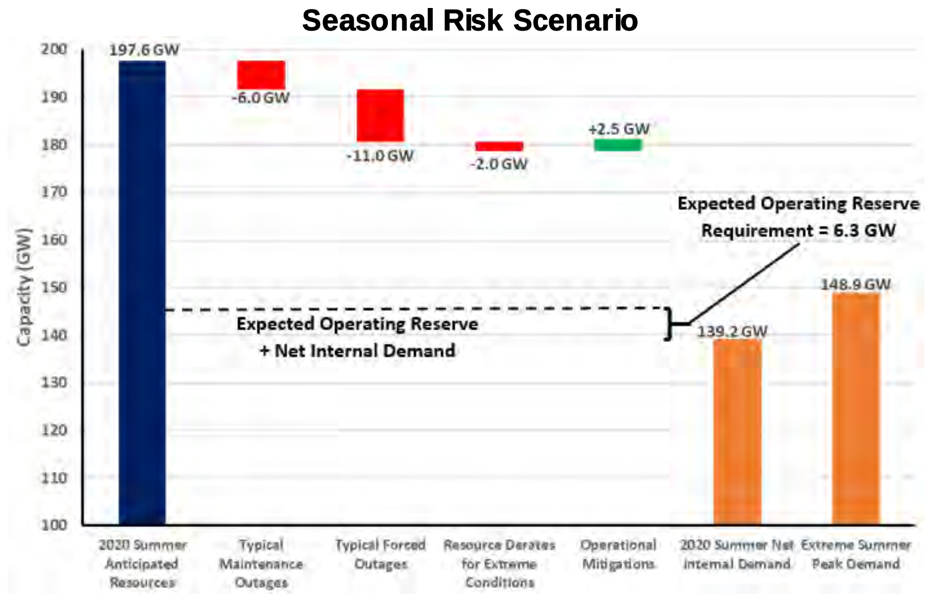
- No resource adequacy or reliability issues are anticipated for the upcoming summer operating period since the Quebec system is winter peaking.
- A strategic 735 kV line was commissioned in May 2019 in order to meet NERC Reliability Standards. The line will provide more flexibility to operators for the upcoming summer period.

PJM

PJM Interconnection is a regional transmission organization that coordinates the movement of wholesale electricity in all or parts of Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, West Virginia, and the District of Columbia.

PJM serves 65 million people and covers 369,089 square miles. PJM is a Balancing Authority, Planning Coordinator, Transmission Planner, Resource Planner, Interchange Authority, Transmission Operator, Transmission Service Provider, and Reliability Coordinator.





PJM Resource Adequacy Data			
Demand, Resource, and Reserve Margin	**2019 SRA**	**2020 SRA**	**2019 vs. 2020 SRA**
Demand Projections	**MW**	**MW**	**Net Change**
Total Internal Demand (50/50)	151,358	148,092	-2.2%
Demand Response: Available	8,154	8,929	9.5%
Net Internal Demand	143,204	139,163	-2.8%
Resource Projections	**MW**	**MW**	**Net Change**
Existing-Certain Capacity	181,013	182,523	0.8%
Tier 1 Planned Capacity	2,200	1,800	-18.2%
Net Firm Capacity Transfers	1,535	1,412	-8.0%
Anticipated Resources	184,748	185,735	7.0%
Existing-Other Capacity	0	0	0.0%
Prospective Resources	184,748	185,735	7.7%
Reserve Margins	**Percent**	**Percent**	**Annual Difference**
Anticipated Reserve Margin	29.0%	33.5%	4.5
Prospective Reserve Margin	29.0%	33.5%	4.5
Reference Margin Level	15.9%	15.5%	-0.4

The table and chart above provide potential seasonal peak demand and resource condition information. The table on the right presents a standard seasonal assessment and comparison to the previous year's assessment. The chart above presents deterministic scenarios for further analysis of different demand and resource levels with adjustments for normal and extreme conditions. PJM determined the adjustments to capacity and peak demand based on methods or assumptions that are summarized below. See the Data Concepts and Assumptions for more information about this table and chart.

Risk Scenario Summary

Resources meet operating reserve requirements under studied scenarios.

Scenario Assumptions

- **Extreme Peak Load:** 90/10 forecast
- **Outages:** Approximate values based on review of previous summer peak periods

Highlights

- PJM's Anticipated Reserve Margin of 33.5% is well over the reserve margin requirement of 15.5%.
- No known operational challenges are anticipated in PJM for the upcoming summer season.
- PJM's capacity performance initiative has resulted in better generator performance than in years preceding its implementation.

SERC

On July 1, 2019, the integration of FRCC entities into SERC resulted in an additional SERC subregion (SERC FL-Peninsula) for inclusion in NERC's reliability assessments.

SERC is a summer-peaking assessment area that covers approximately 350,000 square miles and serves a population estimated at 69 million. SERC is divided into four assessment areas: SERC- E, SERC-N, SERC-SE, and SERC-FL Peninsula. The SERC assessment area includes 33 Balancing Authorities, 26 Planning Authorities, and 4 Reliability Coordinators.

SERC Resource Adequacy Data

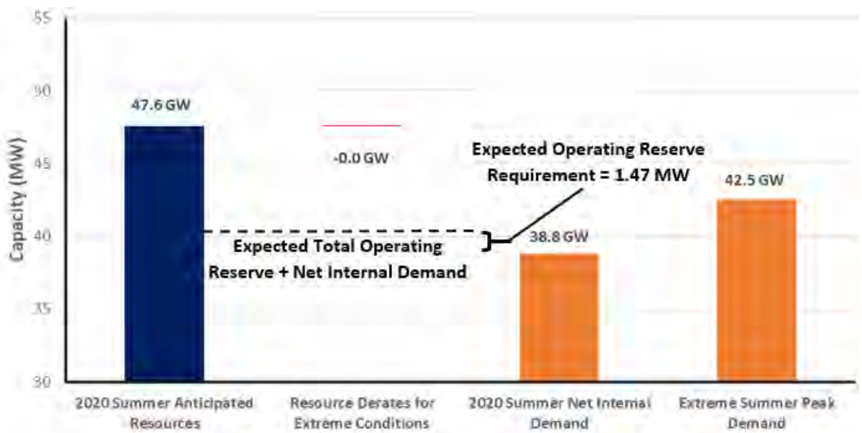
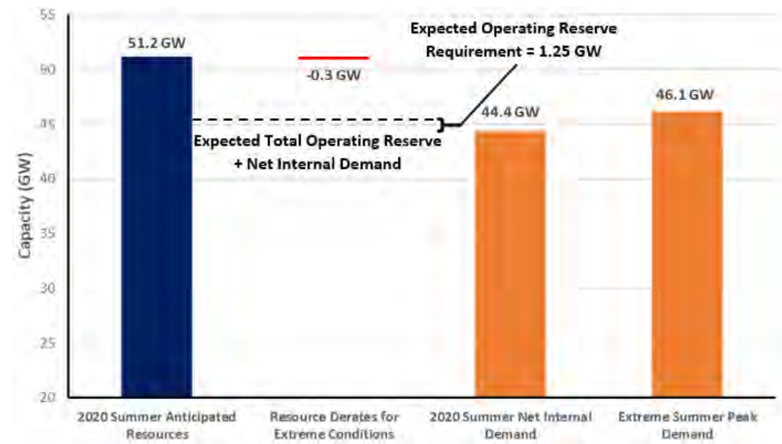
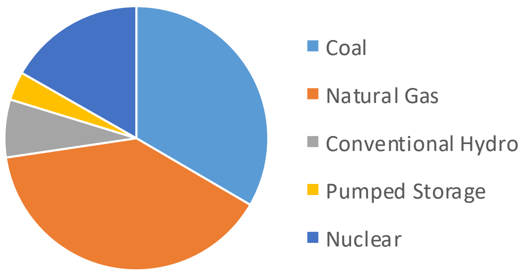
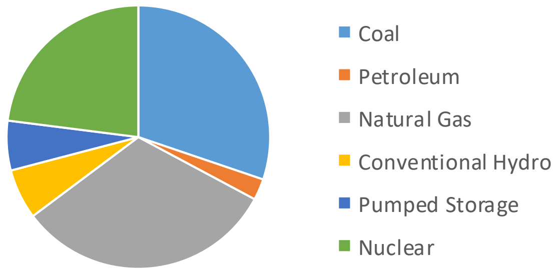
Demand, Resource, and Reserve Margins	SERC-C	SERC-E	SERC-FP	SERC-SE	2019 SRA SERC Total	2020 SRA SERC Total	2019 vs. 2020 SRA
Demand Projections	**Megawatts**	**Megawatts**	**Megawatts**	**Megawatts**	**Megawatts**	**Megawatts**	**Net Change (%)**
Total Internal Demand (50/50)	40,799	43,702	49,286	47,311	179,466	181,098	0.9%
Demand Response: Available	1,970	947	2,906	2,145	8,262	7,968	-3.6%
Net Internal Demand	38,829	42,755	46,380	45,166	171,204	173,130	1.1%
Resource Projections	**Megawatts**	**Megawatts**	**Megawatts**	**Megawatts**	**Megawatts**	**Megawatts**	**Net Change (%)**
Existing-Certain Capacity	48,368	50,825	55,093	61,495	214,712	215,780	0.5%
Tier 1 Planned Capacity	0	88	333	316	2,679	736	-72.5%
Net Firm Capacity Transfers	-807	266	1,146	-972	306	-367	-219.8%
Anticipated Resources	47,561	51,179	56,571	60,839	217,697	216,149	-0.7%
Existing-Other Capacity	4,427	852	529	348	6,034	6,155	2.0%
Prospective Resources	51,988	52,030	57,100	61,186	223,731	222,304	-0.6%
Planning Reserve Margins	**Percent**	**Percent**	**Percent**	**Percent**	**Percent**	**Percent**	**Annual Difference**
Anticipated Reserve Margin	22.5%	19.7%	22.0%	34.7%	27.2%	24.8%	-2.4
Prospective Reserve Margin	33.9%	21.7%	23.1%	35.5%	30.7%	28.4%	-2.3
Reference Margin Level	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	0.0

Highlights

- To date in the SERC region, there are no significant reliability risks expected for the 2020 summer season.
- All subregions within SERC meet or exceed the reserve margin target of 15%.
- Entities in the SERC region continue to participate actively in the SERC Near-Term and Long-Term Working Groups. These groups identify emerging and potential reliability impacts to transmission and resource adequacy along with transfer capability.

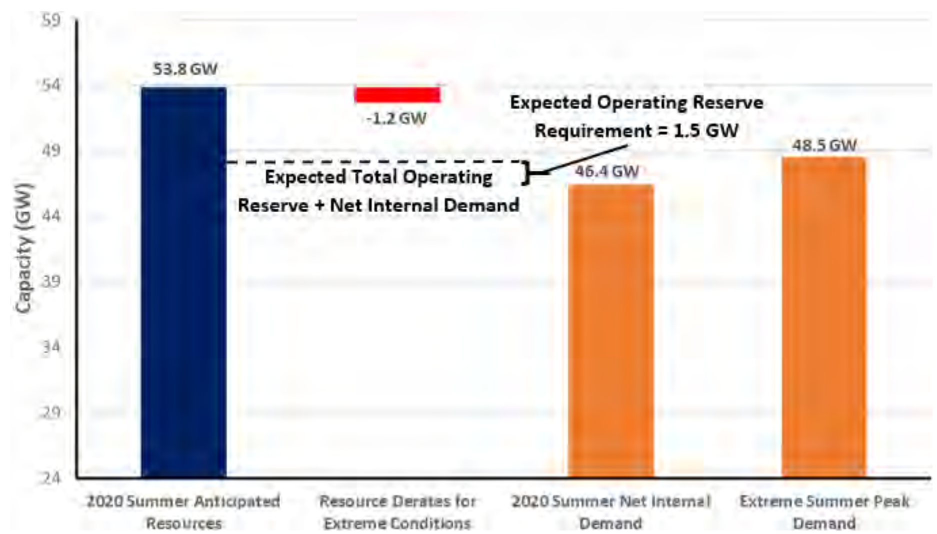
Charts

The charts on the following pages provide potential seasonal peak demand and resource condition information. The table above presents a standard seasonal assessment and comparison to the previous year's assessment. The waterfall charts on the following pages present deterministic scenarios for further analysis of different demand and resource levels with adjustments for normal and extreme conditions. SERC determined the adjustments to capacity and peak demand based on methods or assumptions that are summarized below each chart. See the Data Concepts and Assumptions for more information about the table and charts.

SERC-C	SERC-E
Seasonal Risk Scenario 	**Seasonal Risk Scenario** 
Risk Scenario Summary Resources meet operating reserve requirements under studied scenarios. **Scenario Assumptions** • **Extreme Peak Load:** Developed by adjusting subregional peak forecasted load using the probabilistic load multiplier developed in the SERC Probabilistic Assessment • **Outages:** Based on historical data • **Extreme Derates:** Determined by entities and aggregated at the subregional level 	**Risk Scenario Summary** Resources meet operating reserve requirements under studied scenarios. **Scenario Assumptions** • **Extreme Peak Load:** Developed by adjusting subregional peak forecasted load using the probabilistic load multiplier developed in the SERC Probabilistic Assessment • **Outages:** Based on historical data • **Extreme Derates:** Determined by entities and aggregated at the subregional level 

SERC-FP

Seasonal Risk Scenario

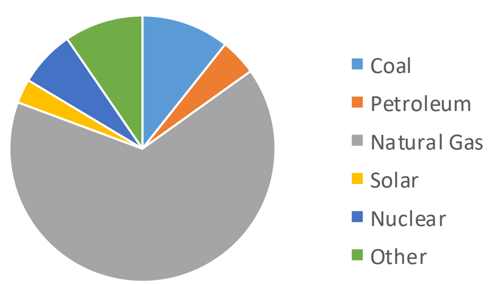


Risk Scenario Summary

Resources meet operating reserve requirements under studied scenarios.

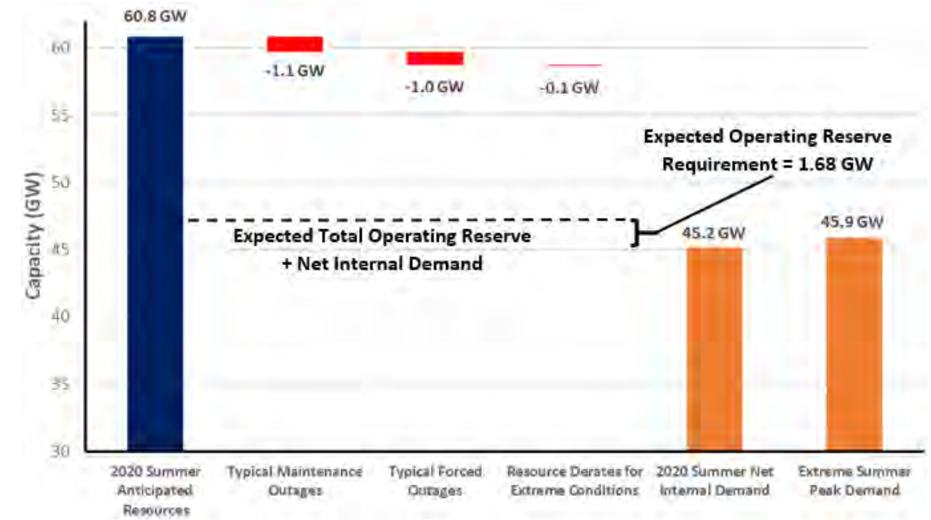
Scenario Assumptions

- **Extreme Peak Load:** Developed by adjusting subregional peak forecasted load using the probabilistic load multiplier developed in the SERC Probabilistic Assessment
- **Outages:** Based on historical data
- **Extreme Derates:** Determined by entities and aggregated at the subregional level



SERC-SE

Seasonal Risk Scenario

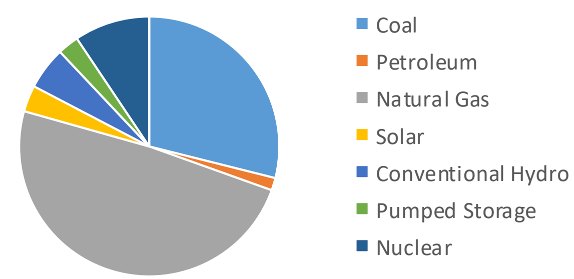


Risk Scenario Summary

Resources meet operating reserve requirements under studied scenarios.

Scenario Assumptions

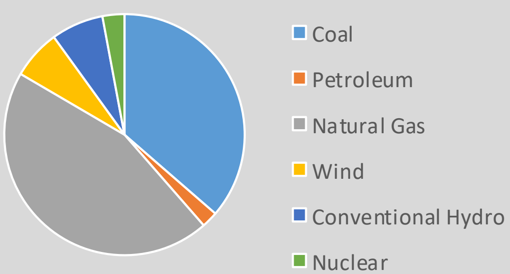
- **Extreme Peak Load:** Developed by adjusting subregional peak forecasted load using the probabilistic load multiplier developed in the SERC Probabilistic Assessment
- **Outages:** Based on historical data
- **Extreme Derates:** Determined by entities and aggregated at the subregional level

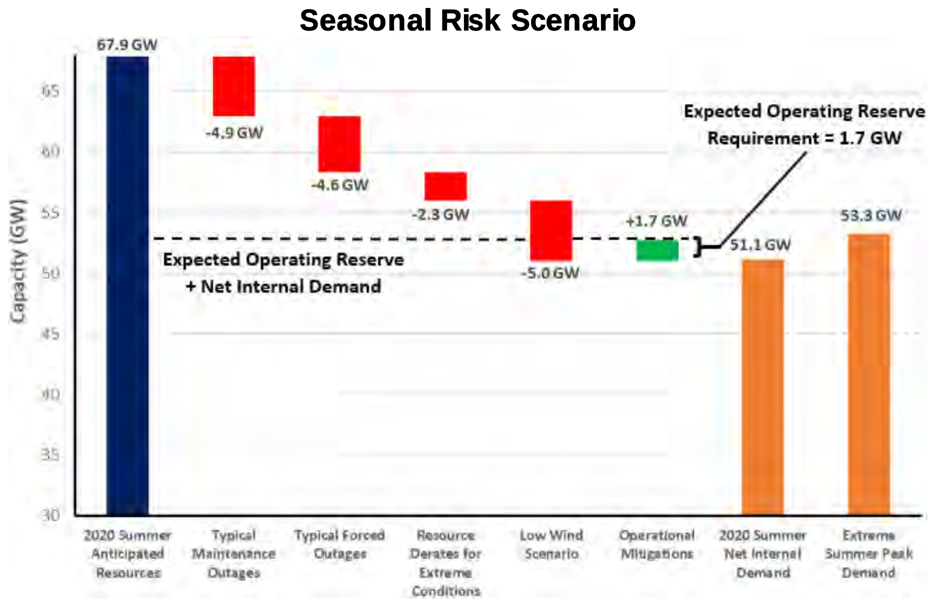


SPP

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 long-term assessment 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 Resource Adequacy Data			
Demand, Resource, and Reserve Margin	**2019 SRA**	**2020 SRA**	**2019 vs. 2020 SRA**
Demand Projections	**MW**	**MW**	**Net Change**
Total Internal Demand (50/50)	51,520	51,943	0.8%
Demand Response: Available	835	835	0.0%
Net Internal Demand	50,686	51,108	0.8%
Resource Projections	**MW**	**MW**	**Net Change**
Existing-Certain Capacity	67,960	69,100	1.7%
Tier 1 Planned Capacity	64	0	-100.0%
Net Firm Capacity Transfers	-1,244	-1,244	0.0%
Anticipated Resources	66,780	67,856	1.6%
Existing-Other Capacity	0	0	0.0%
Prospective Resources	66,780	67,856	1.6%
Reserve Margins	**Percent**	**Percent**	**Annual Difference**
Anticipated Reserve Margin	31.8%	32.8%	1.0
Prospective Reserve Margin	31.8%	32.8%	1.0
Reference Margin Level	12.0%	12.0%	0.0

The table and chart above provide potential seasonal peak demand and resource condition information. The table on the right presents a standard seasonal assessment and comparison to the previous year's assessment. The chart above presents deterministic scenarios for further analysis of different demand and resource levels with adjustments for normal and extreme conditions. SPP determined the adjustments to capacity and peak demand based on methods or assumptions that are summarized below. See the Data Concepts and Assumptions for more information about this table and chart.

Risk Scenario Summary

Operating mitigations and EEAs may be needed under extreme demand and extreme resource derated conditions studied.

Scenario Assumptions

- **Extreme Peak Load:** 90/10 Forecast
- **Outages:** A capacity derate for maintenance outages, forced outages, and performance in extreme weather based on historical data

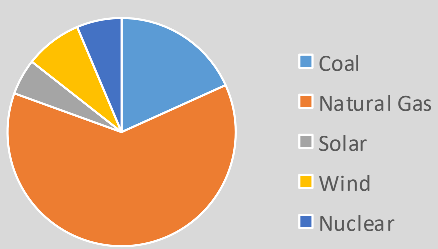
Highlights

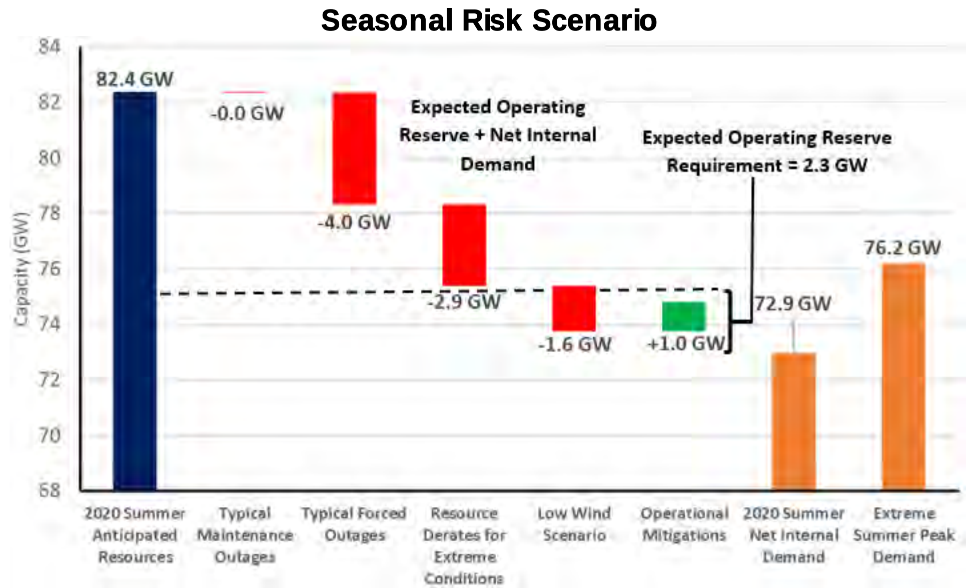
- SPP does not anticipate any emerging reliability issues impacting the area for the 2020 summer season.
- In an effort to minimize declared periods of conservative operations and EEAs that may arise from uncertainty in wind forecasts, SPP created new mitigation processes to deal with high impact areas of concern. SPP has developed operational mitigation teams as well as processes and procedures to maintain real time reliability needs; some of these are new and will be relied upon for the first time in the 2020 summer season.

Texas RE-ERCOT

The Electric Reliability Council of Texas (ERCOT) is the ISO for the ERCOT Interconnection and is located entirely in the state of Texas; it operates as a single Balancing Authority. It also performs financial settlement for the competitive wholesale bulk-power market and administers retail switching for nearly 8 million premises in competitive choice areas. ERCOT is governed by a board of directors and subject to oversight by the Public Utility Commission of Texas and the Texas Legislature.

ERCOT is a summer-peaking Region that covers approximately 200,000 square miles, connects over 46,500 miles of transmission lines, has over 680 generation units, and serves more than 26 million customers. Texas RE is responsible for the regional RE functions described in the *Energy Policy Act of 2005* for the ERCOT Region.





Texas RE-ERCOT Resource Adequacy Data			
Demand, Resource, and Reserve Margin	**2019 SRA**	**2020 SRA**	**2019 vs. 2020 SRA**
Demand Projections	**MW**	**MW**	**Net Change**
Total Internal Demand (50/50)	74,853	75,200	0.5%
Demand Response: Available	2,227	2,251	1.1%
Net Internal Demand	72,626	72,949	0.4%
Resource Projections	**MW**	**MW**	**Net Change**
Existing-Certain Capacity	77,482	79,395	2.5%
Tier 1 Planned Capacity	607	2,172	257.9%
Net Firm Capacity Transfers	721	817	13.3%
Anticipated Resources	78,810	82,384	4.5%
Existing-Other Capacity	0	0	0.0%
Prospective Resources	78,810	82,412	4.6%
Reserve Margins	**Percent**	**Percent**	**Annual Difference**
Anticipated Reserve Margin	8.5%	12.9%	4.4
Prospective Reserve Margin	8.5%	13.0%	4.5
Reference Margin Level	13.75%	13.75%	0.0

The table and chart above provide potential seasonal peak demand and resource condition information. The table on the right presents a standard seasonal assessment and comparison to the previous year's assessment. The chart above presents deterministic scenarios for further analysis of different demand and resource levels with adjustments for normal and extreme conditions. ERCOT determined the adjustments to capacity and peak demand based on methods or assumptions that are summarized below.

Risk Scenario Summary

Operating mitigations and EEAs may be needed to meet extreme demand or extreme resource derated conditions.

Scenario Assumptions

- **Extreme Peak Load:** Based on 2011 historic summer peak load
- **Outages:** A derate for maintenance and forced outages based on the past three summer periods
- **Extreme Derates:** Based on 95th percentile of historical forced outages for June – September, hours ending 2:00 p.m.–8:00 p.m. for the last three summer seasons
- **Operational Mitigations:** Additional resources (e.g., switchable generation resources, additional imports, and voltage reduction) to support maintaining operating reserves, not already counted in SRA reserve margins

Highlights

- ERCOT's anticipated reserve margin, 12.9%, is higher than last summer due mainly to greater planned wind and solar capacity. Increases are attributed to completion of new projects as well as delayed projects from 2019 and improved methods for calculating wind and solar capacity contributions.
- The Planning Reserve Margin is considered tight. ERCOT expects grid operations to be similar to last summer, assuming that peak loads hit record levels as forecasted.
- ERCOT assumes the availability of 817 MW of dc tie net imports from SPP during its forecasted summer peak load hours based on recent historical experience and expected energy market conditions for the upcoming summer. Emergency conditions in both areas simultaneously would impact imports into ERCOT. ERCOT does not expect COVID-19-related delays for planned projects with expected in-service dates prior to the summer season.
- There are no known transmission reliability, fuel supply, or essential reliability service procurement issues projected for summer. Continued penetration of wind and solar resources is expected to further stress system conditions and call for additional actions to maintain system stability. Stability constraints are managed through generic transmission constraints (GTCs) in real-time operations. ERCOT assesses the impact of future planned new generation to determine the adequacy of existing GTCs and the need for developing new GTCs or system improvements.

WECC

WECC is responsible for coordinating and promoting BES reliability in the Western Interconnection. WECC's 329 members, which include 38 Balancing Authorities, represent a wide spectrum of organizations with an interest in the BES. Serving an area of nearly 1.8 million square miles and more than 82 million people, it is geographically the largest and most diverse of the NERC Regional Entities. WECC's service territory extends from Canada to Mexico. It includes the provinces of Alberta and British Columbia in Canada, the northern portion of Baja California in Mexico, and all or portions of the 14 western states of the United States in between. The WECC assessment area is divided into six subregions: Rocky Mountain Reserve Group (RMRG), Southwest Reserve Sharing Group (SRSG), California/Mexico (CA/MX), the Northwest Power Pool (NWPP), and the Canadian areas of Alberta (WECC AB), and British Columbia (WECC BC). These subregional divisions are used for this study as they are structured around reserve sharing groups that have similar annual demand patterns and similar operating practices.

WECC Resource Adequacy Data

Demand, Resource, and Reserve Margins	WECC AB	WECC BC	CA/MX	NWPP-US	RMRG	SRSG	2019	2020	2019 vs. 2020 SRA
Demand Projections	**MW**	**MW**	**MW**	**MW**	**MW**	**MW**	**Total MW**	**Total MW**	**Net Change (%)**
Total Internal Demand (50/50)	11,500	8,278	53,236	53,964	12,568	25,145	156,142	164,691	5.5%
Demand Response: Available	0	0	910	629	240	144	2,164	1,923	-11.1%
Net Internal Demand	11,500	8,278	52,326	53,335	12,328	25,001	153,979	162,768	5.7%
Resource Projections	**MW**	**MW**	**MW**	**MW**	**MW**	**MW**	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	14,356	11,471	63,186	62,770	16,068	29,440	194,208	197,292	1.6%
Tier 1 Planned Capacity	0	215	92	817	53	477	3961	1,653	-58.3%
Net Firm Capacity Transfers	0	0	0	749	0	0	0	749	0.0%
Anticipated Resources	14,356	11,686	63,278	64,336	16,122	29,917	198,169	199,694	0.8%
Existing-Other Capacity	0	0	0	0	0	0	0	0	0.0%
Prospective Resources	14,356	11,686	63,278	64,336	16,122	29,917	198,169	199,694	0.8%
Planning Reserve Margins	**Percent**	**Percent**	**Percent**	**Percent**	**Percent**	**Percent**	**Percent**	**Percent**	**Annual Difference**
Anticipated Reserve Margin	24.8%	41.2%	20.9%	20.6%	30.8%	19.7%	28.7%	22.7%	-6.0
Prospective Reserve Margin	24.8%	41.2%	20.9%	20.6%	30.8%	19.7%	28.7%	22.7%	-6.0
Reference Margin Level	10.4%	10.4%	13.7%	15.7%	13.0%	10.0%	15.4%	15.4%	0.0

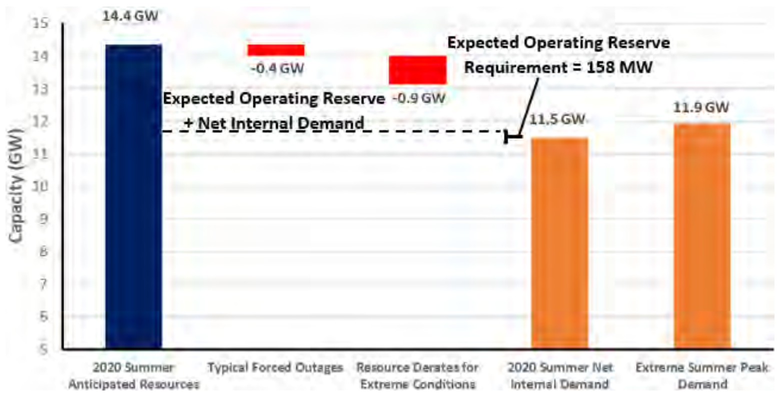
Highlights

- The existing and Anticipated Reserve Margins for WECC, its subregions, and all zones within are expected to exceed their respective NERC Reference Margin Levels for the upcoming season.
- Below-normal hydro conditions are present in California that could reduce energy available from hydro resources throughout the summer. Hydro resources and imports from neighboring areas are important for maintaining system reliability in the California ISO area, where dispatchable generation has declined and variable generation is increasing. Extreme heat extending over California and neighboring areas could pose operating risk if surplus energy for import is reduced. Risks are heightened later in the summer when energy from hydro resources will be lower and solar PV output is near zero at the peak hour.
- Inventories of the Aliso Canyon Natural Gas Storage Facility (Aliso Canyon) remain an item of focus for electric reliability within the Western Interconnection. Going into the 2020 summer, the Southern California Gas Company (SoCalGas) system has more natural gas in storage and additional transmission lines in service, making it better postured to support natural gas users including electricity generators. SoCalGas estimates that it will be able to meet the forecasted peak day demand under a "best case" supply assumption even without supply from Aliso Canyon. Under a "worst case" supply assumption, the forecasted peak day demand cannot be met without curtailment even with the use of supply from Aliso Canyon.

The charts on the next page provide potential peak demand and resource condition information. The table above presents a standard seasonal assessment and comparison to the previous year's assessment. The waterfall charts on the next page present deterministic scenarios for further analysis of different demand and resource levels with adjustments for normal and extreme conditions. WECC entities determined the adjustments to capacity and peak demand based on methods or assumptions that are summarized on the next page. See the Data Concepts and Assumptions for more information about the table and charts.

WECC-Alberta

Seasonal Risk Scenario

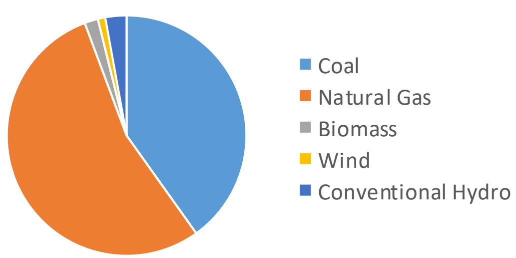


Risk Scenario Summary

Operating mitigations and EEAs may be needed under extreme demand and extreme resource derated conditions studied.

Scenario Assumptions

- **Extreme Peak Load:** Based on 90/10 demand forecast
- **Forced Outages:** Based on historical data
- **Extreme Derates:** Developed using the 10th percentile availability curves for the thermal, wind, and solar resources at the assessment area peak hour



WECC-British Columbia

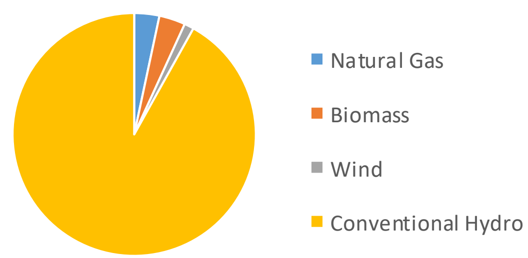
Seasonal Risk Scenario

Risk Scenario Summary

Resources meet operating reserve requirements under studied scenarios.

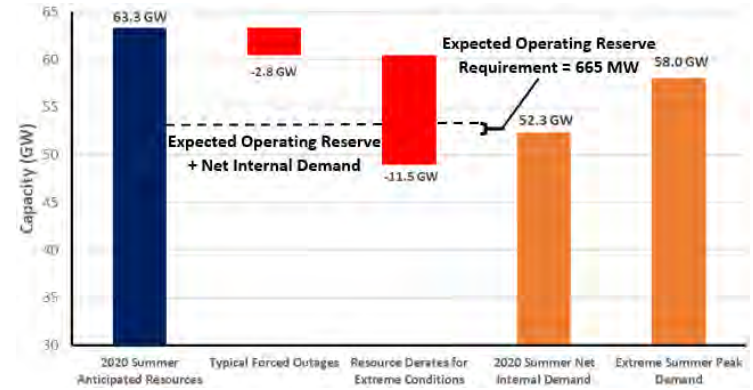
Scenario Assumptions

- **Extreme Peak Load:** Based on 90/10 demand forecast
- **Forced Outages:** Based on historical data
- **Extreme Derates:** Developed using the 10th percentile availability curves for the thermal, wind, and solar resources at the assessment area peak hour



WECC-California / Mexico

Seasonal Risk Scenario

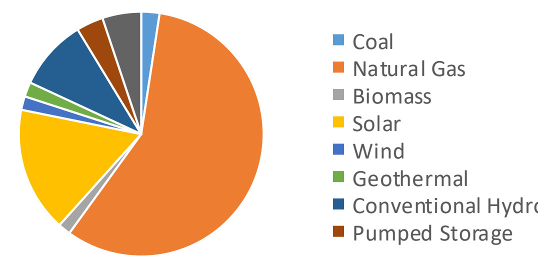


Risk Scenario Summary

Operating mitigations and EEAs may be needed under extreme demand and extreme resource derated conditions.

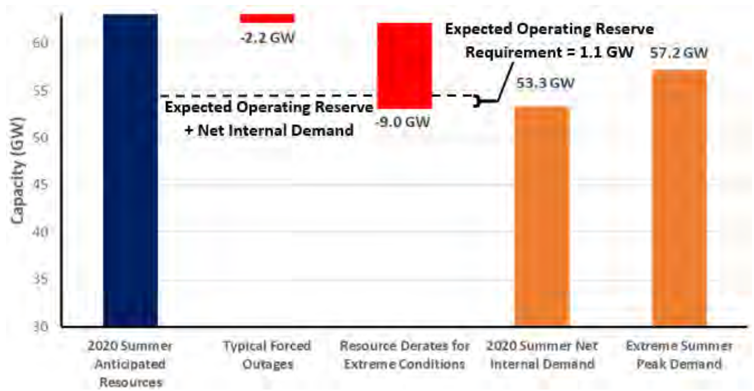
Scenario Assumptions

- **Extreme Peak Load:** Based on 90/10 demand forecast
- **Forced Outages:** Based on historical data
- **Extreme Derates:** Developed using the 10th percentile availability curves for the thermal, wind, and solar resources at the assessment area peak hour



WECC-Northwest Power Pool

Seasonal Risk Scenario

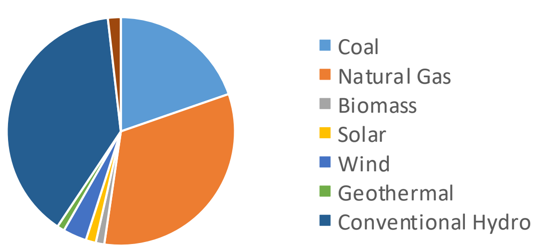


Risk Scenario Summary

Resources meet operating reserve requirements for normal peak-load and outage conditions. Operating mitigations and EEAs may be needed under extreme resource derated conditions.

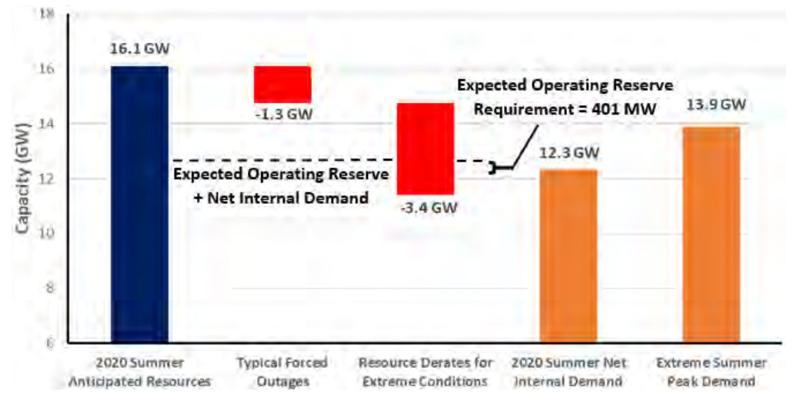
Scenario Assumptions

- **Extreme Peak Load:** Based on 90/10 demand forecast
- **Forced Outages:** Based on historical data
- **Extreme Derates:** Developed using the 10th percentile availability curves for the thermal, wind, and solar resources at the assessment area peak hour



WECC-Rocky Mountain Reserve Sharing Group

Seasonal Risk Scenario

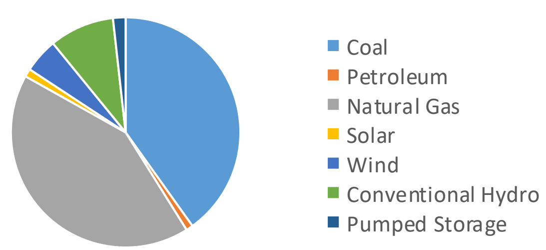


Risk Scenario Summary

Resources meet operating reserve requirements for normal peak-load and outage conditions. Operating mitigations and EEAs may be needed under extreme resource derated conditions.

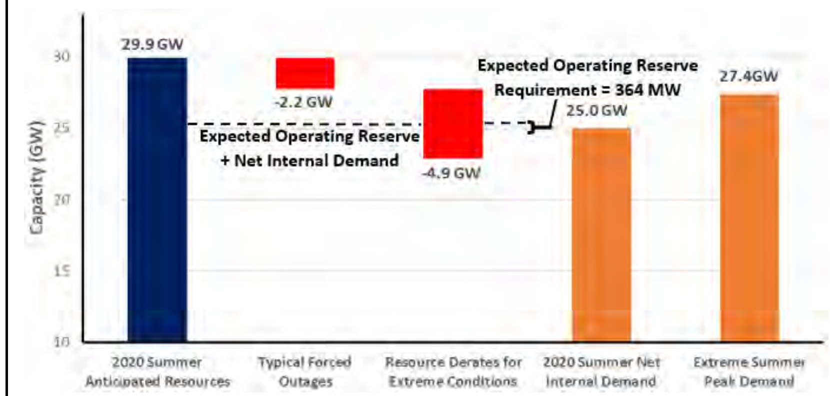
Scenario Assumptions

- **Extreme Peak Load:** Based on 90/10 demand forecast
- **Forced Outages:** Based on historical data
- **Extreme Derates:** Developed using the 10th percentile availability curves for the thermal, wind, and solar resources at the assessment area peak hour



WECC-Southwest Reserve Sharing Group

Seasonal Risk Scenario

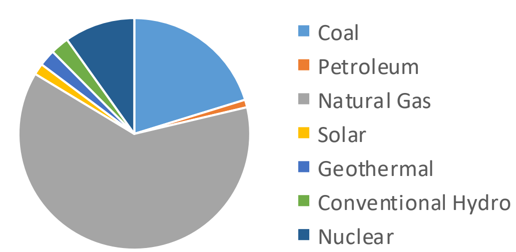


Risk Scenario Summary

Resources meet operating reserve requirements for normal peak-load and outage conditions. Operating mitigations and EEAs may be needed under extreme resource derated conditions.

Scenario Assumptions

- **Extreme Peak Load:** Based on 90/10 demand forecast
- **Forced Outages:** Based on historical data
- **Extreme Derates:** Developed using the 10th percentile availability curves for the thermal, wind, and solar resources at the assessment area peak hour



Data Concepts and Assumptions

The table below explains data concepts and important assumptions used throughout this assessment.

General Assumptions
• Reliability of the interconnected BPS is comprised of both adequacy and operating reliability:
▪ Adequacy is the ability of the electric system to supply the aggregate electric power and energy requirements of the electricity consumers at all times while taking into account scheduled and reasonably expected unscheduled outages of system components.
▪ Operating reliability is the ability of the electric system to withstand sudden disturbances such as electric short-circuits or unanticipated loss of system components.
• The reserve margin calculation is an important industry planning metric used to examine future resource adequacy.
• All data in this assessment is based on existing federal, state, and provincial laws and regulations.
• Differences in data collection periods for each assessment area should be considered when comparing demand and capacity data between year-to-year seasonal assessments.
• *2019 Long-Term Reliability Assessment* data has been used for most of this 2020 assessment period augmented by updated load and capacity data.
• A positive net transfer capability would indicate a net importing assessment area; a negative value would indicate a net exporter.
Demand Assumptions
• Electricity demand projections, or load forecasts, are provided by each assessment area.
• Load forecasts include peak hourly load[11] or total internal demand for the summer and winter of each year.[12]
• Total internal demand projections are based on normal weather (50/50 distribution[13]) and are provided on a coincident[14] basis for most assessment areas.
• Net internal demand is used in all reserve margin calculations, and it is equal to total internal demand then reduced by the amount of controllable and dispatchable demand response projected to be available during the peak hour.
Resource Assumptions
Resource planning methods vary throughout the North American BPS. NERC uses the categories below to provide a consistent approach for collecting and presenting resource adequacy. Table 2 below shows the wind and solar generation resources in each assessment area and describes how capacity contributions values are determined.
Anticipated Resources:
• **Existing-Certain Capacity**: Included in this category are commercially operable generating unit or portions of generating units that meet at least one of the following requirements when examining the period of peak demand for the summer season: unit must have a firm capability and have a power purchase agreement (PPA) with firm transmission that must be in effect for the unit; unit must be classified as a designated network resource; and/or where energy-only markets exist, unit must be a designated market resource eligible to bid into the market.
• **Tier 1 Capacity Additions**: This category includes capacity that either is under construction or has received approved planning requirements.
• **Net Firm Capacity Transfers (Imports minus Exports)**: This category includes transfers with firm contracts.
Prospective Resources: Includes all anticipated resources plus the following:
Existing-Other Capacity: Included in this category are commercially operable generating units or portions of generating units that could be available to serve load for the period of peak demand for the season but do not meet the requirements of existing-certain.
Reserve Margin Descriptions
Planning Reserve Margin: This is the primary metric used to measure resource adequacy; it is defined as the difference in resources (anticipated or prospective) and net internal demand then divided by net internal demand and shown as a percentage.

[11] *Glossary of Terms* used in NERC Reliability Standards

[12] The summer season represents June–September and the winter season represents December–February.

[13] Essentially, this means that there is a 50% probability that actual demand will be higher and a 50% probability that actual demand will be lower than the value provided for a given season/year.

[14] Coincident: This is the sum of two or more peak loads that occur in the same hour. Noncoincident: This is the sum of two or more peak loads on individual systems that do not occur in the same time interval; this is meaningful only when considering loads within a limited period of time, such as a day, a week, a month, a heating or cooling season, and usually for not more than one year. SERC and FRCC calculate total internal demand on a noncoincidental basis.

Reference Margin Level: The assumptions and naming convention of this metric vary by assessment area. The Reference Margin Level can be determined using both deterministic and probabilistic (based on a 0.1/year loss of load study) approaches. In both cases, this metric is used by system planners to quantify the amount of reserve capacity in the system above the forecasted peak demand that is needed to ensure sufficient supply to meet peak loads. Establishing a Reference Margin Level is necessary to account for long-term factors of uncertainty involved in system planning, such as unexpected generator outages and extreme weather impacts that could lead to increase demand beyond what was projected in the 50/50 load forecasted. In many assessment areas, a Reference Margin Level is established by a state, provincial authority, ISO/RTO, or other regulatory body. In some cases, the Reference Margin Level is a requirement. Reference Margin Levels may be different for the summer and winter seasons. If a Reference Margin Level is not provided by an assessment area, NERC applies 15% for predominately thermal systems and 10% for predominately hydro systems.

Seasonal Risk Scenario Chart Description

Each assessment area performed an operational risk analysis that was used to produce the seasonal risk scenario charts in the Regional Assessment Dashboards. The chart presents deterministic scenarios for further analysis of different resource and demand levels: The left blue column shows anticipated resources (from the resource adequacy data table), and the two orange columns at the right show the two demand scenarios of the normal peak net internal demand from the resource adequacy data table and the extreme summer peak demand—both determined by the assessment area. The middle red or green bars show adjustments that are applied cumulatively to the anticipated resources, such as the following:

- Reductions for typical generation outages (i.e., maintenance and forced, not already accounted for in anticipated resources)
- Reductions that represent additional outage or performance derating by resource type for extreme, low-probability conditions (e.g., drought condition impacts on hydroelectric generation, low-wind scenario affecting wind generation, fuel supply limitations, or extreme temperature conditions that result in reduced thermal generation output)
- Additional capacity resources that represent quantified capacity from operational procedures, if any, that are made available during scarcity conditions

Not all assessment areas have the same categories of adjustments to anticipated resources. Furthermore, each assessment area determined the adjustments to capacity based on methods or assumptions that are summarized below the chart. Methods and assumptions differ by assessment area and may not be comparable.

The chart enables evaluation of resource levels against levels of expected operating reserve requirement and the forecasted demand. Further, the effects from low-probability, extreme events can also be examined by comparing resource levels after applying extreme-scenario derates and/or extreme summer peak demand. Because such extreme scenario analysis depicts the cumulative impact resulting from the occurrence of multiple low-probability events, the overall likelihood of this scenario is very low.

BPS Wind and Solar Generation Resources by Assessment Area

Assessment Area	Wind			Solar		
	Nameplate (MW)	Available Peak Demand Hour Capacity (MW)	Available/Nameplate (%)	Nameplate (MW)	Available Peak Demand Hour Capacity (MW)	Available/Nameplate (%)
MISO	21,594	4,417	20.5%	663	390	58.8%
MRO-Manitoba Hydro	259	44	17.0%	0	0	-
MRO-SaskPower	241	55.8	23.2%	29	0	0.0%
NPCC-Maritimes	1,170	283	24.2%	2	0	0.0%
NPCC-New England	1,421	178	12.5%	200	119	59.5%
NPCC-New York	1,985	301	15.2%	57	16	27.7%
NPCC-Ontario	4,846	664	13.7%	478	66	13.8%

BPS Wind and Solar Generation Resources by Assessment Area						
Assessment Area	Wind			Solar		
	Nameplate (MW)	Available Peak Demand Hour Capacity (MW)	Available/Nameplate (%)	Nameplate (MW)	Available Peak Demand Hour Capacity (MW)	Available/Nameplate (%)
NPCC-Quebec	3,904	0	0.0%	0	0	-
PJM	10,399	1,648	15.8%	4,684	2,415	51.6%
SERC-C	480	456	95.0%	10	8	80.0%
SERC-E	0	0	-	555	546	98.4%
SERC-FP	0	0	-	2,969.3	1,582.3	-
SERC-SE	0	0	-	2,266	2,259	99.7%
SPP	23,529	5,761	24.5%	272	201	73.9%
Texas RE-ERCOT	27,847	6,924	24.9%	3,735	2,838	76.0%
WECC-AB	1,445	142	9.8%	115	4.5	3.9%
WECC-BC	727.5	146	20.1%	2	0.6	30.0%
WECC-CAMX	6,773	1,097	16.2%	13,774	10,090	73.3%
WECC-NWPP-US	10,898	2,023	18.6%	5,831	883	15.1%
WECC-RMRG	3,852	774	20.1%	756	180	23.8%
WECC-SRSG	1,327	203	15.3%	1,698	458	27.0%

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

2021 Summer Reliability Assessment

May 2021

Table of Contents

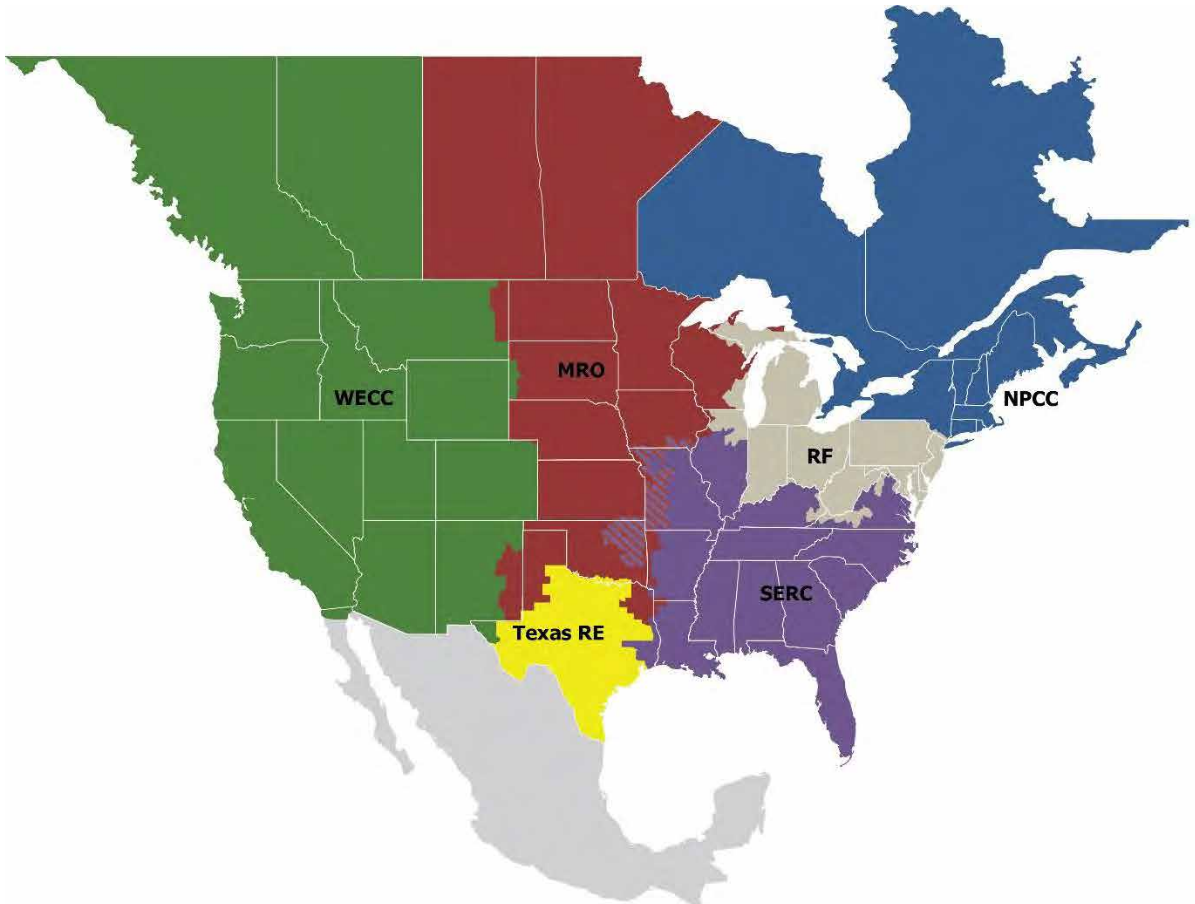
Preface

The vision for the Electric Reliability Organization Enterprise, which is comprised of the North American Electric Reliability Corporation (NERC) and the six Regional Entities (RE), 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 below. The multicolored area denotes overlap as some load-serving entities participate in one RE while associated Transmission Owners/Operators participate in another. Refer to the **Data Concepts and Assumptions** section for more information. A map and list of the assessment areas can be found in the **Regional Assessments Dashboards** section.



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

About this Report

NERC's *2021 Summer Reliability Assessment* (SRA) identifies, assesses, and reports on areas of concern regarding the reliability of the North American BPS for the upcoming summer season. In addition, the SRA presents peak electricity demand and supply changes and highlights any unique regional challenges or expected conditions that might impact the BPS. The reliability assessment process is a coordinated reliability evaluation between the Reliability Assessment Subcommittee (RAS), the RE, and NERC staff. This report reflects NERC's independent assessment and is intended to inform industry leaders, planners, operators, and regulatory bodies so that they are better prepared to take necessary actions to ensure BPS reliability. This report also provides an opportunity for the industry to discuss plans and preparations to ensure reliability for the upcoming summer period.

Findings

NERC's annual SRA covers Summer 2021 (June–September). This assessment provides an evaluation of the resource and transmission system adequacy that is necessary to meet projected summer peak demands. In addition to assessing resource adequacy, the SRA monitors and identifies potential reliability issues of interest and regional topics of concern. The following key findings represent NERC's independent evaluation of electric generation and transmission capacity as well as potential operational concerns that may need to be addressed for the upcoming summer:

- Parts of North America are at elevated risk to energy emergencies (see **Figure 1**). Above-normal heat in summer can challenge grid operators by increasing demand from temperature-dependent loads (such as air-conditioning and refrigeration) and reducing electricity supplies as a result of lower-than-capacity resource output or increased outages. Wide-area heat events (such as the August 2020 heat wave that affected much of the Western United States and Mexico) are especially challenging as fewer resources are available for electricity transfers between areas because they are required to serve native load:
  - In **Texas RE**, on-peak Planning Reserve Margins have increased to 15.3% from 12.9% last summer with the addition of 7,858 MW wind, solar, and battery resources since 2020. However, extreme weather can affect both generation and demand and cause energy shortages that lead to energy emergencies in the Electric Reliability Council of Texas (ERCOT). Furthermore, with a significant portion of electricity supply coming from wind generation, operators must have sufficient flexible resources to cover periods of low-wind output.
  - Across most of **WECC**, resource and energy adequacy is a significant concern for the summer with overall capacity and demand projections for the area at similar levels to those seen in 2020 when a wide-area heat event caused energy emergencies and managed firm load loss. Though new flexible resources have been added in California, peak demand projections have also increased in many parts of the west, and overall resource capacity is lower compared to 2020. Increasing demand and lower resource capacity across WECC can mean the availability of surplus capacity for transfer into stressed areas is declining.
  - **MISO** and **NPCC-New England** have sufficient resources for periods of peak demand. However, the above-normal levels of demand in the 90/10 forecast are likely to exceed capacity resources and require additional non-firm transfers from surrounding areas.
  - All other areas have sufficient resources to manage normal summer peak demand and are at low risk of energy shortfalls from more extreme demand or generation outage conditions. Anticipated Reserve Margins meet or surpass the Reference Margin Level, indicating that planned resources in these areas are adequate to manage the risk of a capacity deficiency under normal conditions.[1] Furthermore, based on risk scenario analysis in these areas, resources and energy appear adequate.

Figure 1: Energy Emergency Risk Areas

- **WECC-California is at risk of energy emergencies during periods of normal peak summer demand and high risk when above-normal demand is widespread in the west.** Prior to summer, the planning reserve margin (which is based on existing and firm capacity) for the California-Mexico assessment area was below the 18.4% Reference Margin Level that WECC calculates is

[1] For more information, see the description of the "Reference Margin Level" in the **Data Concepts and Assumptions** section of this report or refer to NERC's *Long-term Reliability Assessment*: https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_LTRA_2020.pdf

needed for maintaining loss-of-load risk below a 1-day-in-10-year benchmark (a 400 MW shortfall at peak demand). Probabilistic studies indicate 10,185 MWh of energy in the area is expected to go unserved this summer. Over 3 GW of additional resources are expected for this summer with most coming in the form of new solar photovoltaic (PV) generation. These generation plants can provide energy to support peak demand; however, solar PV output falls off rapidly in late afternoon while high demand often remains.

Imports to the area are needed to maintain reliability when demand peaks in the afternoon and to ramp up even further for several hours as internal resources draw down. California will have 675 MW of new battery energy storage systems on-line at the start of the summer that can continue to supply stored energy for periods when needed. Reliance on non-firm imports to cover high demand or low resource output conditions heightens the risk that operators will need to use energy emergency alerts (EEA)—and trigger the shedding of firm load in above-normal heat conditions—to maintain a stable BPS at times. Planned resource additions of 1,300 MW over the summer, including 825 MW of new battery storage, are expected to help mitigate late-summer risks.

- **Protecting the critical electrical workforce from health risks during pandemic remains a priority.** Protocols put in place for reducing risks to personnel in control centers and on the front lines, including mutual assistance in hurricane-damaged areas, should be maintained as warranted by public health conditions. Also related to the coronavirus (COVID-19) pandemic, operators must continue to give attention to daily load shapes that can be sensitive to changing behaviors of the workforce and commercial loads. In 2021, there is remaining uncertainty in demand projections as governments adjust to changing public health guidelines and conditions and as the behavior of society adapts.
- **The Late-summer wildfire season in Western United States and Canada poses risk to BPS reliability.** Government agencies warn of the potential for above-normal wildfire risk beginning in July in parts of the Western United States as well as Central and Western Canada.[2,3] Operation of the BPS can be impacted in areas where wildfires are active as well as areas where there is heightened risk of wildfire ignition due to weather and ground conditions (see **Figure 3**).

Implications and Recommendations

The summer of 2021 is shaping up to be a challenge for electric system operators in many parts of North America, combining the resource situation described above with significant drought, fire, and high temperature risk assessments by independent agencies. In the near term, NERC recommends the following:

- Load-serving entities (LSE) and regulators work with their Balancing Authorities (BA) and Reliability Coordinators (RC) to ensure that clear lines of communication are open for coordination during periods of system stress. RC, BA, and Transmission Operators review outage schedules well in advance and coordinate across the RC area.
- BA and RC conduct drills on their alert programs to ensure that they are prepared to signal need for conservative operations, restrictive maintenance periods, etc. BA and Generator Operators verify protocols and operator training for communication and dispatch.
- LSE prepare for demand-side conservation measures and potentially condition customers to their need and efficacy.
- RC and BA maintain the highest vigilance during peak risk hours and forecasted high temperature periods.
- LSE review non-firm customer inventories and rolling black out procedures to ensure that no critical infrastructure loads (e.g., natural gas, telecommunications, etc.) would be affected.

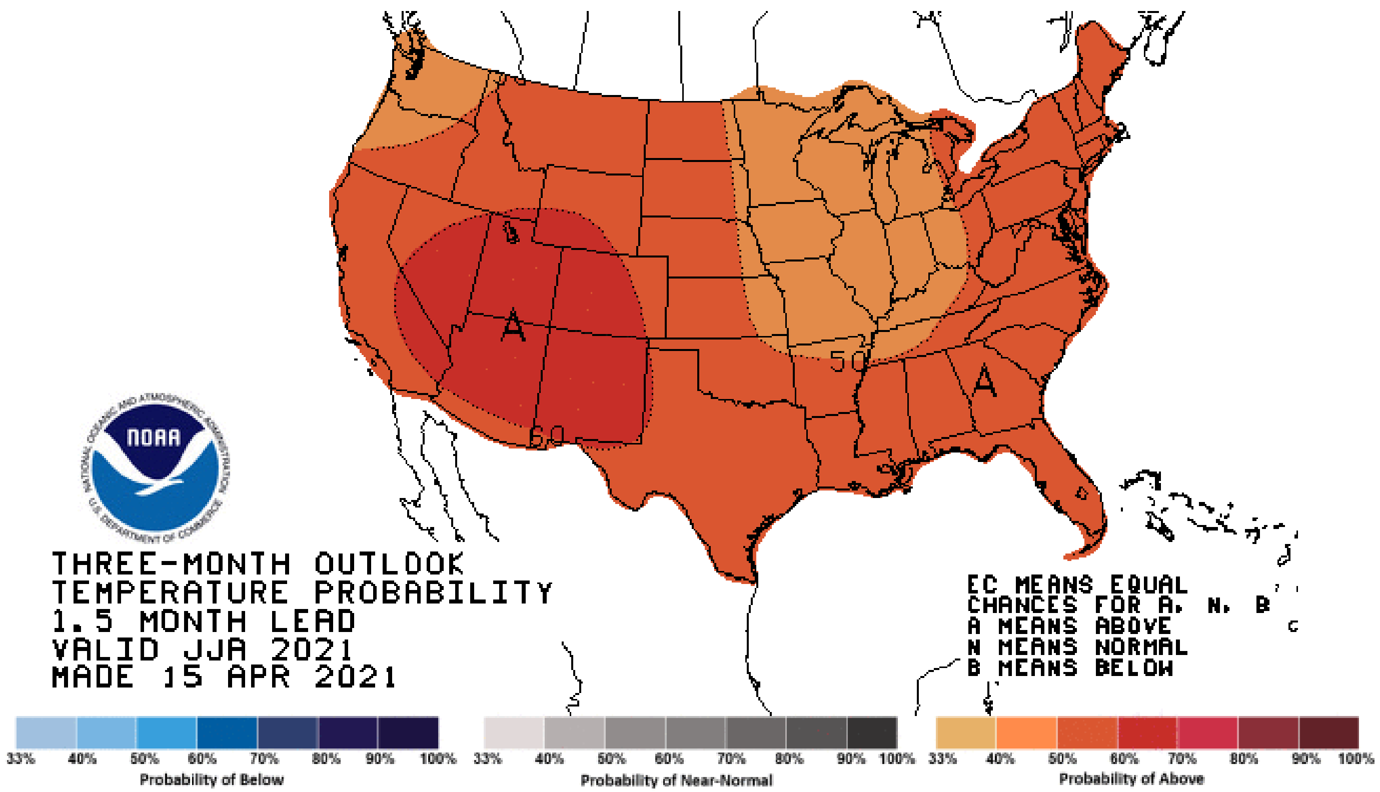
Finally, the potential for these conditions to emerge were reflected in NERC's *2018* and *2020 Long-Term Reliability Assessments*; we recommend policy makers, system planners, LSE, and Generator Owners review these assessments and factor them into their integrated resource plans, and ISO/RTO factor them into their own generation queue management and long-range planning processes.[4]

---

[2] See North American Seasonal Fire Assessment and Outlook, April 2021: https://www.predictiveservices.nifc.gov/outlooks/NA_Outlook.pdf.
[3] See Natural Resources Canada seasonal wildland fire forecasts: https://cwfis.cfs.nrcan.gc.ca/maps/forecasts
[4] NERC's Reliability Assessments web page: https://www.nerc.com/pa/RAPA/ra/Pages/default.aspx

Summer Temperature and Drought Forecasts

Peak electricity demand in most areas is strongly influenced by temperature. Weather officials are expecting above normal temperatures for much of North America this summer (see Figure 2). Assessment area load forecasts account for many years of historical demand data, often up to 30 years, to predict summer peak demand and prepare for more extreme conditions. Above average seasonal temperatures can contribute to high peak demand as well as increases in forced outages for generation and some BPS equipment. Effective preseason maintenance and preparations are particularly important to BPS reliability in severe or prolonged periods of above-normal temperatures.



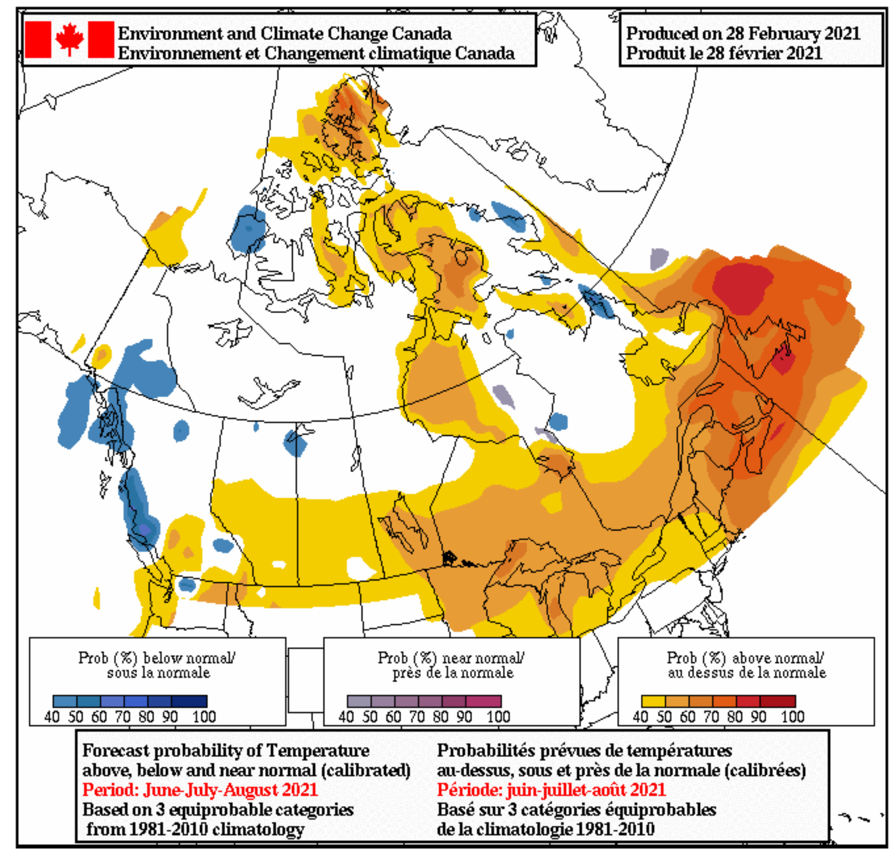


Figure 2: United States and Canada Summer Temperature Outlook[5]

[5] Seasonal forecasts obtained from U.S. National Weather Service and Natural Resources Canada: https://www.cpc.ncep.noaa.gov/products/predictions/long_range/ and https://weather.gc.ca/saisons/prob_e.html

Wildfire Risk Potential and BPS Impacts

Drought conditions extend over the western half of the United States and the middle-third of Canada. Above-normal fire risk at the beginning of the summer exists in the Southwest United States and over the middle-third of North America in the spring, setting the stage for an active fire season at the beginning of the summer (see **Figure 3**). Government agencies predict an active early fire season in the Southwest United States as well as above-normal risk in the lower half of central Canada (Southern Prairies, Boreal forest, grassland and parkland areas).[6] In late summer, hotter and drier conditions are expected to cause elevated fire risk in California and the United States West Coast. BPS operation can be impacted in areas where wildfires are active as well as areas where there is heightened risk of wildfire ignition due to weather and ground conditions (see **Finding: Risk Discussion**).

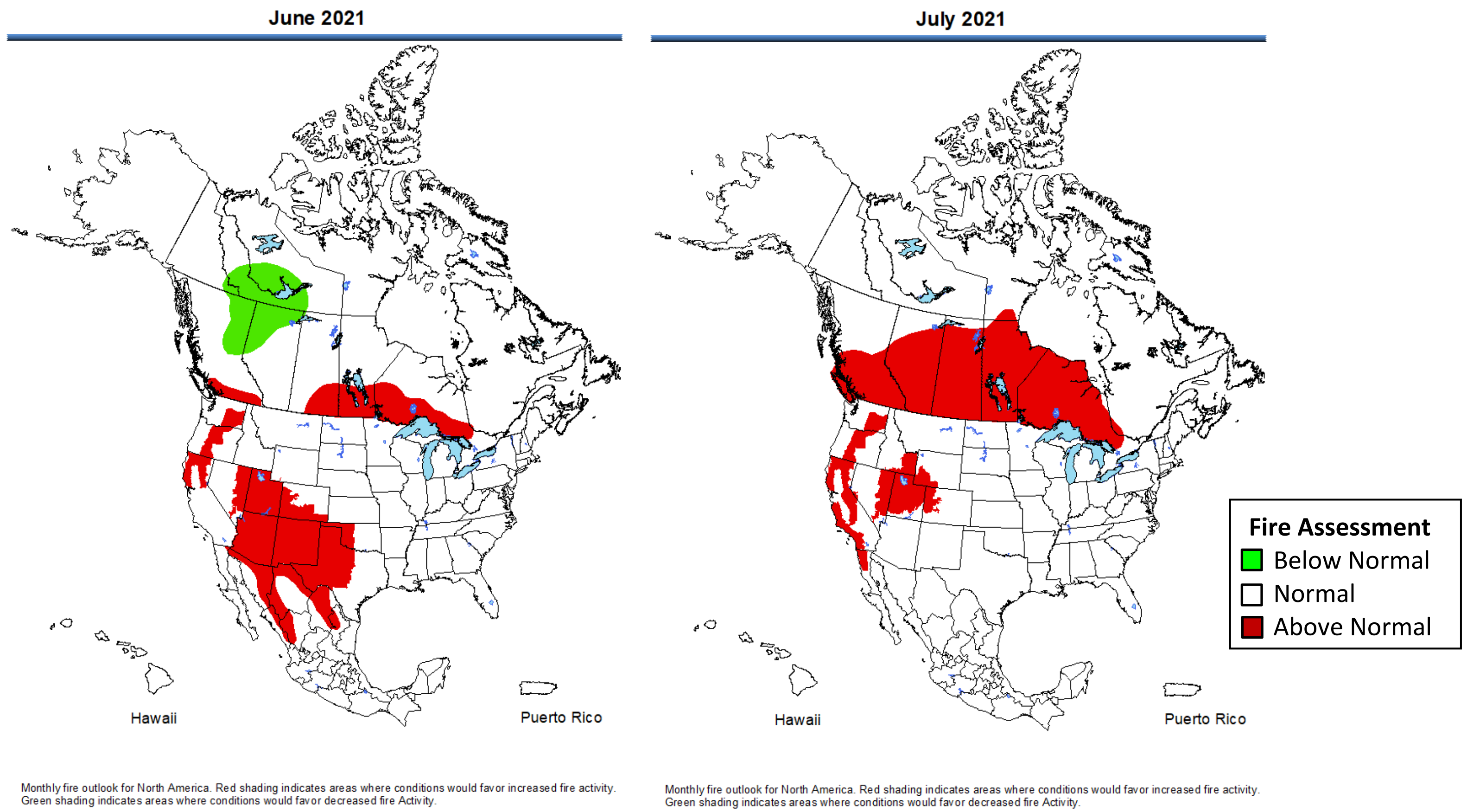


Figure 3: North American Seasonal Fire Assessment for June and July 2021

[6] See North American Seasonal Fire Assessment and Outlook, April 2021: https://www.predictiveservices.nifc.gov/outlooks/NA_Outlook.pdf

Finding: Risk Discussion

Texas RE: ERCOT Interconnection

With forecasted growth in peak demand and new generation resources primarily coming in the form of variable wind and solar generation, the risk of shortages that lead to energy emergencies in ERCOT continues for the upcoming summer. On-peak Planning Reserve Margins have increased to 15.3% from 12.9% last summer with the addition of 7,858 MW wind, solar, and battery resources since 2020; This exceeds the 13.75% Reference Margin Level established in ERCOT for reliably serving demand under normal summer peak conditions. However, extreme weather can affect both resource and demand and cause energy shortages that lead to energy emergencies in ERCOT. Furthermore, with a significant portion of electricity supply coming from wind generation, operators must have sufficient flexible resources to cover periods of low-wind output (see Figure 4 for a risk scenario involving 90/10 low wind conditions and normal 50/50 peak demand). Operational mitigations may be needed in unexpected wind generation shortfalls to avoid energy emergencies.

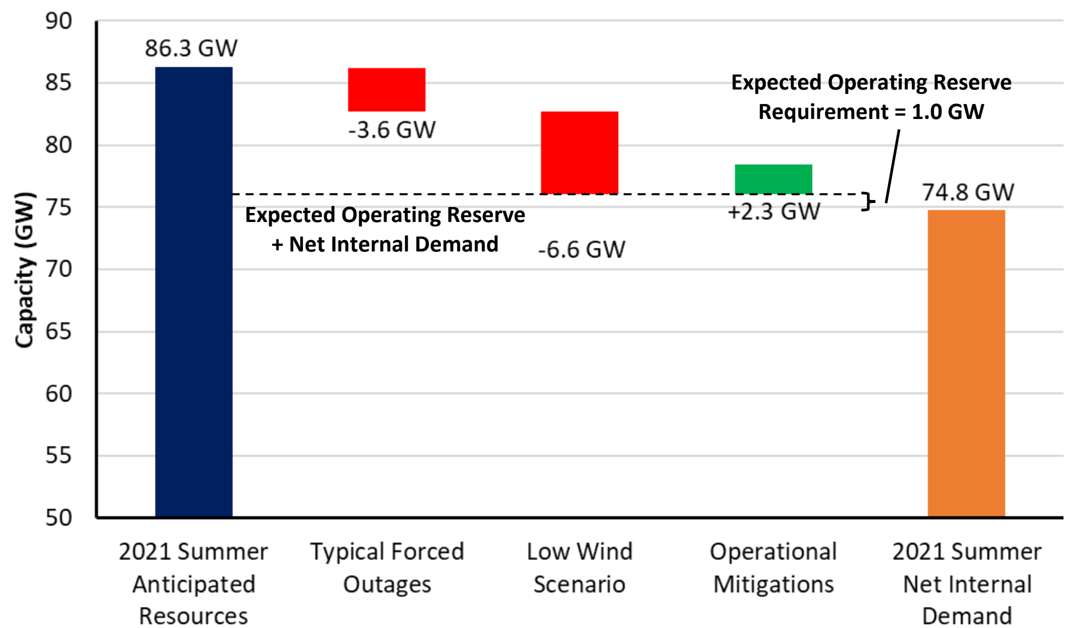


Figure 4: Combination of Low-Wind and Normal Generator Outages at Peak Demand in ERCOT

Weather conditions can create an elevated risk of operating emergencies in ERCOT in the event that higher demand or lower resource output diminishes the relatively low reserve margins that exist on the system. Shown in Figure 5 are the 1-in-10 year high demand levels alongside an extreme low-resource scenario: 12.1% of expected thermal resources are unavailable as well as 76.8% reduced output of expected wind (this is 6.2% of the total installed nameplate wind capacity operating). Combinations of high peak demand and extreme low resource output are exceedingly rare; however, they are plausible and provide industry and stakeholders with insights into potential emergency conditions. The result of the described scenario is a 12.7 GW shortfall. In challenging conditions like those depicted, operators would resort to implementing rotating outages as a measure of preserving the BPS.

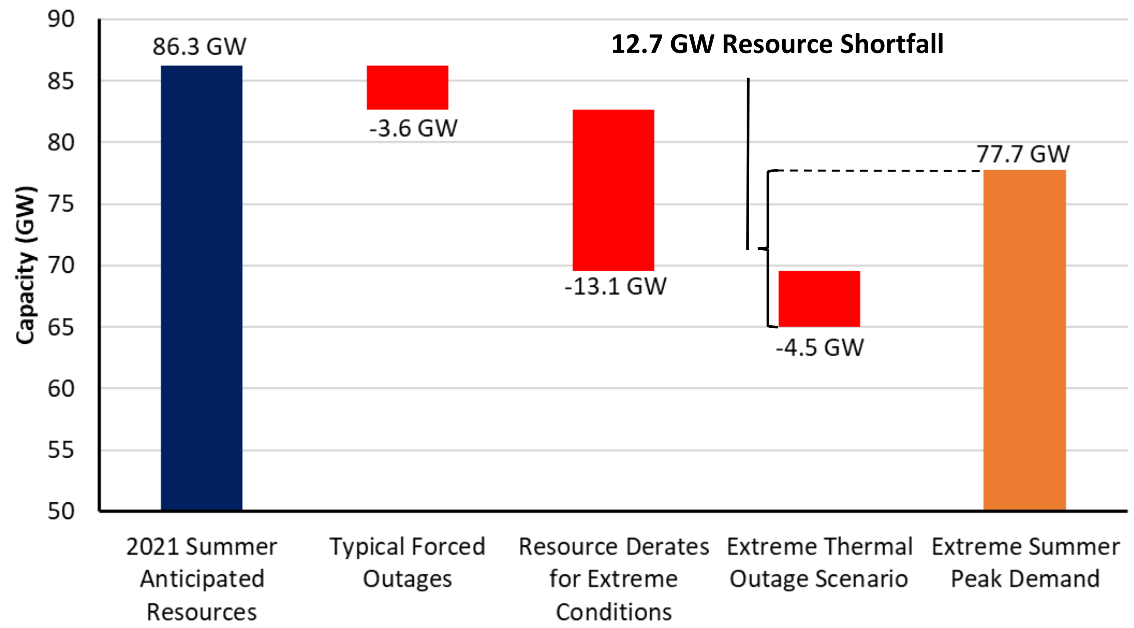


Figure 5: Impact of Extreme Demand and Resource Outages in ERCOT

In addition to the 1-in-10 year demand scenario above, ERCOT conducted an additional extreme demand scenario based on a wide-area heat event. In this scenario, peak demand increases by over 4,900 MW from a normal 50/50 demand forecast as all of ERCOT's eight weather zones show simultaneous high levels of demand from higher temperatures. Even with the normal resource performance and low outages typically seen in ERCOT, the electricity demand from a wide-area heat event would likely lead to operating emergencies and a potential for unserved load.[7]

Currently, much of Texas is experiencing a drought, and projections for below-normal rainfall are cause for concern for electric reliability.[8] If drought conditions continue to deteriorate, the likelihood of the actual summer peak demand exceeding the forecast and/or generation derates due to low cooling lake levels increases. Generator outages are expected to increase during severe and prolonged drought conditions due to cooling water supply and temperature issues. These issues can cause forced outages of the thermal and wind fleet.

Generator performance in ERCOT is optimized for summer conditions, supporting reliable system performance despite relatively lower reserve margins. The generation fleet in ERCOT is a diverse mix of fuel types, including natural gas, nuclear, on-shore and coastal wind, solar, and a small amount of coal-fired generation. Some design choices, such as open-air thermal plants, provide optimum summer efficiency but may contribute to operating stress at other times. The availability of reliable, flexible generation is important to balancing system needs with a high penetration of variable, weather-dependent generation from wind and solar.

---

[7] See ERCOT's *2021 Summer Seasonal Assessment of Resource Adequacy (SARA)*: http://www.ercot.com/content/wcm/lists/219840/SARA-FinalSummer2021.pdf
[8] https://droughtmonitor.unl.edu/CurrentMap/StateDroughtMonitor.aspx?TX

WECC: Western Interconnection

Resource and energy adequacy is a significant concern for the summer across most of the Western Interconnection with overall capacity and demand projections for the area at similar levels to those seen in 2020 when a wide-area heat event caused energy emergencies and managed firm load loss. New flexible resources have been added in California and some plans for generation retirements have been put on hold to improve resource availability for periods of peak demand as well as for times when variable generation output falls off. However, peak demand projections have also increased in many parts of the Western United States, and overall resource capacity is lower compared to 2020 (see **Table 1**). Increased demand and lower resource capacity across the Western Interconnection can mean limited availability of surplus capacity for transfer into load centers for parts of California.

August 2020 Heatwave Event in the Western Interconnection

From August 14 through August 19, 2020, the Western United States suffered an intense and prolonged heatwave that affected many areas across the Western Interconnection.[9] Because of above-average temperatures, generation and transmission capacity struggled to keep up with increased electricity demand. Throughout many supply-constrained hours over this same period, generation resource output was below preseason peak forecasts for nearly all resource types, including natural gas, wind, solar, and hydro. During the event, 10 Western Interconnection BA issued 18 separate EEA. The impacts of the August heatwave struck the entirety of the Western Interconnection and caused a peak demand record of 162,017 MW on August 18, 2020, at 4:00 p.m. Mountain time. Although demand peaked on August 18, the most severe reliability consequence of the heatwave event occurred at the beginning, when 1,087 MW of firm load was shed on August 14 and 692 MW was shed on August 15 in California. An in-depth evaluation of the August 2020 Heatwave Event on BPS operations will be included in the 2021 State of Reliability report. The State of Reliability covers significant BPS events from the prior year and is typically published mid-year.

Table 1: Western Interconnection On-Peak Resource Adequacy

WECC - AB			
	2020 SRA	2021 SRA	2020 vs. 2021 SRA
Demand Projections	Megawatts (MW)	Megawatts (MW)	Net Change (%)
Total Internal Demand (50/50)	11,500	10,886	-5.3%
Net Internal Demand	11,500	10,886	-5.3%
Resource Projections	Megawatts (MW)	Megawatts (MW)	Net Change (%)
Existing-Certain Capacity	14,356	12,205	-15.0%
Anticipated Resources	14,356	13,928	-3.0%
Reserve Margins	Percent (%)	Percent (%)	Annual Difference
Anticipated Reserve Margin	24.8%	27.9%	3.1
Reference Margin Level	10.4%	9.7%	-0.7
WECC - BC			
Demand, Resource, and Reserve Margins	2020 SRA	2021 SRA	2020 vs. 2021 SRA
Demand Projections	Megawatts (MW)	Megawatts (MW)	Net Change (%)
Total Internal Demand (50/50)	8,278	8,264	-0.2%
Net Internal Demand	8,278	8,264	-0.2%
Resource Projections	Megawatts (MW)	Megawatts (MW)	Net Change (%)
Existing-Certain Capacity	11,471	11,178	-2.6%
Anticipated Resources	11,686	11,363	-2.8%
Reserve Margins	Percent (%)	Percent (%)	Annual Difference

[9] WECC August Heat Wave Event information provided by WECC's *August Heat Wave Analysis* Presentation

Table 1: Western Interconnection On-Peak Resource Adequacy			
Anticipated Reserve Margin	41.2%	37.5%	-3.7
Reference Margin Level	10.4%	9.7%	-0.7
WECC - CA / MX			
Demand, Resource, and Reserve Margins	2020 SRA	2021 SRA	2020 vs. 2021 SRA
Demand Projections	Megawatts (MW)	Megawatts (MW)	Net Change (%)
Total Internal Demand (50/50)	53,236	55,409	4.1%
Net Internal Demand	52,326	54,487	4.1%
Resource Projections	Megawatts (MW)	Megawatts (MW)	Net Change (%)
Existing-Certain Capacity	63,186	63,396	0.3%
Anticipated Resources	63,278	67,440	6.6%
Reserve Margins	Percent (%)	Percent (%)	Annual Difference
Anticipated Reserve Margin	20.9%	23.8%	2.9
Reference Margin Level	13.7%	18.4%	4.7
WECC - NWPP-US & RMRG			
Demand, Resource, and Reserve Margins	2020 SRA	2021 SRA	2020 vs. 2021 SRA
Demand Projections	Megawatts (MW)	Megawatts (MW)	Net Change (%)
Total Internal Demand (50/50)	66,532	67,117	0.9%
Net Internal Demand	65,664	66,030	0.6%
Resource Projections	Megawatts (MW)	Megawatts (MW)	Net Change (%)
Existing-Certain Capacity	78,839	70,069	-11.1%
Anticipated Resources	80,457	77,210	-4.0%
Reserve Margins	Percent (%)	Percent (%)	Annual Difference
Anticipated Reserve Margin	*	16.9%	*
Reference Margin Level	*	14.3%	*
WECC - SRSG			
Demand, Resource, and Reserve Margins	2020 SRA	2021 SRA	2020 vs. 2021 SRA
Demand Projections	Megawatts (MW)	Megawatts (MW)	Net Change (%)
Total Internal Demand (50/50)	25,145	24,751	-1.6%
Net Internal Demand	25,001	24,419	-2.3%
Resource Projections	Megawatts (MW)	Megawatts (MW)	Net Change (%)
Existing-Certain Capacity	29,440	26,850	-8.8%
Anticipated Resources	29,917	27,904	-6.7%
Reserve Margins	Percent (%)	Percent (%)	Annual Difference
Anticipated Reserve Margin	19.7%	14.3%	-5.4
Reference Margin Level	10.0%	9.8%	-0.2

Responding to supply shortages from August 2020 and a directive from the California Public Utilities Commission, utilities in California have been procuring additional generating capacity for Summer 2021.[10] Existing on-peak capacity for the California-Mexico (CAMX) assessment area is 63.4 GW, a slight increase from 2020. However, a total of 3.4 GW of new resources are in late-stage planning for addition this summer; without these resources, the CAMX area will have an on-peak planning reserve margin of 17.6%, just short of the 18.4% Reference Margin Level target set by WECC for the area.[11] See **Figure 6** for peak hour existing certain and anticipated resource reserve margins for the Western Interconnection assessment areas.

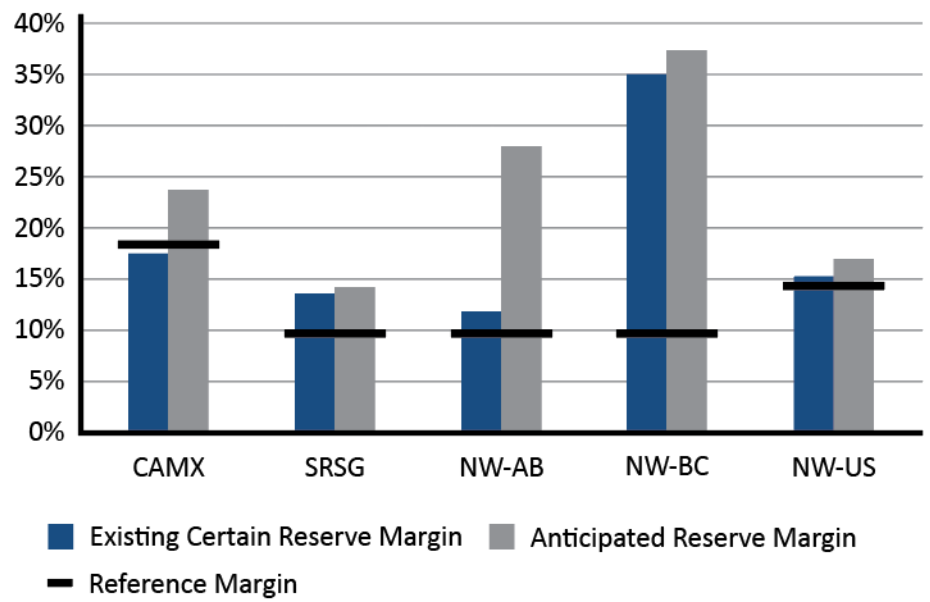


Figure 6: On-Peak Planning Reserve Margins in the Western Interconnection Assessment Areas

Most of the resource additions in California come in the form of new solar PV generation. These generation plants can provide energy to support peak demand; however, solar PV output falls off rapidly in late afternoon while summer demand often remains (see the discussion in the **Western Interconnection Risk Scenarios** section). Battery storage systems can supply energy to smooth the system ramping needs associated with high amounts of variable generation; by summer, nearly 600 MW of large-scale battery storage projects will have come on-line in California with an additional 800 MW expected by August 1.[12] The California Independent System Operator (CAISO) has performed significant work to support the integration of these new technologies into market and operating systems so that they will enhance grid reliability.

Throughout the Western Interconnection, BAs rely on flexible resources to support balancing the increasingly weather-dependent load with the variable generation within the resource mix. Dispatchable generation from hydroelectric and thermal plants internal to the BA's area as well as imports from surplus energy in another area are called upon by operators when area shortfalls are anticipated. Under normal

---

[10] See California Public Utilities Commission Emergency Reliability Rulemaking R.20-11-003

[11] WECC's Reference Margin Levels are based on a probabilistic approach for Loss-of-Load Probability (LOLP) less than or equal to 0.02% (approximately a 1-day-in-10-year loss of load). For more information see the *NERC 2020 Long-Term Reliability Assessment (LTRA)* Table 10: https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_LTRA_2020.pdf

[12] A summary of resource additions in the CAISO area is found in Table 10 of the *CAISO Summer Loads and Resources Assessment, May 2021*: http://www.caiso.com/Documents/2021-Summer-Loads-and-Resources-Assessment.pdf

conditions, there is sufficient energy and resource capacity and an adequate transmission network for transfers between areas to meet system ramping needs. However, conditions such as wide-area heat events can reduce the availability of resources for transfer as areas serve higher internal demands. Additionally, transmission networks can become stressed when events such as wildfires or wide-area heatwaves cause network congestion. The growing reliance on transfers within the Western Interconnection and falling resource capacity in many adjacent areas increases the risk that extreme events will lead to load interruption.

Western Interconnection Risk Scenarios

Probabilistic studies performed by WECC identified a continued risk of energy shortfalls. For the upcoming summer, the WECC-CAMX area has 10,180 MWh of expected unserved energy (EUE) and the Northwest Power Pool and the Rocky Mountain Reserve Sharing Group (WECC-NWPP & RMRG) has 3,442 MWh of EUE; all other WECC areas have negligible EUE. WECC examined risk across a wide probability spectrum of potential combinations of high loads and low generation levels, with and without dependency on neighboring BA areas, and how deviations from those expected means would affect reliability.[13] The risk analysis charts in the **Regional Assessments Dashboards** illustrate the potential for above-normal peak demand and resource outage scenarios, similar to those seen in 2020, to result in operating emergencies in all WECC assessment areas with the exception of the winter-peaking Canadian provinces. For example, **Figure 7** is for the WECC CAMX area. Wide-area heatwave events can heighten energy shortfall risks throughout the Western Interconnection by reducing the availability of surplus capacity for sharing or by loading the transmission network to the limits of its transfer capability.

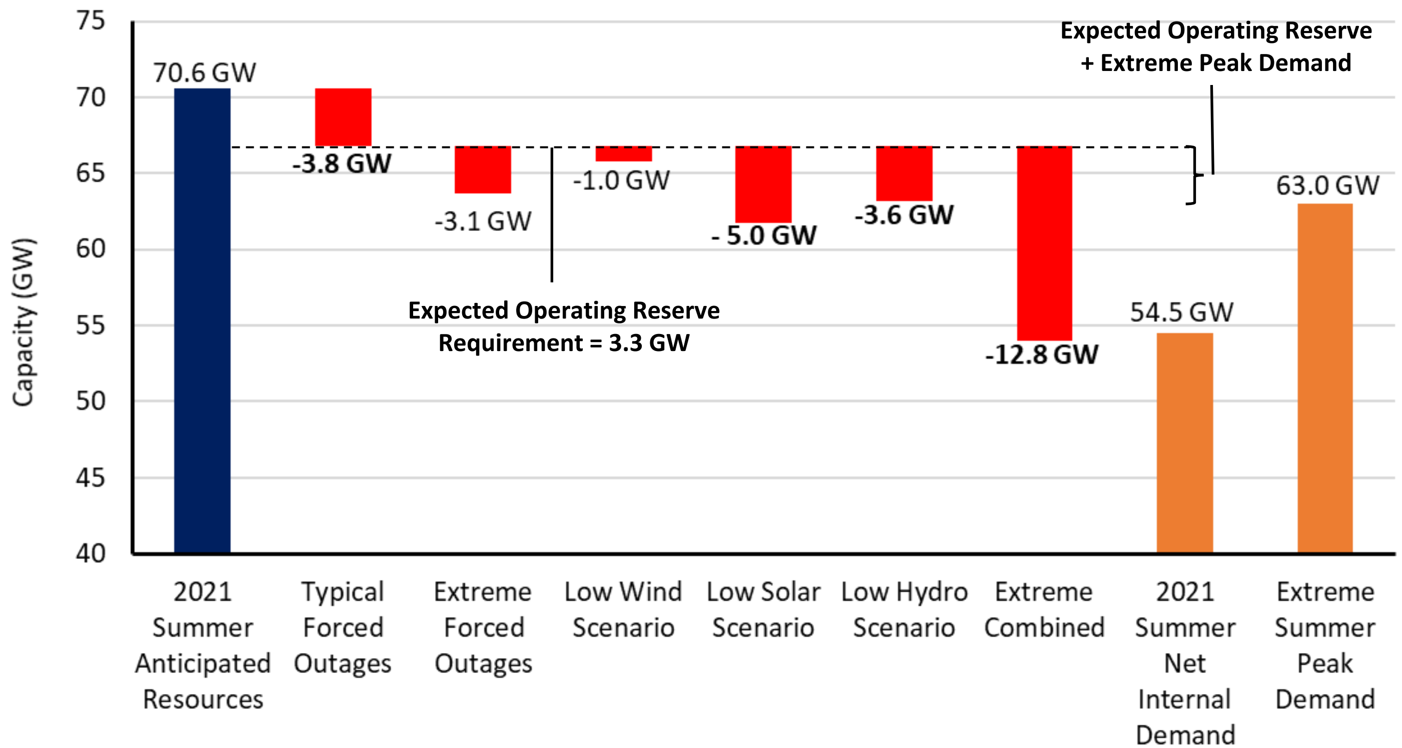


Figure 7: CAMX On-Peak Risk Scenario

[13] See *Western Assessment of Resource Adequacy Report*: Western Assessment of Resource Adequacy Report 12-18 (Final).pdf.pdf (wecc.org)

In summer, CAMX can be exposed to greater risk of resource shortfall for the hours that immediately follow the peak demand. The reason the risk is greater in these hours is that solar resource output is rapidly diminishing with the setting sun. Shown in the scenario depicted in Figure 8, anticipated resources are lower than on peak due to the reduced solar PV outputs. During periods of peak demand and normal forced outages, imports provide the needed energy to ensure demand and operating reserve requirements are met. Demand or resource derates from extreme conditions that cannot be satisfied with imports will result in energy emergencies and the potential for load shedding. Though trends for off-peak risk are increasing in other parts of the Western Interconnection, WECC's analysis indicates that greater risk exposure after the demand peak is only exhibited in CAMX.

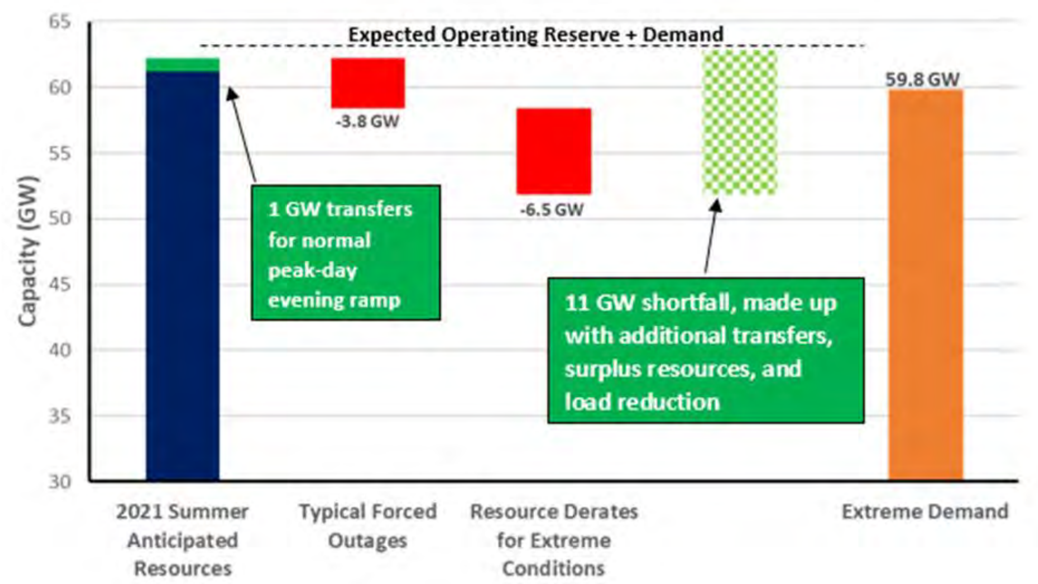


Figure 8: CAMX Highest Risk Hour Scenario (Hour Ending 7:00 p.m. Pacific Time)

Given that little has changed in the available electricity resources and the expected demand throughout the Western Interconnection, the summer-peaking areas remain at risk for localized shortfalls to exceed the availability of resource assistance and transmission deliverability during events like the 2020 August wide-area heat wave. Early generation and load forecasting based on long-term meteorological conditions will be important to maximize available generation and prepare load management plans for challenging weather. Enhancements to day-ahead markets and operational planning that were put in place and were effective in mitigating the impacts of the second, higher temperature heat wave that extended across the Western United States in September 2020 will need to be employed again to support BPS reliability in similar conditions.

Wildfire Impacts to the BPS in the Western Interconnections

Operation of the BPS can be impacted in areas where wildfires are active as well as areas where there is heightened risk of wildfire ignition due to weather and ground conditions. Wildfire prevention planning in California and other areas include power shut-off programs in high fire-risk areas. When conditions warrant implementing these plans, power lines (including transmission-level lines) may be preemptively de-energized in high fire-risk areas to prevent wildfire ignitions. Other wildfire risk mitigation activities include implementing enhanced vegetation management, equipment inspections, system hardening, and added situational awareness measures. In January 2021, the Electric Reliability Organization published the *Wildfire Mitigation Reference Guide*[14] to promote preparedness within the North American electric power industry and share the experience and practices from utilities in the Western Interconnection.

On-Peak Planning Reserve Margins

The Anticipated Reserve Margin, which is based on available resource capacity, is a metric used to evaluate resource adequacy by comparing the projected capability of anticipated resources to serve forecasted peak demand.[15] Large year-to-year changes in anticipated resources or forecasted peak demand (net internal demand) can greatly impact Planning Reserve Margin calculations. All assessment areas have sufficient Anticipated Reserve Margins to meet or exceed their Reference Margin Level for Summer 2021 (see **Figure 9**). Variable energy resources, including wind, solar, and types of hydro generation, often contribute significantly less of their installed capability at the period of peak demand. Consequently, the capacity contribution of variable energy resources to an areas anticipated resources may be a fraction of the installed capacity (see **Variable Energy Resource Contributions**).

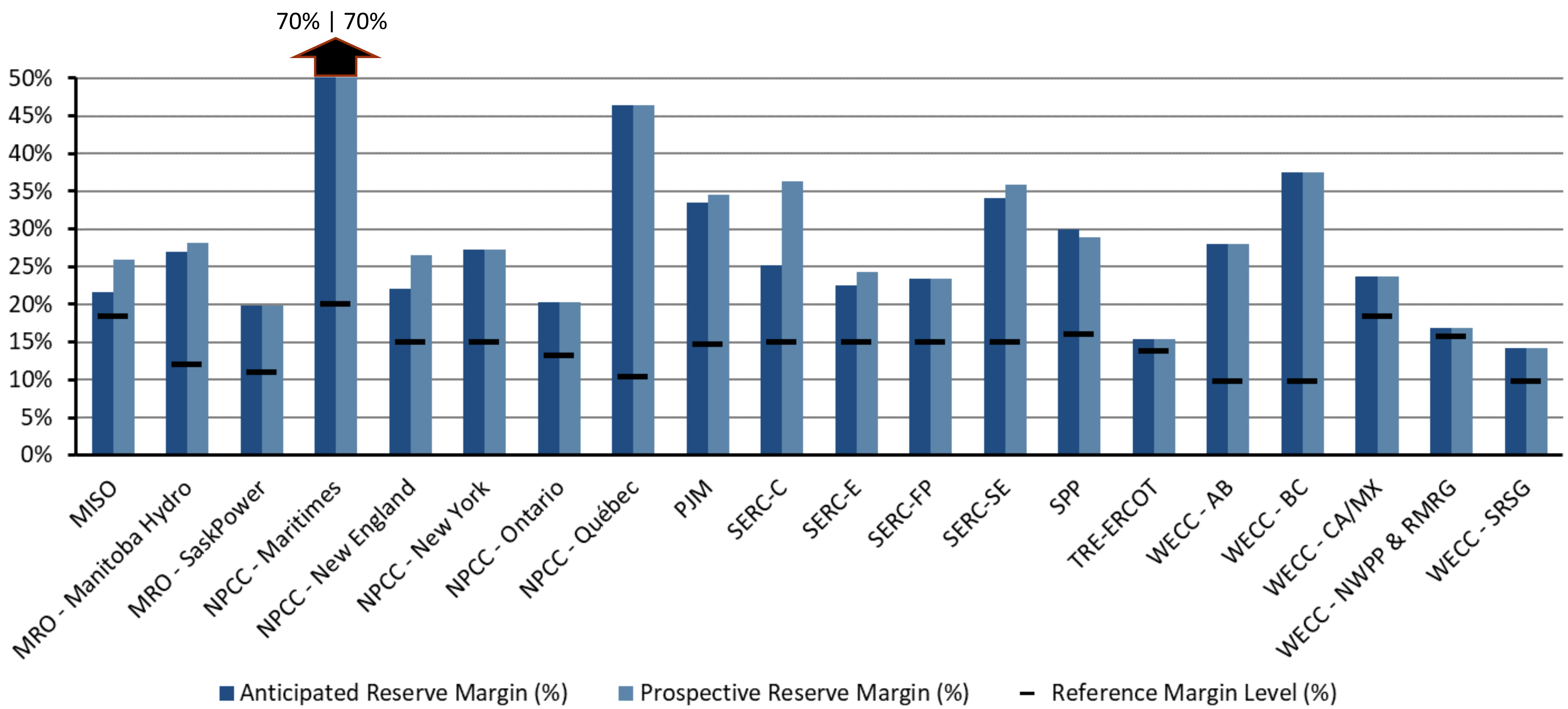


Figure 9: Summer 2021 Anticipated / Prospective Reserve Margins Compared to Reference Margin Level

[14] See the NERC Wildfire Mitigation Reference Guide, January 2021: https://nerc.com/comm/RSTC/Documents/Wildfire%20Mitigation%20Reference%20Guide_January_2021.pdf

[15] Generally, anticipated resources include generators and firm capacity transfers that are expected to be available to serve load during electrical peak loads for the season. Prospective Resources are those that could be available but do not meet criteria to be counted as Anticipated Resources. Refer to the **Data Concepts and Assumptions** section for additional information on Anticipated/Prospective Reserve Margins, Anticipated/Prospective Resources, and Reference Margin Levels.

Changes from Year-to-Year

Understanding the changes from year-to-year can give insights for the upcoming season. Figure 10 provides the relative change from the Summer 2020 to the Summer 2021 period. The assessment area tables in the Demand and Resource Tables section provide details of the demand and resource components that make up the Anticipated Reserve Margins for each assessment area. In the following areas, Anticipated Reserve Margin changed by more than five percentage points, and none of the changes result in a resource adequacy concern for the upcoming summer:

- **MRO-Manitoba Hydro:** New hydro generators begin operation in May and July.
- **NPCC-Maritimes:** A decrease in demand-side management availability accounts for the majority of Anticipated Reserve Margin loss for the Maritimes footprint.
- **NPCC-New England, Québec, and WECC-SRSG:** Resources have fallen year-on-year with generation retirements.

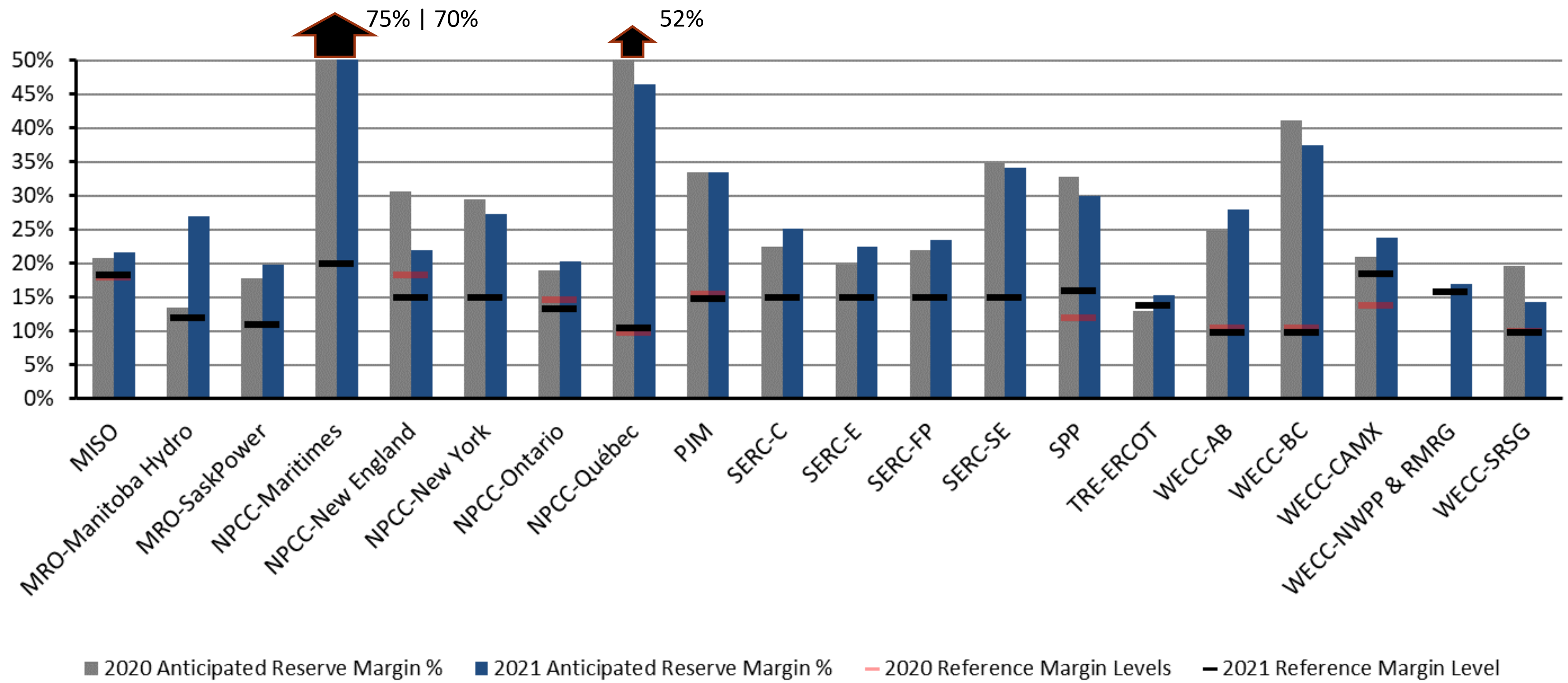


Figure 10: Summer 2020 to Summer 2021 Anticipated Reserve Margins Year-to-Year Change[16]

[16] WECC-NWPP and WECC-RMRG merged in 2020, so an Anticipated Reserve Margin or a Reference Margin Level was not produced for the 2020 assessment year for comparison.

Risk Assessments of Resource and Demand Scenarios

Areas can face energy shortfalls despite having Planning Reserve Margins that exceed Reference Margin Levels. Operating resources may be insufficient during periods of peak demand for reasons that could include generator scheduled maintenance, forced outages due to normal and more extreme weather conditions and loads, and low-likelihood conditions that affect generation resource performance or unit availability, including constrained fuel supplies. Grid operators employ operating mitigations or EEA (see **Table 2**) to obtain resources necessary to meet peak demands when operating resources are insufficient. The **Regional Assessments Dashboards** section in this report includes a seasonal risk scenario for each area that illustrates potential variation in resource and load as well as the potential effects that operating actions can have to mitigate shortfalls in operating reserves when insufficiencies occur.

About the Seasonal Risk Assessment

The operational risk analysis shown in the **Regional Assessments Dashboards** provides a deterministic scenario for understanding how various factors affecting resources and demand can combine to impact overall resource adequacy. Adjustments are applied cumulatively to anticipated capacity—such as reductions for typical generation outages (maintenance and forced not already accounted for in anticipated resources) and additions that represent the quantified capacity from operational tools, if any—that are available during scarcity conditions but have not been accounted for in the SRA reserve margins.

Resources throughout the scenario are compared against expected operating reserve requirements that are based on peak load and normal weather. The effects from low-probability events are also factored in through additional resource derates or low-output scenarios and extreme summer peak load conditions. Because the seasonal risk scenario shows the cumulative impact resulting from the occurrence of multiple low-probability events, the overall likelihood of the scenario is very low.

Table 2: Energy Emergency Alert Levels

EEA Level	Description	Circumstances
EEA 1	All available generation resources in use	• The BA is experiencing conditions where all available generation resources are committed to meet firm load, firm transactions, and reserve commitments, and is concerned about sustaining its required contingency reserves. • Non-firm wholesale energy sales (other than those that are recallable to meet reserve requirements) have been curtailed.
EEA 2	Load management procedures in effect	• The BA is no longer able to provide its expected energy requirements and is an energy deficient BA. • An energy deficient BS has implemented its operating plan(s) to mitigate emergencies. • An energy deficient BA is still able to maintain minimum contingency reserve requirements.
EEA 3	Firm Load interruption is imminent or in progress	• The energy deficient BA is unable to meet minimum contingency reserve requirements.

Transfers in a Wide-Area Event

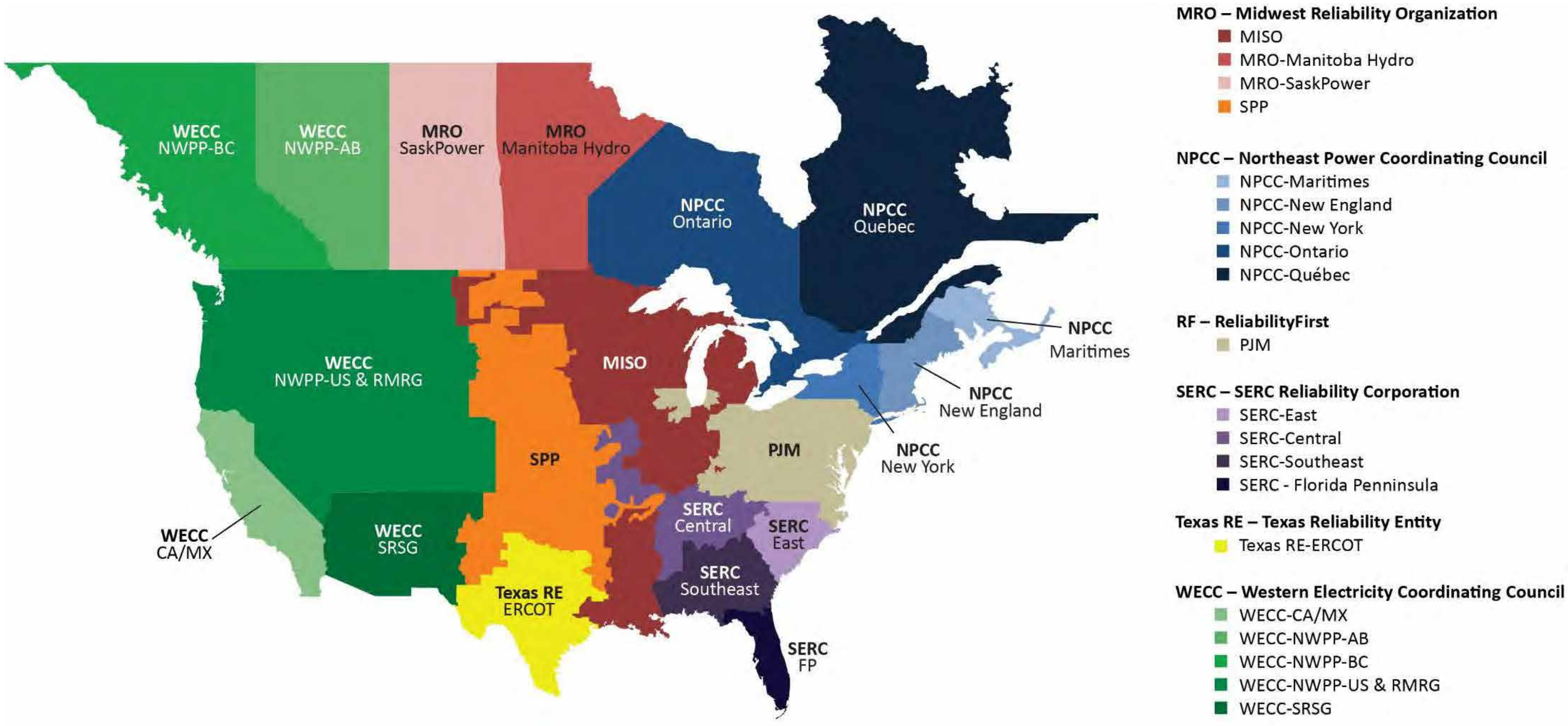
When above-normal temperatures extend over a wide area, resources can be strained in multiple assessment areas simultaneously, increasing the risk of shortfalls. Some assessment areas expect imports from other areas to be available to meet periods of peak demand and have contracted for firm transfer commitments. A summary of area firm on-peak imports and exports is shown in **Table 3**. Firm resource transactions, such as these, are accounted for in all assessment area anticipated resources and reserve margins. Areas with net imports show a positive transfer amount, and areas with net exports show a negative transfer amount. Only areas that contained transfers for the previous or upcoming summer seasons are shown in **Table 3**; the data in this table is sourced from the data adequacy tables in the **Data Concepts and Assumptions** section. In the unlikely event that multiple assessment areas are experiencing energy emergencies as could occur in a wide-area heatwave, some transfers may be at risk of not being fulfilled. Transfer agreements may include provisions that allow the exporting entity to prioritize serving native load. Loss of transfers could exacerbate resource shortages that occur from outages and derates.

Table 3: 2020 and 2021 On-Peak Net Firm Transfers

Assessment Area	2020 Summer Transfers (MW)	2021 Summer Transfers (MW)	Year-to-Year Change
MISO	2,795	2,979	6.6%
MRO-Manitoba	-1,526	-1,596	4.6%
MRO-SaskPower	125	125	0.0%
NPCC-Maritimes	-53	-57	7.5%
NPCC-New England	1,510	1,208	-20.0%
NPCC-New York	1,562	1,816	16.3%
NPCC-Ontario	0	80	N/A
NPCC-Quebec	-1,963	-1,995	1.6%
PJM	1,412	1,460	3.4%
SERC-C	-807	172	-121.3%
SERC-E	266	562	111.3%
SERC-FP	1,146	1,007	-12.1%
SERC-SE	-972	-1,115	14.7%
SPP	-1,244	186	-115.0%
TRE-ERCOT	817	210	-74.3%
WECC-AB	0	0	N/A
WECC-BC	0	0	N/A
WECC-CAMX	0	686	N/A
WECC-NWPP-US and RMRG	749	6,139	719.6%
WECC-SRSG	0	866	N/A

Regional Assessments Dashboards

The following assessment area dashboards and summaries were developed based on data and narrative information collected by NERC from the six RE on an assessment area basis.

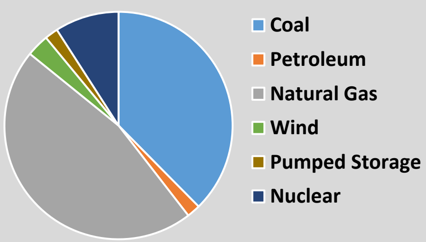


MISO

The Midcontinent Independent System Operator, Inc. (MISO) is a not-for-profit, member-based organization that administers wholesale electricity markets that provide customers with valued service; reliable, cost-effective systems and operations; dependable and transparent prices; open access to markets; and planning for long-term efficiency.

MISO manages energy, reliability, and operating reserve markets that consist of 36 local BA and 394 market participants, serving approximately 42 million customers. Although parts of MISO fall in three NERC RE, MRO is responsible for coordinating data and information submitted for NERC's reliability assessments.

On-Peak Fuel Mix



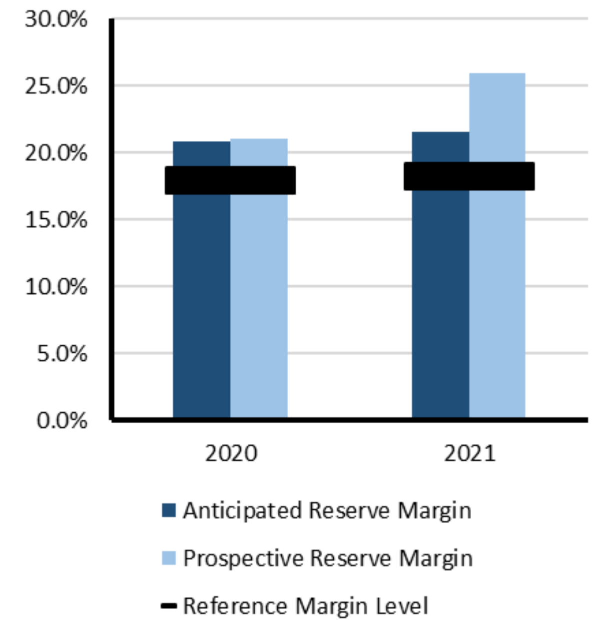
Highlights

- Summer scenarios with high resource outages and high demand may require use of load modifying resources (LMRs) and non-firm imports during peak periods. LMRs are an increasingly important segment of MISO resource portfolio. Operators designate resource constrained periods (Maximum Generation Events) to access LMRs.
- All MISO zones have met local capacity clearing requirements in the wholesale market auction and are projected to have sufficient resources for the summer.
- Covid-19 impacts on MISO load through late 2020 and the first quarter of 2021 have been much less pronounced than they were at the beginning of the pandemic. During the pandemic, MISO load has run 1–2% below normal in mild weather and 1–2% above normal in hotter weather. MISO expects load to trend close to normal through the summer; however, during a heatwave, load could trend 1–3% above normal due to increased residential demand.
- Based on probabilistic studies performed by MISO, the area has low amounts of EUE (18.6 MWh) for the summer season. Greatest risk occurs in the month of July, coinciding with the typical peak in annual demand.

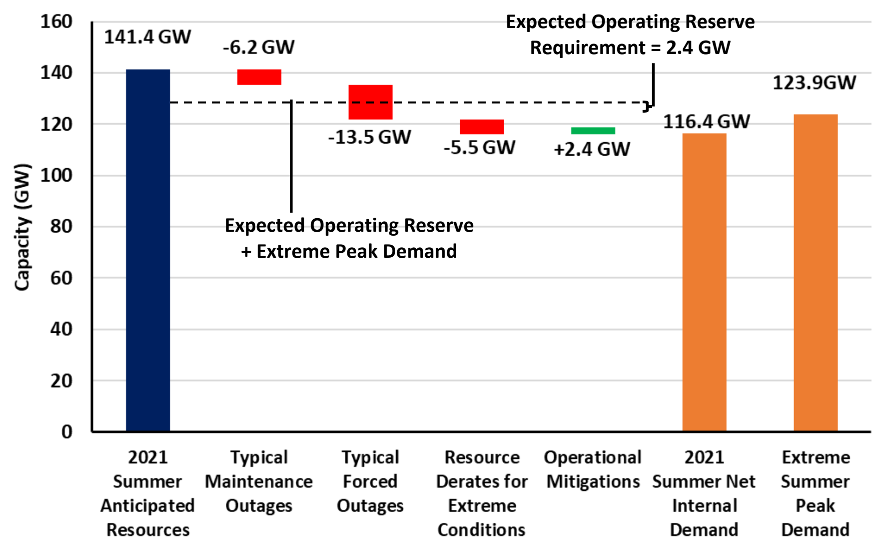
Risk Scenario Summary

Expected resources meet operating reserve requirements under normal peak-demand scenarios. Above-normal summer peak load and outage conditions could result in the need to employ operating mitigations (i.e., demand response, transfers, and short-term load interruption).

On-Peak Reserve Margins



Risk-Period Scenario



Scenario Description

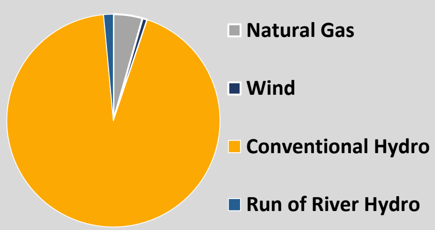
- **Risk Period:** Highest risk for unserved energy at peak demand hour (late afternoon).
- **Demand Scenarios:** Net internal demand (50/50) and 90/10 demand forecast using 30 years of historical data
- **Maintenance Outages:** Rolling five-year average of maintenance and planned outages
- **Forced Outages:** Five-year average of all outages that were not planned
- **Extreme Derates:** Maximum of last five years of outages
- **Operational Mitigation:** A total of 2.4 GW capacity resources available during extreme operating conditions.

MRO-Manitoba Hydro

Manitoba Hydro is a provincial crown corporation that provides electricity to about 580,000 customers throughout Manitoba and natural gas service to about 282,000 customers in various communities throughout Southern Manitoba. The Province of Manitoba has a population of about 1.3 million in an area of 250,946 square miles.

Manitoba Hydro is winter-peaking. No change in the footprint area is expected during the assessment period. Manitoba Hydro is its own Planning Coordinator and BA. Manitoba Hydro is a coordinating member of MISO. MISO is the Reliability Coordinator for Manitoba Hydro.

On-Peak Fuel Mix

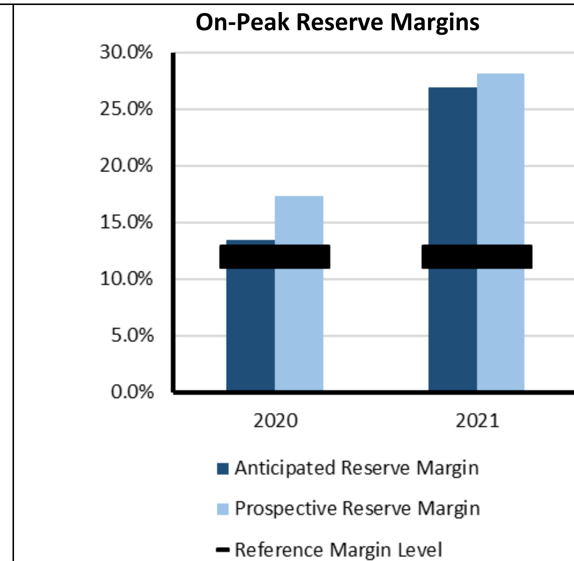


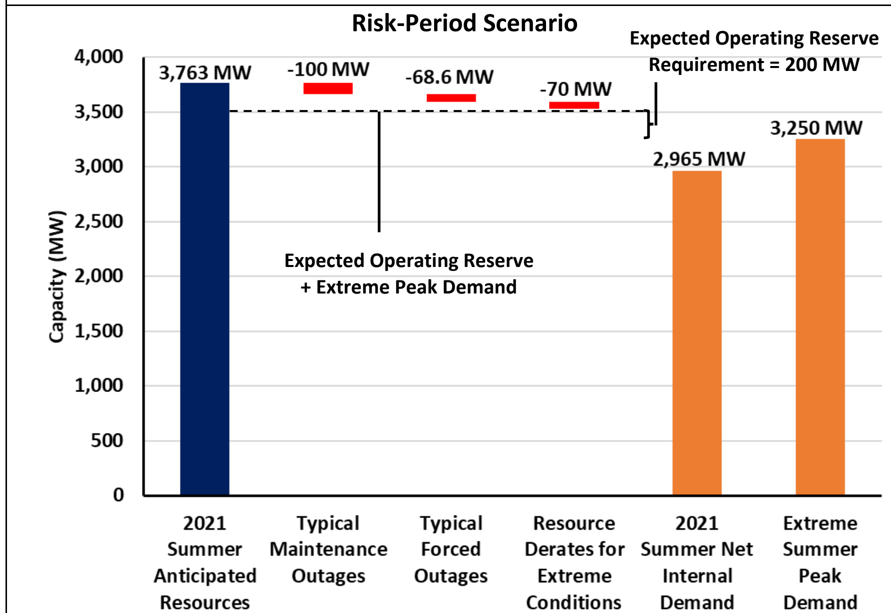
Highlights

- While the COVID-19 pandemic is expected to continue over the summer, no impact on area BPS reliability is anticipated as Manitoba Hydro has measures in place to minimize risk to operations. As of mid-March 2021, the pandemic situation in Manitoba appears stable with the implemented government measures.
- Reservoir storage levels are average and adequate to withstand the design drought.
- The first of seven Keeyask units is expected in May and the second is expected by July 1, 2021 (93 MW per unit).
- Based on the NERC 2020 Probabilistic Assessment (ProbA) and analysis of summer demand and resources, Manitoba Hydro is unlikely to experience resource shortages requiring operating procedures over the summer.

Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed scenarios.





Scenario Description

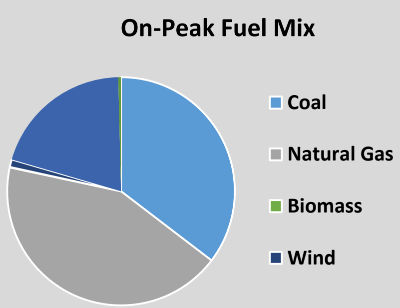
- **Risk Period:** Periods of peak demand
- **Demand Scenarios:** Net internal demand (50/50) and minimum probability of exceedance forecast load
- **Outages:** Accounts for planned maintenance and average forced outages
- **Extreme Derates:** Capacity derate for thermal resources for extreme conditions.

MRO-SaskPower

Saskatchewan is a province of Canada and comprises a geographic area of 651,900 square kilometers (251,700 square miles) with approximately 1.1 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 and is the principal supplier of electricity in the province.

SaskPower is a provincial crown corporation and, under provincial legislation, is responsible for the reliability oversight of the Saskatchewan Bulk Electric System (BES) and its interconnections.

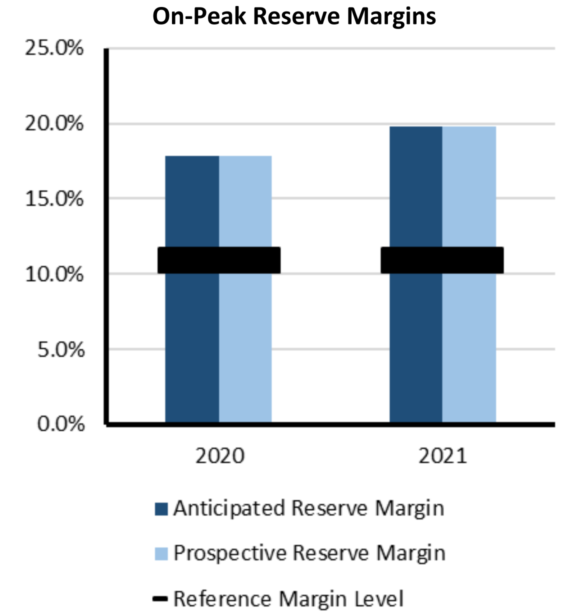


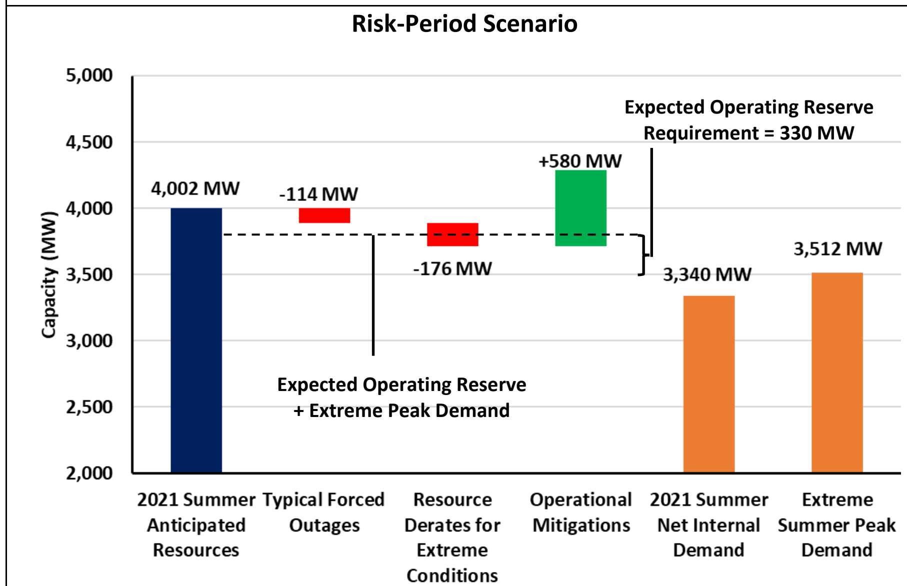
Highlights

- SaskPower experiences high load in summer as a result of hot weather.
- SaskPower conducts an annual summer joint operating study with Manitoba Hydro with inputs from Basin Electric (North Dakota) and prepares operating guidelines for any identified issues.
- Based on a SaskPower probability-based assessment, a low-likelihood scenario (1.8%) of capacity forced outages totaling 450 MW or greater that coincides with peak loads poses some risk of energy emergencies and unserved load. In the case of extreme hot weather conditions combined with large generation forced outages, SaskPower would use available demand response programs, short term power transfers from neighboring utilities, and short-term load interruptions. Risk is higher at the end of August to early October when larger amounts of generation maintenance is planned.

Risk Scenario Summary

Expected resources meet operating reserve requirements under normal peak-demand scenarios. Above-normal summer peak load and outage conditions could result in the need to employ operating mitigations (i.e., demand response, transfers, and short-term load interruption).



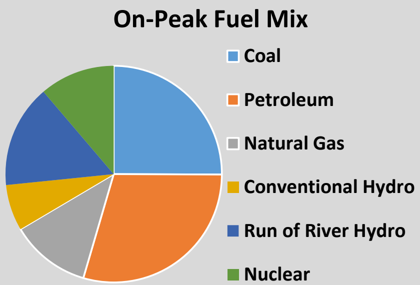


Scenario Description

- **Risk Period:** Periods of peak demand, afternoon (Risk is higher at the end of August to early October when more generation planned maintenance occurs.)
- **Demand Scenarios:** Net internal demand (50/50) and above-normal scenario based on peak demand with lighting and all consumer loads
- **Maintenance Outages:** Estimated based on averages from June-September 2020
- **Forced Outages:** Estimated using SaskPower forced outage model
- **Extreme Derates:** Estimated derate on natural gas units under extreme warm weather (>35 ˚C) based on historic performance and manufacturer data
- **Operational Mitigation:** Based on operational/emergency procedures

NPCC-Maritimes

The Maritimes assessment area is a winter-peaking NPCC area that contains two BA. It is comprised of the Canadian provinces of New Brunswick, Nova Scotia, and Prince Edward Island, and the northern portion of Maine, which is radially connected to the New Brunswick power system. The area covers 58,000 square miles with a total population of 1.9 million.

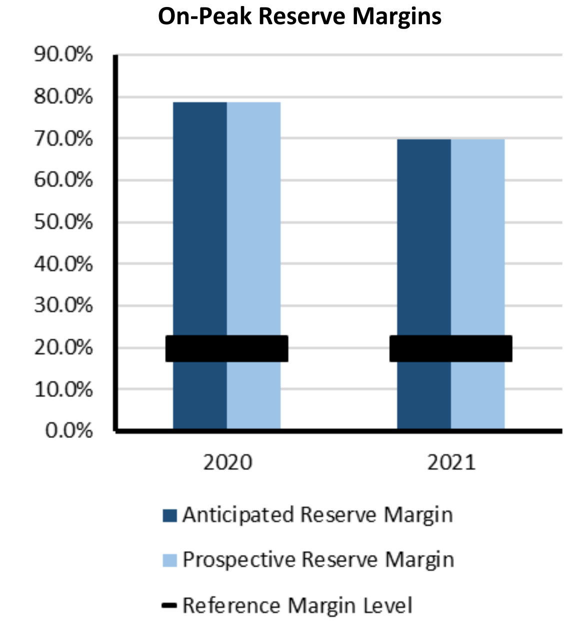


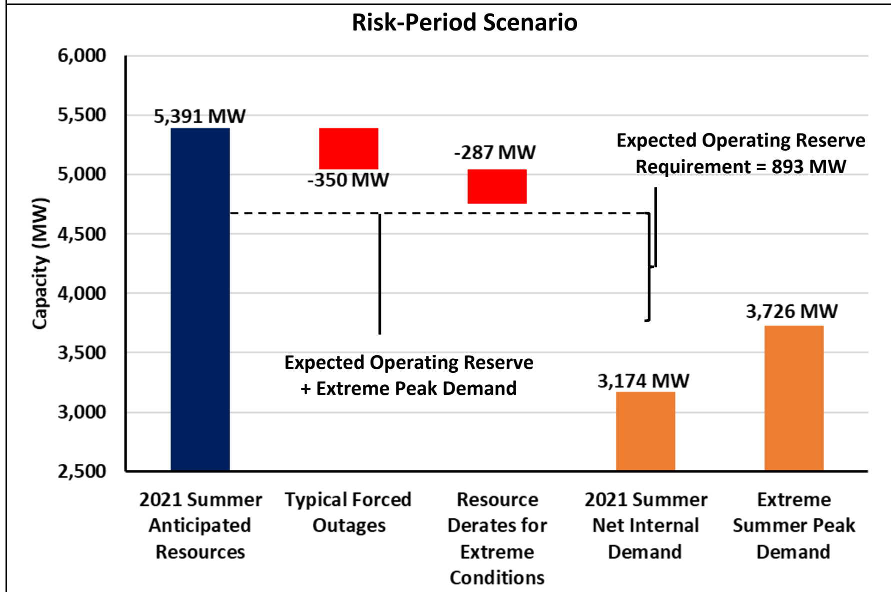
Highlights

- The Maritimes Area has not identified any operational issues that are expected to impact system reliability. If an event was to occur, there are emergency operations and planning procedures in place. All declared firm capacity is expected to be operational for the summer.
- As part of the planning process, dual-fueled units will have sufficient supplies of heavy fuel oil (HFO) on-site to enable sustained operation in the event of natural gas supply interruptions.
- The effects of the COVID-19 pandemic on load patterns, energy usage, and peak demands will continue to be evaluated during the pandemic.
- The Maritimes are evaluating contingency plans for transmission, distribution and generation planned work, planned maintenance, and forced outages to proceed conservatively while mitigating short term and longer term reliability risks.
- Based on an NPCC probabilistic assessment, the Maritimes assessment area is estimated to require a limited use of their operating procedures designed to mitigate resource shortages during Summer 2021. Negligible amounts of LOLE, LOLH, and EUE were estimated over the summer period for all the scenarios modeled.

Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed scenarios.





Scenario Description

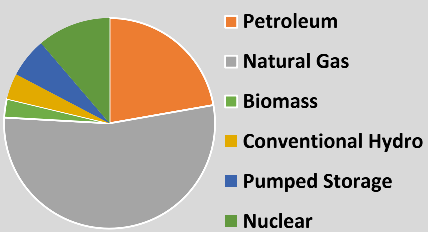
- **Risk Period:** Periods of peak demand
- **Demand Scenarios:** Net internal demand (50/50) and 90/10 demand forecast
- **Outages:** Based on historical operating experience
- **Extreme Derates:** A low-likelihood scenario resulting in no wind resources

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 BPS.

The New England BPS serves approximately 14.5 million customers over 68,000 square miles.

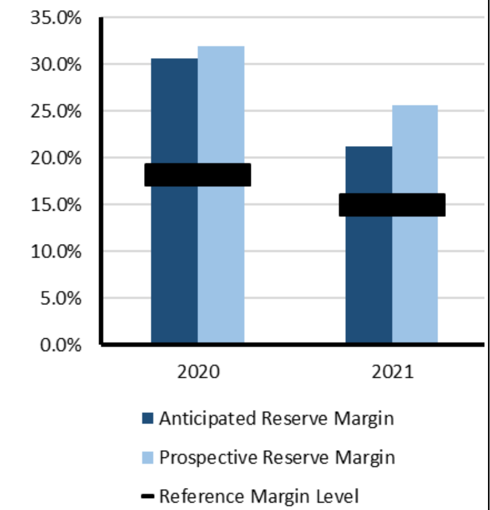
On-Peak Fuel Mix



Highlights

- ISO New England (ISO-NE) expects to have sufficient resources to meet the area summer peak demand forecast. Peak summer demand is forecast to be 24,810 MW occurring the week of August 8 with a projected net margin of 1,910 MW (7.6%). The summer demand forecast takes into account the demand reductions associated with energy efficiency, load management, behind-the-meter photovoltaic systems, and distributed generation.
- ISO-NE is producing a weekly analysis of the impact the response to COVID-19 is having on New England system demand, posted on its external website every Tuesday.[17] ISO-NE will adjust forecasts based on trends.
- Based on an NPCC probabilistic assessment with scenarios, the New England assessment area is expected to require limited use of their operating procedures designed to mitigate resource shortages during Summer 2021. Negligible amounts of LOLE, LOLH, and EUE were estimated over the summer period for all the scenarios modeled except the severe low-likelihood case. The two highest peak load levels for this severe case resulted in LOLE of 0.3 days, with an associated LOLH of 1.3 hours, and an associated EUE of 868 MWh. This scenario is based exclusively on the two highest load levels representing an average 10–15% increase in peak loads over the 50/50 forecast with a combined 7% probability of occurrence. Additional constraints include 10% reduction in NPCC resources and PJM reductions.

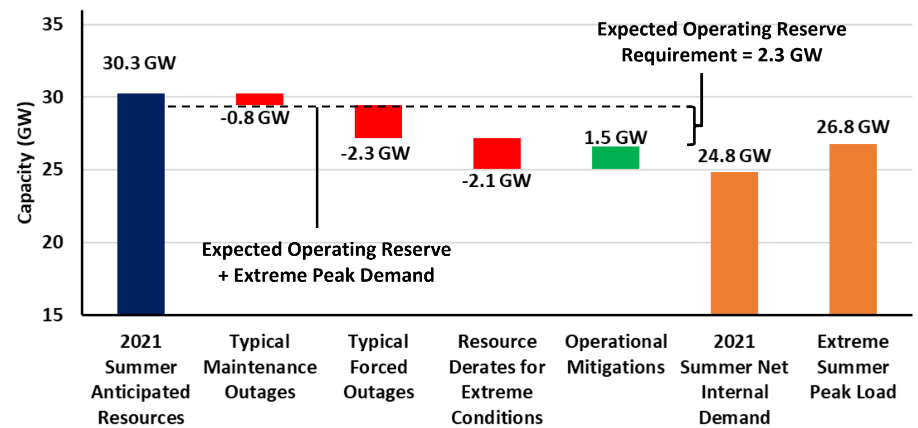
On-Peak Reserve Margins



Risk Scenario Summary

Expected resources meet operating reserve requirements under normal peak-demand scenarios. Above-normal summer peak load and outage conditions could result in the need to employ operating mitigations (i.e., demand response, transfers, and short-term load interruption.)

Risk-Period Scenario



Scenario Description

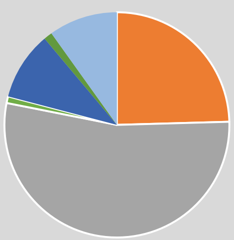
- **Risk Period:** Period of greatest risk coincides with peak demand (afternoon)
- **Demand Scenarios:** Net internal demand (50/50) and 90/10 demand forecast
- **Outages:** Based on weekly averages
- **Extreme Derates:** Represent a 90/10 case based on historical observation of force outages and additional reductions for generation at risk due to natural gas supply
- **Operational Mitigation:** Based on ISO-NE operating procedures

[17] https://www.iso-ne.com/markets-operations/system-forecast-status/estimated-impacts-of-covid-19-on-demand

NPCC-New York

The New York Independent System Operator (NYISO) is responsible for operating New York's BPS, administering wholesale electricity markets, and conducting system planning. The New York Independent System Operator (NYISO) is the only BA within the state of New York. The BPS encompasses approximately 11,000 miles of transmission lines, 760 power generation units, and serves 19.5 million customers. New York experienced its all-time peak demand of 33,956 MW in Summer 2013. The NERC Reference Margin Level is 15%. Wind, grid-connected solar, and run-of-river totals were derated for this calculation. However, New York requires load serving entities to procure capacity for their loads equal to their peak demand plus an Installed Reserve Margin (IRM). The IRM requirement represents a percentage of capacity above peak load forecast and is approved annually by the New York State Reliability Council (NYSRC). NYSRC approved the 2020–2021 IRM at 20.7%."

On-Peak Fuel Mix



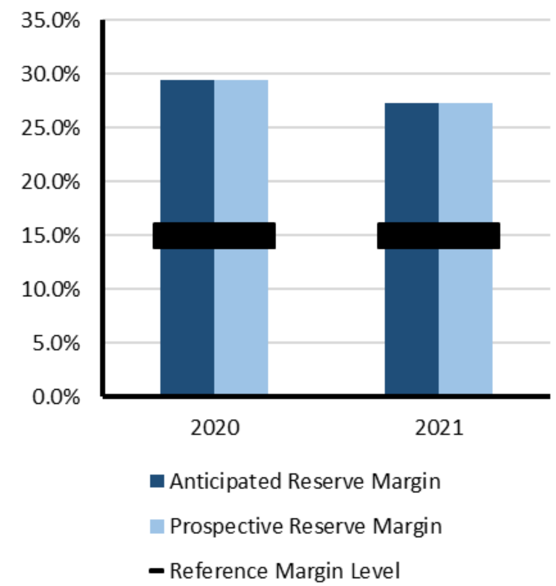
Highlights

- The NYISO is not anticipating any operational issues in the New York control area for the upcoming summer operating period. Adequate capacity margins are anticipated and existing operating procedures are sufficient to handle any issues that may occur.
- High capacity factors on certain New York City peaking units could result in possible violations of their daily NOx emission limits if they were to fully respond to the NYISO dispatch signals; this could occur during long duration hot weather events or following the loss of significant generation or transmission assets. Protocols with state agencies provide for reliable operation during emergencies.
- Based on an NPCC probabilistic assessment with scenarios, the New York assessment area is expected to require limited use of their operating procedures designed to mitigate resource shortages during Summer 2021. New York's LOLE risk is correlated to simultaneous high loads occurring in PJM, Ontario, and MISO, which limits the availability of external support. Negligible amounts of LOLE, LOLH, and EUE were estimated over the summer period for all the scenarios modeled except for the low-likelihood severe case that assumes simultaneous stressed system conditions for NPCC and the modeled external systems. The two highest peak load levels for this severe case resulted in an estimated LOLE of one occurrence in July, with an associated LOLH of four hours and an EUE of 3,020 MWh risk. The highest peak load level results were based exclusively on only the two highest load levels (representing on average 10–15% increase in peak loads over the 50/50 forecast) having a combined 7% chance of occurring. Additional constraints include 10% reduction in NPCC resources and PJM reductions.

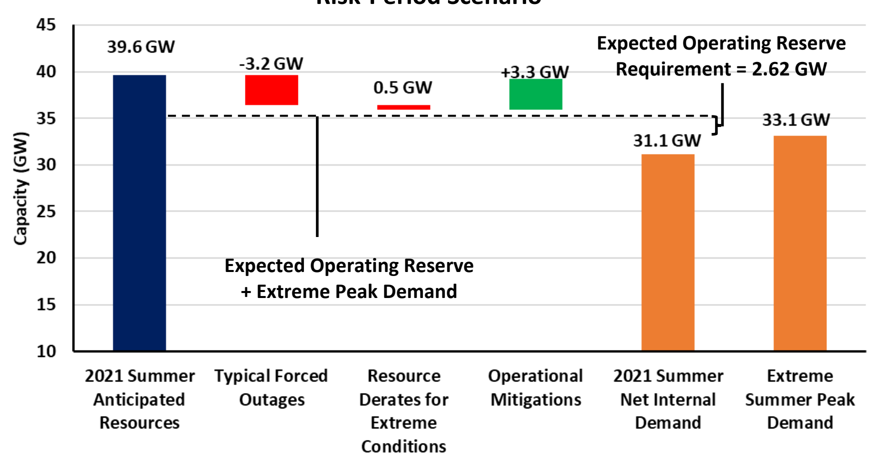
Risk Scenario Summary

Expected resources meet operating reserve requirements under assessed scenarios.

On-Peak Reserve Margins



Risk-Period Scenario



Scenario Description

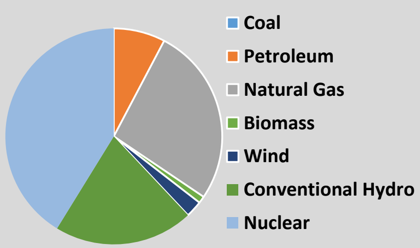
- **Risk Period:** Periods of peak demand
- **Demand Scenarios:** Net internal demand (50/50) and 90/10 demand forecast with demand response adjustments
- **Forced Outages:** Based on historical 5-year averages
- **Extreme Derates:** Capacity derate for thermal resources for extreme conditions
- **Operational Mitigation:** 3.3 GW based on operational/emergency procedures in area *Emergency Operations Manual*

NPCC-Ontario

The Independent Electricity System Operator (IESO) is the BA for the province of Ontario. The province of Ontario covers more than 1 million square kilometers (415,000 square miles) and has a population of more than 14 million.

Ontario is interconnected electrically with Québec, MRO-Manitoba, states in MISO (Minnesota and Michigan), and NPCC-New York.

On-Peak Fuel Mix



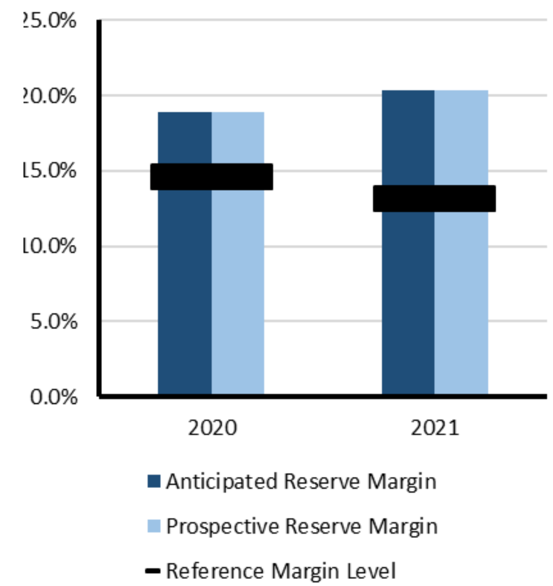
Highlights

- Ontario expects to have sufficient generation resources available to meet its needs throughout the summer, and its transmission system is expected to continue to reliably supply province-wide demand
- In December 2020, the IESO ran its first capacity auction, clearing 992.1 MW of capacity for the 2021 summer period. The capacity auction will be an important tool for meeting Ontario's future reliability needs.
- The ongoing transmission outage at the New York-St Lawrence interconnection continues to impact import and export capacity between Ontario and New York. The issue is being jointly managed by entities involved.
- Based on an NPCC probabilistic assessment, the Ontario assessment area is estimated to require a limited use of their operating procedures designed to mitigate resource shortages during Summer 2021. Ontario's LOLE risk is correlated to the availability of their external imports at the time of Ontario's peak load. Negligible amounts of LOLE, LOLH, and EUE were estimated over the summer period for all the scenarios modeled except the low-likelihood severe case and highest peak load levels (which resulted in an LOLE of 0.4 days with an associated LOLH of 1.2 hours and an associated EUE of 1,042 MWh risk in July). The highest peak load level results were based exclusively on only the two highest load levels of the seven modeled, having a combined 7% chance of occurring in this already low-likelihood case (with about a 10% reduction in NPCC resources and PJM reductions).

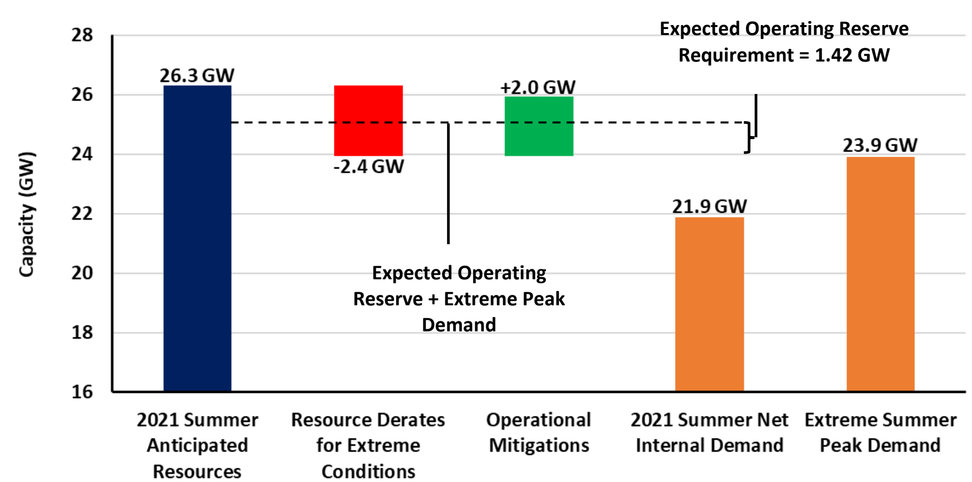
Risk Scenario Summary

Expected resources meet operating reserve requirements under normal peak-demand scenarios. Extreme summer peak load and outage conditions could result in the need to employ operating mitigations (i.e., demand response, transfers, and short-term load interruption).

On-Peak Reserve Margins



Risk-Period Scenario



Scenario Description

- **Risk Period:** Period of greatest risk coincides with peak demand (afternoon)
- **Demand Scenarios:** Net internal demand (50/50 Forecast) and highest weather-adjusted daily demand from 31 years of demand history
- **Forced Outages:** Estimated using market forced outage model
- **Extreme Derates:** Hydro derates are based on 2012 (dry-year) conditions. Thermal derates are estimated using an extreme temperature from 31 years of historical data.
- **Operational Mitigation:** Imports anticipated from neighbors during emergencies

NPCC-Québec

The Québec assessment area (Province of Québec) is a winter-peaking NPCC area that covers 595,391 square miles with a population of 8 million.

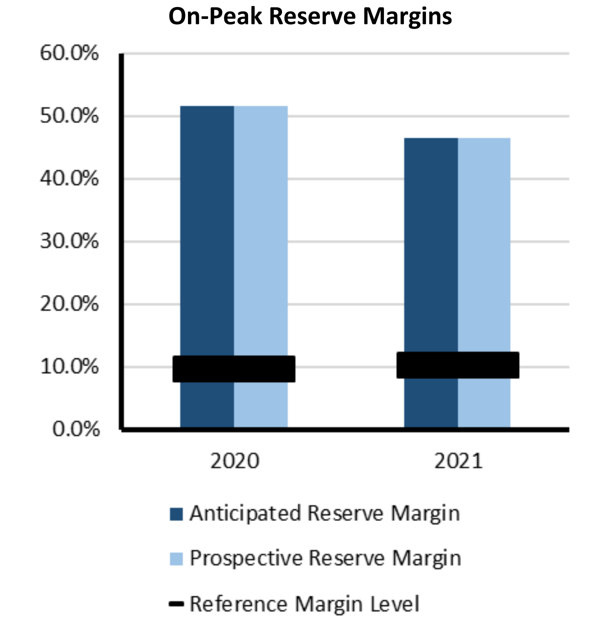
Québec is one of the four NERC Interconnections in North America; it has ties to Ontario, New York, New England, and the Maritimes; consisting of either HVDC ties, radial generation, or load to and from neighboring systems.

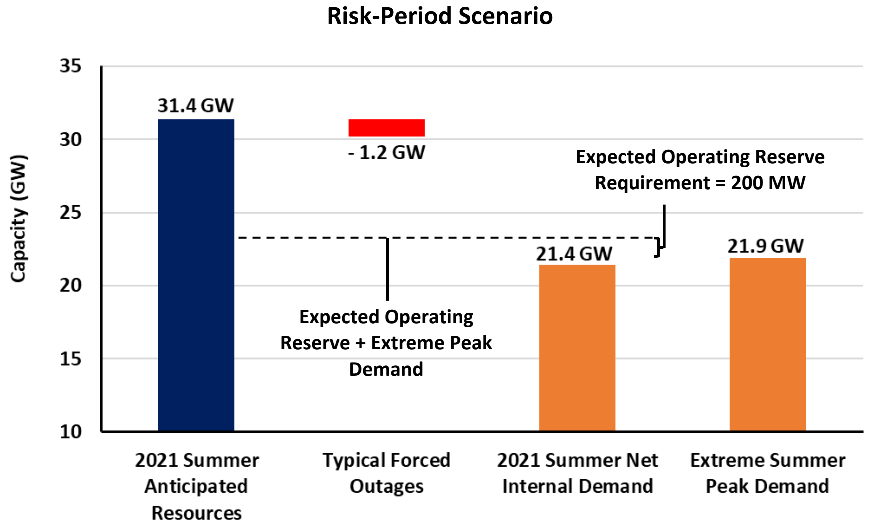
Highlights

- No issues are anticipated for the summer since the Québec system is winter peaking.
- Based on an NPCC probabilistic assessment, the Québec assessment area is not expected to require use of their operating procedures designed to mitigate resource shortages during Summer 2021. The Québec area is winter peaking and has a large reserve margin for the summer period; as a result, Québec did not demonstrate any measurable amounts of LOLE, LOLH, or EUE risk over the summer period for all the scenarios modeled.

Risk Scenario Summary

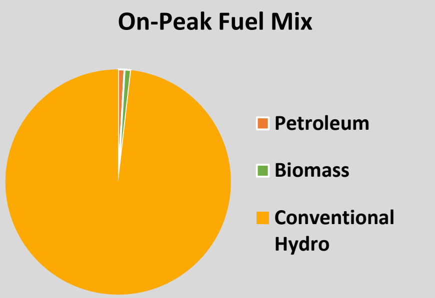
Expected resources meet operating reserve requirements under assessed scenarios.





Scenario Description

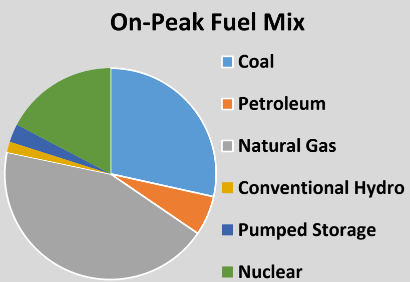
- **Risk Period:** Period of peak demand (afternoons)
- **Demand Scenarios:** Net internal demand (50/50) and 90/10 demand forecast
- **Extreme Derates:** Rare scenario of 1,200 MW in unplanned outages



PJM

PJM Interconnection is a regional transmission organization that coordinates the movement of wholesale electricity in all or parts of Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, West Virginia, and the District of Columbia. PJM serves 65 million people and covers 369,089 square miles.

PJM is a BA, Planning Coordinator, Transmission Planner, Resource Planner, Interchange Authority, Transmission Operator, Transmission Service Provider, and Reliability Coordinator.

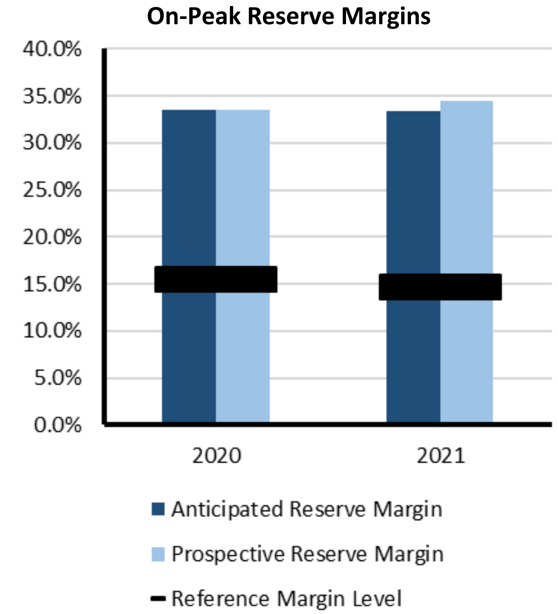


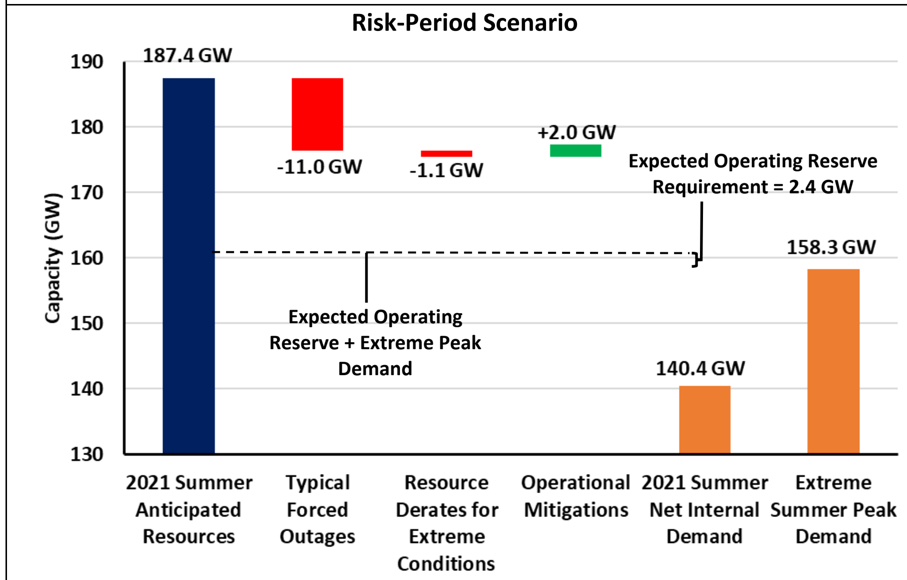
Highlights

- PJM expects no resource problems over the entire 2021 summer peak season. Installed capacity is almost double the Reference Margin Level and there are currently no known deliverability restrictions.
- Probabilistic studies performed by PJM indicate that there is low risk of resource shortfall for summer. The analysis included a range of load, generation, and outage scenarios.
- PJM's Reference Margin Level decreased from 15.1% to 14.9% due to lower average expected forced outage rates in the 2020 PJM capacity model compared to prior years.

Risk Scenario Summary

Expected resources meet operating reserve requirements under assessed scenarios.





Scenario Description

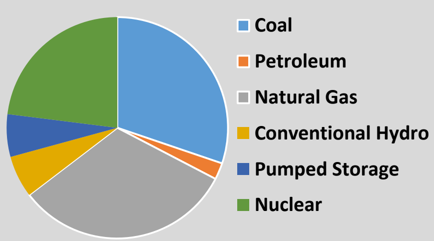
- **Risk Period:** Highest risk for unserved energy at peak demand hour (afternoon)
- **Demand Scenarios:** Net internal demand (50/50) and 90/10 demand forecast
- **Outages:** Based on historical data and trending
- **Extreme Derates:** Derate accounts for reduced thermal capacity contributions due to performance in extreme conditions
- **Operational Mitigation:** A total of 2 GW obtained through emergency requests for behind-the-meter generation dispatch

SERC-East

SERC-East is a summer-peaking assessment area within the SERC RE. SERC-East includes North Carolina and South Carolina.

SERC is one of the six companies across North America that are responsible for the work under Federal Energy Regulatory Commission approved delegation agreements with NERC. SERC is specifically responsible for the reliability and security of the electric grid across the southeastern and central areas of the United States. This area covers approximately 630,000 square miles and serves a population of more than 91 million.

The SERC RE includes 36 BA, 28 Planning Authorities, and 6 Reliability Coordinators.

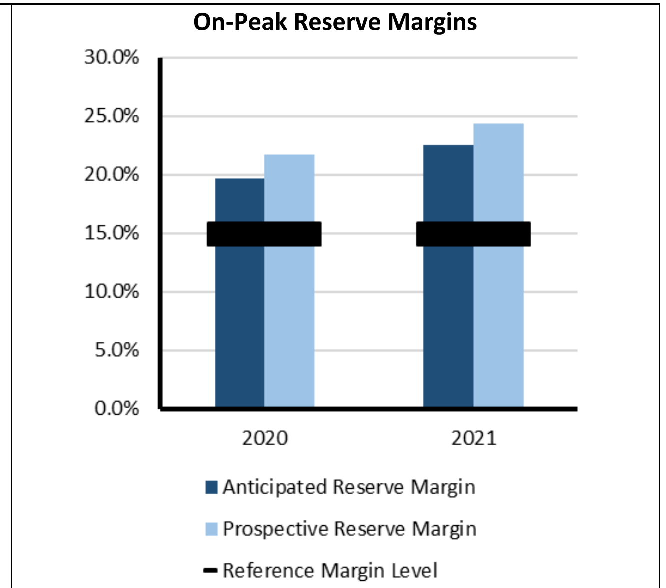


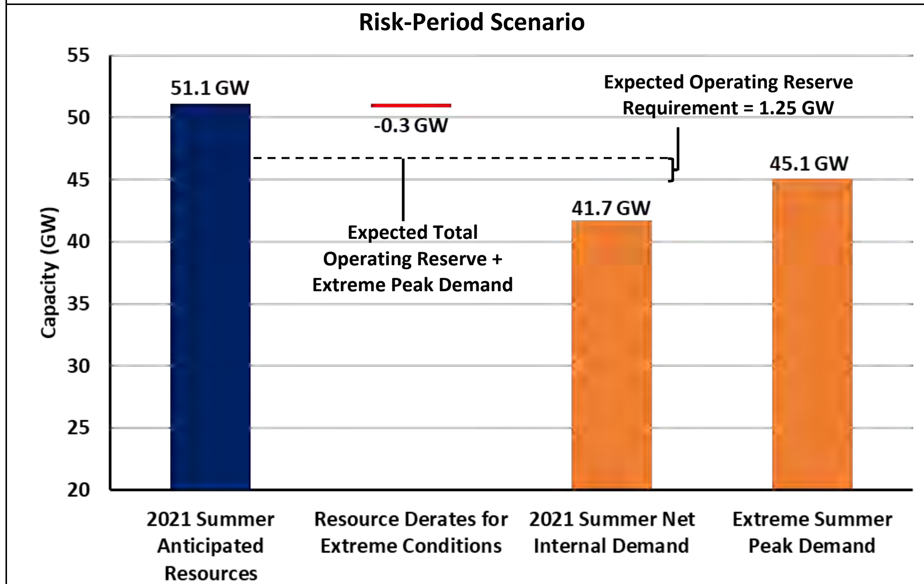
Highlights

- Entities in SERC-East have not identified any potential reliability issues for the upcoming season. The entities continue to perform resource studies to ensure resource adequacy to meet the summer peak demand and to maintain reliability to the system. Entities reported that coal inventory is in the upper allowed range to maintain reliability.
- Entities in the SERC RE continue to participate actively in the SERC Near-Term and Long-Term Working Groups. These groups identify emerging and potential reliability impacts to transmission and resource adequacy as well as with transfer capability.
- Entities in SERC-East are not anticipating operational challenges for the upcoming summer season.
- Probabilistic analysis performed for SERC-East shows almost no risk for resource shortfall for the summer. SERC-East has a small amount of EUE in August but a negligible amount at other times (EUE < 0.4 MWh).

Risk Scenario Summary

Expected resources meet operating reserve requirements under assessed scenarios.





Scenario Description

- **Risk Period:** Highest risk for unserved energy at peak demand hour (afternoon)
- **Demand Scenarios:** Net internal demand (50/50) and 90/10 demand forecast
- **Forced Outages:** Weighted average forced outage rates on-peak are factored into the anticipated resources calculation
- **Extreme Derates:** Account for reduced thermal capacity contributions due to performance in extreme conditions

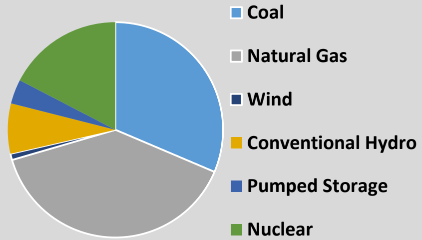
SERC-Central

SERC-Central is a summer peaking assessment area within the SERC RE. SERC-Central includes all of Tennessee and portions of Georgia, Alabama, Mississippi, and Kentucky.

SERC is one of the six companies across North America that are responsible for the work under Federal Energy Regulatory Commission approved delegation agreements with NERC. SERC is specifically responsible for the reliability and security of the electric grid across the southeastern and central areas of the United States. This area covers approximately 630,000 square miles and serves a population of more than 91 million.

The SERC RE includes 36 BA, 28 Planning Authorities, and 6 Reliability Coordinators.

On-Peak Fuel Mix



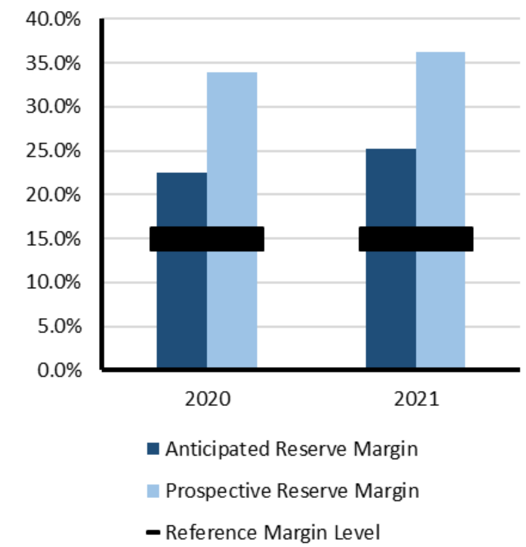
Highlights

- Entities in SERC-Central have not identified any potential reliability issues for the upcoming season. Entities have noted that planned outages are on schedule to be completed prior to the summer season and not anticipated to result in potential reliability issues.
- Entities in the SERC RE continue to participate actively in the SERC Near-Term and Long-Term Working Groups. These groups identify emerging and potential reliability impacts to transmission and resource adequacy along with transfer capability.
- Probabilistic analysis performed for SERC-Central shows low risk for resource shortfall for the summer. Load loss and unserved energy indices are negligible for SERC-Central.

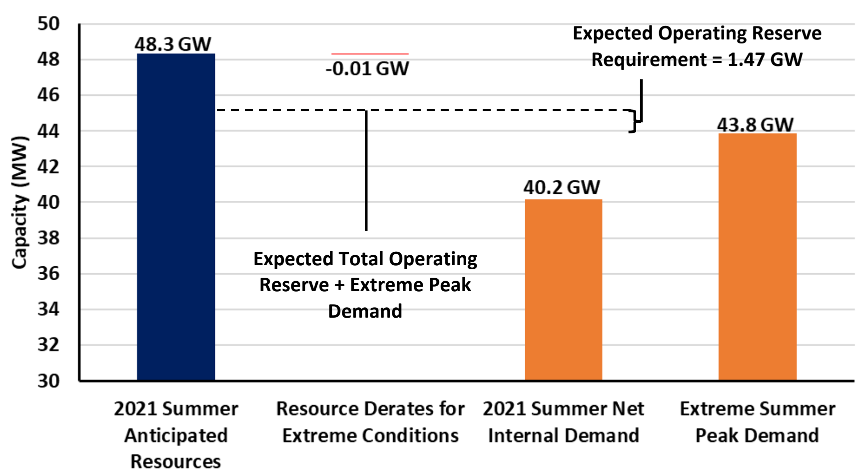
Risk Scenario Summary

Expected resources meet operating reserve requirements under assessed scenarios.

On-Peak Reserve Margins



Risk-Period Scenario



Scenario Description

- **Risk Period:** Highest risk for unserved energy at peak demand hour (afternoon)
- **Demand Scenarios:** Net internal demand (50/50) and 90/10 demand forecast
- **Forced Outages:** Weighted average forced outage rates on-peak are factored into the anticipated resources calculation
- **Extreme Derates:** Account for reduced thermal capacity contributions due to performance in extreme conditions

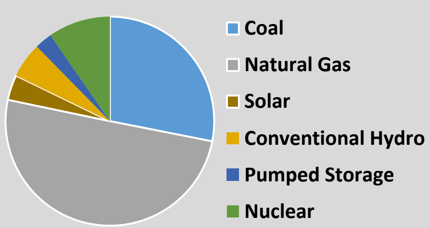
SERC-Southeast

SERC-Southeast is a summer peaking assessment area within the SERC RE. SERC-Southeast includes all or portions of Georgia, Alabama, and Mississippi.

SERC is one of the six companies across North America that are responsible for the work under Federal Energy Regulatory Commission approved delegation agreements with NERC. SERC is specifically responsible for the reliability and security of the electric grid across the southeastern and central areas of the United States. This area covers approximately 630,000 square miles and serves a population of more than 91 million.

The SERC RE includes 36 BA, 28 Planning Authorities, and 6 Reliability Coordinators.

On-Peak Fuel Mix



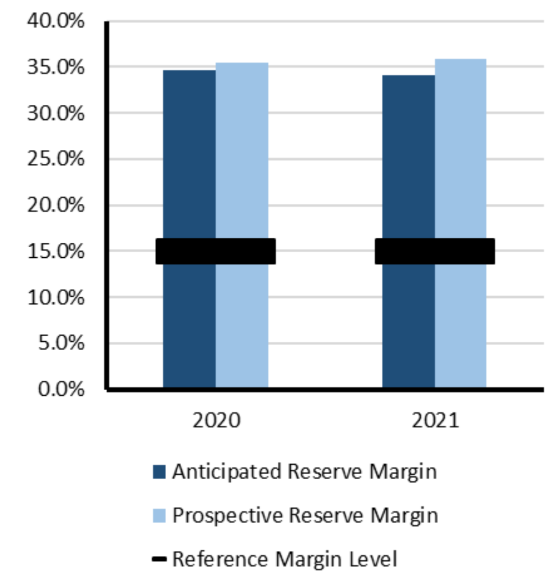
Highlights

- Entities in SERC Southeast have not identified any emerging reliability issues for the upcoming season that will impact resource adequacy. The available system capacity for the upcoming season meets or exceeds the reserve margin target. Reliability is supported by a diverse fuel mix, firm gas contracts, and power purchases.
- Entities in the SERC area continue to participate actively in the SERC Near-Term and Long-Term Working Groups. These groups identify emerging and potential reliability impacts to transmission and resource adequacy along with transfer capability.
- Probabilistic analysis performed for SERC-Southeast shows there is low risk for resource shortfall for the summer. Load loss and unserved energy indices are negligible for SERC-Southeast throughout the summer.

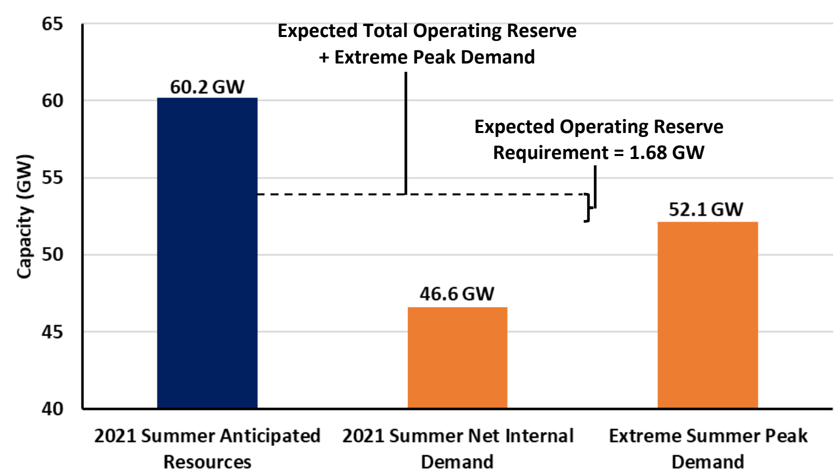
Risk Scenario Summary

Expected resources meet operating reserve requirements under assessed scenarios.

On-Peak Reserve Margins



Risk-Period Scenario



Scenario Description

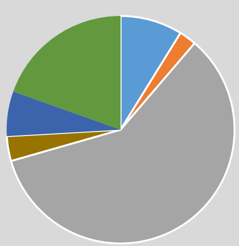
- **Risk Period:** Highest risk for unserved energy at peak demand hour (afternoon)
- **Demand Scenarios:** Net internal demand (50/50) and 90/10 demand forecast
- **Forced Outages and Extreme Derates:** All outages and derates are factored into the anticipated resources calculation

SERC-Florida Peninsula

SERC-Florida Peninsula is a summer peaking assessment area within the SERC RE.

SERC is one of the six companies across North America that are responsible for the work under Federal Energy Regulatory Commission approved delegation agreements with NERC. SERC is specifically responsible for the reliability and security of the electric grid across the southeastern and central areas of the United States. This area covers approximately 630,000 square miles and serves a population of more than 91 million.

The SERC RE includes 36 BA, 28 Planning Authorities, and 6 Reliability Coordinators.

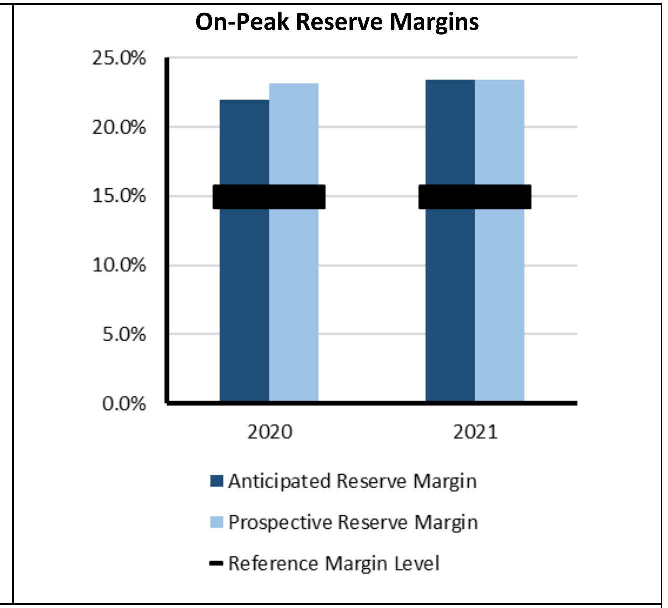


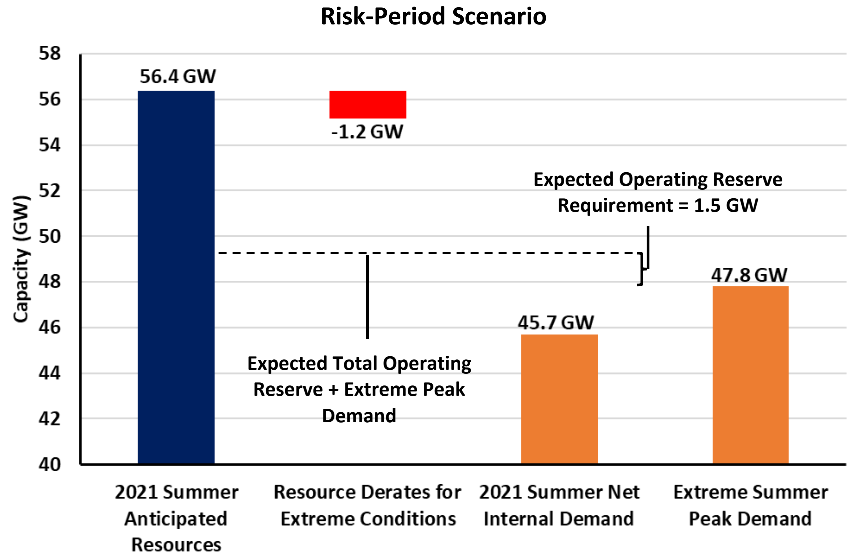
Highlights

- Entities in SERC-Florida Peninsula have not identified any emerging reliability issues or operational concerns for the upcoming summer. Entities in the SERC Region continue to participate actively in the SERC Near-Term and Long-Term Working Groups. These groups identify emerging and potential reliability impacts to transmission and resource adequacy along with transfer capability.
- Entities within the Florida Peninsula area have reported no operational challenges for the upcoming summer season based on current expected system conditions, the BES within the Florida Peninsula is expected to perform reliably for the anticipated 2021 summer season.
- Probabilistic analysis performed for SERC-Florida Peninsula shows there is low risk for resource shortfall for the summer. Load loss and unserved energy indices for SERC-Florida Peninsula are spread across the summer months but are relatively low (LOLH < 0.03 and EUE < 18 MWH).

Risk Scenario Summary

Expected resources meet operating reserve requirements under assessed scenarios.





Scenario Description

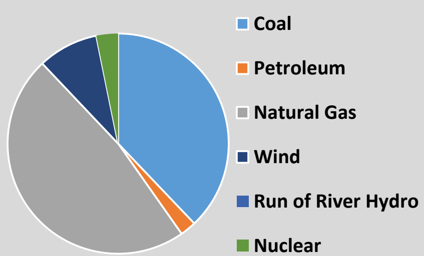
- **Risk Period:** Highest risk for unserved energy at peak demand hour (afternoon)
- **Demand Scenarios:** Net internal demand (50/50) and 90/10 demand forecast
- **Forced Outages:** Weighted average forced outage rates on-peak are factored into the anticipated resources calculation
- **Extreme Derates:** Account for reduced thermal capacity contributions due to performance in extreme conditions

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 long-term assessment is reported based on the Planning Coordinator footprint, which touches parts of the Midwest Reliability Organization RE, and the WECC RE. 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.

On-Peak Fuel Mix



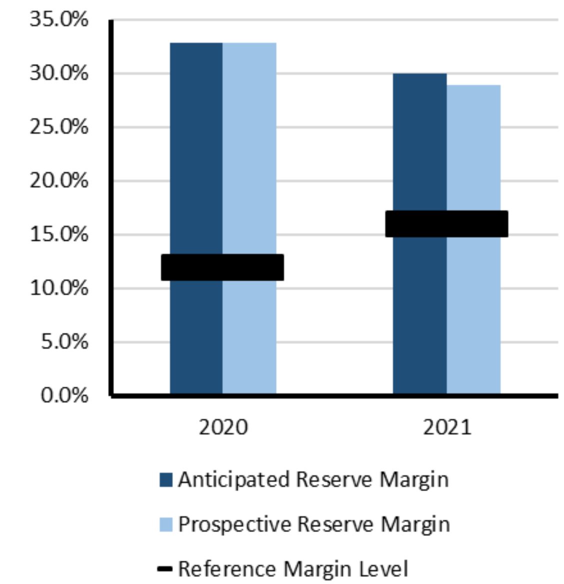
Highlights

- At this time, SPP does not anticipate any emerging reliability issues impacting the area for the 2021 summer season.
- Wind generation occupies a greater share of the SPP resource mix, requiring increased attention to weather-dependent forecasts. The SPP Uncertainty Response Team uses historical data to predict and develop mitigation plans for load forecast errors up to seven days in advance. Potential errors are predicted based on the levels of expected load, wind, and traditional resource outage in forecast. Mitigation may be obtained by scheduling longer-lead resources, controlling planned outages, and communicating with owners and operators.
- Using the current operational processes and procedures, SPP will continue to assess the needs for the 2021 summer season and will adjust as needed to ensure that real time reliability is maintained throughout the summer time frame.
- Probabilistic studies performed by SPP indicate for the 2021 summer season indicate that the current Planning Reserve Margin is sufficient for the 2021 summer season.

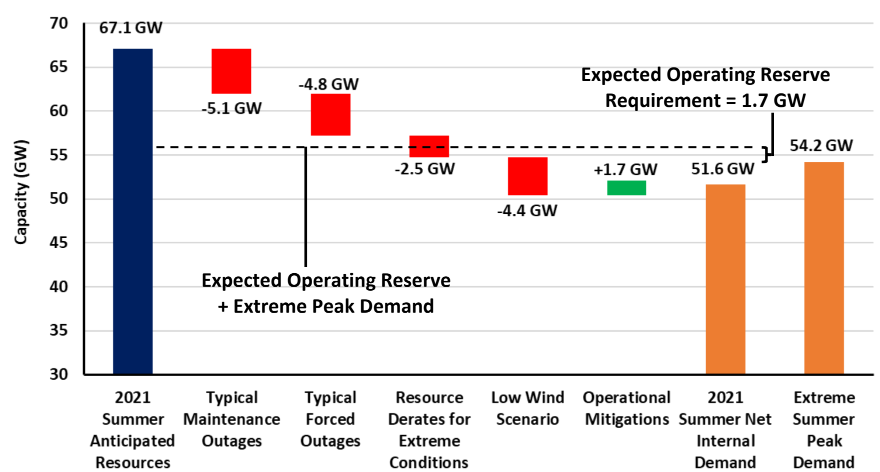
Risk Scenario Summary

Expected resources meet operating reserve requirements under normal peak-demand scenarios. Extreme summer peak load and outage conditions could result in the need to employ operating mitigations (i.e., demand response, transfers, and short-term load interruption).

On-Peak Reserve Margins



Risk-Period Scenario



Scenario Description

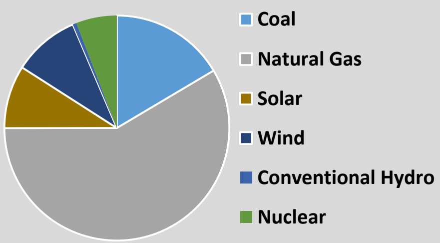
- **Risk Period:** Highest risk for unserved energy at peak demand hour (late afternoon)
- **Demand Scenarios:** Net internal demand (50/50) and 90/10 demand forecast
- **Maintenance Outages:** Based on historical summer average for the past three years
- **Forced Outages:** Based on historical summer average for the past three years
- **Extreme Thermal Derates:** Derate accounts for reduced capacity contributions due to performance in extreme conditions
- **Low-Wind Scenario:** Rare scenario with only 320 MW (of 26,800 MW installed capacity) contributing to meet demand
- **Operational Mitigation:** 1,700 MW based on operational/emergency procedures

Texas RE-ERCOT

The Electric Reliability Council of Texas (ERCOT) is the ISO for the ERCOT Interconnection and is located entirely in the state of Texas; it operates as a single BA. It also performs financial settlement for the competitive wholesale bulk-power market and administers retail switching for nearly 8 million premises in competitive choice areas. ERCOT is governed by a board of directors and subject to oversight by the Public Utility Commission of Texas and the Texas Legislature.

ERCOT is a summer-peaking RE that covers approximately 200,000 square miles, connects over 46,500 miles of transmission lines, has over 710 generation units, and serves more than 25 million customers. Lubbock Power & Light joins the ERCOT grid on June 1, 2021. Texas RE is responsible for the RE functions described in the *Energy Policy Act of 2005* for the ERCOT RE.

On-Peak Fuel Mix



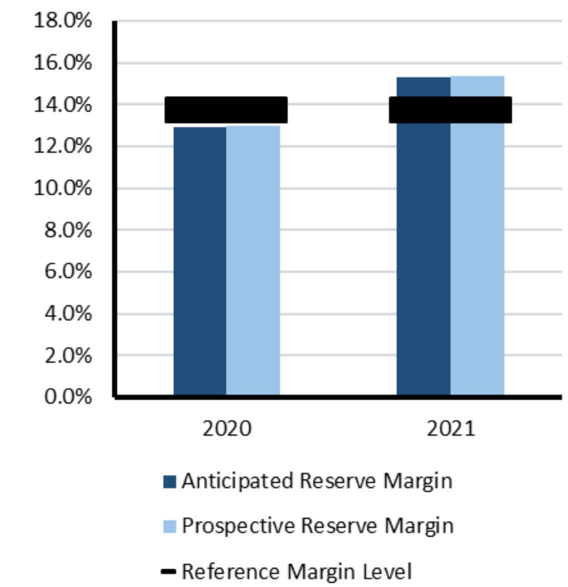
Highlights

- Summer probabilistic analysis performed by ERCOT indicates that the risk of unserved energy is low. Hour-ending 5:00 p.m. continues to be ERCOT's highest-risk hour for unserved energy with the likelihood of unserved energy less than 0.2%.
- Variable energy resources from wind and solar are critical to meeting peak electricity demand in ERCOT. Periods of low wind generation or higher-than expected thermal outages create a reliability risk during peak load hours. ERCOT appears to be in a weather cycle that may increase the risk of intensifying drought conditions and higher than normal summer temperatures. These weather factors could result in actual summer peak demand exceeding the forecast, which already anticipates record peak demand levels. Thermal outages may increase during severe and prolonged drought conditions due to cooling water supply and temperature issues.
- Given an Anticipated Reserve Margin of 15.3% and Reference Reserve Margin of 13.75%, ERCOT expects to have sufficient operating reserves for summer system conditions.
- Delays or cancellations of planned transmission expansion projects in the western part of the Lower Rio Grande Valley, if they occur, may contribute to potential localized reliability concerns.

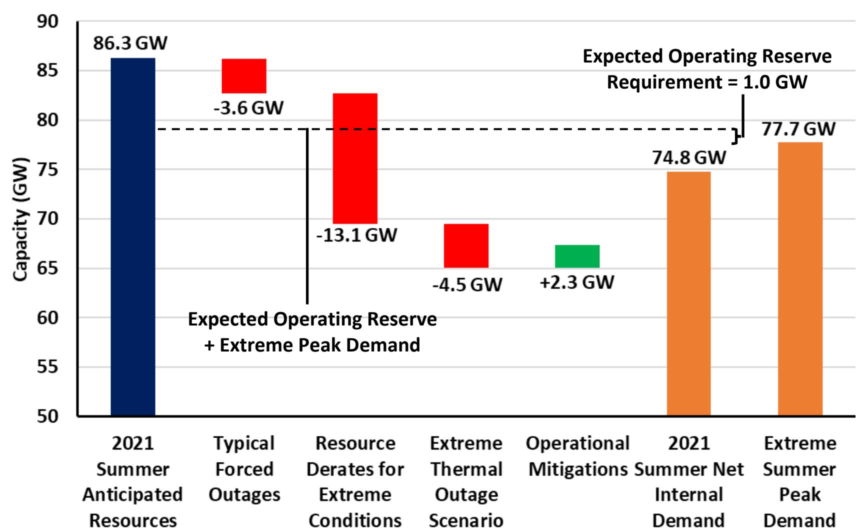
Risk Scenario Summary

Expected resources meet operating reserve requirements under normal peak-demand scenarios. Above-normal summer peak load and outage conditions could result in the need to employ operating mitigations (i.e., demand response, transfers, and short-term load interruption).

On-Peak Reserve Margins



Risk-Period Scenario



Scenario Description

- **Risk Period:** Highest risk for unserved energy at peak demand hour, late afternoon (Risk can extend for 1–2 hours after peak as solar PV output diminishes. Periods of low-wind, which usually occur 1–2 hours before peak demand, can also result in extended shortfall risk.
- **Demand Scenarios:** Net internal demand (50/50) and extreme demand based on 2011 historic summer peak demand (approximates 90/10 demand forecast)
- **Forced Outages:** Based on historical average of forced outages for June through September weekdays, hours ending 3:00–8:00 p.m., for the last three summer seasons (2018–2020)
- **Extreme Derates:** Additional derates of 2,605 MW (thermal), 6,576 MW (wind), and 2,953 MW (PV) for extreme conditions (i.e., based on the 95th percentile of historical forced outages for June–September weekdays, hours ending 3:00–8:00 p.m., for the last three years.
- **Extreme Outage Scenario:** Additional increments of thermal and hydro forced outages equating to highest hourly forced outages from 2011–2021 **(**When combined with extreme derates shown in the Risk-Period Scenario, it represents a very rare resource condition.)
- **Operational Mitigation:** Additional resources, primarily from load resources, but also switchable generation, additional imports, and voltage reduction)

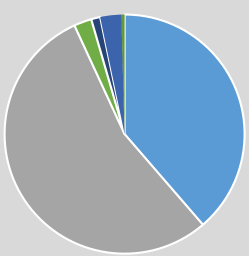
WECC-AB

WECC-Alberta is an assessment area in the WECC RE that consists of the province of Alberta, Canada.

WECC is responsible for coordinating and promoting BES reliability in the Western Interconnection. WECC's 329 members, which include 38 BA, represent a wide spectrum of organizations with an interest in the BES. Serving an area of nearly 1.8 million square miles and more than 82 million people, it is geographically the largest and most diverse of the NERC RE.

WECC's service territory extends from Canada to Mexico. It includes the provinces of Alberta and British Columbia in Canada, the northern portion of Baja California in Mexico, and all or portions of the 14 Western United States in between.

On-Peak Fuel Mix



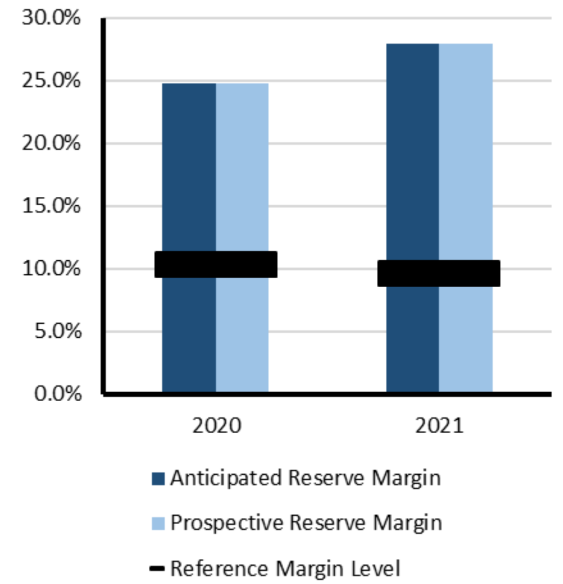
Highlights

- WECC-Alberta is a winter peaking province. Sufficient resources are anticipated to meet summer demand.
- Based on a WECC probabilistic assessment, the WECC-AB assessment area had negligible LOLH and EUE.

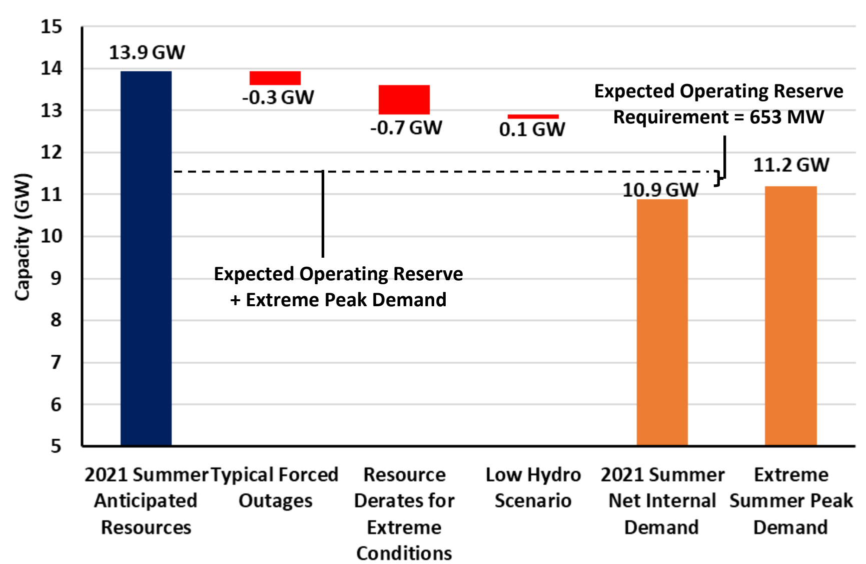
Risk Scenario Summary

Expected resources meet operating reserve requirements under assessed scenarios.

On-Peak Reserve Margins



Risk-Period Scenario



Scenario Description

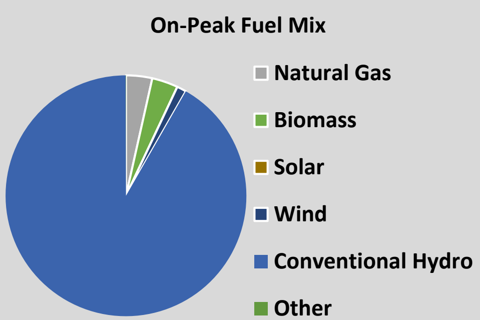
- **Risk Period:** Highest risk for unserved energy at peak demand hour (afternoon)
- **Demand Scenarios:** Net internal demand (50/50) and 90/10 demand forecast
- **Forced Outages:** Average seasonal outages
- **Extreme Derates:** Derate using 90/10 scenario

WECC-BC

WECC-British Columbia is an assessment area in the WECC RE that consists of the province of British Columbia, Canada.

WECC is responsible for coordinating and promoting BES reliability in the Western Interconnection. WECC's 329 members, which include 38 BA, represent a wide spectrum of organizations with an interest in the BES. Serving an area of nearly 1.8 million square miles and more than 82 million people, it is geographically the largest and most diverse of the NERC RE.

WECC's service territory extends from Canada to Mexico. It includes the provinces of Alberta and British Columbia in Canada, the northern portion of Baja California in Mexico, and all or portions of the 14 Western United States in between.

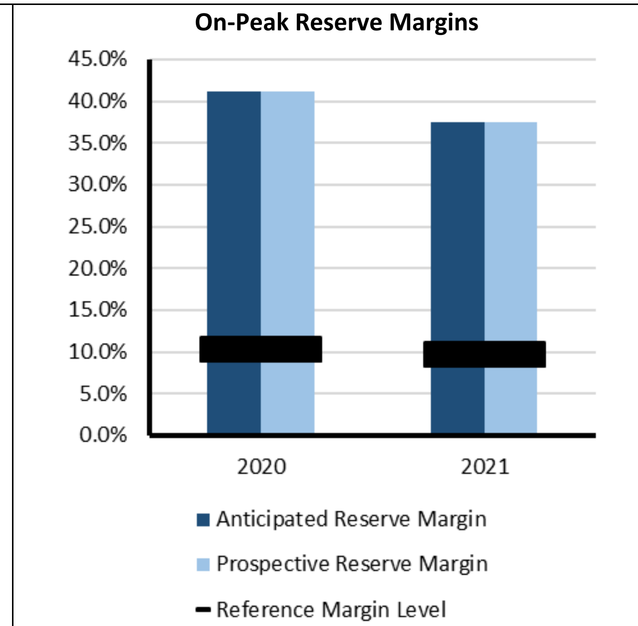


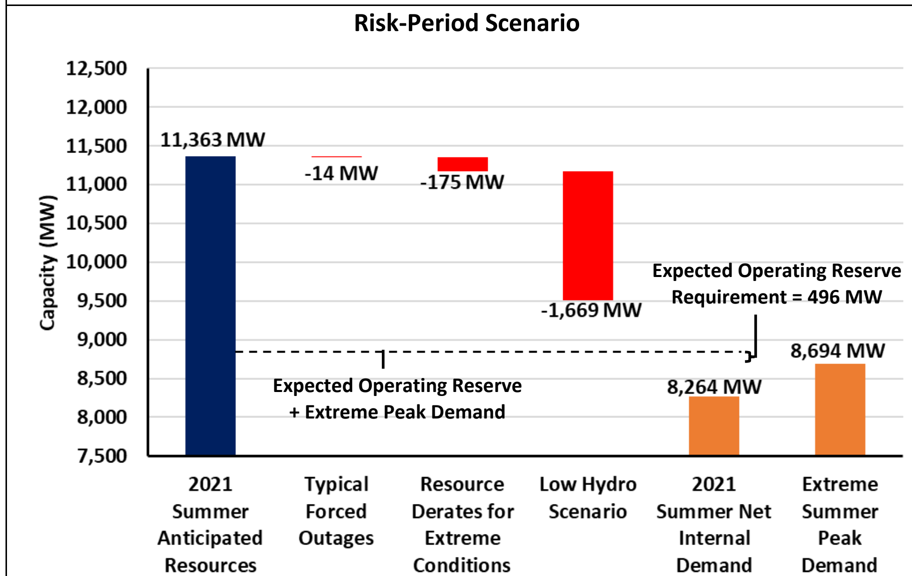
Highlights

- WECC-British Columbia is a winter peaking province. Sufficient resources are anticipated to meet summer demand.
- Based on a WECC probabilistic assessment, the WECC-AB assessment area had negligible LOLH and EUE.

Risk Scenario Summary

Expected resources meet operating reserve requirements under assessed scenarios.





Scenario Description

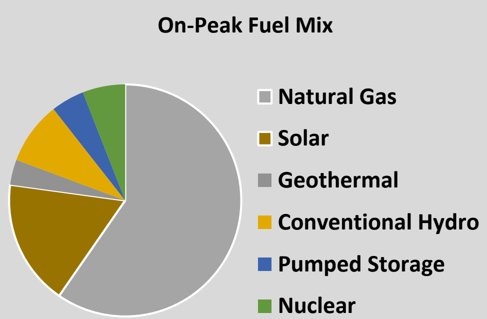
- **Risk Period:** Highest risk for unserved energy at peak demand hour (afternoon)
- **Demand Scenarios:** Net internal demand (50/50) and 90/10 demand forecast
- **Forced Outages:** Average seasonal outages
- **Extreme Derates:** Derate using 90/10 scenario

WECC-CAMX

WECC California-Mexico is an assessment area in the WECC RE that includes parts of California, Nevada, and Baja California, Mexico.

WECC is responsible for coordinating and promoting BES reliability in the Western Interconnection. WECC's 329 members, which include 38 BA, represent a wide spectrum of organizations with an interest in the BES. Serving an area of nearly 1.8 million square miles and more than 82 million people, it is geographically the largest and most diverse of the NERC RE.

WECC's service territory extends from Canada to Mexico. It includes the provinces of Alberta and British Columbia in Canada, the northern portion of Baja California in Mexico, and all or portions of the 14 Western United States in between.

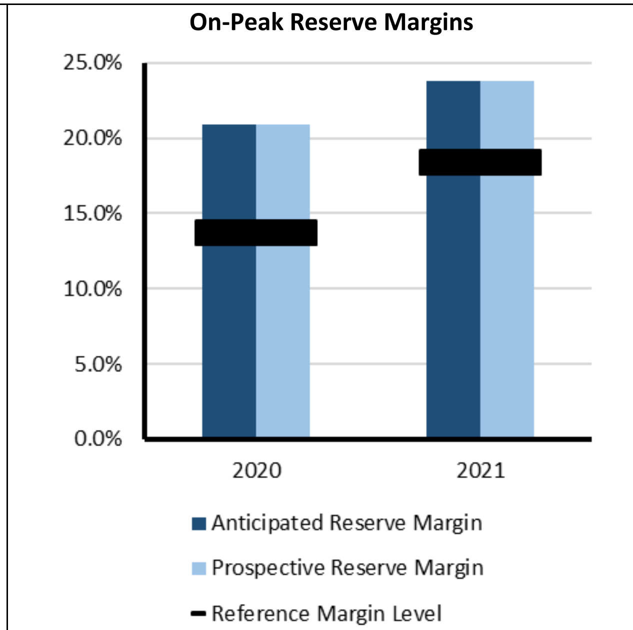


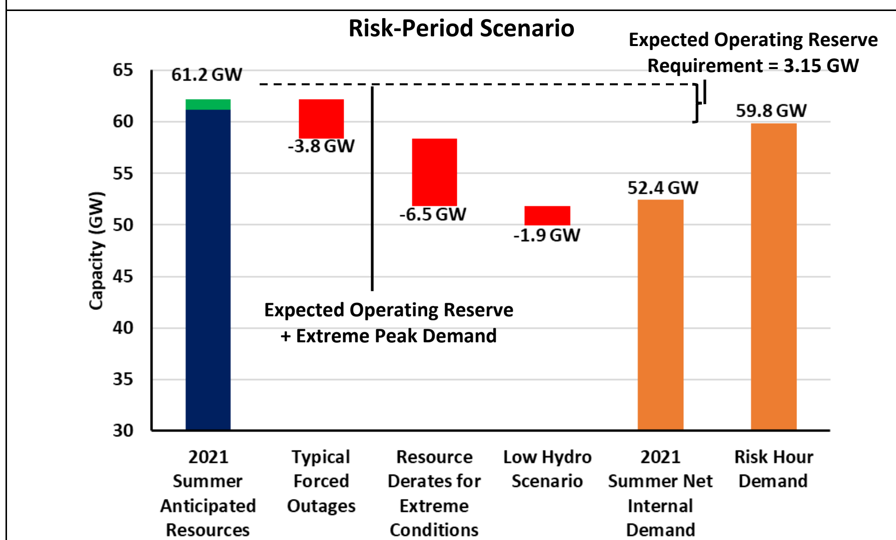
Highlights

- Anticipated resources, which include new capacity in development as well as imports, are expected to be sufficient to meet summer peak demand. However, supply shortfalls from unanticipated low variable generation output, limited imports, or thermal generation outages could lead to energy emergencies. Extreme demand, as seen in 2020, could also lead to emergencies.
- WECC-CAMX has planned resource additions of 1,300 MW over the summer, including 825 MW of new battery storage that are in development. Owners and operators must keep focus on project timelines and implementation milestones to meet anticipated resource levels and help reduce resource adequacy risks in late-summer.
- The Western Interconnection is at risk of experiencing operating challenges from wildfires. Transmission lines may be removed from service in areas with active wildfires or heightened wildfire risk. These transmission outages can impose BPS operational constraints resulting in loss of load events.
- Based on a WECC probabilistic assessment, the California portion of the assessment area has an LOLH of 0.20 hours and an EUE of 10,185 MWh. The Mexico portion has negligible LOLH and EUE.

Risk Scenario Summary

Expected resources (including summer additions) meet operating reserve requirements under normal demand scenarios. Above-normal peak load would cause area resource shortages during periods of peak demand and extend into evenings as solar PV output diminishes while demand remains high. High thermal resource outages or reduced availability of imports associated with extreme or wide-area heat events are likely to result in firm load-shed.





Scenario Description

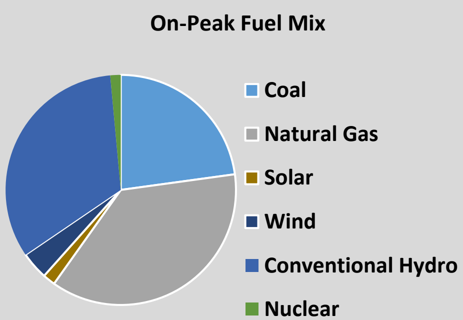
- **Risk Period:** Period of greatest risk typically within two hours following afternoon peak demand as solar PV output diminishes
- **Demand Scenarios:** Net internal demand (50/50) and 90/10 demand forecast
- **Forced Outages:** Estimated using market forced outage model
- **Extreme Derates:** Derate on natural gas units based on historic data and manufacturer data for temperature performance and outages

WECC-NWPP & RMRG

WECC Northwest Power Pool and Rocky Mountain Reserve Sharing Group is an assessment area in the WECC RE. The area includes Colorado, Idaho, Montana, Oregon, Utah, Washington, and Wyoming and parts of California, Nebraska, Nevada, and South Dakota.

WECC is responsible for coordinating and promoting BES reliability in the Western Interconnection. WECC's 329 members, which include 38 BA, represent a wide spectrum of organizations with an interest in the BES. Serving an area of nearly 1.8 million square miles and more than 82 million people, it is geographically the largest and most diverse of the NERC RE.

WECC's service territory extends from Canada to Mexico. It includes the provinces of Alberta and British Columbia in Canada, the northern portion of Baja California in Mexico, and all or portions of the 14 Western United States in between.

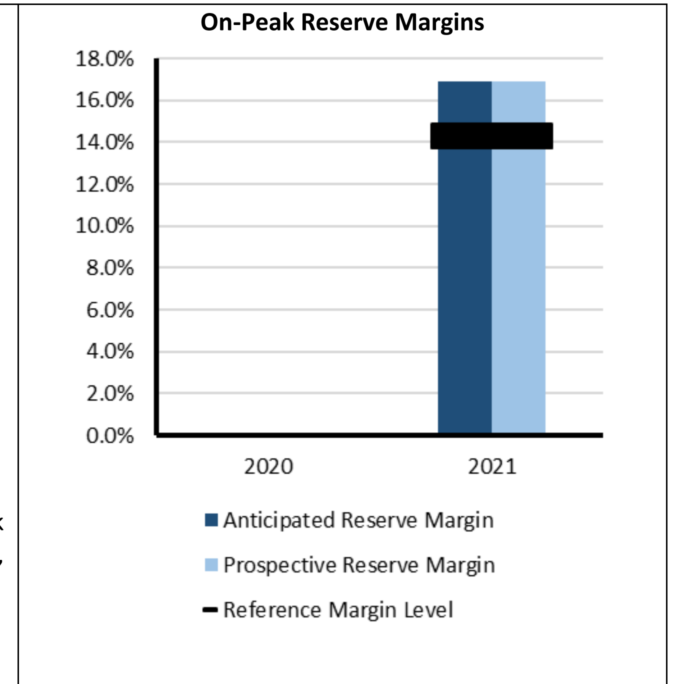


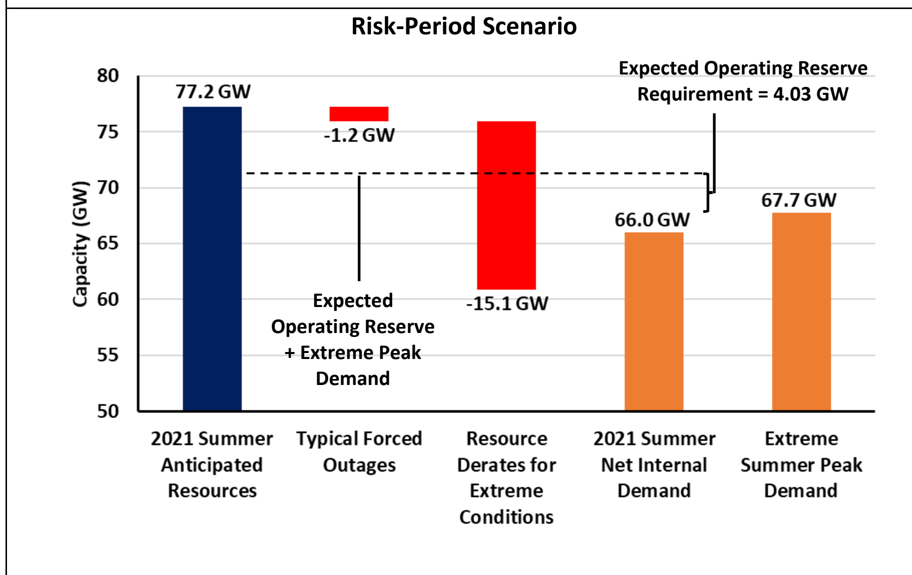
Highlights

- The anticipated reserve margins for WECC, its subregions, and all zones within are expected to exceed their respective NERC Reference Margin Levels for the upcoming season
- WECC merged the NWPP and RMRG assessment areas in late 2020, so an Anticipated Reserve Margin or a Reference Margin Level was not produced for the 2020 assessment year for comparison. However, it is estimated that anticipated resources have declined by 4% since 2020 while demand is not significantly changed in the merged area for the upcoming summer (see Demand and Resource Tables).
- Localized short-term operational issues may occur due to wildfires. Due to the widely dispersed nature of the transmission system, outages due to wildfires are generally not widespread.
- Based on a WECC probabilistic assessment, the WECC-NWPP assessment area had an LOLH of 0.06 hour and a EUE of 3,442 MWh.

Risk Scenario Summary

Expected resources meet operating reserve requirements under normal peak-demand scenarios. Extreme summer peak load and outage conditions could result in the need to employ operating mitigations (i.e., demand response, transfers, and short-term load interruption).





Scenario Description

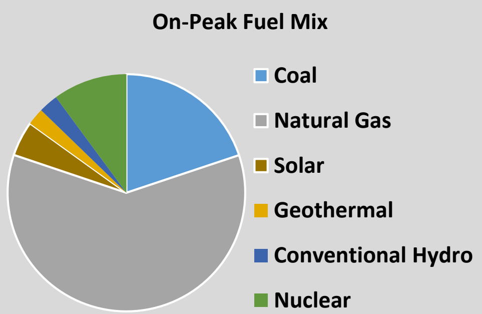
- **Risk Period:** Highest risk for unserved energy at peak demand hour (late afternoon)
- **Demand Scenarios:** Net internal demand (50/50) and 90/10 demand forecast
- **Forced Outages:** Average seasonal outages
- **Extreme Derates:** Derate using 90/10 scenario

WECC-SRSG

WECC Southwest Reserve Sharing Group is an assessment area in the WECC RE. It includes Arizona and New Mexico and part of California and Texas.

WECC is responsible for coordinating and promoting BES reliability in the Western Interconnection. WECC's 329 members, which include 38 BA, represent a wide spectrum of organizations with an interest in the BES. Serving an area of nearly 1.8 million square miles and more than 82 million people, it is geographically the largest and most diverse of the NERC RE.

WECC's service territory extends from Canada to Mexico. It includes the provinces of Alberta and British Columbia in Canada, the northern portion of Baja California in Mexico, and all or portions of the 14 Western United States in between.

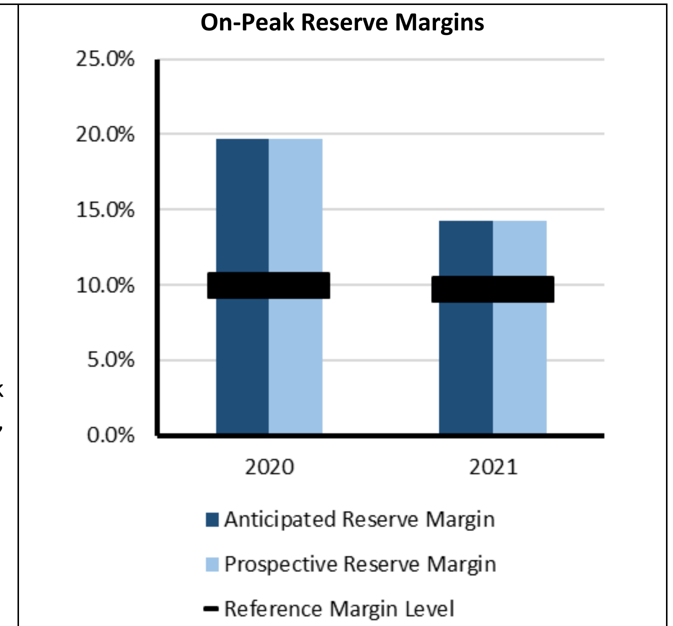


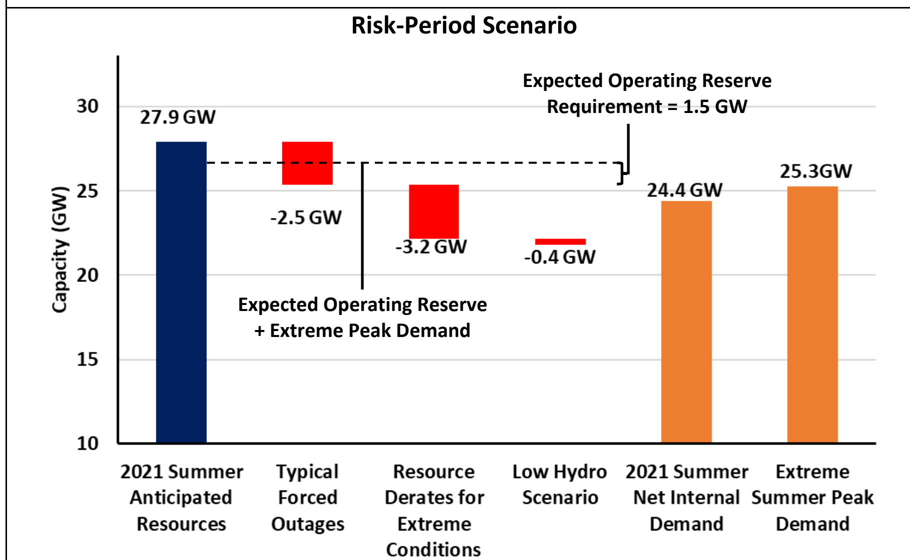
Highlights

- The Anticipated Reserve Margins for WECC, its subregions, and all zones within are expected to exceed their respective NERC Reference Margin Levels for the upcoming season.
- For the upcoming summer season, California ISO is procuring resources to improve reliability risks.
- Localized short-term operational issues may occur due to wildfires. Due to the widely dispersed nature of the transmission system, outages due to wildfires are generally not widespread.
- Based on a WECC probabilistic assessment, the WECC-SRSG assessment area had negligible LOLH and EUE.

Risk Scenario Summary

Expected resources meet operating reserve requirements under normal peak-demand scenarios. Extreme summer peak load and outage conditions could result in the need to employ operating mitigations (i.e., demand response, transfers, and short-term load interruption).





Scenario Description

- **Risk Period:** Highest risk for unserved energy at peak demand hour (late afternoon)
- **Demand Scenarios:** Net internal demand (50/50) and 90/10 demand forecast
- **Forced Outages:** Average seasonal outages
- **Extreme Derates:** Derate using 90/10 scenario

Data Concepts and Assumptions

The table below explains data concepts and important assumptions used throughout this assessment.

General Assumptions
• Reliability of the interconnected BPS is comprised of both adequacy and operating reliability:
▪ Adequacy is the ability of the electric system to supply the aggregate electric power and energy requirements of the electricity consumers at all times while taking into account scheduled and reasonably expected unscheduled outages of system components.
▪ Operating reliability is the ability of the electric system to withstand sudden disturbances such as electric short-circuits or unanticipated loss of system components.
• The reserve margin calculation is an important industry planning metric used to examine future resource adequacy.
• All data in this assessment is based on existing federal, state, and provincial laws and regulations.
• Differences in data collection periods for each assessment area should be considered when comparing demand and capacity data between year-to-year seasonal assessments.
• *2020 Long-Term Reliability Assessment* data has been used for most of this 2021 assessment period augmented by updated load and capacity data.
• A positive net transfer capability would indicate a net importing assessment area; a negative value would indicate a net exporter.
Demand Assumptions
• Electricity demand projections, or load forecasts, are provided by each assessment area.
• Load forecasts include peak hourly load[18] or total internal demand for the summer and winter of each year.[19]
• Total internal demand projections are based on normal weather (50/50 distribution[20]) and are provided on a coincident[21] basis for most assessment areas.
• Net internal demand is used in all reserve margin calculations, and it is equal to total internal demand then reduced by the amount of controllable and dispatchable demand response projected to be available during the peak hour.
Resource Assumptions
Resource planning methods vary throughout the North American BPS. NERC uses the categories below to provide a consistent approach for collecting and presenting resource adequacy. **Table 2** below shows the wind and solar generation resources in each assessment area and describes how capacity contributions values are determined.
Anticipated Resources: • **Existing-Certain Capacity**: Included in this category are commercially operable generating unit or portions of generating units that meet at least one of the following requirements when examining the period of peak demand for the summer season: unit must have a firm capability and have a power purchase agreement (PPA) with firm transmission that must be in effect for the unit; unit must be classified as a designated network resource; and/or where energy-only markets exist, unit must be a designated market resource eligible to bid into the market. • **Tier 1 Capacity Additions**: This category includes capacity that either is under construction or has received approved planning requirements. • **Net Firm Capacity Transfers (Imports minus Exports)**: This category includes transfers with firm contracts.
Prospective Resources: Includes all anticipated resources plus the following: **Existing-Other Capacity**: Included in this category are commercially operable generating units or portions of generating units that could be available to serve load for the period of peak demand for the season but do not meet the requirements of existing-certain.
Reserve Margin Descriptions

[18] *Glossary of Terms* used in NERC Reliability Standards
[19] The summer season represents June–September and the winter season represents December–February.
[20] Essentially, this means that there is a 50% probability that actual demand will be higher and a 50% probability that actual demand will be lower than the value provided for a given season/year.
[21] Coincident: This is the sum of two or more peak loads that occur in the same hour. Noncoincident: This is the sum of two or more peak loads on individual systems that do not occur in the same time interval; this is meaningful only when considering loads within a limited period of time, such as a day, a week, a month, a heating or cooling season, and usually for not more than one year. SERC and FRCC calculate total internal demand on a noncoincidental basis.

Planning Reserve Margin: This is the primary metric used to measure resource adequacy; it is defined as the difference in resources (anticipated or prospective) and net internal demand then divided by net internal demand and shown as a percentage.

Reference Margin Level: The assumptions and naming convention of this metric vary by assessment area. The Reference Margin Level can be determined using both deterministic and probabilistic (based on a 0.1/year loss of load study) approaches. In both cases, this metric is used by system planners to quantify the amount of reserve capacity in the system above the forecasted peak demand that is needed to ensure sufficient supply to meet peak loads. Establishing a Reference Margin Level is necessary to account for long-term factors of uncertainty involved in system planning, such as unexpected generator outages and extreme weather impacts that could lead to increase demand beyond what was projected in the 50/50 load forecasted. In many assessment areas, a Reference Margin Level is established by a state, provincial authority, ISO/RTO, or other regulatory body. In some cases, the Reference Margin Level is a requirement. Reference Margin Levels may be different for the summer and winter seasons. If a Reference Margin Level is not provided by an assessment area, NERC applies 15% for predominately thermal systems and 10% for predominately hydro systems.

Seasonal Risk Scenario Chart Description

Each assessment area performed an operational risk analysis that was used to produce the seasonal risk scenario charts in the **Regional Assessments Dashboards**. The chart presents deterministic scenarios for further analysis of different resource and demand levels: The left blue column shows anticipated resources (from the resource adequacy data table), and the two orange columns at the right show the two demand scenarios of the normal peak net internal demand from the resource adequacy data table and the extreme summer peak demand—both determined by the assessment area. The middle red or green bars show adjustments that are applied cumulatively to the anticipated resources, such as the following:

- Reductions for typical generation outages (i.e., maintenance and forced, not already accounted for in anticipated resources)
- Reductions that represent additional outage or performance derating by resource type for extreme, low-probability conditions (e.g., drought condition impacts on hydroelectric generation, low-wind scenario affecting wind generation, fuel supply limitations, or extreme temperature conditions that result in reduced thermal generation output)
- Additional capacity resources that represent quantified capacity from operational procedures, if any, that are made available during scarcity conditions

Not all assessment areas have the same categories of adjustments to anticipated resources. Furthermore, each assessment area determined the adjustments to capacity based on methods or assumptions that are summarized below the chart. Methods and assumptions differ by assessment area and may not be comparable.

The chart enables evaluation of resource levels against levels of expected operating reserve requirement and the forecasted demand. Further, the effects from low-probability, extreme events can also be examined by comparing resource levels after applying extreme-scenario derates and/or extreme summer peak demand. Because such extreme scenario analysis depicts the cumulative impact resulting from the occurrence of multiple low-probability events, the overall likelihood of this scenario is very low.

Demand and Resource Tables

Peak demand and supply capacity data for each assessment area are provided below.

MISO Resource Adequacy Data			
Demand, Resource, and Reserve Margins	**2020 SRA**	**2021 SRA**	**2020 vs. 2021 SRA**
Demand Projections	**Megawatts (MW)**	**Megawatts (MW)**	**Net Change (%)**
Total Internal Demand (50/50)	124,866	122,398	-2.0%
Demand Response: Available	6,172	6,038	-2.2%
Net Internal Demand	118,694	116,360	-2.0%
Resource Projections	**Megawatts (MW)**	**Megawatts (MW)**	**Net Change (%)**
Existing-Certain Capacity	140,636	138,464	-1.5%
Tier 1 Planned Capacity	0	0	-
Net Firm Capacity Transfers	2,795	2,979	6.6%
Anticipated Resources	143,430	141,443	-1.4%
Existing-Other Capacity	290	633	118.1%
Prospective Resources	143,720	146,586	2.0%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	20.8%	21.6%	0.8
Prospective Reserve Margin	21.1%	26.0%	4.9
Reference Margin Level	18.0%	18.3%	0.3

MRO-SaskPower Resource Adequacy Data			
Demand, Resource, and Reserve Margins	**2020 SRA**	**2021 SRA**	**2020 vs. 2021 SRA**
Demand Projections	**Megawatts (MW)**	**Megawatts (MW)**	**Net Change (%)**
Total Internal Demand (50/50)	3,480	3,400	-2.3%
Demand Response: Available	60	60	0.0%
Net Internal Demand	3,420	3,340	-2.3%
Resource Projections	**Megawatts (MW)**	**Megawatts (MW)**	**Net Change (%)**
Existing-Certain Capacity	3,904	3,863	-1.1%
Tier 1 Planned Capacity	0	14	-
Net Firm Capacity Transfers	125	125	0.0%
Anticipated Resources	4,029	4,002	-0.7%
Existing-Other Capacity	0	0	-
Prospective Resources	4,029	4,002	-0.7%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	17.8%	19.8%	2.0
Prospective Reserve Margin	17.8%	19.8%	2.0
Reference Margin Level	11.0%	11.0%	0.0

MRO-Manitoba Hydro Resource Adequacy Data			
Demand, Resource, and Reserve Margins	**2020 SRA**	**2021 SRA**	**2020 vs. 2021 SRA**
Demand Projections	**Megawatts (MW)**	**Megawatts (MW)**	**Net Change (%)**
Total Internal Demand (50/50)	3,272	2,965	-9.4%
Demand Response: Available	0	0	-
Net Internal Demand	3,272	2,965	-9.4%
Resource Projections	**Megawatts (MW)**	**Megawatts (MW)**	**Net Change (%)**
Existing-Certain Capacity	5,239	5,173	-1.3%
Tier 1 Planned Capacity	0	186	-
Net Firm Capacity Transfers	-1,526	-1,596	4.6%
Anticipated Resources	3,713	3,763	1.4%
Existing-Other Capacity	125	37	-70.3%
Prospective Resources	3,838	3,800	-1.0%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	13.5%	26.9%	13.4
Prospective Reserve Margin	17.3%	28.2%	10.9
Reference Margin Level	12.0%	12.0%	0.0

NPCC-Maritimes Resource Adequacy Data			
Demand, Resource, and Reserve Margins	**2020 SRA**	**2021 SRA**	**2020 vs. 2021 SRA**
Demand Projections	**Megawatts (MW)**	**Megawatts (MW)**	**Net Change (%)**
Total Internal Demand (50/50)	3,370	3,479	3.2%
Demand Response: Available	369	305	-17.3%
Net Internal Demand	3,001	3,174	5.8%
Resource Projections	**Megawatts (MW)**	**Megawatts (MW)**	**Net Change (%)**
Existing-Certain Capacity	5,312	5,448	2.6%
Tier 1 Planned Capacity	0	0	-
Net Firm Capacity Transfers	-53	-57	7.5%
Anticipated Resources	5,259	5,391	2.5%
Existing-Other Capacity	0	0	-
Prospective Resources	5,259	5,391	2.5%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	75.2%	69.8%	-5.4
Prospective Reserve Margin	75.2%	69.8%	-5.4
Reference Margin Level	20.0%	20.0%	0.0

NPCC-New England Resource Adequacy Data			
Demand, Resource, and Reserve Margins	**2020 SRA**	**2021 SRA**	**2020 vs. 2021 SRA**
Demand Projections	**Megawatts (MW)**	**Megawatts (MW)**	**Net Change (%)**
Total Internal Demand (50/50)	25,158	25,244	0.3%
Demand Response: Available	443	434	-2.0%
Net Internal Demand	24,715	24,810	0.4%
Resource Projections	**Megawatts (MW)**	**Megawatts (MW)**	**Net Change (%)**
Existing-Certain Capacity	30,791	29,065	-5.6%
Tier 1 Planned Capacity	0	0	-
Net Firm Capacity Transfers	1,510	1,208	-20.0%
Anticipated Resources	32,301	30,273	-6.3%
Existing-Other Capacity	324	1,115	244.1%
Prospective Resources	32,625	31,388	-3.8%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	30.7%	22.0%	-8.7
Prospective Reserve Margin	32.0%	26.5%	-5.5
Reference Margin Level	18.3%	15.0%	-3.3

NPCC-Ontario Resource Adequacy Data			
Demand, Resource, and Reserve Margins	**2020 SRA**	**2021 SRA**	**2020 vs. 2021 SRA**
Demand Projections	**Megawatts (MW)**	**Megawatts (MW)**	**Net Change (%)**
Total Internal Demand (50/50)	22,195	22,500	1.4%
Demand Response: Available	518	621	20.0%
Net Internal Demand	21,677	21,879	0.9%
Resource Projections	**Megawatts (MW)**	**Megawatts (MW)**	**Net Change (%)**
Existing-Certain Capacity	25,719	26,217	1.9%
Tier 1 Planned Capacity	49	22	-55.6%
Net Firm Capacity Transfers	0	80	-
Anticipated Resources	25,768	26,319	2.1%
Existing-Other Capacity	0	0	-
Prospective Resources	25,768	26,319	2.1%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	18.9%	20.3%	1.4
Prospective Reserve Margin	18.9%	20.3%	1.4
Reference Margin Level	14.6%	13.2%	-1.4

NPCC-New York Resource Adequacy Data			
Demand, Resource, and Reserve Margins	**2020 SRA**	**2021 SRA**	**2020 vs. 2021 SRA**
Demand Projections	**Megawatts (MW)**	**Megawatts (MW)**	**Net Change (%)**
Total Internal Demand (50/50)	32,296	32,333	0.1%
Demand Response: Available	1,282	1,199	-6.5%
Net Internal Demand	31,014	31,134	0.4%
Resource Projections	**Megawatts (MW)**	**Megawatts (MW)**	**Net Change (%)**
Existing-Certain Capacity	38,475	37,805	-1.7%
Tier 1 Planned Capacity	101.2	0	-100.0%
Net Firm Capacity Transfers	1,562	1,816	16.3%
Anticipated Resources	40,138	39,621	-1.3%
Existing-Other Capacity	0	0	-
Prospective Resources	40,138	39,621	-1.3%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	29.4%	27.3%	-2.1
Prospective Reserve Margin	29.4%	27.3%	-2.1
Reference Margin Level	15.0%	15.0%	0.0

NPCC-Québec Resource Adequacy Data			
Demand, Resource, and Reserve Margins	**2020 SRA**	**2021 SRA**	**2020 vs. 2021 SRA**
Demand Projections	**Megawatts (MW)**	**Megawatts (MW)**	**Net Change (%)**
Total Internal Demand (50/50)	21,635	21,436	-0.9%
Demand Response: Available	0	0	-
Net Internal Demand	21,635	21,436	-0.9%
Resource Projections	**Megawatts (MW)**	**Megawatts (MW)**	**Net Change (%)**
Existing-Certain Capacity	34,771	33,380	-4.0%
Tier 1 Planned Capacity	14.25	0	-100.0%
Net Firm Capacity Transfers	-1,963	-1,995	1.6%
Anticipated Resources	32,822	31,385	-4.4%
Existing-Other Capacity	0	0	-
Prospective Resources	32,822	31,385	-4.4%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	51.7%	46.4%	-5.3
Prospective Reserve Margin	51.7%	46.4%	-5.3
Reference Margin Level	9.8%	10.4%	0.6

PJM Resource Adequacy Data

Demand, Resource, and Reserve Margins	2020 SRA	2021 SRA	2020 vs. 2021 SRA
Demand Projections	**Megawatts (MW)**	**Megawatts (MW)**	**Net Change (%)**
Total Internal Demand (50/50)	148,092	149,224	0.8%
Demand Response: Available	8,929	8,779	-1.7%
Net Internal Demand	139,163	140,445	0.9%
Resource Projections	**Megawatts (MW)**	**Megawatts (MW)**	**Net Change (%)**
Existing-Certain Capacity	182,523	183,572	0.6%
Tier 1 Planned Capacity	1800	2,400	33.3%
Net Firm Capacity Transfers	1,412	1,460	3.4%
Anticipated Resources	185,735	187,431	0.9%
Existing-Other Capacity	0	0	-
Prospective Resources	185,735	188,891	1.7%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	33.5%	33.5%	0.0
Prospective Reserve Margin	33.5%	34.5%	1.0
Reference Margin Level	15.5%	14.7%	-0.8

SERC-E Resource Adequacy Data

Demand, Resource, and Reserve Margins	2020 SRA	2021 SRA	2020 vs. 2021 SRA
Demand Projections	**Megawatts (MW)**	**Megawatts (MW)**	**Net Change (%)**
Total Internal Demand (50/50)	43,702	42,680	-2.3%
Demand Response: Available	947	970	2.4%
Net Internal Demand	42,755	41,710	-2.4%
Resource Projections	**Megawatts (MW)**	**Megawatts (MW)**	**Net Change (%)**
Existing-Certain Capacity	50,825	50,539	-0.6%
Tier 1 Planned Capacity	88	0	-100.0%
Net Firm Capacity Transfers	266	562	111.3%
Anticipated Resources	51,179	51,101	-0.2%
Existing-Other Capacity	851.5	766	-10.0%
Prospective Resources	52,030	51,867	-0.3%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	19.7%	22.5%	2.8
Prospective Reserve Margin	21.7%	24.4%	2.7
Reference Margin Level	15.0%	15.0%	0.0

SERC-C Resource Adequacy Data

Demand, Resource, and Reserve Margins	2020 SRA	2021 SRA	2020 vs. 2021 SRA
Demand Projections	**Megawatts (MW)**	**Megawatts (MW)**	**Net Change (%)**
Total Internal Demand (50/50)	40,799	40,341	-1.1%
Demand Response: Available	1,970	1,744	-11.5%
Net Internal Demand	38,829	38,597	-0.6%
Resource Projections	**Megawatts (MW)**	**Megawatts (MW)**	**Net Change (%)**
Existing-Certain Capacity	48,368	47,987	-0.8%
Tier 1 Planned Capacity	0	154	-
Net Firm Capacity Transfers	-807	172	-121.3%
Anticipated Resources	47,561	48,314	1.6%
Existing-Other Capacity	4427	4,290	-3.1%
Prospective Resources	51,988	52,604	1.2%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	22.5%	25.2%	2.7
Prospective Reserve Margin	33.9%	36.3%	2.4
Reference Margin Level	15.0%	15.0%	0.0

SERC-FP Resource Adequacy Data

Demand, Resource, and Reserve Margins	2020 SRA	2021 SRA	2020 vs. 2021 SRA
Demand Projections	**Megawatts (MW)**	**Megawatts (MW)**	**Net Change (%)**
Total Internal Demand (50/50)	49,286	48,710	-1.2%
Demand Response: Available	2,906	3,030	4.3%
Net Internal Demand	46,380	45,680	-1.5%
Resource Projections	**Megawatts (MW)**	**Megawatts (MW)**	**Net Change (%)**
Existing-Certain Capacity	55,093	55,351	0.5%
Tier 1 Planned Capacity	333	0	-100.0%
Net Firm Capacity Transfers	1,146	1,007	-12.1%
Anticipated Resources	56,571	56,358	-0.4%
Existing-Other Capacity	529	0	-100.0%
Prospective Resources	57,100	56,358	-1.3%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	22.0%	23.4%	1.4
Prospective Reserve Margin	23.1%	23.4%	0.3
Reference Margin Level	15.0%	15.0%	0.0

SERC-SE Resource Adequacy Data			
Demand, Resource, and Reserve Margins	**2020 SRA**	**2021 SRA**	**2020 vs. 2021 SRA**
Demand Projections	**Megawatts (MW)**	**Megawatts (MW)**	**Net Change (%)**
Total Internal Demand (50/50)	47,311	46,631	-1.4%
Demand Response: Available	2,145	1,671	-22.1%
Net Internal Demand	45,166	44,960	-0.5%
Resource Projections	**Megawatts (MW)**	**Megawatts (MW)**	**Net Change (%)**
Existing-Certain Capacity	61,495	61,263	-0.4%
Tier 1 Planned Capacity	316	142	-55.0%
Net Firm Capacity Transfers	-972	-1,115	14.7%
Anticipated Resources	60,839	60,290	-0.9%
Existing-Other Capacity	348	783	125.3%
Prospective Resources	61,186	61,073	-0.2%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	34.7%	34.1%	-0.6
Prospective Reserve Margin	35.5%	35.8%	0.3
Reference Margin Level	15.0%	15.0%	0.0

Texas RE-ERCOT Resource Adequacy Data			
Demand, Resource, and Reserve Margins	**2020 SRA**	**2021 SRA**	**2020 vs. 2021 SRA**
Demand Projections	**Megawatts (MW)**	**Megawatts (MW)**	**Net Change (%)**
Total Internal Demand (50/50)	75,200	77,144	2.6%
Demand Response: Available	2,251	2,341	4.0%
Net Internal Demand	72,949	74,803	2.5%
Resource Projections	**Megawatts (MW)**	**Megawatts (MW)**	**Net Change (%)**
Existing-Certain Capacity	79,395	80,569	1.5%
Tier 1 Planned Capacity	2172	5,489	152.7%
Net Firm Capacity Transfers	817	210	-74.3%
Anticipated Resources	82,384	86,268	4.7%
Existing-Other Capacity	0	0	-
Prospective Resources	82,412	86,296	4.7%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	12.9%	15.3%	2.4
Prospective Reserve Margin	13.0%	15.4%	2.4
Reference Margin Level	13.75%	13.75%	0.0

SPP Resource Adequacy Data			
Demand, Resource, and Reserve Margins	**2020 SRA**	**2021 SRA**	**2020 vs. 2021 SRA**
Demand Projections	**Megawatts (MW)**	**Megawatts (MW)**	**Net Change (%)**
Total Internal Demand (50/50)	51,943	52,249	0.6%
Demand Response: Available	835	606	-27.4%
Net Internal Demand	51,108	51,643	1.0%
Resource Projections	**Megawatts (MW)**	**Megawatts (MW)**	**Net Change (%)**
Existing-Certain Capacity	69,100	66,600	-3.6%
Tier 1 Planned Capacity	0	300	-
Net Firm Capacity Transfers	-1,244	186	-115.0%
Anticipated Resources	67,856	67,086	-1.1%
Existing-Other Capacity	0	0	-
Prospective Resources	67,856	66,539	-1.9%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	32.8%	29.9%	-2.9
Prospective Reserve Margin	32.8%	28.8%	-4.0
Reference Margin Level	12.0%	16.0%	4.0

WECC-AB Resource Adequacy Data			
Demand, Resource, and Reserve Margins	**2020 SRA**	**2021 SRA**	**2020 vs. 2021 SRA**
Demand Projections	**Megawatts (MW)**	**Megawatts (MW)**	**Net Change (%)**
Total Internal Demand (50/50)	11,500	10,886	-5.3%
Demand Response: Available	0	0	-
Net Internal Demand	11,500	10,886	-5.3%
Resource Projections	**Megawatts (MW)**	**Megawatts (MW)**	**Net Change (%)**
Existing-Certain Capacity	14,356	12,205	-15.0%
Tier 1 Planned Capacity	0	1,723	-
Net Firm Capacity Transfers	0	0	-
Anticipated Resources	14,356	13,928	-3.0%
Existing-Other Capacity	0	0	-
Prospective Resources	14,356	13,928	-3.0%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	24.8%	27.9%	3.1
Prospective Reserve Margin	24.8%	27.9%	3.1
Reference Margin Level	10.4%	9.7%	-0.7

WECC-BC Resource Adequacy Data			
Demand, Resource, and Reserve Margins	**2020 SRA**	**2021 SRA**	**2020 vs. 2021 SRA**
Demand Projections	**Megawatts (MW)**	**Megawatts (MW)**	**Net Change (%)**
Total Internal Demand (50/50)	8,278	8,264	-0.2%
Demand Response: Available	0	0	-
Net Internal Demand	8,278	8,264	-0.2%
Resource Projections	**Megawatts (MW)**	**Megawatts (MW)**	**Net Change (%)**
Existing-Certain Capacity	11,471	11,178	-2.6%
Tier 1 Planned Capacity	215	185	-13.8%
Net Firm Capacity Transfers	0	0	-
Anticipated Resources	11,686	11,363	-2.8%
Existing-Other Capacity	0	0	-
Prospective Resources	11,686	11,363	-2.8%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	41.2%	37.5%	-3.7
Prospective Reserve Margin	41.2%	37.5%	-3.7
Reference Margin Level	10.4%	9.7%	-0.7

WECC-NWPP-US and RMRG Resource Adequacy Data			
Demand, Resource, and Reserve Margins	**2020 SRA**	**2021 SRA**	**2020 vs. 2021 SRA**
Demand Projections	**Megawatts (MW)**	**Megawatts (MW)**	**Net Change (%)**
Total Internal Demand (50/50)	66,532	67,117	0.9%
Demand Response: Available	868	1,087	25.2%
Net Internal Demand	65,664	66,030	0.6%
Resource Projections	**Megawatts (MW)**	**Megawatts (MW)**	**Net Change (%)**
Existing-Certain Capacity	78,839	70,069	-11.1%
Tier 1 Planned Capacity	870	1,002	15.2%
Net Firm Capacity Transfers	749	6,139	719.6%
Anticipated Resources	80,457	77,210	-4.0%
Existing-Other Capacity	0	0	-
Prospective Resources	80,457	77,210	-4.0%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin		16.9%	
Prospective Reserve Margin		16.9%	
Reference Margin Level		14.3%	

WECC-CA/MX Resource Adequacy Data			
Demand, Resource, and Reserve Margins	**2020 SRA**	**2021 SRA**	**2020 vs. 2021 SRA**
Demand Projections	**Megawatts (MW)**	**Megawatts (MW)**	**Net Change (%)**
Total Internal Demand (50/50)	53,236	55,409	4.1%
Demand Response: Available	910	922	1.2%
Net Internal Demand	52,326	54,487	4.1%
Resource Projections	**Megawatts (MW)**	**Megawatts (MW)**	**Net Change (%)**
Existing-Certain Capacity	63,186	63,396	0.3%
Tier 1 Planned Capacity	92	3,358	3555.6%
Net Firm Capacity Transfers	0	686	-
Anticipated Resources	63,278	67,440	6.6%
Existing-Other Capacity	0	0	-
Prospective Resources	63,278	67,440	6.6%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	20.9%	23.8%	2.9
Prospective Reserve Margin	20.9%	23.8%	2.9
Reference Margin Level	13.7%	18.4%	4.7

WECC-SRSG Resource Adequacy Data			
Demand, Resource, and Reserve Margins	**2020 SRA**	**2021 SRA**	**2020 vs. 2021 SRA**
Demand Projections	**Megawatts (MW)**	**Megawatts (MW)**	**Net Change (%)**
Total Internal Demand (50/50)	25,145	24,751	-1.6%
Demand Response: Available	144	332	129.9%
Net Internal Demand	25,001	24,419	-2.3%
Resource Projections	**Megawatts (MW)**	**Megawatts (MW)**	**Net Change (%)**
Existing-Certain Capacity	29,440	26,850	-8.8%
Tier 1 Planned Capacity	477	188	-60.6%
Net Firm Capacity Transfers	0	866	-
Anticipated Resources	29,917	27,904	-6.7%
Existing-Other Capacity	0	0	-
Prospective Resources	29,917	27,904	-6.7%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	19.7%	14.3%	-5.4
Prospective Reserve Margin	19.7%	14.3%	-5.4
Reference Margin Level	10.0%	9.8%	-0.2

Variable Energy Resource Contributions

Because electrical output of variable energy resources (e.g., wind, solar) depends on weather conditions, on-peak capacity contributions are less than nameplate capacity. The table below shows the capacity contribution of existing wind and solar resources for each assessment area.

BPS Variable Generation Resources by Assessment Area									
	Wind			Solar			Hydro		
Assessment Area / Interconnection	Nameplate Wind	Expected Wind	Expected Share of Nameplate (%)	Nameplate Solar	Expected Solar	Expected Share of Nameplate (%)	Nameplate Hydro	Expected Hydro	Expected Share of Nameplate (%)
MISO	26,829	3,872	14%	725	469	65%	2,440	2,361	97%
MRO-Manitoba Hydro	259	43	17%	-	-	-	5,461	4,903	90%
MRO-SaskPower	616	66	11%	-	-	-	864	787	91%
NPCC-Maritimes	1,188	287	24%	4	-	0%	1,318	1,186	90%
NPCC-New England	1,505	166	11%	375	112	30%	3,890	2,736	70%
NPCC-New York	2,211	502	23%	57	32	56%	6,725	4,666	69%
NPCC-Ontario	4,946	678	14%	478	66	14%	9,060	5,305	59%
NPCC-Québec	3,880		0%	10		0%	41,339	32,750	79%
PJM	8,790	1,410	16%	2,421	997	41%	3,057	3,057	100%
SERC-C	964	958	99%	521	336	65%	5,005	3,572	71%
SERC-E	-	-	-	649	641	99%	3,131	3,085	99%
SERC-FP	-	-	-	3,624	2,049	57%	-	-	-
SERC-SE	-	-	-	2,735	2,282	83%	3,242	3,288	101%
SPP	26,885	4,670	17%	275	252	92%	5,441	5,130	94%
Texas RE-ERCOT	31,829	8,565	27%	7,608	6,086	80%	556	474	85%
WECC-AB	2,219	162	7%	314	202	64%	894	378	42%

BPS Variable Generation Resources by Assessment Area									
	Wind			Solar			Hydro		
Assessment Area / Interconnection	Nameplate Wind	Expected Wind	Expected Share of Nameplate (%)	Nameplate Solar	Expected Solar	Expected Share of Nameplate (%)	Nameplate Hydro	Expected Hydro	Expected Share of Nameplate (%)
WECC-BC	717	142	20%	2	1	50%	16,334	10,088	62%
WECC-CAMX	7,686	1,089	14%	16,918	10,442	62%	11,821	5,993	51%
WECC-NWPP-US-RMRG	16,180	2,318	14%	5,234	4,028	77%	40,992	20,986	51%
WECC-NWPP-SRSG	3,141	636	20%	1,797	1,265	70%	1,303	558	43%
EASTERN INTERCONNECTION	69,446	12,378	18%	9,005	5,463	61%	49,185	39,183	80%
QUÉBEC INTERCONNECTION	3,880	-	0%	10	-	0%	41,339	32,750	79%
TEXAS INTERCONNECTION	31,829	8,565	27%	7,608	6,086	80%	556	474	85%
WECC INTERCONNECTION	29,943	4,347	15%	24,256	15,938	66%	71,344	38,003	53%
TOTAL-NERC	**135,097**	**25,290**	**19%**	**40,887**	**27,488**	**67%**	**162,425**	**110,410**	**68%**

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

2022 Summer Reliability Assessment

May 2022

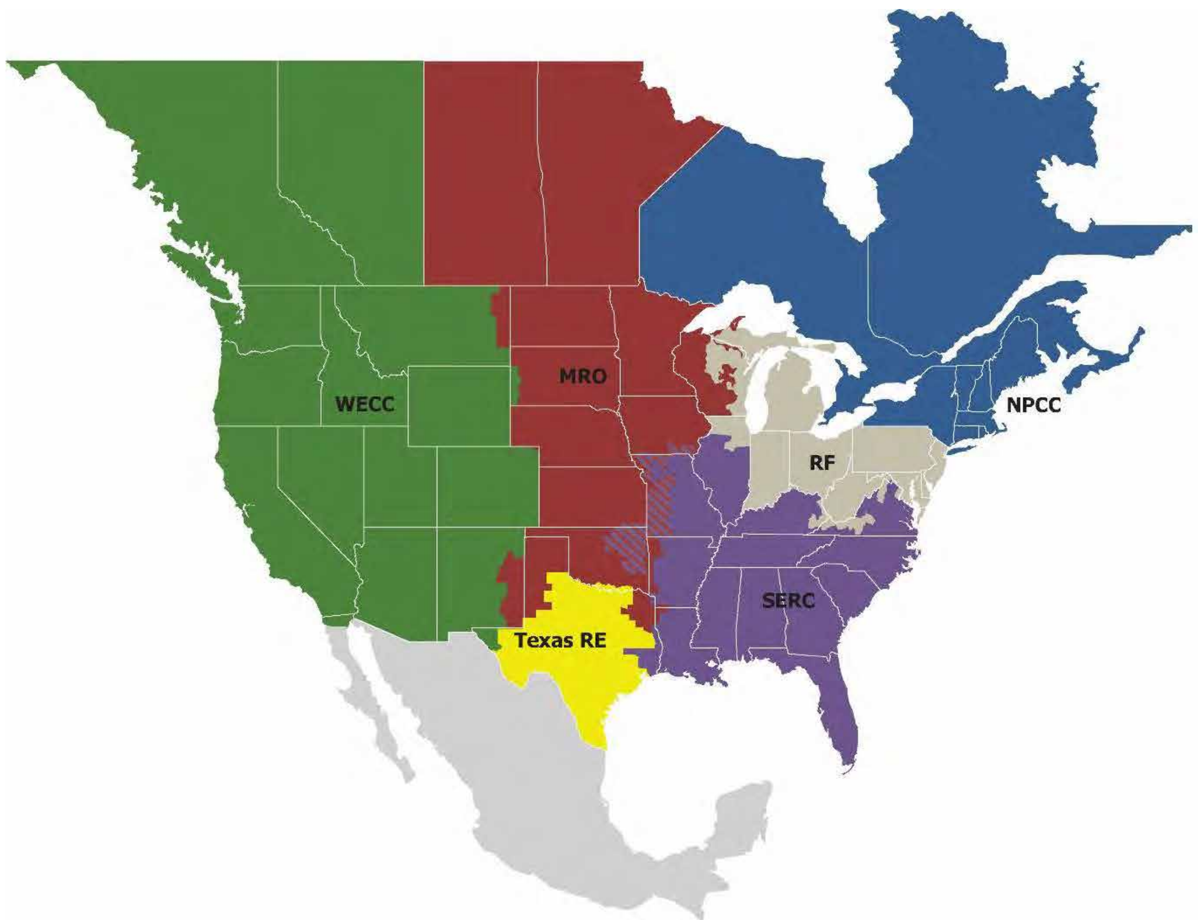
Table of Contents

Preface

The vision for the Electric Reliability Organization Enterprise, which is comprised of the North American Electric Reliability Corporation (NERC) and the six Regional Entities, is a highly reliable and secure North American bulk power system (BPS). Our mission is to assure the effective and efficient reduction of risks to the reliability and security of the grid.

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

The North American BPS is made up of six Regional Entities boundaries as shown in the map below. The multicolored area denotes overlap as some load-serving entities participate in one Regional Entities while associated Transmission Owners/Operators participate in another. Refer to the **Data Concepts and Assumptions** section for more information. A map and list of the assessment areas can be found in the **Regional Assessments Dashboards** section.



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

About this Assessment

NERC's *2022 Summer Reliability Assessment* (*SRA*) identifies, assesses, and reports on areas of concern regarding the reliability of the North American BPS for the upcoming summer season. In addition, the *SRA* presents peak electricity demand and supply changes as well as highlights any unique regional challenges or expected conditions that might impact the BPS. The reliability assessment process is a coordinated reliability evaluation between the NERC Reliability Assessment Subcommittee, the Regional Entities, and NERC staff with demand and resource projections obtained from the assessment areas. This report reflects NERC and the ERO Enterprise's independent assessment and is intended to inform industry leaders, planners, operators, and regulatory bodies so that they are better prepared to take necessary actions to ensure BPS reliability. This report also provides an opportunity for the industry to discuss plans and preparations to ensure reliability for the upcoming summer period.

Key Findings

NERC's annual SRA covers the upcoming four-month (June–September) summer period. This assessment provides an evaluation of generation resource and transmission system adequacy and energy sufficiency to meet projected summer peak demands and operating reserves. This assessment identifies potential reliability issues of interest and regional topics of concern. While the scope of this seasonal assessment is focused on the upcoming summer, the key findings are consistent with risks and issues that NERC has highlighted in the *2021 Long-Term Reliability Assessment* and other earlier reliability assessments and reports.

The following findings are NERC and the ERO Enterprise's independent evaluation of electricity generation and transmission capacity and potential operational concerns that may need to be addressed for the 2022 summer:

Summer Resource Adequacy Assessment and Energy Risk Analysis

- **Midcontinent ISO (MISO) faces a capacity shortfall in its North and Central areas, resulting in high risk of energy emergencies during peak summer conditions.** Capacity shortfall projections reported in the *2021 LTRA* and as far back as the *2018 LTRA* have continued. Load serving entities in 4 of 11 zones entered the annual planning resource auction (PRA) in April 2022 without enough owned or contracted capacity to cover their requirements. Across MISO, peak demand projections have increased by 1.7% since last summer due in part to a return to normal demand patterns that have been altered in prior years by the pandemic. However, more impactful is the drop in capacity in the most recent PRA: MISO will have 3,200 MW (2.3%) less generation capacity than in the summer of 2021. System operators in MISO are more likely to need operating mitigations, such as load modifying resources or non-firm imports, to meet reserve requirements under normal peak summer conditions. More extreme temperatures, higher generation outages, or low wind conditions expose the MISO North and Central areas to higher risk of temporary operator-initiated load shedding to maintain system reliability.
- **At the start of the summer, a key transmission line connecting MISO's northern and southern areas will be out of service.** Restoration continues on a 4-mile section of 500 kV transmission line that was damaged by a tornado during severe storms on December 10, 2021. The transmission outage affects 1,000 MW of firm transfers between the Midwestern and Southern MISO system that includes parts of Arkansas, Louisiana, and Mississippi. The transmission line is expected to be restored at the end of June 2022.
- **Anticipated resource capacity in Saskatchewan will be strained to meet peak demand projections, which have risen by over 7.5% since 2021.** SaskPower is projected to remain above their planning reserve margin threshold and have sufficient operating reserves for normal peak conditions. However, external assistance is expected to be needed in extreme conditions that cause above-normal generator outages or demand.
- **Drought conditions create heightened reliability risk for the summer.** Drought exists or threatens wide areas of North America, resulting in unique challenges to area electricity supplies and potential impacts on demand:
  - **Energy output from hydro generators throughout most of the Western United States is being affected by widespread drought and below-normal snowpack.** Dry hydrological conditions threaten the availability of hydroelectricity for transfers throughout the Western Interconnection. Some assessment areas, including WECC's California-Mexico (CA/MX) and Southwest Reserve Sharing Group (SRSG), depend on substantial electricity imports to meet demand on hot summer evenings and other times when variable energy resource (e.g., wind, solar) output is diminishing. In the event of wide-area extreme heat event, all U.S. assessment areas in the Western Interconnection are at risk of energy emergencies due to the limited supply of electricity available for transfer.
  - **Extreme drought across much of Texas can produce weather conditions that are favorable to prolonged, wide-area heat events and extreme peak electricity demand.** Resource additions to the ERCOT system in recent years—predominantly solar and some wind—have raised Anticipated Reserve Margins above Reference Margin Levels and ease concerns of capacity shortfalls for normal peak demand. However, extreme heat increases peak demand and can be accompanied by weather patterns that lead to increased forced outages or reduced energy output from resources of all types. A combination of extreme peak demand, low wind, and high outage rates from thermal generators could require system operators to use emergency procedures, up to and including temporary manual load shedding.
  - **As drought conditions continue over the Missouri River Basin, output from thermal generators that use the Missouri River for cooling in Southwest Power Pool (SPP) may be affected in summer months.** Low water levels in the river can impact generators with once-through cooling and lead to reduced output capacity. Energy output from hydro generators on the river can also be affected by drought conservation measures implemented in the reservoir system. Outages and reduced output from thermal and hydro generation could lead to energy shortfalls at peak demand. Periods of above normal wind generator output may give some relief, however, this energy is not assured. System operators could require emergency procedures to meet peak demand during periods of high generator unavailability.

- **All other areas have sufficient resources to manage normal summer peak demand and are at low risk of energy shortfalls from more extreme demand or generation outage conditions.** Anticipated Reserve Margins meet or surpass the Reference Margin Level, indicating that planned resources in these areas are adequate to manage the risk of a capacity deficiency under normal conditions. Furthermore, based on risk scenario analysis in these areas, resources and energy appear adequate.

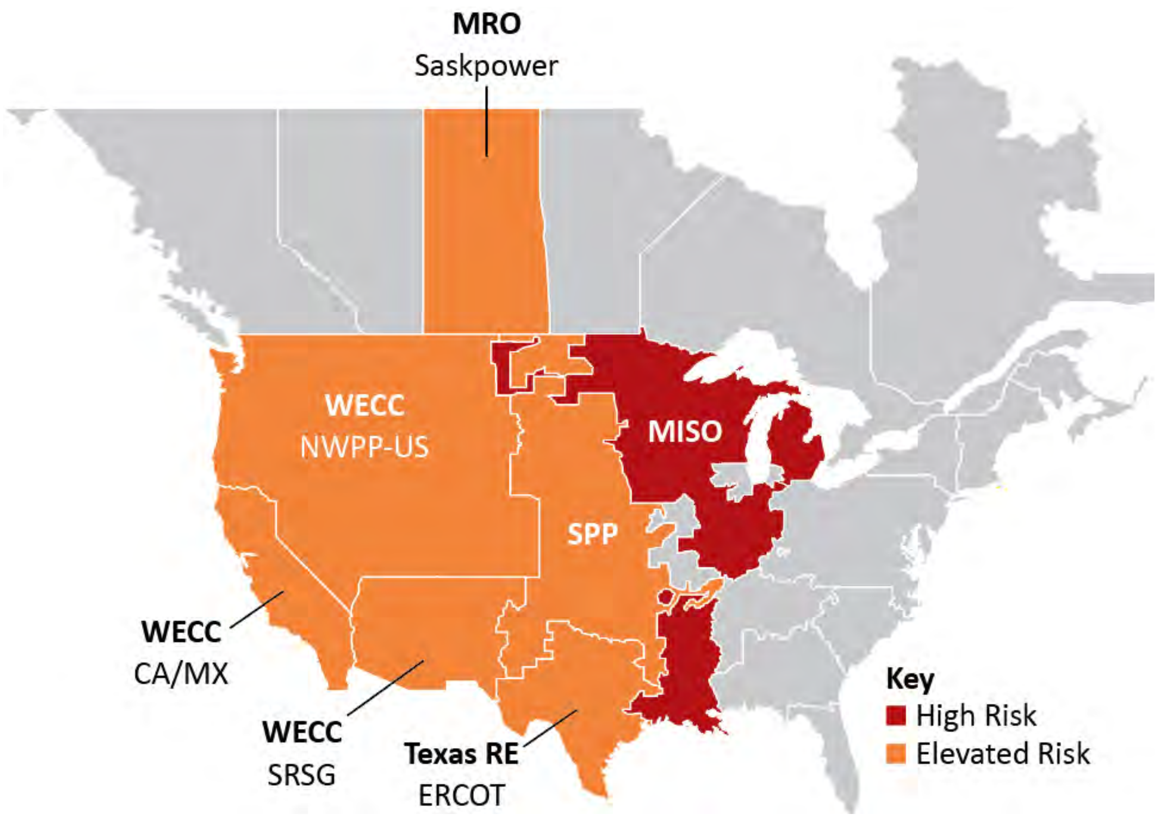


Figure 1: Summer Reliability Risk Area Summary

Seasonal Risk Assessment Summary	
High	Potential for insufficient operating reserves in normal peak conditions
Elevated	Potential for insufficient operating reserves in above-normal conditions
Low	Sufficient operating reserves expected

Other Reliability Issues for Summer

- **Supply chain issues and commissioning challenges on new resource and transmission projects are a concern in areas where completion is needed for reliability during summer peak periods.** Assessment areas report that some generation and transmission projects are being impacted by product unavailability, shipping delays, and labor shortages. At the time of this assessment publication, WECC-CA/MX, and WECC-SRSG have sizeable amounts of generation capacity in development and included in their resource projections for summer. In Texas (ERCOT), transmission expansion projects are underway to alleviate transmission constraints and maintain system stability as the BPS is adapted to rapid growth in new generation; delays or cancellations of transmission projects can cause transmission system congestion during peak conditions and affect the ability to serve load in localized areas. Should project delays emerge, affected Generator Owners (GOs) and Transmission Owners must communicate changes to Balancing Authorities (BAs), Transmission Operators, and Reliability Coordinators, so that impacts are understood and steps are taken to reduce risks of capacity deficiencies or energy shortfalls.

- **Coal-fired GOs are having difficulty obtaining fuel and non-fuel consumables as supply chains are stressed.** No specific BPS reliability impacts are currently foreseen; however, coal stockpiles at power plants are relatively low compared to historical levels. Some owners and operators report challenges in arranging replenishment due to mine closures, rail shipping limitations, and increased coal exports. Some GOs have implemented controls to maintain sufficient stocks for peak months while BAs and Reliability Coordinators are continuing to conduct fuel surveys and monitoring the situation.

- **The electricity and other critical infrastructure sectors face cyber security threats from Russia and other potential actors amid heightened geopolitical tensions in addition to ongoing cyber risks.** Russian attackers may be planning or attempting malicious cyber activity to gain access and disrupt the electric grid in North America in retaliation for support to Ukraine. The Electricity Infrastructure Sharing and Analysis Center (E-ISAC) continues to exchange information with its members and has posted communications and guidance from government partners and other advisories on its Portal. E-ISAC members are encouraged to check in regularly to receive updates and to actively share information regarding threats and other malicious activities with the E-ISAC to enable broader communication with other sector participants and government partners.

- **Unexpected tripping of solar photovoltaic (PV) resources during grid disturbances continues to be a reliability concern.** In May and June 2021, the Texas Interconnection experienced widespread solar PV loss events like those previously observed in the California area. Similarly, four additional solar PV loss events occurred between June and August 2021 in California.

- During these events, widespread loss of solar PV resources was also coupled with the loss of synchronous generation, unintended interactions with remedial action schemes, and some tripping of distributed energy resources. As industry urgently takes steps to address systemic reliability issues through modeling, planning, and interconnection processes, system operators in areas with significant amounts of solar PV resources should be aware of the potential for resource loss events during grid disturbances.
- **An active late-summer wildfire season in the Western United States and Canada is anticipated, posing BPS reliability risks.** Government agencies warn of the potential for above-normal wildfire risk beginning in June across much of Canada, in the U.S. South Central states, and Northern California. If drought conditions persist, the fire outlook for late summer would likely extend across the Western half of North America. The interconnected transmission system can be impacted in areas where wildfires are active as well as areas where there is heightened risk of wildfire ignition due to dry weather and ground conditions. In addition, smoke from wildfires can cause diminished output from solar PV resources, and electricity supply will be affected by lower output from BPS-connected solar PV resources. Conversely, system demand may increase as part of distribution demand served by rooftop solar PV is less in smoky conditions.

ERO Actions to Reduce Risks of Unexpected Solar PV Tripping

Industry experience with unexpected tripping of BPS-connected solar PV generation units can be traced back to the 2016 Blue Cut fire in California, and similar events have occurred as recently as Summer 2021. A common thread with these events is the lack of inverter-based resource (IBR) ride-through capability causing a minor system disturbance to become a major disturbance. The latest disturbance report reinforces that improvements to NERC Reliability Standards are needed to address systemic issues with IBRs. At a high level, these include the following:

- **Performance-Based Requirements:** A number of NERC Reliability Standards require documentation that demonstrates compliance with the requirement (i.e., PRC-024-3); however, they do not specify a certain degree of performance that must be met. NERC has initiated action against this issue by developing a standards authorization request and strongly recommends that PRC-024 be retired and replaced with a comprehensive ride-through standard that focuses specifically on the generator protections and controls.
- **Performance Validation Requirement:** NERC has initiated action against this issue by developing a reliability guideline on interconnection requirements as well as issuing recommendations from recent disturbance reports. NERC strongly recommends that a performance validation standard be developed that ensures that Reliability Coordinators, Transmission Operators, or BAs are assessing the performance of interconnected facilities during grid disturbances, identifying any abnormalities, and executing corrective actions with affected facility owners to eliminate these issues. This requires entities to have strong interconnection requirements as NERC highlights in its reliability guidelines and disturbance reports.
- **Electromagnetic Transient Modeling and Model Quality Assurance:** NERC has initiated action against this issue by issuing recommendations in recent disturbance reports and strongly recommends that electromagnetic transient (EMT) modeling and studies be incorporated into NERC Reliability Standards to ensure that adequate reliability studies are conducted to ensure reliable operation of the BPS moving forward. Existing positive sequence simulation platforms have limitations in their ability to identify possible performance issues, many of which can be identified using EMT modeling and studies. As the penetration of IBRs continues to grow across North America, the need for EMT modeling and studies will only grow exponentially. Furthermore, NERC Reliability Standards need enhancements to ensure that model accuracy and model quality checks are explicitly defined.

Summer Temperature and Drought Forecasts

Peak electricity demand in most areas is directly influenced by temperature. Weather officials are expecting above normal temperatures for much of North America this summer (see Figure 2). In addition, drought exists or threatens wide areas of North America, resulting in unique challenges to area electricity supplies and potential impacts on demand.[1] Assessment area load forecasts account for many years of historical demand data, often up to 30 years, to predict summer peak demand and prepare for more extreme conditions. Above average seasonal temperatures can contribute to high peak demand as well as increases in forced outages for generation and some BPS equipment. Effective preseason maintenance and preparations are particularly important to BPS reliability in severe or prolonged periods of above-normal temperatures.

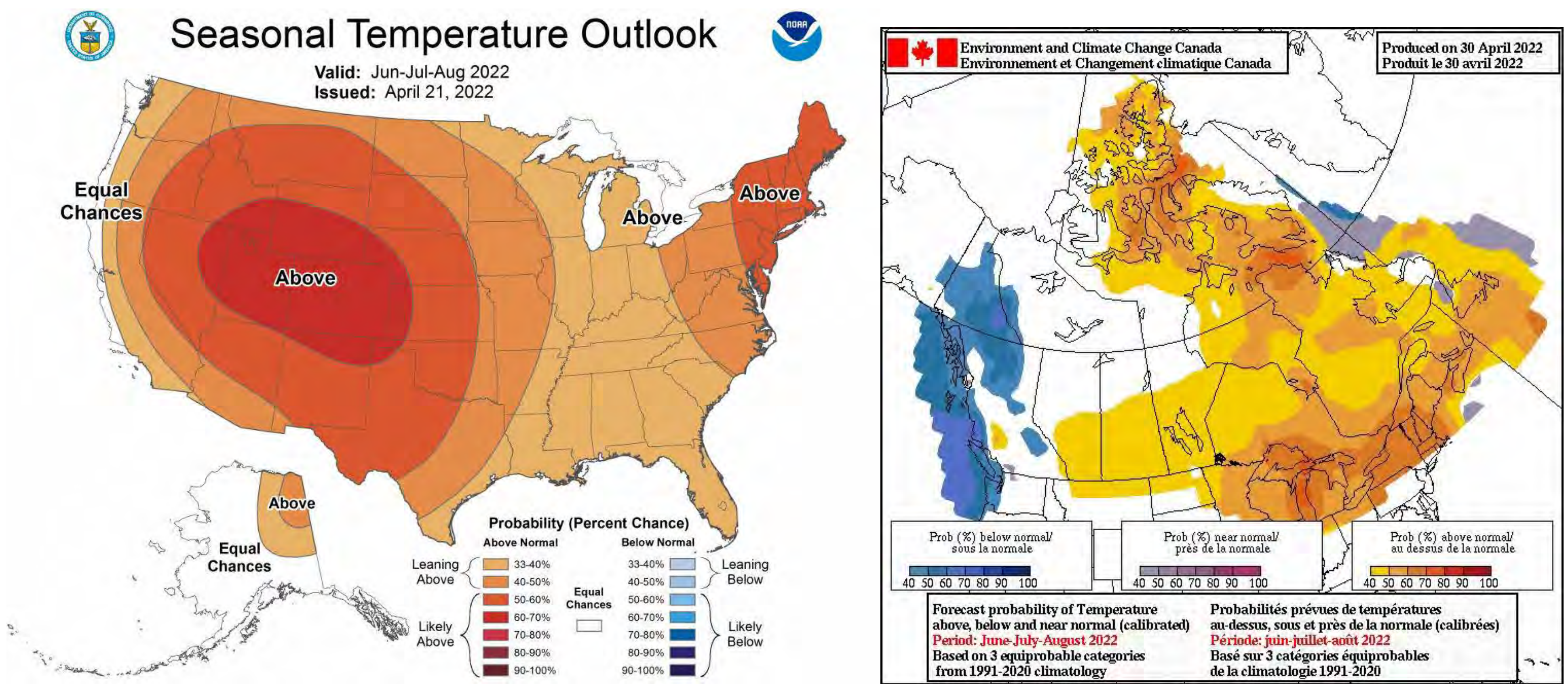


Figure 2: United States and Canada Summer Temperature Outlook[2]

[1] See North American Drought Monitor: https://www.ncdc.noaa.gov/temp-and-precip/drought/nadm/maps

[2] Seasonal forecasts obtained from U.S. National Weather Service and Natural Resources Canada: https://www.cpc.ncep.noaa.gov/products/predictions/long_range/ and https://weather.gc.ca/saisons/prob_e.html

Wildfire Risk Potential and BPS Impacts

Above-normal fire risk at the beginning of the summer exists in much of Canada as well as in the U.S. South Central states, Northern California, and Oregon, setting the stage for an active fire season at the beginning of the summer (see **Figure 3**). In late summer, hotter and drier conditions are expected to cause elevated fire risk in California and the U.S. West Coast. BPS operation can be impacted in areas where wildfires are active as well as areas where there is heightened risk of wildfire ignition due to weather and ground conditions.

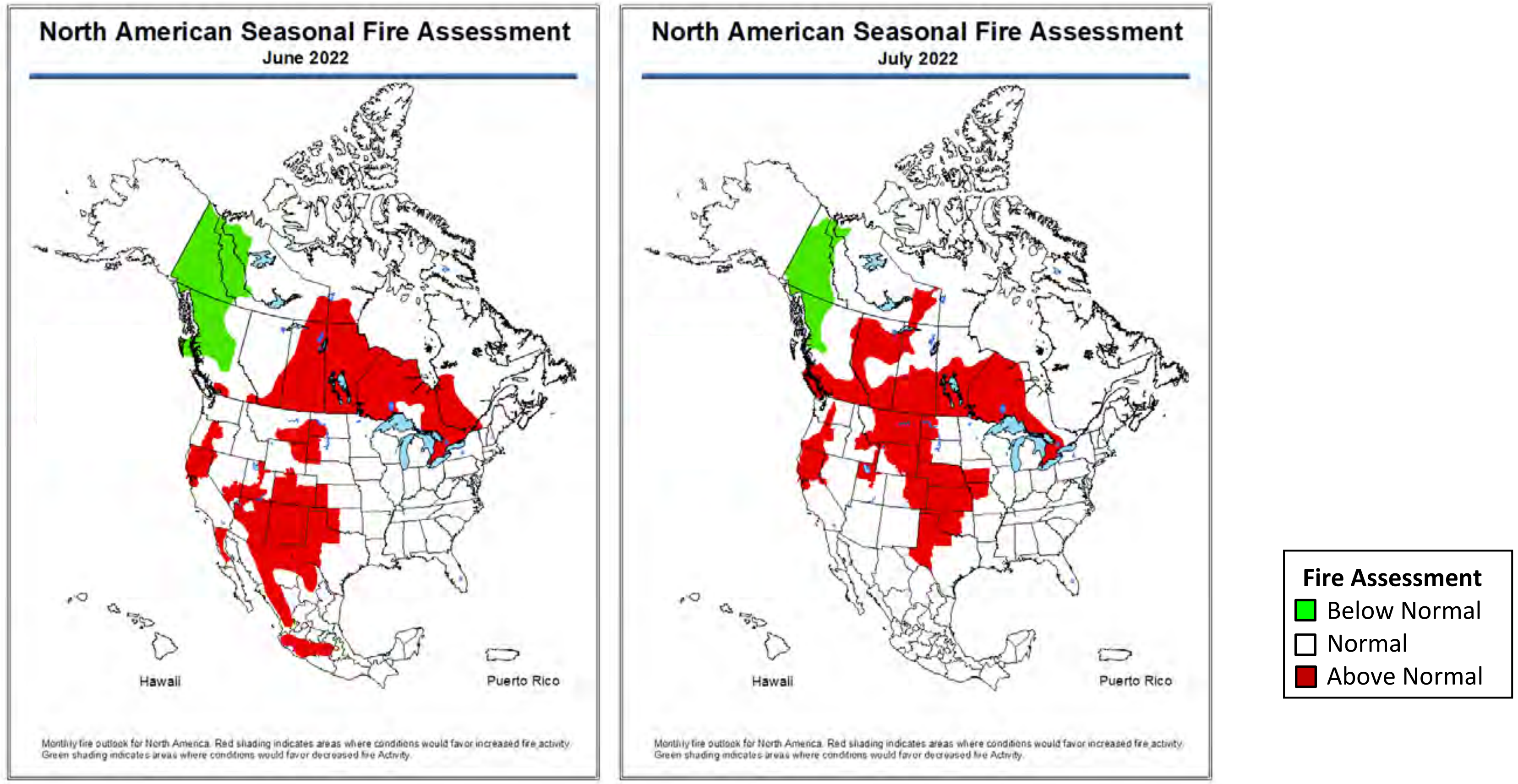


Figure 3: North American Seasonal Fire Assessment for June and July 2022[3]

Wildfire prevention planning in California and other areas includes power shut-off programs in high fire-risk areas. When conditions warrant implementing these plans, power lines (including transmission-level lines) may be preemptively de-energized in high fire-risk areas to prevent wildfire ignitions. Other wildfire risk mitigation activities include implementing enhanced vegetation management, equipment inspections, system hardening, and added situational awareness measures. In January 2021, the ERO published the *Wildfire Mitigation Reference Guide*[4] to promote preparedness within the North American electricity power industry and share the experience and practices from utilities in the Western Interconnection.

[3] *See North American Seasonal Fire Assessment and Outlook*, April 2022: https://www.predictiveservices.nifc.gov/outlooks/NA_Outlook.pdf
[4] See the NERC *Wildfire Mitigation Reference Guide*, January 2021: https://nerc.com/comm/RSTC/Documents/Wildfire%20Mitigation%20Reference%20Guide_January_2021.pdf

Risk Discussion

WECC: Western Interconnection

An elevated risk of energy emergencies persists across the U.S. Western Interconnection this summer as dry hydrological conditions threaten the availability of hydroelectric energy for transfer. Periods of high demand over a wide area will result in reduced supplies of energy for transfer, causing operators to rely primarily on alternative resources for system balancing, including natural-gas-fired generators and battery systems.

Throughout the Western Interconnection, BAs rely on flexible resources to support balancing the increasingly weather-dependent load with the variable energy generation within the resource mix. Dispatchable generation from hydroelectric and thermal plants internal to the BA's area as well as imports of surplus energy in another area are called upon by operators when area shortfalls are anticipated. Under normal conditions, there is sufficient energy and resource capacity and an adequate transmission network for transfers between areas to meet system ramping needs. However, conditions like wide-area heat events can reduce the availability of resources for transfer as areas serve higher internal demands. Additionally, transmission networks can become stressed when events like wildfires or wide-area heatwaves cause network congestion. The growing reliance on transfers within the Western Interconnection and falling resource capacity in many adjacent areas increases the risk that extreme events will lead to load interruption.

Recent Heatwave Events in the Western Interconnection

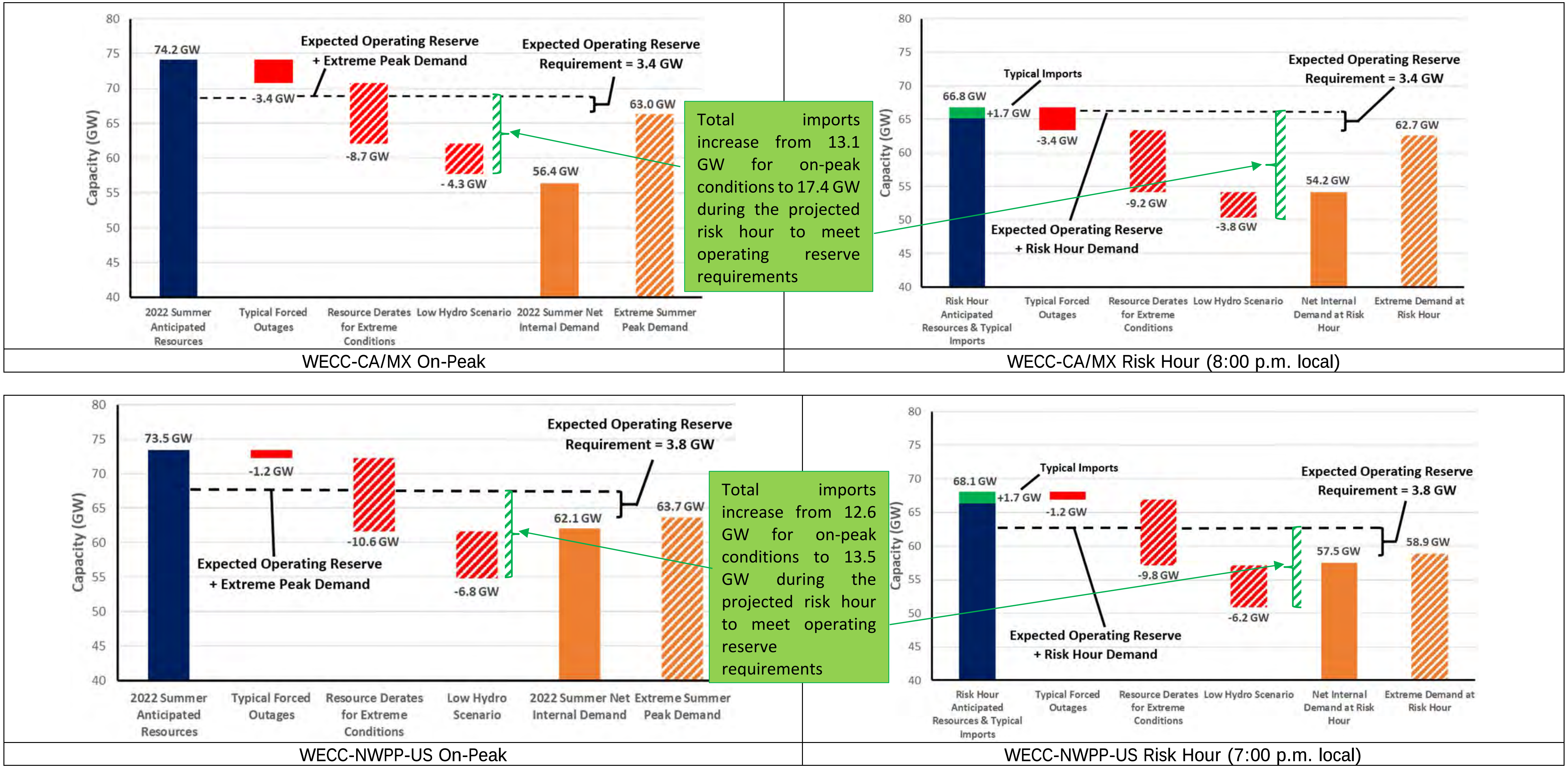
From August 14 through August 19, 2020, the Western United States suffered an intense and prolonged heatwave that affected many areas across the Western Interconnection.[5] Because of above-average temperatures, generation and transmission capacity struggled to keep up with increased electricity demand. Throughout many supply-constrained hours over this same period, generation resource output was below preseason peak forecasts for nearly all resource types, including natural gas, wind, solar, and hydroelectric. During the event, 10 Western Interconnection BAs issued 18 separate energy emergency alerts (EEA). The impacts of the August heatwave struck the entirety of the Western Interconnection and caused a peak demand record of 162,017 MW on August 18, 2020, at 4:00 p.m. Mountain time. Although demand peaked on August 18, the most severe reliability consequence of the heatwave event occurred at the beginning, when 1,087 MW of firm load was shed on August 14 and 692 MW was shed on August 15 in California. System operators at the California ISO initiated rotating electricity outages to reduce demand during early evening hours so that operating reserves would be sufficient to prevent even greater consequences for the system.

The West experienced another wide-area extreme temperature event in 2021. From late-June through mid-July, high temperatures extended over a broad area that included Northern California, Idaho, Western Nevada, Oregon, and Washington state in the United States as well as in British Columbia and (in its latter phase) Alberta, Manitoba, the Northwest Territories, Saskatchewan, and Yukon areas in Canada. Temperatures reached 121 degrees Fahrenheit in some areas, and peak demand records were set in British Columbia and Alberta. BAs in California, the U.S. Northwest, and the Canadian province of Saskatchewan issued EEAs.

In summer, WECC's CA/MX, the Northwest Power Pool (NWPP), and SRSG assessment areas can be exposed to greater risk of resource shortfalls for the hours that immediately follow afternoon peak demand. The reason the risk is greater in these hours is that solar resource output is diminishing with the setting sun while demand is still near its daily high. The scenarios for all three areas shown in **Figure 4** illustrate (six charts) how the need for imports changes from the peak demand hour to the higher risk hours that follow; see the **Data Concepts and Assumptions** for more information about these charts. Anticipated resources in the high risk hours are lower than the on peak hours due to reduced solar PV output. During periods of peak demand and normal forced outages, anticipated resources in each assessment area provide the needed energy to ensure demand and operating reserve requirements are met. Demand or resource derates from extreme conditions that cannot be remedied with imports will result in energy emergencies and the potential for load shedding. In prior summers, only CA/MX had greatest risk exposure in hours after peak demand; off-peak risk has increased in other parts of the Western Interconnection this year.

---

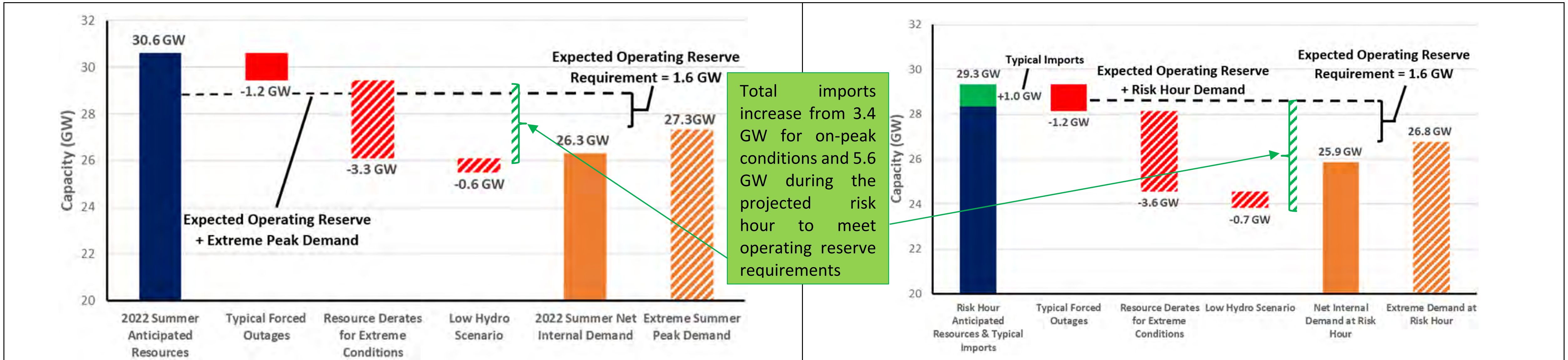
[5] WECC August Heat Wave Event information: WECC's *August Heat Wave Analysis* Presentation



WECC-CA/MX On-Peak | WECC-CA/MX Risk Hour (8:00 p.m. local)

WECC-NWPP-US On-Peak | WECC-NWPP-US Risk Hour (7:00 p.m. local)

Figure 4: Risk Scenarios for WECC U.S. Assessment Areas



WECC-SRSG On-Peak	WECC-SRSG Risk Hour (7:00 p.m. local)

Figure 4 (continued): Risk Scenarios for WECC U.S. Assessment Areas

WECC performed probabilistic studies and identified a continued risk of energy shortfalls for the WECC-CA/MX area. Their analysis models expected demand and resource contribution over all hours and accounts for variability with historical distributions. Assuming that the nearly 3.4 GW of new resource additions come into service in California for the summer, the Loss-of-Load Hours (LOLH) metric of projected hours with insufficient resources to meet planning reserve criteria will be one hour for the California portion. In a scenario without the new resource additions, the LOLH increases to four hours. Expected unserved energy (EUE) in California for these two scenarios is 4 MWh and 8,755 MWh, respectively. In the Mexico portion of CA/MX, LOLH of 10 and 14 hours and EUE of 100 and 200 MWh, respectively, are projected. All other WECC assessment areas have negligible load-loss and unserved energy for the summer. WECC's probabilistic study modeling includes non-firm transfers between WECC assessment areas and provides a wide-area assessment of resource adequacy. The WECC studies show that, as more areas experience the same high-demand conditions during wide-area heat events, the supply of electricity for transfer across the Interconnection is reduced and the risk of unserved energy increases.

Risk Assessments of Resource and Demand Scenarios

Seasonal risk scenarios for each assessment area are presented in the Regional Assessments Dashboards section. The on-peak reserve margins and seasonal risk scenario chart in each dashboard provide potential summer peak demand and resource condition information. The reserve margins on the right side of the dashboard pages provide a comparison to the previous year's assessment. The seasonal risk scenario charts present deterministic scenarios for further analysis of different demand and resource levels with adjustments for normal and extreme conditions. The assessment areas determined the adjustments to capacity and peak demand based on methods or assumptions that are summarized below the seasonal risk scenario charts; see the Data Concepts and Assumptions for more information about this chart.

The seasonal risk scenario charts can be expressed in terms of reserve margins. In Table 1, each assessment area's Anticipated Reserve Margins are shown alongside the reserve margins for a typical generation outage scenario (where applicable) and the extreme demand and resource conditions in their seasonal risk scenario. Highlighted areas are identified as having resource adequacy or energy risks for the summer in the key findings discussion. The typical outages reserve margin is comprised of anticipated resources minus the capacity that is likely to be in maintenance or forced outage at peak demand. If the typical maintenance or forced outage margin is the same as the anticipated reserve margin, it is because an assessment area has already factored typical outages into the anticipated resources. The extreme conditions margin includes all components of the scenario and represents the most severe operating conditions of an area's scenario. Note that any reserve margin below zero indicates that the resources fall below demand in the scenario.

Extreme generation outages, low resource output, and peak loads similar to those experienced in August 2020 are reliability risks in certain areas for the upcoming summer. When forecasted resources fall below expected demand, grid operators would need to employ operating mitigations or EEAs to obtain the capacity and energy necessary to meet extreme peak demands. Table 2 describes the various EEA levels and the circumstances for each.

Table 2: Energy Emergency Alert Levels

EEA Level	Description	Circumstances
EEA 1	All available generation resources in use	The BA is experiencing conditions where all available generation resources are committed to meet firm load, firm transactions, and reserve commitments and is concerned about sustaining its required contingency reserves. Non-firm wholesale energy sales (other than those that are recallable to meet reserve requirements) have been curtailed.
EEA 2	Load management procedures in effect	The BA is no longer able to provide its expected energy requirements and is an energy deficient BA. An energy deficient BA has implemented its operating plan(s) to mitigate emergencies. An energy deficient BA is still able to maintain minimum contingency reserve requirements.
EEA 3	Firm Load interruption is imminent or in progress	The energy deficient BA is unable to meet minimum contingency reserve requirements.

Table 1: Seasonal Risk Scenario On-Peak Reserve Margins

Assessment Area	Anticipated Reserve Margin	Anticipated Reserve Margin with Typical Outages	Anticipated Reserve Margin with Higher Demand, Outages, Derates in Extreme Conditions
MISO	21.1%	3.2%	-8.3%
MRO-Manitoba	27.3%	21.5%	7.8%
MRO-SaskPower	12.2%	2.6%	-5.3%
NPCC-Maritimes	39.2%	28.7%	11.7%
NPCC-New England	20.6%	9.3%	-2.5%[6]
NPCC-New York	30.4%	22.4%	13.5%
NPCC-Ontario	18.0%	18.0%	3.0%
NPCC-Québec	40.3%	40.3%	35.0%
PJM	31.7%	23.9%	16.1%
SERC-Central	18.3%	10.7%	3.3%
SERC-East	21.4%	18.3%	11.3%
SERC-Florida Peninsula	20.7%	17.3%	15.1%
SERC-Southeast	29.8%	25.4%	17.4%
SPP	30.6%	12.3%	-4.7%
Texas RE-ERCOT	22.0%	15.9%	1.1%
WECC-NWPP-AB	19.7%	17.2%	5.3%
WECC-NWPP-BC	39.3%	39.1%	10.4%
WECC-CA/MX	31.5%	25.4%	-13.1%
WECC-NWPP-US	18.3%	16.3%	-13.8%
WECC-SRSG	16.3%	11.8%	-6.8%

[6] Energy and capacity is sufficient for a broad range of normal and above-normal scenarios in the NPCC-New England area for the summer. This negative reserve margin indicates that a scenario combining extreme high demand and extremely-low resources could, however, result in an energy emergency.

Transfers in a Wide-Area Event

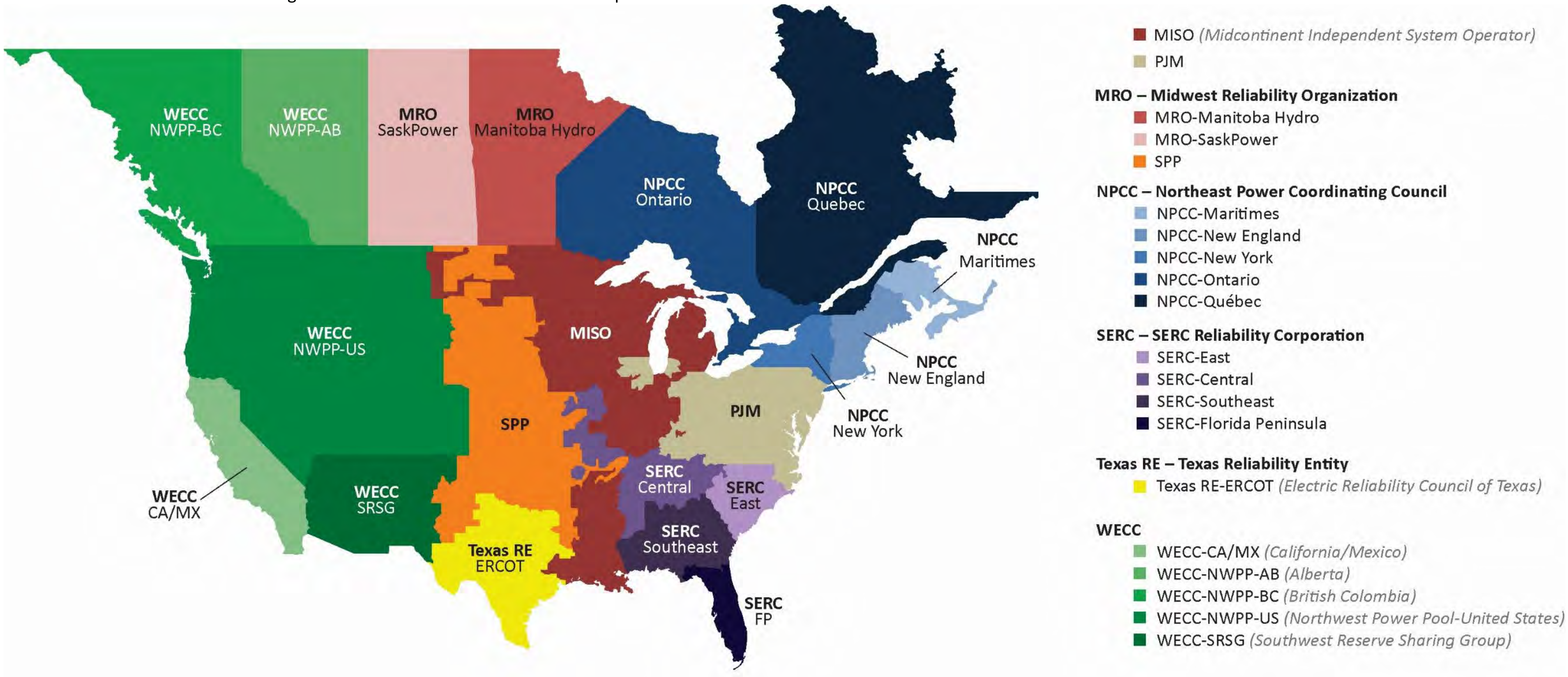
When above-normal temperatures extend over a wide area, resources can be strained in multiple assessment areas simultaneously, increasing the risk of shortfalls. Some assessment areas expect imports from other areas to be available to meet periods of peak demand and have contracted for firm transfer commitments. A summary of area firm on-peak imports and exports is shown in **Table 3**. Firm resource transactions like these are accounted for in all assessment area anticipated resources and reserve margins. Areas with net imports show a positive transfer amount, and areas with net exports show a negative transfer amount. Only areas that contained transfers for the previous or upcoming summer seasons are shown in **Table 3**; the data in this table is sourced from the data adequacy tables in the **Data Concepts and Assumptions** section. In the unlikely event that multiple assessment areas are experiencing energy emergencies as could occur in a wide-area heatwave, some transfers may be at risk of not being fulfilled. Transfer agreements may include provisions that allow the exporting entity to prioritize serving native load. Loss of transfers could exacerbate resource shortages that occur from outages and derates.

Table 3: 2021 and 2022 On-Peak Net Firm Transfers

Assessment Area	2021 Summer Transfers (MW)	2022 Summer Transfers (MW)	Year-to-Year Change
MISO	2,979	1,353	-54.6%
MRO-Manitoba	-1,596	-1,816	13.8%
MRO-SaskPower	125	290	132.0%
NPCC-Maritimes	-57	64	-212.3%
NPCC-New England	1,208	1,292	7.0%
NPCC-New York	1,816	2,465	35.7%
NPCC-Ontario	80	150	87.5%
NPCC-Québec	-1,995	-2,304	15.5%
PJM	1,460	124	-91.5%
SERC-Central	172	-795	-561.6%
SERC-East	562	612	8.9%
SERC-Florida Peninsula	1,007	300	-70.2%
SERC-Southeast	-1,115	-2,524	126.4%
SPP	186	-144	-177.6%
Texas RE-ERCOT	210	20	-90.5%
WECC-AB	0	437	N/A
WECC-BC	0	0	N/A
WECC-CA/MX	686	0	-100.0%
WECC-NWPP-US	6,139	2,517	-59.0%
WECC-SRSG	866	1,002	15.7%

Regional Assessments Dashboards

The following assessment area dashboards and summaries were developed based on data and narrative information collected by NERC from the six Regional Entities on an assessment area basis. The operational risk analysis shown in the following regional assessments dashboard pages provides a deterministic scenario for understanding how various factors that affect resources and demand can combine to impact overall resource adequacy. For each assessment area, there is a risk-period scenario graphic; the left blue column shows anticipated resources (from the **Demand and Resource Tables**), and the two orange columns at the right show the two demand scenarios of the normal peak net internal demand (from the **Demand and Resource Tables**) and the extreme summer peak demand determined by the assessment area. The middle red or green bars show adjustments that are applied cumulatively to the anticipated resources. Adjustments may include reductions for typical generation outages (maintenance and forced not already accounted for in anticipated resources) and additions that represent the quantified capacity from operational tools (if any) that are available during scarcity conditions but have not been accounted for in the SRA reserve margins. Resources throughout the scenario are compared against expected operating reserve requirements that are based on peak load and normal weather. The cumulative effects from extreme events are also factored in through additional resource derates or low-output scenarios.

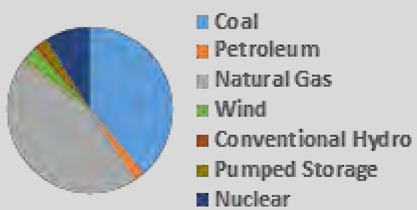


MISO

MISO is a not-for-profit, member-based organization that administers wholesale electricity markets that provide customers with valued service; reliable, cost-effective systems and operations; dependable and transparent prices; open access to markets; and planning for long-term efficiency.

MISO manages energy, reliability, and operating reserve markets that consist of 36 local BA and 394 market participants, serving approximately 42 million customers. Although parts of MISO fall in three Regional Entities, MRO is responsible for coordinating data and information submitted for NERC's reliability assessments.

On-Peak Fuel Mix



Highlights

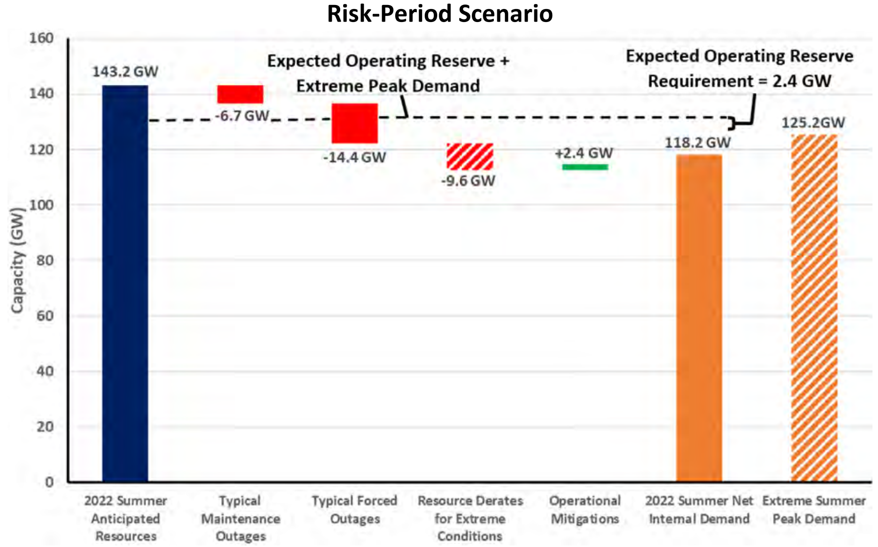
- Tighter than normal operating conditions are anticipated, particularly in the MISO North/Central region, which cleared too little capacity in the 2022–2023 PRA. The PRA capacity shortfall of 1,230 MW signals a potential for operating risk during peak summer conditions.
- Continued operating measures, such as MISO maximum generation events, can be expected in order to give system operators access load modifying resources (demand response) that can only be called upon once available generation is at maximum capacity.
- MISO performs an annual loss-of-load expectation (LOLE) study to determine its installed reserve margin and other probabilistic reliability indices. Based on results of the 2021 analysis, MISO expects low amounts of EUE in the summer season. The greatest risk occurs in the month of July, coinciding with the typical peak in annual demand.

Risk Scenario Summary

Expected resources do not meet operating reserve requirements under normal peak-demand and outage scenarios. Above-normal summer peak load and outage conditions could result in the need to employ operating mitigations (i.e., demand response and transfers) and EEAs. Load shedding may be needed under extreme peak demand and outage scenarios studied.

On-Peak Reserve Margins

Risk-Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: Net internal demand (50/50) and (90/10) demand forecast using 30 years of historical data

Maintenance Outages: Rolling five-year average of maintenance and planned outages

Forced Outages: Five-year average of all outages that were not planned

Extreme Derates: Maximum of last five years of outages

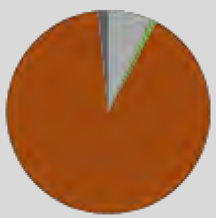
Operational Mitigations: Total of 2.4 GW capacity resources available during extreme operating conditions

MRO-Manitoba Hydro

Manitoba Hydro is a provincial crown corporation that provides electricity to about 580,000 customers throughout Manitoba and natural gas service to about 282,000 customers in various communities throughout Southern Manitoba. The Province of Manitoba has a population of about 1.3 million in an area of 250,946 square miles.

Manitoba Hydro is winter-peaking. No change in the footprint area is expected during the assessment period. Manitoba Hydro is its own Planning Coordinator and Balancing Authority. Manitoba Hydro is a coordinating member of MISO. MISO is the Reliability Coordinator for Manitoba Hydro.

On-Peak Fuel Mix



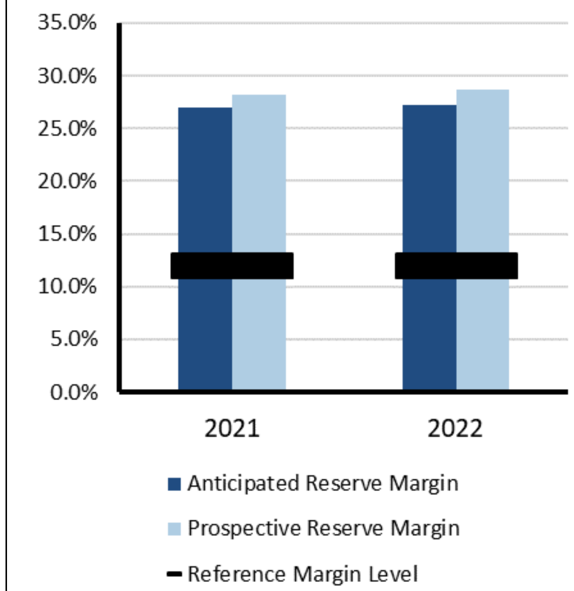
Highlights

- Manitoba Hydro is not anticipating any emerging reliability issues in its assessment area for the upcoming season.
- Four Keeyask hydro units were added this past year (approximately 93 MW each). Two additional Keeyask generating units are anticipated to come on line for Summer 2022, and these are listed as Planned Tier 1 generation.
- There are no significant seasonal reliability issues identified in neighboring assessment areas that have the potential to impact Manitoba Hydro operations.
- The probability-based resource adequacy risk assessment for the summer (June–September) season is that there is a very low risk of resource adequacy issues.

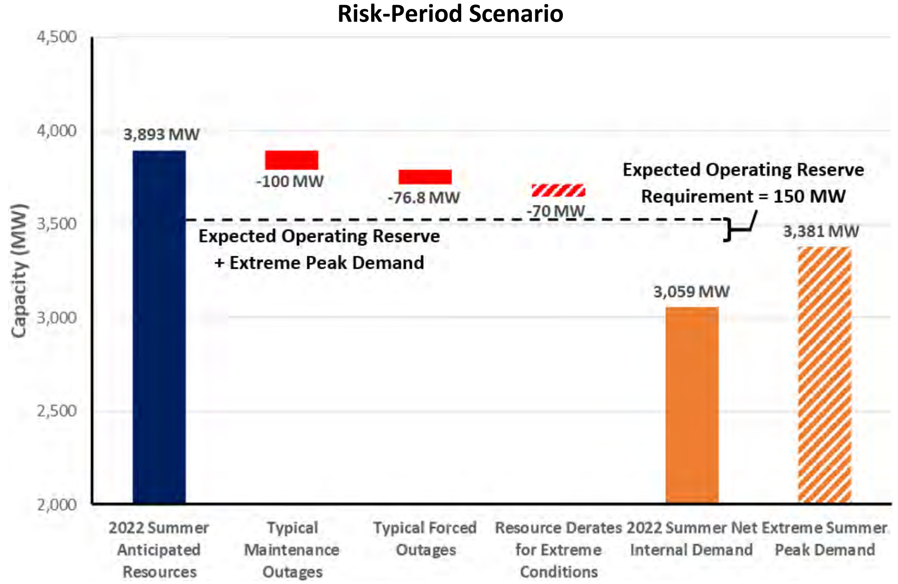
Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed scenarios.

On-Peak Reserve Margins



Risk-Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: Net internal demand (50/50) and minimum probability of exceedance forecast load

Outages: Accounts for average forced outages, including 69 MW of reduced generation capacity due to drought conditions

Extreme Derates: Brandon units 6 and 7 summer capacity temperature derates

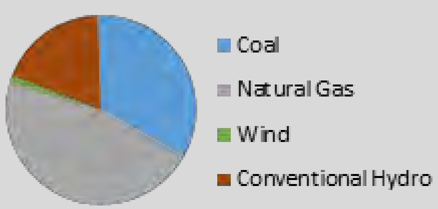
MRO-SaskPower

Saskatchewan is a province of Canada and comprises a geographic area of 651,900 square kilometers (251,700 square miles) with approximately 1.1 million customers. Peak demand is experienced in the winter.

The Saskatchewan Power Corporation (SaskPower) is the Planning Coordinator and Reliability Coordinator for the province of Saskatchewan and is the principal supplier of electricity in the province.

SaskPower is a provincial crown corporation and, under provincial legislation, is responsible for the reliability oversight of the Saskatchewan Bulk Electric System (BES) and its interconnections.

On-Peak Fuel Mix



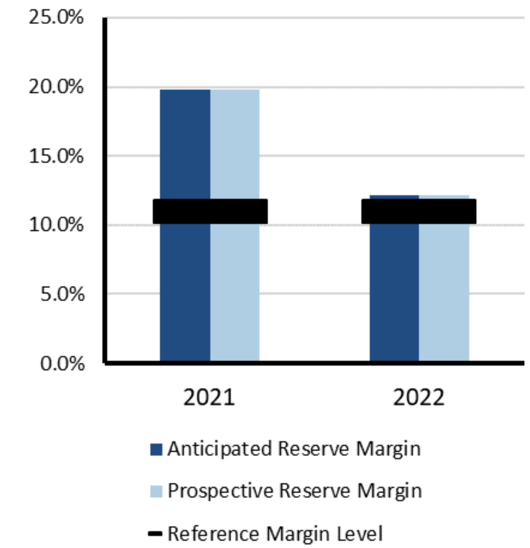
Highlights

- Saskatchewan experiences high load in summer as a result of extreme hot weather.
- SaskPower conducts an annual summer joint operating study with Manitoba Hydro with inputs from Basin Electric (North Dakota) and prepares operating guidelines for any identified issues.
- The risk of operating reserve shortage during peak load times or EEAs could increase if large generation forced outages combine with large planned maintenance outages during peak load times in May, June, July, August, and October.
- In case of extreme thermal conditions combined with large generation forced outages, SaskPower would use available demand response programs, short-term power transfers from neighboring utilities, and short-term load interruptions.
- SaskPower has performed a probability-based capacity adequacy study to assess risk of high forced outages that would lead to the use of emergency operating procedures. Forced outages of 300 MW or greater that coincide with peak demand may result in demand response and potential load interruptions to maintain system balance. There is an 8.2% probability of having forced outages of 300 MW or greater this summer.

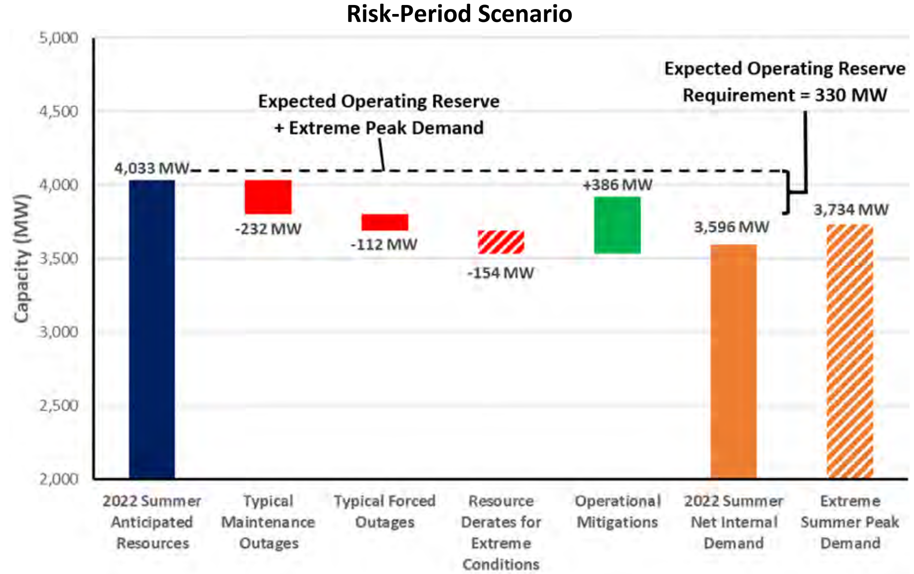
Risk Scenario Summary

Expected resources meet operating reserve requirements under normal peak-demand scenarios. Above-normal summer peak load and outage conditions could result in the need to employ operating mitigations (i.e., demand response and transfers) and EEAs. Load shedding may be needed under extreme peak demand and outage scenarios.

On-Peak Reserve Margins



Risk-Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: Net internal demand (50/50) and above-normal scenario based on peak demand with lighting and all consumer loads

Maintenance Outages: Average of planned maintenance outages for the summer months of June–September 2021

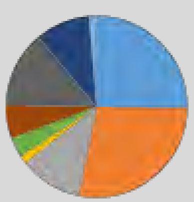
Forced Outages: Estimated by using SaskPower forced outage model

Operational Mitigations: Estimated average value based on short-term transfer capability from neighboring utilities for the upcoming 2022 summer

NPCC-Maritimes

The Maritimes assessment area is a winter-peaking NPCC area that contains two Balancing Authorities. It is comprised of the Canadian provinces of New Brunswick, Nova Scotia, and Prince Edward Island, and the Northern portion of Maine, which is radially connected to the New Brunswick power system. The area covers 58,000 square miles with a total population of 1.9 million.

On-Peak Fuel Mix



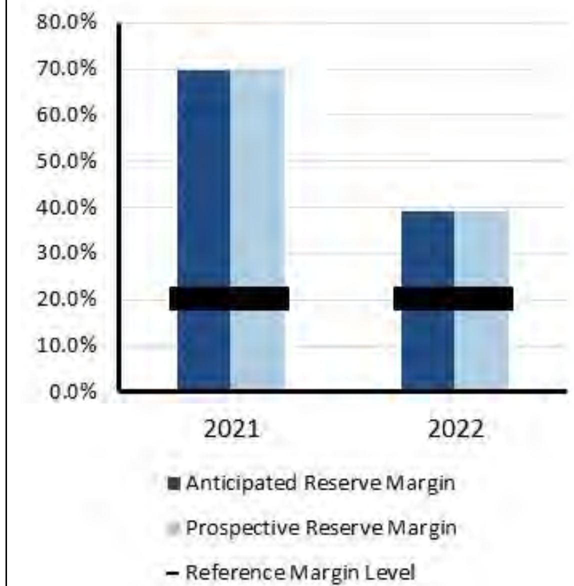
Highlights

- The Maritimes area has not identified any operational issues that are expected to impact system reliability. If an event was to occur, there are emergency operations and planning procedures in place. All of the area's declared firm capacity is expected to be operational for the summer operating period.
- Dual-fuel units will have sufficient supplies of heavy fuel oil on-site as part of the planning process to enable sustained operation in the event of natural gas supply interruptions.
- Based on an NPCC probabilistic assessment, the Maritimes assessment area shows a cumulative likelihood greater than 0.5 days/period of using their operating procedures and a cumulative likelihood of reducing their 30-minute reserve requirements (10 days/period) and initiating interruptible loads (5 days/period) over the 2022 summer period for the base case scenario, assuming the highest peak load levels.
- The Maritimes area is winter peaking. No significant cumulative LOLE, LOLH, and EUE risks were estimated over the summer May–September period for all scenarios simulated.

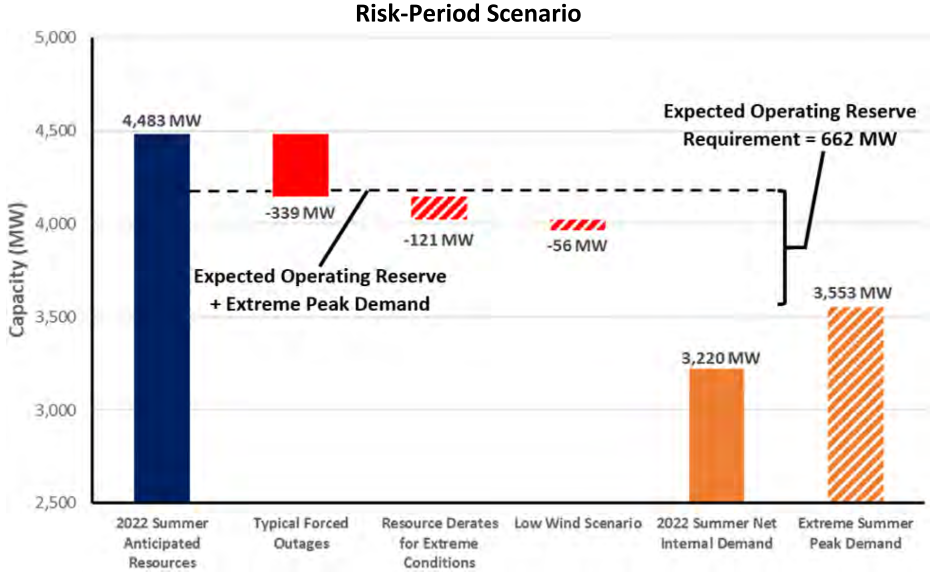
Risk Scenario Summary

Expected resources meet operating reserve requirements under normal peak-demand scenarios. Above-normal summer peak load and outage conditions could result in the need to employ operating mitigations (i.e., demand response and transfers) and EEAs. Load shedding may be needed under extreme peak demand and outage scenarios.

On-Peak Reserve Margins



Risk-Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: Net internal demand (50/50) and (99/1) extreme demand forecast

Outages: Based on historical operating experience

Extreme Derates: Based on historical data for ambient temperature thermal de-rates

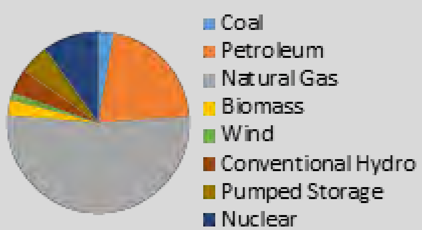
Low Wind Scenario: A low-likelihood scenario resulting in no wind resources

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 BPS.

The New England BPS serves approximately 14.5 million customers over 68,000 square miles.

On-Peak Fuel Mix



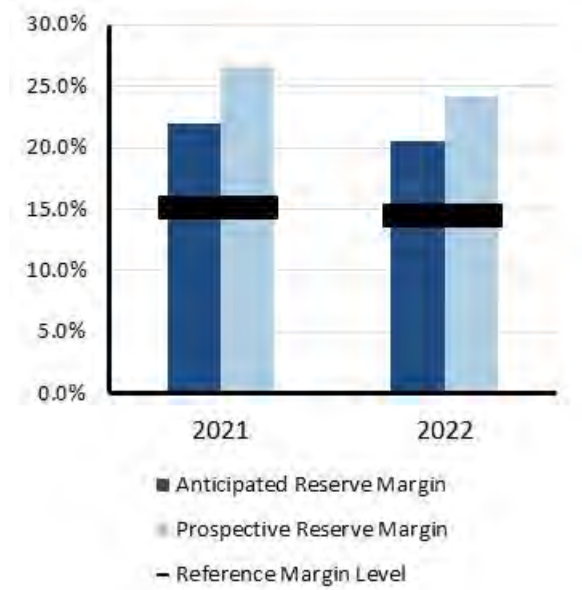
Highlights

- The New England area expects to have sufficient capacity to meet the 2022 summer peak demand forecast. As of April 5, 2022, the peak summer (net internal) demand is forecast to be 24,817 MW for the week of July 24, 2022, with a projected net margin of 1,705 MW (6.9%). The 2022 summer (net internal) demand forecast takes into account the demand reductions associated with energy efficiency, load management, behind-the-meter PV systems, and distributed generation.
- Based on an NPCC probabilistic assessment, ISO-NE may rely on limited use of its operating procedures designed to mitigate resource and energy shortages during the summer. Negligible cumulative LOLE, LOLH, and EUE risks were estimated over the summer period for all modeled scenarios except the severe low-likelihood case. This reduced resource case with highest peak load scenario resulted in a small estimated cumulative LOLE risk of ~0.6 days/period with associated LOLH (~2.1 hours/period) and EUE (~1,603 MWh/period) risk this is divided between June and August. This scenario is based exclusively on the two highest load levels with a 7% chance of occurring and a low resource case consisting of 10% reduction in NPCC resources and PJM reductions.

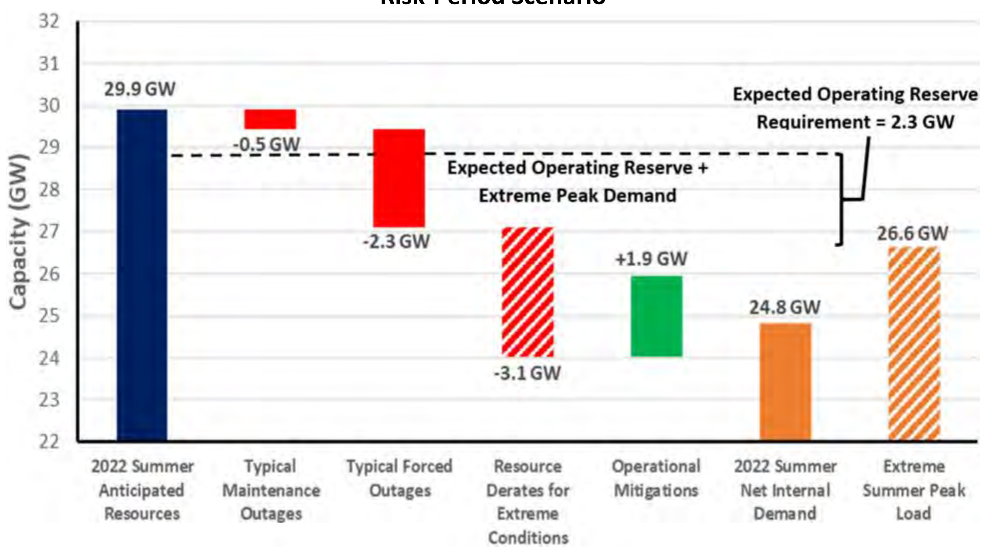
Risk Scenario Summary

Expected resources meet operating reserve requirements under normal peak-demand scenarios. Above-normal summer peak load, combined with extreme outage conditions, could result in the need to employ operating mitigations (i.e., demand response and transfers) and EEAs.

On-Peak Reserve Margins



Risk-Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy occurs at peak demand hour

Demand Scenarios: Peak net internal demand (50/50) and (90/10) extreme demand forecast

Maintenance & Forced Outages: Based on historical weekly averages

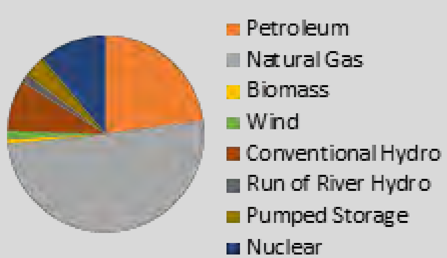
Extreme Derates: Represent a case that is beyond the (90/10) conditions based on historical observation of force outages, additional reductions for generation at risk due to operating issues at extreme hot temperatures, and other outage causes reported by generators

Operational Mitigations: Based on load and capacity relief assumed available from invocation of ISO-NE operating procedures

NPCC-New York

The New York Independent System Operator (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 BPS encompasses over 11,000 miles of transmission lines, 760 power generation units, and serves 20.2 million customers. The established Reference Margin Level is 15%. Wind, grid-connected solar, and run-of-river totals were derated for this calculation. However, New York requires load serving entities to procure capacity for their loads equal to their peak demand plus an IRM. The IRM requirement represents a percentage of capacity above peak load forecast and is approved annually by the New York State Reliability Council (NYSRC). NYSRC approved the 2022–2023 IRM at 19.6%.”

On-Peak Fuel Mix



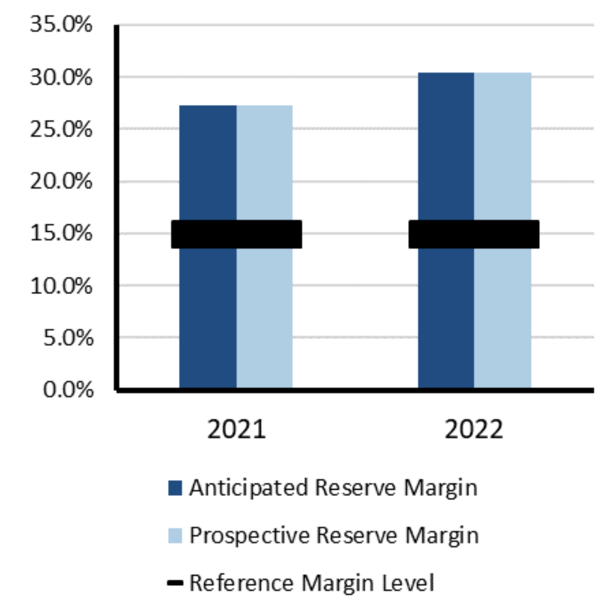
Highlights

- The NYISO is not anticipating any operational issues in the New York control area for the upcoming summer operating period. Adequate capacity margins are anticipated and existing operating procedures are sufficient to handle any issues that may occur.
- Based on an NPCC probabilistic assessment, NYISO is expected to require limited use of operating procedures designed to mitigate resource shortages during the summer. Only the highest peak load scenarios with base and reduced resource cases require operating procedures. Negligible cumulative LOLE, LOLH, and EUE risks were estimated over the summer period for all modeled scenarios.
- The analysis included simulation of a base case (normal 50/50 demand and expected resources) and a highest peak load scenario as well as including a low-likelihood reduced resource case that considers the impacts of extended maintenance in Southeastern New York, reduction in the effectiveness of demand response programs, and reduced import and transfer capabilities. This low-likelihood reduced resource scenario is based exclusively on the two highest load levels representing an average 10–15% increase in peak loads over the 50/50 forecast with a combined 7% probability of occurring. Additional constraints include an estimated 10% reduction in NPCC resources and PJM reductions.

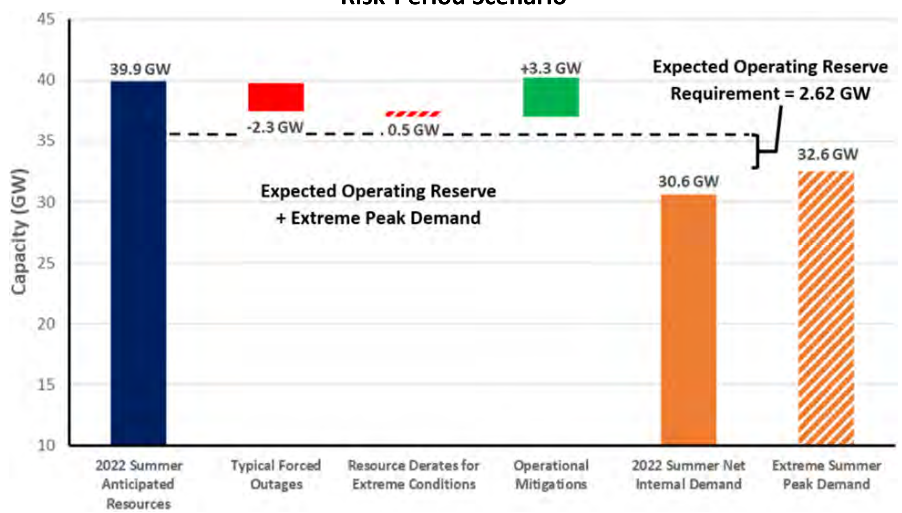
Risk Scenario Summary

Expected resources meet operating reserve requirements under assessed scenarios.

On-Peak Reserve Margins



Risk-Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: Net internal demand (50/50) and (90/10) extreme demand forecast

Forced Outages: Based on historical 5-year averages

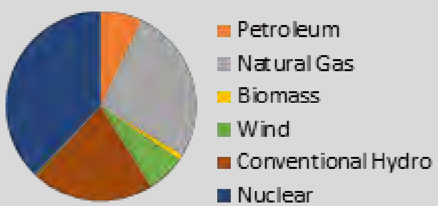
Operational Mitigations: A total of 3.3 GW based on operational/emergency procedures in area *Emergency Operations Manual*

NPCC-Ontario

The Independent Electricity System Operator (IESO) is the Balancing Authority for the province of Ontario. The province of Ontario covers more than 1 million square kilometers (415,000 square miles) and has a population of more than 14 million.

Ontario is interconnected electrically with Québec, MRO-Manitoba, states in MISO (Minnesota and Michigan), and NPCC-New York.

On-Peak Fuel Mix



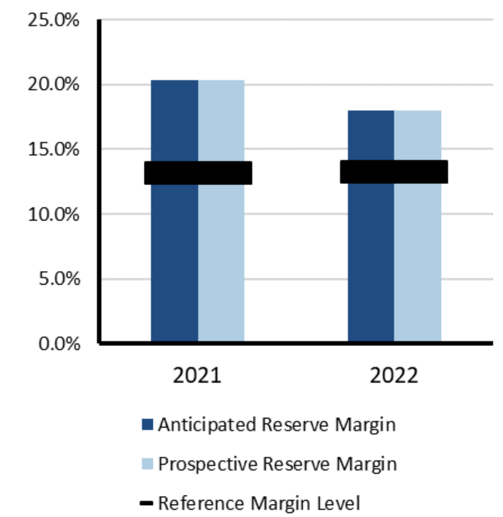
Highlights

- The ongoing transmission outage at the New York-St Lawrence interconnection continues to impact import and export capacity between Ontario and New York. This issue is expected to be resolved by the third quarter of 2022.
- Ontario is entering a period of tighter supply conditions brought on by rising demand and the ongoing nuclear refurbishment program; during summer months, planned generation maintenance outages will be more challenging to accommodate than they have been previously. Nonetheless, Ontario expects to have sufficient generation resources available to meet its needs throughout the summer of 2022, and its transmission system is expected to continue to reliably supply province-wide demand throughout the season.
- Based on an NPCC probabilistic assessment, IESO is expected to require limited use of operating procedures designed to mitigate resource shortages during the summer for the low-likelihood reduced resource case. This low-likelihood reduced resource scenario is based exclusively on the two highest load levels that represent an average 10–15% increase in peak loads over the 50/50 forecast with a combined 7% probability of occurring. Additional constraints include an estimated 10% reduction in NPCC resources and PJM reductions.
- Negligible cumulative LOLE, LOLH, and EUE risks are estimated over the May–September summer period for all simulated scenarios.

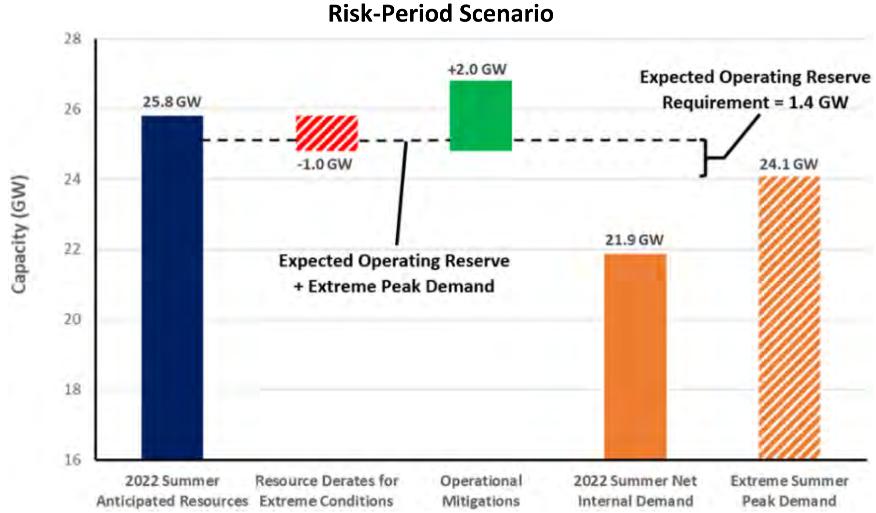
Risk Scenario Summary

Expected resources meet operating reserve requirements under normal peak-demand scenarios. Above-normal summer peak load and outage conditions could result in the need to employ operating mitigations (i.e., demand response and transfers) and EEAs. Load shedding may be needed under extreme peak demand and outage scenarios studied.

On-Peak Reserve Margins



Risk-Period Scenario



Scenario Description (See [Data Concepts and Assumptions])

Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: Net internal demand (50/50 Forecast) and highest weather-adjusted daily demand based on 31 years of demand history

Extreme Derates: Derived from weather-adjusted temperature rating of thermal units and adjustments to expected hydro production for low water conditions

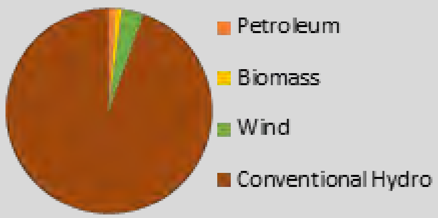
Operational Mitigations: Imports anticipated from neighbors during emergencies

NPCC-Québec

The Québec assessment area (Province of Québec) is a winter-peaking NPCC area that covers 595,391 square miles with a population of 8 million.

Québec is one of the four Interconnections in North America; it has ties to Ontario, New York, New England, and the Maritimes; consisting of either HVDC ties, radial generation, or load to and from neighboring systems.

On-Peak Fuel Mix



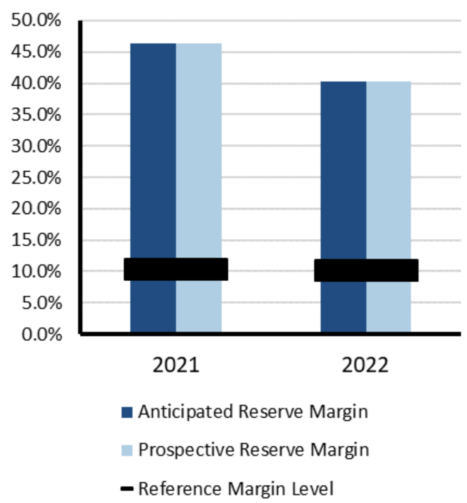
Highlights

- Québec is a winter peaking system, and no particular resource adequacy problems are forecast for the upcoming summer.
- Québec expects to be able to provide assistance to other areas if needed up to the transfer capability available.
- Québec has had no major generation or transmission additions since the *2021 NERC SRA*.
- The Québec assessment area is not expected to require use of their operating procedures that are designed to mitigate resource shortages during the summer of 2022 based on an NPCC probability assessment. The Québec area is winter peaking and has a large reserve margin for the summer period. As a result, Québec does not indicate having any measurable amounts of cumulative LOLE, LOLH, or EUE risks over the May–September summer period for all the scenarios modeled.

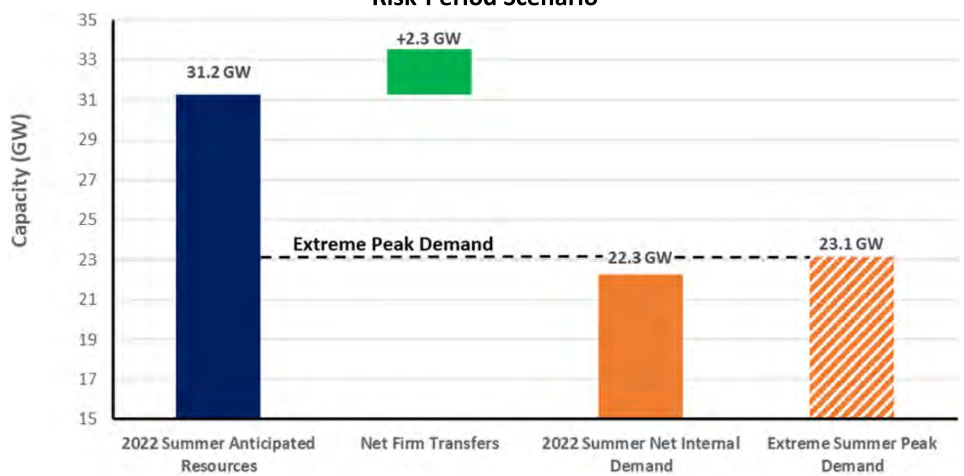
Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed scenarios.

On-Peak Reserve Margins



Risk-Period Scenario



Scenario Description (See [Data Concepts and Assumptions](#))

Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: Net internal demand (50/50) and (90/10) demand forecast

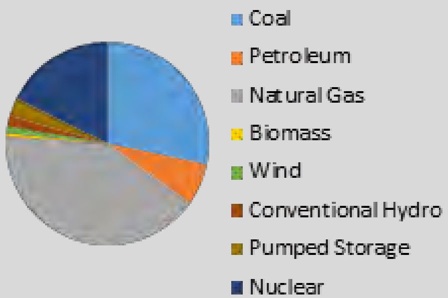
Net Firm Transfers: Imports anticipated from neighbors during emergencies

PJM

PJM Interconnection is a regional transmission organization that coordinates the movement of wholesale electricity in all or parts of Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, West Virginia, and the District of Columbia. PJM serves 65 million customers and covers 369,089 square miles.

PJM is a Balancing Authority, Planning Coordinator, Transmission Planner, Resource Planner, Interchange Authority, Transmission Operator, Transmission Service Provider, and Reliability Coordinator.

On-Peak Fuel Mix



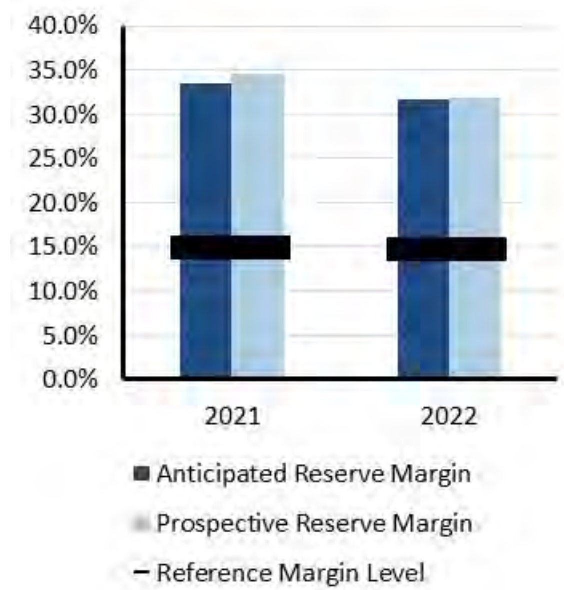
Highlights

- PJM expects no resource problems over the entire 2022 summer peak season because installed capacity is over two times the reserve requirement.
- PJM continues to request fuel inventory and supply data of coal and oil resources (including dual-fuel units). This data request, sent every two weeks, started prior to the 2021–2022 winter season as a result of increasing reports of existing and future supply shortages of fuel and non-fuel consumables. In order to maintain situational awareness throughout the spring and into the summer of 2022, PJM is continuing efforts to monitor potential impacts of fuel and non-fuel consumables supply as well as delivery status on generation resources.
- PJM is expecting a low risk of experiencing periods of resources falling below required operating reserves during Summer 2022 based on the 2021 PJM Reserve Requirement Study. As indicated in the study, PJM is forecasting around 33% installed reserves (including expected committed Demand Resources), well above the target installed reserve margin of 14.9%.
- No other reliability issues are expected.

Risk Scenario Summary

Expected resources meet operating reserve requirements under assessed scenarios.

On-Peak Reserve Margins



Risk-Period Scenario

Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: Net internal demand (50/50) and (90/10) demand forecast

Forced Outages: Based on historical data and trending

Extreme Derates: Accounts for reduced thermal capacity contributions due to performance in extreme conditions

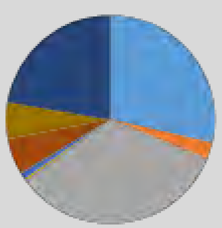
Operational Mitigations: A total of 2.3 GW based on operational/emergency procedures

SERC-East

SERC-East is a summer-peaking assessment area within the SERC Regional Entity. SERC-East includes North Carolina and South Carolina.

SERC is one of the six companies across North America that are responsible for the work under Federal Energy Regulatory Commission approved delegation agreements with NERC. SERC is specifically responsible for the reliability and security of the electric grid across the Southeastern and Central areas of the United States. This area covers approximately 630,000 square miles and serves a population of more than 91 million.

The SERC Regional Entity includes 36 Balancing Authorities, 28 Planning Authorities, and 6 Reliability Coordinators.

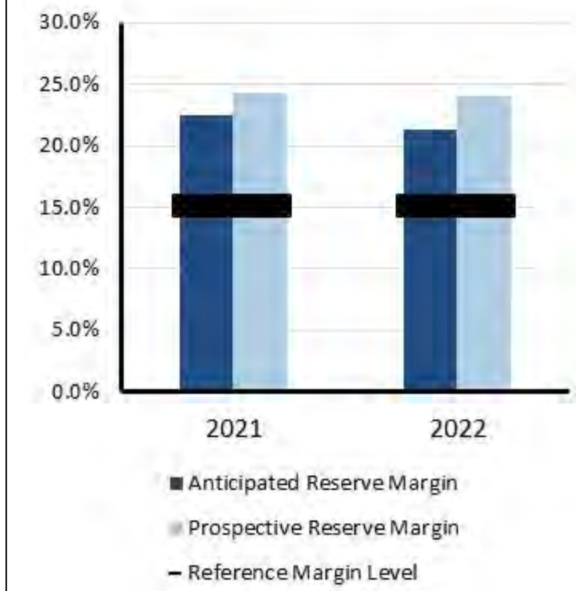


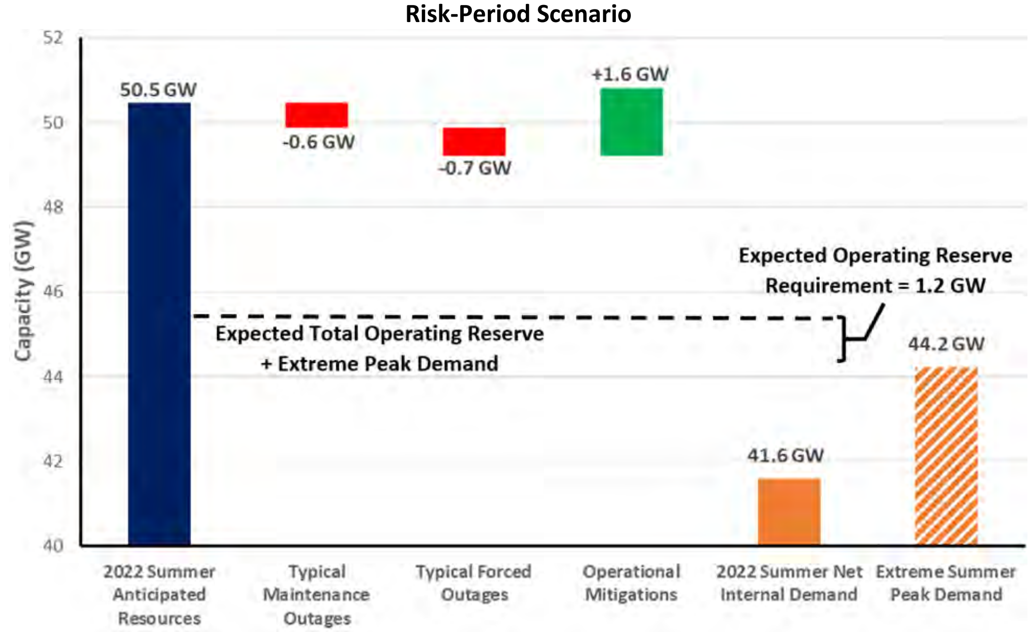
Highlights

- Entities in SERC-East have not identified any potential reliability issues for the upcoming season. The entities continue to perform resource studies to ensure resource adequacy to meet the summer peak demand and to maintain system reliability. Entities reported that coal inventory is in the upper allowed range to maintain reliability.
- Entities in SERC-East continue to participate actively in the SERC Near-Term and Long-Term Working Groups. These groups identify emerging and potential reliability impacts to transmission and resource adequacy as well as with transfer capability.
- Entities in SERC-East are not anticipating operational challenges for the upcoming summer season.
- Probabilistic analysis performed for SERC-East shows almost no risk for resource shortfall for the summer. SERC-East has a small amount of EUE in August but a negligible amount at other times (EUE < 0.4 MWh).

Risk Scenario Summary

Expected resources meet operating reserve requirements under assessed scenarios.





Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: Net internal demand (50/50) and (90/10) demand forecast

Maintenance Outages: Adjusted for higher outages resulting from extreme summer temperatures and aggregated on a SERC subregional level

Forced Outages: Accounts for reduced thermal capacity contributions due to performance in extreme conditions

Operational Mitigations: A total of 1.6 GW based on operational/emergency procedures

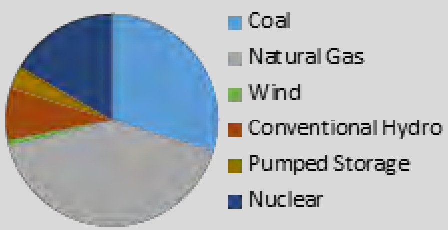
SERC-Central

SERC-Central is a summer peaking assessment area within the SERC Regional Entity. SERC-Central includes all of Tennessee, portions of Georgia, Alabama, Mississippi, Missouri, and Kentucky.

SERC-Central is one of the six companies across North America that are responsible for the work under Federal Energy Regulatory Commission approved delegation agreements with NERC. SERC-Central is specifically responsible for the reliability and security of the electric grid across the Southeastern and Central areas of the United States. This area covers approximately 630,000 square miles and serves a population of more than 91 million.

The SERC Regional Entity includes 36 Balancing Authorities, 28 Planning Authorities, and 6 Reliability Coordinators.

On-Peak Fuel Mix



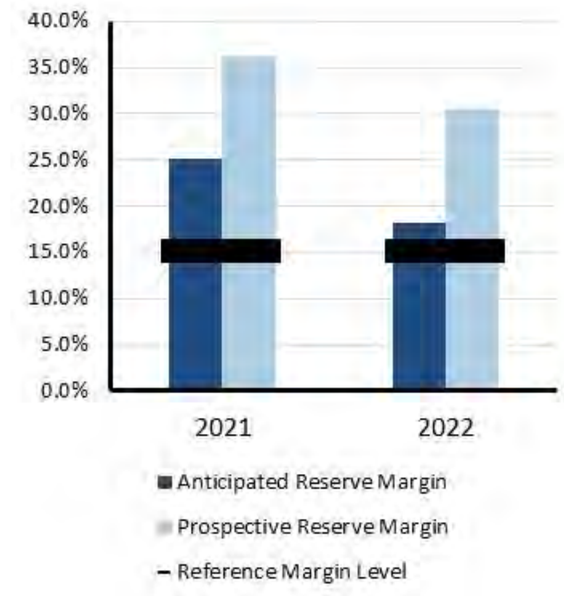
Highlights

- Entities in SERC-Central continue to work collaboratively to ensure reliability for its area within SERC and to promote reliability and adequacy.
- Entities in SERC-Central continue to participate actively in the SERC Near-Term and Long-Term Working Groups, among others, in order to identify and address emerging and potential reliability impacts to transmission and resource adequacy along with transfer capability.
- Entities in SERC-Central have not identified any potential reliability issues for the upcoming summer season.
- Entities anticipate having adequate system capacity for the upcoming season and are equipped to address unexpected, short-term issues leveraging its diverse generation portfolio and spot purchases from the power markets when necessary.
- Probabilistic analysis performed for SERC-Central indicates minimal risk for resource shortfall.

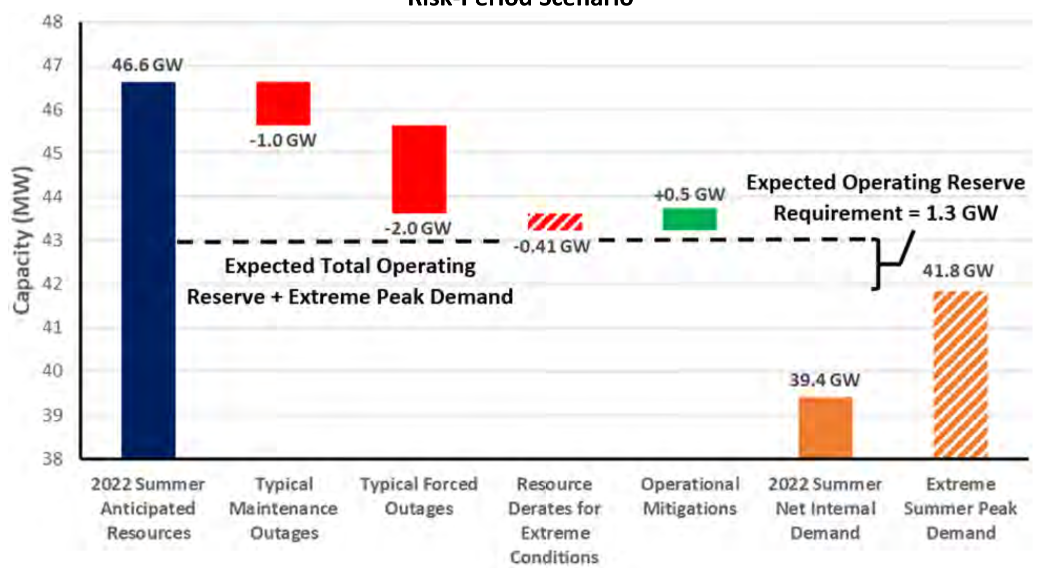
Risk Scenario Summary

Expected resources meet operating reserve requirements under assessed scenarios.

On-Peak Reserve Margins



Risk-Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: Net internal demand (50/50) and (90/10) demand forecast

Maintenance Outages: Adjusted for higher outages resulting from extreme summer temperatures and aggregated on a SERC subregional level

Forced Outages: Accounts for reduced thermal capacity contributions due to performance in extreme conditions

Operational Mitigations: A total of 0.5 GW based on operational/emergency procedures

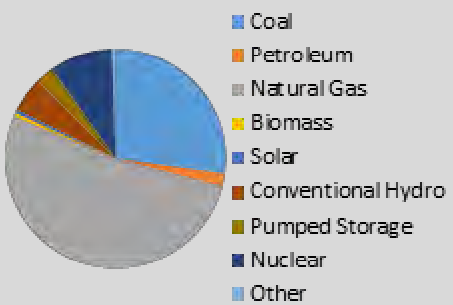
SERC-Southeast

SERC-Southeast is a summer peaking assessment area within the SERC Regional Entiey. SERC-Southeast includes all or portions of Georgia, Alabama, and Mississippi.

SERC is one of the six companies across North America that are responsible for the work under Federal Energy Regulatory Commission approved delegation agreements with NERC. SERC is specifically responsible for the reliability and security of the electric grid across the Southeastern and Central areas of the United States. This area covers approximately 630,000 square miles and serves a population of more than 91 million.

The SERC Regional Entity includes 36 Balancing Authorities, 28 Planning Authorities, and 6 Reliability Coordinators.

On-Peak Fuel Mix



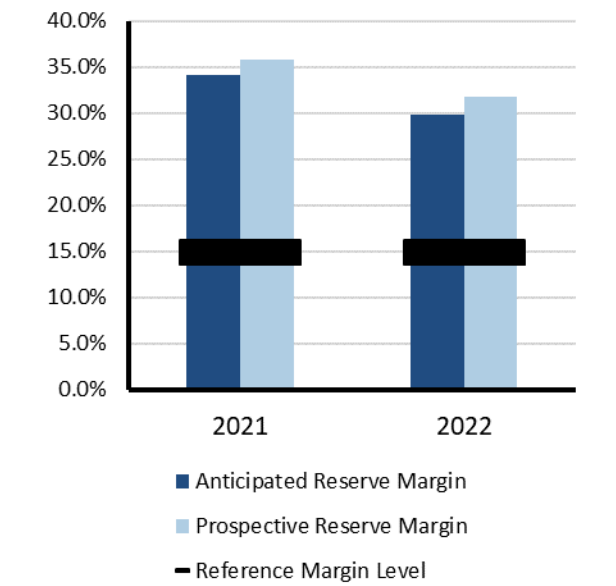
Highlights

- Entities in SERC-Southeast have not identified any emerging reliability issues for the upcoming summer that will impact resource adequacy. The available system capacity for the upcoming summer meets or exceeds the reserve margin target. Reliability is supported by a diverse fuel mix, firm natural gas contracts, and power purchases.
- Entities in SERC-Southeast continue to participate actively in the SERC Near-Term and Long-Term Working Groups. These groups identify emerging and potential reliability impacts to transmission and resource adequacy along with transfer capability.
- Probabilistic analysis performed for SERC-Southeast shows there is low risk for resource shortfall for the summer. Load loss and unserved energy indices are negligible for SERC-Southeast throughout the summer.

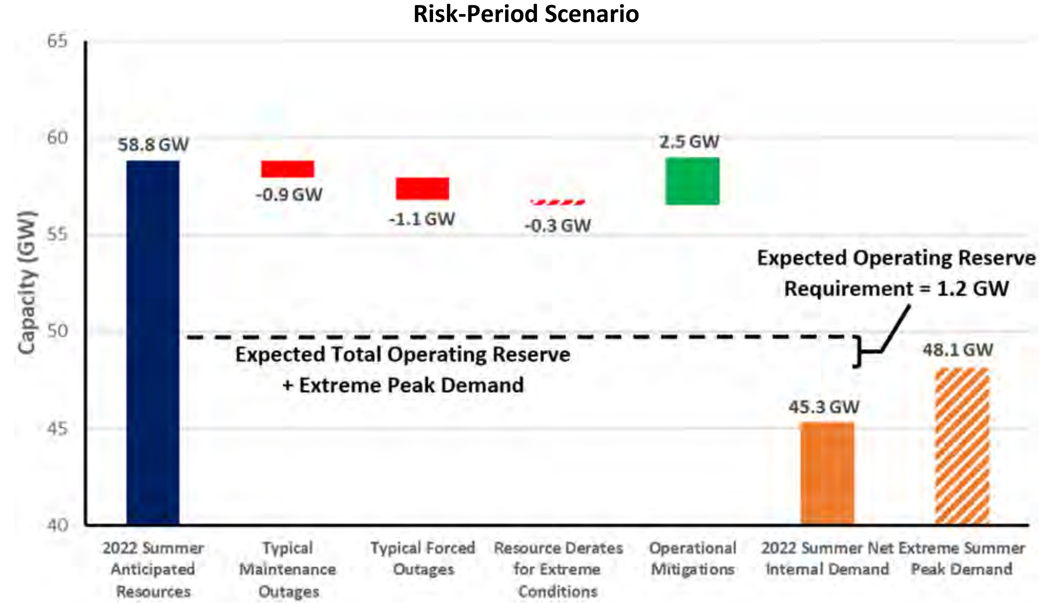
Risk Scenario Summary

Expected resources meet operating reserve requirements under assessed scenarios.

On-Peak Reserve Margins



Risk-Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: Net internal demand (50/50) and (90/10) demand forecast

Maintenance Outages: Adjusted for higher outages resulting from extreme summer temperatures and aggregated on a SERC subregional level

Forced Outages: Accounts for reduced thermal capacity contributions due to performance in extreme conditions

Operational Mitigations: A total of 2.5 GW based on operational/ emergency procedures

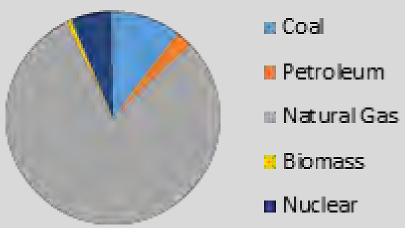
SERC-Florida Peninsula

SERC-Florida Peninsula is a summer peaking assessment area within SERC.

SERC is one of the six companies across North America that are responsible for the work under Federal Energy Regulatory Commission approved delegation agreements with NERC. SERC is specifically responsible for the reliability and security of the electric grid across the Southeastern and Central areas of the United States. This area covers approximately 630,000 square miles and serves a population of more than 91 million.

The SERC Regional Entity includes 36 Balancing Authorities, 28 Planning Authorities, and 6 Reliability Coordinators.

On-Peak Fuel Mix



Highlights

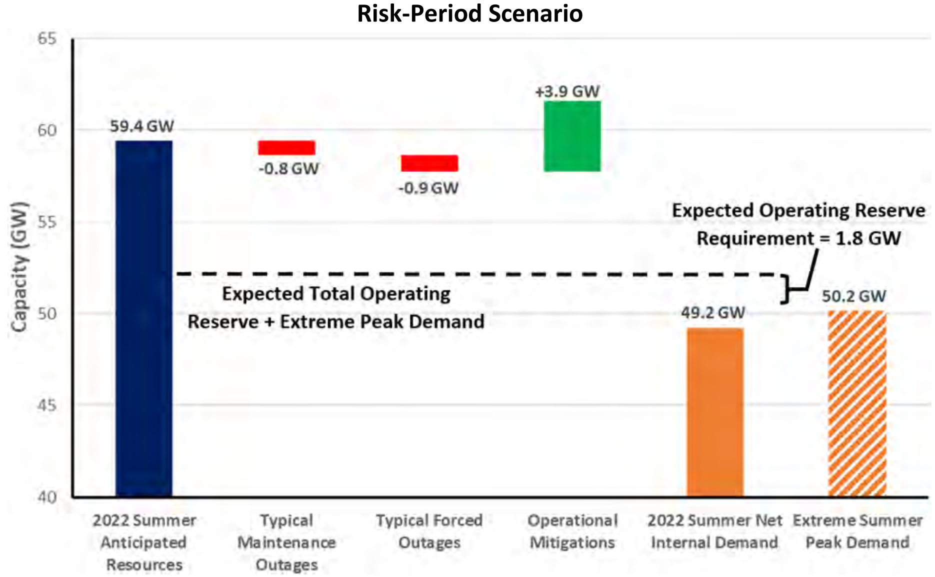
- Entities in SERC-Florida Peninsula have not identified any emerging reliability issues or operational concerns for the upcoming summer.
- Entities in SERC-Florida Peninsula continue to participate actively in the SERC Near-Term and Long-Term Working Groups. These groups identify emerging and potential reliability impacts to transmission and resource adequacy along with transfer capability.
- Entities within the Florida Peninsula area have reported no operational challenges for the upcoming summer based on current expected system conditions. The BES within the Florida Peninsula is expected to perform reliably for the anticipated 2022 summer season.
- SERC Probabilistic analysis performed for SERC-Florida Peninsula shows there is low risk for resource shortfall for the summer. Load loss and unserved energy indices for SERC-Florida Peninsula are spread across the summer months and remain relatively low (LOLH < 0.03 and EUE < 18 MWH).

Risk Scenario Summary

Expected resources meet operating reserve requirements under assessed scenarios.

On-Peak Reserve Margins

Risk-Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: Net internal demand (50/50) and (90/10) demand forecast

Maintenance Outages: Adjusted for higher outages resulting from extreme summer temperatures and aggregated on a SERC subregional level

Forced Outages: Accounts for reduced thermal capacity contributions due to performance in extreme conditions

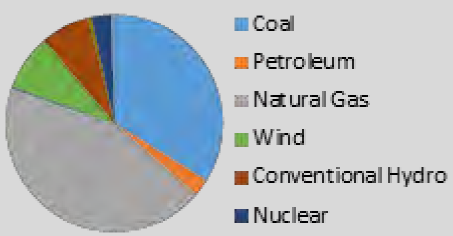
Operational Mitigations: A total of 3.9 GW based on operational/ emergency procedures

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 long-term assessment 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.

On-Peak Fuel Mix



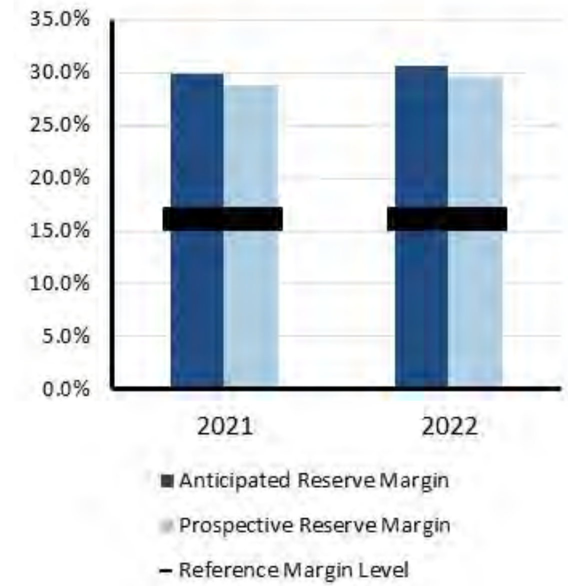
Highlights

- SPP projects a low likelihood of any emerging reliability issues impacting the area for the 2022 summer season.
- The current planning reserve margin should minimize risks of BA capacity deficiencies for summer.
- BA generation capacity deficiency risks remain depending on wind generation output levels and unanticipated generation outages in combination with high load periods.
- There are concerns that drought conditions will impact the Missouri River and other water sources used by generation resources that rely on once-through cooling processes.
- Using current operational processes and procedures, SPP will continue to assess the needs for the 2022 summer season and will adjust as needed to ensure that real time reliability is maintained throughout the summer.

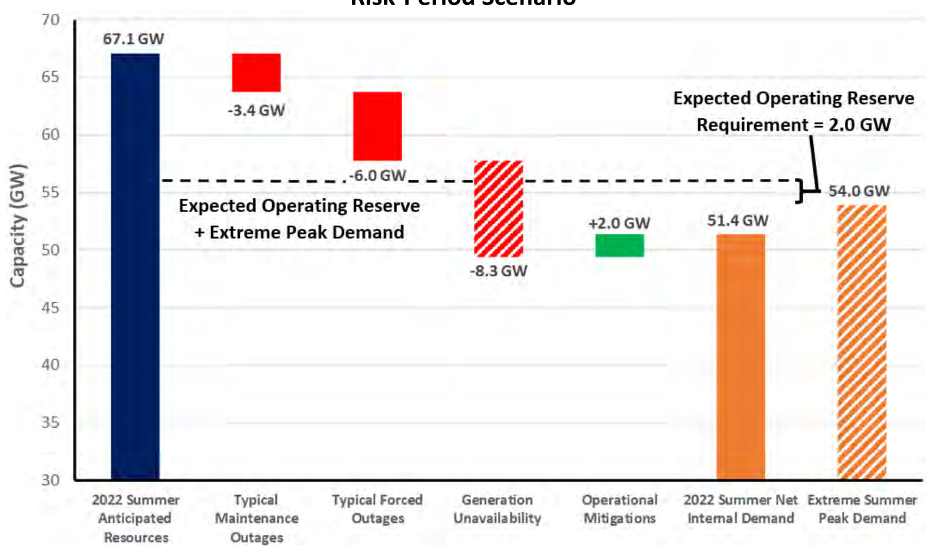
Scenario Summary

Expected resources meet operating reserve requirements under normal peak-demand scenarios. Above-normal summer peak load and outage conditions could result in the need to employ operating mitigations (i.e., demand response and transfers) and EEAs. Load shedding may be needed under extreme peak demand and outage scenarios studied.

On-Peak Reserve Margins



Risk-Period Scenario



Scenario Description (See [Data Concepts and Assumptions])

Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: Net internal demand (50/50) and extreme demand is a 5% increase from net internal demand

Maintenance & Forced Outages: Calculated from SPP's generator assessment process

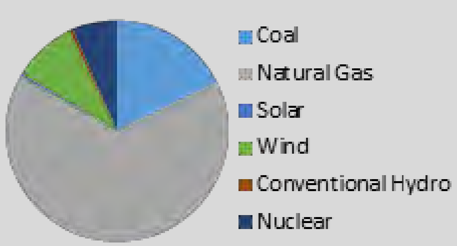
Generation Unavailability: Risk from higher outages to protect against 99.5th percentile of historical coincident generation

Operational Mitigations: A total of 2 GW of behind the meter generation and demand response to be deployed in the event of an emergency alert

Texas RE-ERCOT

The Electric Reliability Council of Texas (ERCOT) is the ISO for the ERCOT Interconnection and is located entirely in the state of Texas; it operates as a single BA. It also performs financial settlement for the competitive wholesale bulk-power market and administers retail switching for nearly 8 million premises in competitive choice areas. ERCOT is governed by a board of directors and subject to oversight by the Public Utility Commission of Texas and the Texas Legislature. ERCOT is a summer-peaking Regional Entity that covers approximately 200,000 square miles, connects over 52,700 miles of transmission lines, has over 1,000 generation units, and serves more than 26 million customers. Lubbock Power & Light joined the ERCOT grid on June 1, 2021. Texas RE is responsible for the Regional Entity functions described in the Energy Policy Act of 2005 for the ERCOT Regional Entity.

On-Peak Fuel Mix



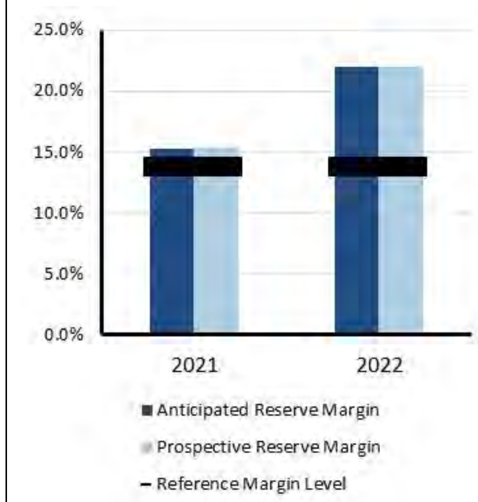
Highlights

- The amount of renewable installed capacity expected to be available during upcoming summer peak demand hours is higher by about 4,100 MW relative to the amount reported in last year's SRA.
- Most of ERCOT is experiencing severe drought conditions, setting the stage for a hotter-than-normal summer.
- Transmission expansion projects in development to add resources or address system performance are being closely monitored for delays or cancellations. Occurrences may contribute to localized reliability concerns.
- On May 9, 2021, a single-line-to-ground fault occurred at a combined-cycle power plant near Odessa, Texas. The fault impacted several solar and wind plants. In response to the NERC report on the disturbance event, ERCOT established an Inverter-based Resource Task Force to facilitate assessment of recommendations to address IBR issues identified in the report.
- An emerging challenge for transmission planning and system operations is the interest in developing new cryptocurrency mining facilities in ERCOT. ERCOT and its stakeholders have recently formed a task force to address the issues associated with these large flexible loads.
- ERCOT's Summer 2022 probabilistic assessment indicates a low risk (6% probability) of declaring a Level 1 Energy Emergency Alert (EEA1) during the expected daily peak load hour. The EEA1 risk is slightly higher from 6:00–8:00 p.m. Central time with the highest-risk hour being 7:00 p.m. This shifting of capacity scarcity risk to later hours is due to the large increase in solar capacity over the last two years. Nevertheless, the overall daily risk is lower than for the Summer 2021 model simulation. For example, the EEA1 peak load hour risk for Summer 2021 was higher at 12%.

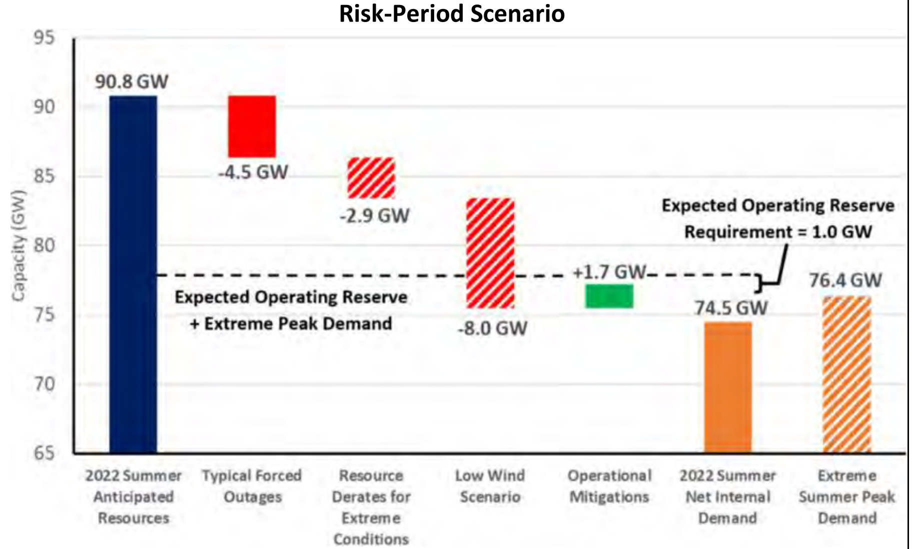
Risk Scenario Summary

Expected resources meet operating reserve requirements under normal peak-demand scenarios. Above-normal summer peak load and outage conditions could result in the need to employ interruptible load programs and additional operating mitigations reflected in the scenario. Load shedding may be needed under extreme peak demand and outage scenarios studied.

On-Peak Reserve Margins



Risk-Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: Net internal demand (50/50) and extreme demand represents 90th percentile of forecasted summer peaks from 2006–2020

Forced Outages: Based on the historical averages of forced outages for June through September weekdays, hours ending 3:00–8:00 p.m. local time for the last three (2019–2021) summer seasons

Extreme Derates: Based on the 95th percentile of historical averages of forced outages for June through September weekdays, hours ending 3:00–8:00 p.m. local time for the last three (2019–2021) summer seasons

Operational Mitigations: Additional capacity from switchable generation and additional imports

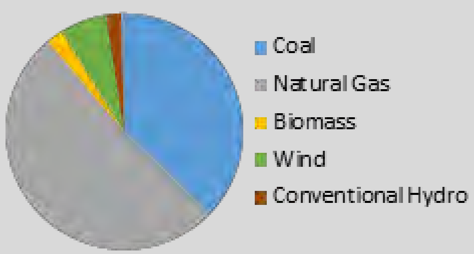
WECC-NWPP-AB

WECC-NWPP-AB (Alberta) is an assessment area in the WECC Regional Entity that consists of the province of Alberta, Canada.

WECC is responsible for coordinating and promoting BES reliability in the Western Interconnection. WECC's 329 members, which include 39 Balancing Authorities, represent a wide spectrum of organizations with an interest in the BES. Serving an area of nearly 1.8 million square miles and more than 82 million customers, it is geographically the largest and most diverse Regional Entity.

WECC's service territory extends from Canada to Mexico. It includes the provinces of Alberta and British Columbia in Canada, the Northern portion of Baja California in Mexico as well as all or portions of the 14 Western United States in between.

On-Peak Fuel Mix



Highlights

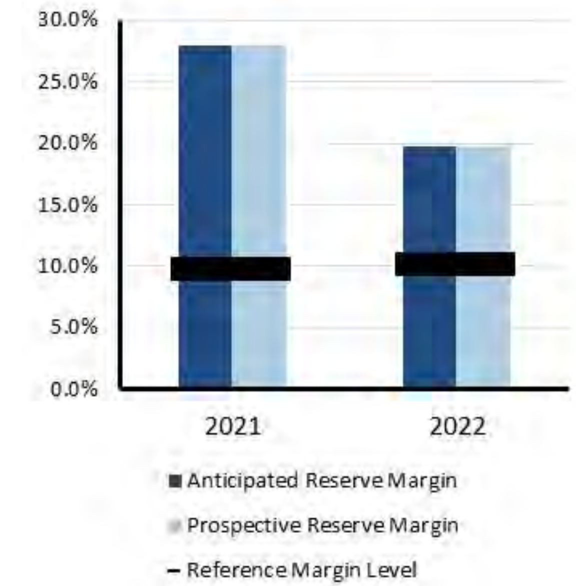
- There are potential natural gas supply-side tightening concerns.
- Reserve margins are tighter but still expected to be adequate.
- Based on a WECC probabilistic assessment, the WECC-NWPP-AB assessment area had negligible LOLH and EUE.

  On the peak risk hour at 6:00 p.m. local time, under a summer peak defined as a one-in-ten probability at the 90th percentile, and with either one of the combination of derates on their own or any two in combination, Alberta is expected to have sufficient resource availability to meet demand and cover reserves. However, if all derate conditions were combined concurrently, Alberta would likely need to seek external assistance for imports.

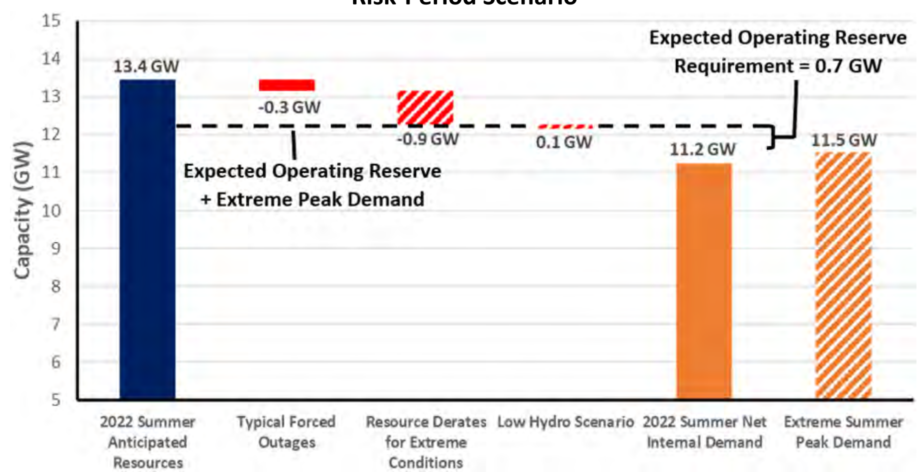
Risk Scenario Summary

Expected resources meet operating reserve requirements under normal peak-demand scenarios. Above-normal summer peak load and outage conditions could result in the need to employ operating mitigations (i.e., demand response and transfers) and EEAs. Load shedding may be needed under extreme peak demand and outage scenarios studied.

On-Peak Reserve Margins



Risk-Period Scenario



Scenario Description (See [Data Concepts and Assumptions])

Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: Net internal demand (50/50) and (90/10) demand forecast

Forced Outages: Average seasonal outages

Extreme Derates: Using (90/10) scenario

Low Hydro Scenario: Reduced hydro availability resulting from drought conditions

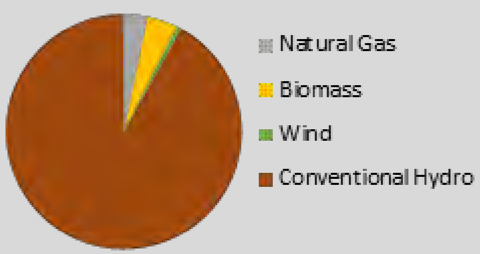
WECC-NWPP-BC

WECC-NWPP-BC (British Columbia) is an assessment area in the WECC Regional Entity that consists of the province of British Columbia, Canada.

WECC is responsible for coordinating and promoting BES reliability in the Western Interconnection. WECC's 329 members, which include 39 Balancing Authorities, represent a wide spectrum of organizations with an interest in the BES. Serving an area of nearly 1.8 million square miles and more than 82 million customers, it is geographically the largest and most diverse Regional Entity.

WECC's service territory extends from Canada to Mexico. It includes the provinces of Alberta and British Columbia in Canada, the Northern portion of Baja California in Mexico as well as all or portions of the 14 Western United States in between.

On-Peak Fuel Mix



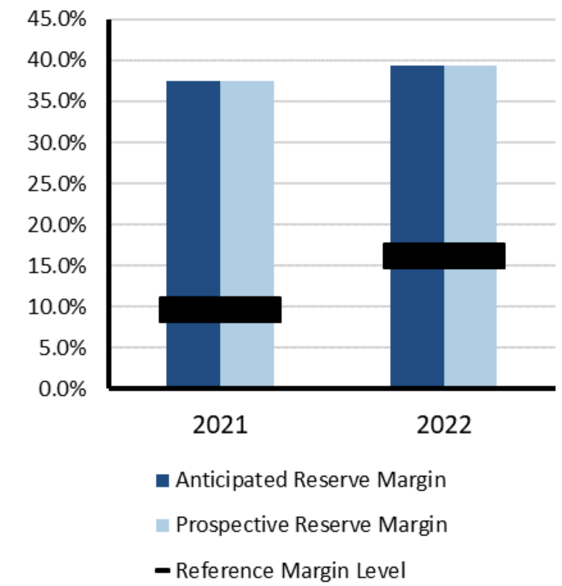
Highlights

- Planned resources in Tier 1 have moved into existing certain.
- Reserve margins are up across the board and adequate.
- Based on a WECC probabilistic assessment, the WECC-NWPP-BC assessment area had negligible LOLH and EUE.
- On the peak risk hour at 6:00 p.m. local time, under a summer peak defined as a 1-in-10 probability at the 90th percentile, and with any combination of derates other than hydro, BC is expected to have sufficient resource availability to meet demand and cover reserves. However, if a 1-in-10 probability at the 10th percentile of hydro conditions was to occur, BC would need to locate external assistance for imports. Summer 2022 hydro availability in BC is not expected to fall that low despite continued mega-drought conditions across much of the West.

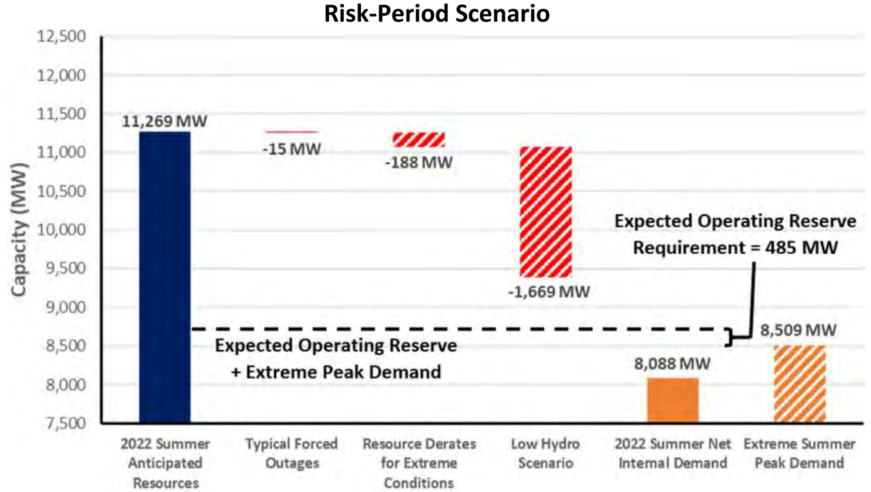
Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed scenarios.

On-Peak Reserve Margins



Risk-Period Scenario



Scenario Description (See [Data Concepts and Assumptions](#))

Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: Net internal demand (50/50) and (90/10) demand forecast

Forced Outages: Average seasonal outages

Extreme Derates: Using (90/10) scenario

Low Hydro Scenario: Reduced hydro availability resulting from drought conditions

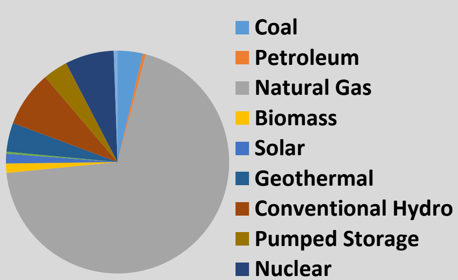
WECC-CA/MX

WECC-CA/MX (California-Mexico) is an assessment area in the WECC Regional Entity that includes parts of California, Nevada, and Baja California, Mexico.

WECC is responsible for coordinating and promoting BES reliability in the Western Interconnection. WECC's 329 members, which include 39 Balancing Authorizes, represent a wide spectrum of organizations with an interest in the BES. Serving an area of nearly 1.8 million square miles and more than 82 million customers, it is geographically the largest and most diverse Regional Entity.

WECC's service territory extends from Canada to Mexico. It includes the provinces of Alberta and British Columbia in Canada, the Northern portion of Baja California in Mexico as well as all or portions of the 14 Western United States in between.

On-Peak Fuel Mix



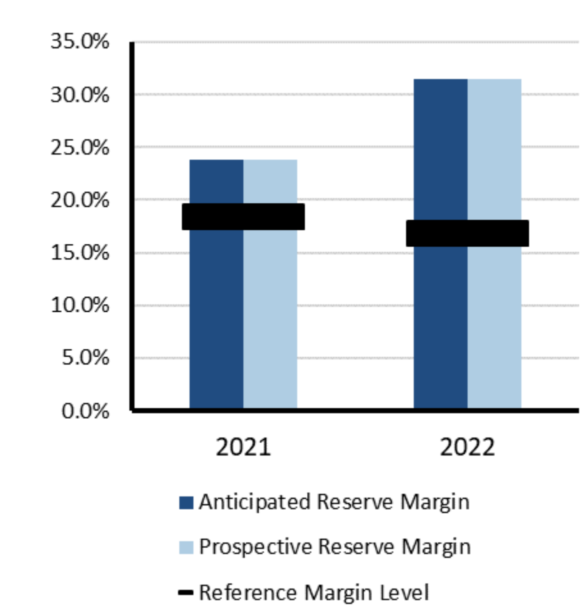
Highlights

- California ISO is procuring resources to improve reliability risks.
- Localized short-term operational issues may occur due to wildfires, droughts, and/or supply chain issues.
- As cooling degree days continue to rise across the Western Interconnection, there is a risk that is higher than the historical average of prolonged heatwave events
- Based on a WECC probabilistic assessment, the California portion of the assessment area is projected to have an LOLH of 1.0 hours and an EUE of 4 MWh. The Mexico portion is projected to have an LOLH of 10.0 hours and an EUE of 100 MWh.
- On the peak risk hour at 8:00 p.m. local time, there is an under 1-in-10 summer peak probability at the 90th percentile, including firm transfers. The CA/MX area is not expected to have sufficient resource availability to meet demand and cover reserves under any of the scenarios on their own, including typical forced outages; CA/MX will need to locate additional external assistance for imports.

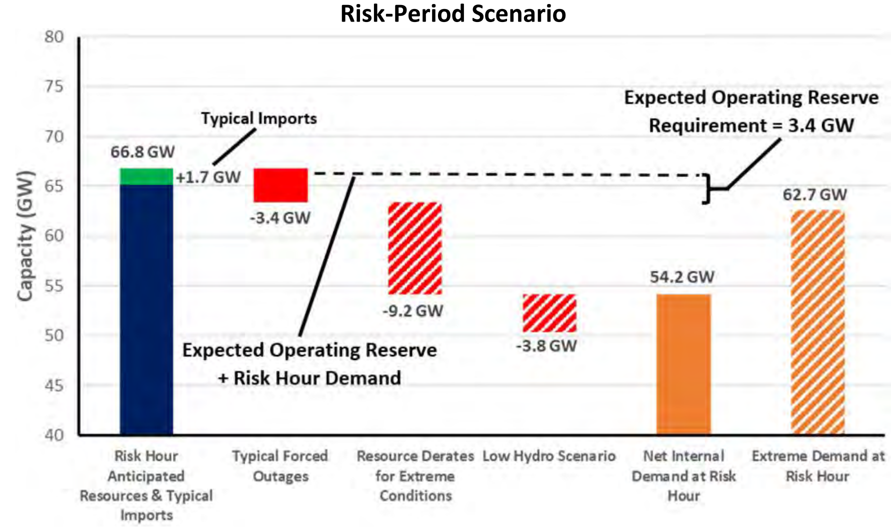
Risk Scenario Summary

Expected resources meet operating reserve requirements under normal peak-demand scenarios. Above-normal summer peak load and outage conditions could result in the need to employ operating mitigations (i.e., demand response and transfers) and EEAs. Load shedding may be needed under extreme peak demand and outage scenarios studied.

On-Peak Reserve Margins



Risk-Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at 8:00 p.m. local time as solar PV output is diminished and demand remains high

Demand Scenarios: Net internal demand (50/50) at risk hour and (90/10) demand forecast at risk hour

Forced Outages: Estimated using market forced outage model

Extreme Derates: On natural gas units based on historic data and manufacturer data for temperature performance and outages

Low Hydro Scenario: Reduced hydro availability resulting from drought conditions

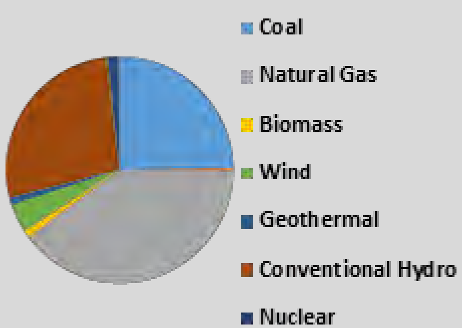
WECC-NWPP-US

WECC-NWPP-US (Northwest Power Pool) is an assessment area in the WECC Regional Entity. The area includes Colorado, Idaho, Montana, Oregon, Utah, Washington, Wyoming and parts of California, Nebraska, Nevada, and South Dakota.

WECC is responsible for coordinating and promoting BES reliability in the Western Interconnection. WECC's 329 members, which include 39 Balancing Authorities, represent a wide spectrum of organizations with an interest in the BES. Serving an area of nearly 1.8 million square miles and more than 82 million customers, it is geographically the largest and most diverse Regional Entity.

WECC's service territory extends from Canada to Mexico. It includes the provinces of Alberta and British Columbia in Canada, the Northern portion of Baja California in Mexico as well as all or portions of the 14 Western United States in between.

On-Peak Fuel Mix



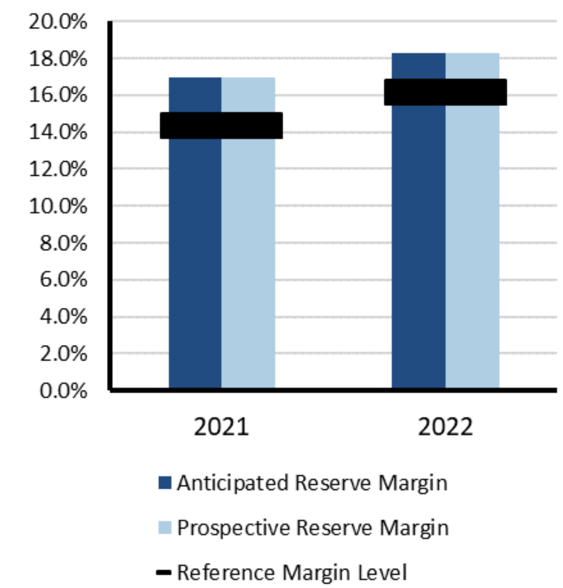
Highlights

- Potential drought conditions remain a concern.
- Reserve margins are up across the board and adequate.
- Based on a WECC probabilistic assessment, the WECC-NWPP-US assessment area had negligible LOLH and EUE.
- On the peak risk hour at 7:00 p.m., local time and under a summer peak defined as a 1-in-10 probability, including firm transfers, the WECC-NWPP-US area is not expected to have sufficient resource availability to meet demand and cover reserves under any of the scenarios on their own, including typical forced outages; WECC-NWPP-US will need to locate additional external assistance for imports.

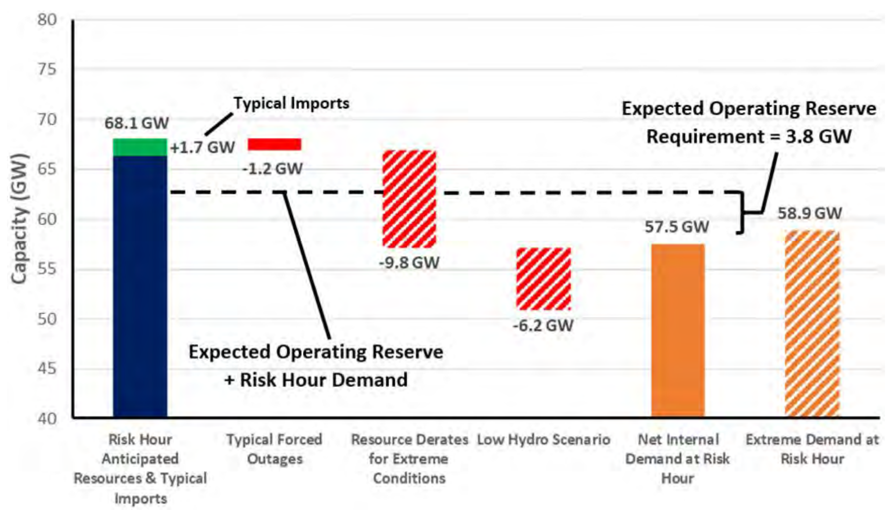
Risk Scenario Summary

Expected resources meet operating reserve requirements under normal peak-demand scenarios. Above-normal summer peak load and outage conditions could result in the need to employ operating mitigations (i.e., demand response and transfers) and EEAs. Load shedding may be needed under extreme peak demand and outage scenarios studied.

On-Peak Reserve Margins



Risk-Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at 7:00 p.m. local time as solar PV output is diminished and demand remains high

Demand Scenarios: Net internal demand (50/50) at risk hour and (90/10) demand forecast at risk hour

Forced Outages: Average seasonal outages

Extreme Derates: Using (90/10) scenario

Low Hydro Scenario: Reduced hydro availability resulting from drought conditions

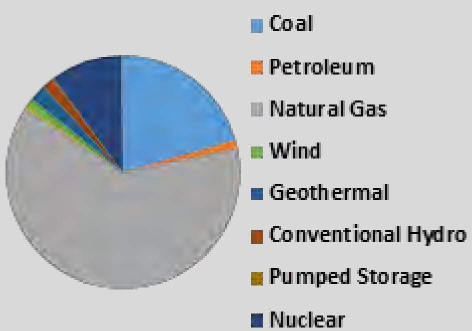
WECC-SRSG

WECC-SRSG (Southwest Reserve Sharing Group) is an assessment area in the WECC Regional Entity. It includes Arizona, New Mexico, and part of California and Texas.

WECC is responsible for coordinating and promoting BES reliability in the Western Interconnection. WECC's 329 members, which include 39 Balancing Authorities, represent a wide spectrum of organizations with an interest in the BES. Serving an area of nearly 1.8 million square miles and more than 82 million customers, it is geographically the largest and most diverse Regional Entity.

WECC's service territory extends from Canada to Mexico. It includes the provinces of Alberta and British Columbia in Canada as well as the Northern portion of Baja California in Mexico and all or portions of the 14 Western United States in between.

On-Peak Fuel Mix



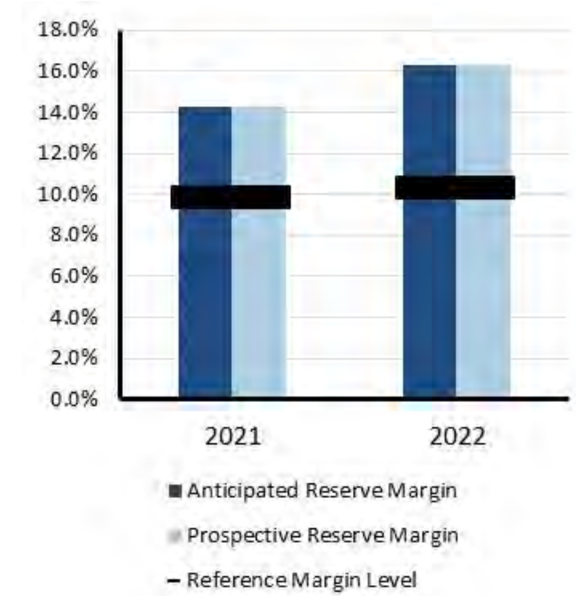
Highlights

- Drought and supply chain issues are the main reliability concerns. Many solar developers are indicating to utilities that they will not be able to meet expected commission dates under executed and approved power purchase agreements, including at least 120 MW of PV planned for the 2022 summer.
- Reserve margins are expected to be adequate.
- Based on a WECC probabilistic assessment, the WECC-SRSG assessment area had negligible LOLH and EUE.
- On the peak risk hour is at 7:00 p.m., local time, under a summer peak defined as a 1-in-10 probability, and with either one of the derates on their own, SRSG is not expected to have sufficient resource availability to meet demand and cover reserves; SRSG will likely need to locate additional external assistance for imports.

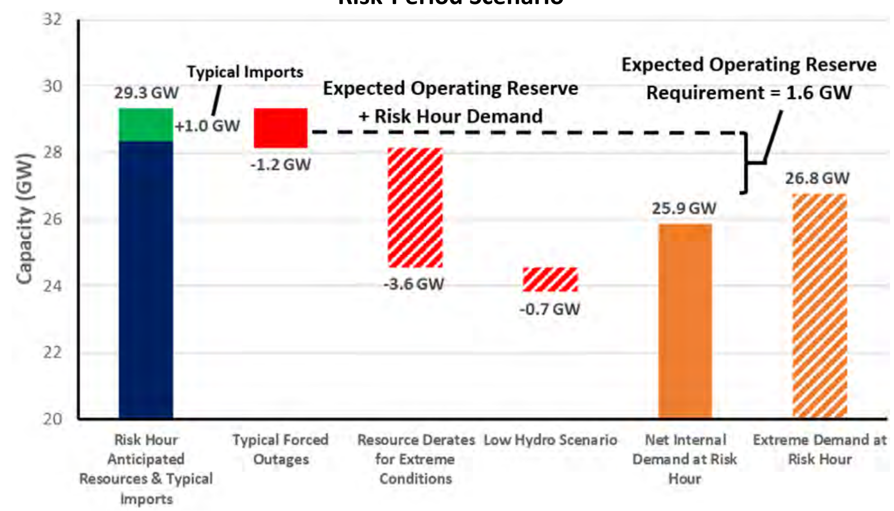
Risk Scenario Summary

Expected resources meet operating reserve requirements under normal peak-demand scenarios. Above-normal summer peak load and outage conditions could result in the need to employ operating mitigations (i.e., demand response and transfers) and EEAs. Load shedding may be needed under extreme peak demand and outage scenarios studied.

On-Peak Reserve Margins



Risk-Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at 7:00 p.m. local time as solar PV output is diminished and demand remains high

Demand Scenarios: Net internal demand (50/50) at risk hour and (90/10) demand forecast at risk hour

Forced Outages: Average seasonal outages

Extreme Derates: Using (90/10) scenario

Low Hydro Scenario: Reduced hydro availability resulting from drought conditions

Data Concepts and Assumptions

The table below explains data concepts and important assumptions used throughout this assessment.

General Assumptions
• Reliability of the interconnected BPS is comprised of both adequacy and operating reliability:
▪ Adequacy is the ability of the electricity system to supply the aggregate electric power and energy requirements of the electricity consumers at all times while taking into account scheduled and reasonably expected unscheduled outages of system components.
▪ Operating reliability is the ability of the electricity system to withstand sudden disturbances such as electric short-circuits or unanticipated loss of system components.
• The reserve margin calculation is an important industry planning metric used to examine future resource adequacy.
• All data in this assessment is based on existing federal, state, and provincial laws and regulations.
• Differences in data collection periods for each assessment area should be considered when comparing demand and capacity data between year-to-year seasonal assessments.
• *2021 Long-Term Reliability Assessment* data has been used for most of this 2022 summer assessment period augmented by updated load and capacity data.
• A positive net transfer capability would indicate a net importing assessment area; a negative value would indicate a net exporter.
Demand Assumptions
• Electricity demand projections, or load forecasts, are provided by each assessment area.
• Load forecasts include peak hourly load[7] or total internal demand for the summer and winter of each year.[8]
• Total internal demand projections are based on normal weather (50/50 distribution[9]) and are provided on a coincident[10] basis for most assessment areas.
• Net internal demand is used in all reserve margin calculations, and it is equal to total internal demand then reduced by the amount of controllable and dispatchable demand response projected to be available during the peak hour.
Resource Assumptions
Resource planning methods vary throughout the North American BPS. NERC uses the categories below to provide a consistent approach for collecting and presenting resource adequacy. Because the electrical output of variable energy resources (e.g., wind, solar) depends on weather conditions, their contribution to reserve margins and other on-peak resource adequacy analysis is less than their nameplate capacity.

[7] *Glossary of Terms* used in NERC Reliability Standards
[8] The summer season represents June–September and the winter season represents December–February.
[9] Essentially, this means that there is a 50% probability that actual demand will be higher and a 50% probability that actual demand will be lower than the value provided for a given season/year.
[10] Coincident: This is the sum of two or more peak loads that occur in the same hour. Noncoincident: This is the sum of two or more peak loads on individual systems that do not occur in the same time interval; this is meaningful only when considering loads within a limited period of time, such as a day, a week, a month, a heating or cooling season, and usually for not more than one year. SERC and FRCC calculate total internal demand on a noncoincidental basis.

Anticipated Resources:

- **Existing-Certain Capacity**: Included in this category are commercially operable generating unit or portions of generating units that meet at least one of the following requirements when examining the period of peak demand for the summer season: unit must have a firm capability and have a power purchase agreement with firm transmission that must be in effect for the unit; unit must be classified as a designated network resource; and/or where energy-only markets exist, unit must be a designated market resource eligible to bid into the market.
- **Tier 1 Capacity Additions**: This category includes capacity that either is under construction or has received approved planning requirements.
- **Net Firm Capacity Transfers (Imports minus Exports)**: This category includes transfers with firm contracts.

Prospective Resources: Includes all anticipated resources plus the following:

Existing-Other Capacity: Included in this category are commercially operable generating units or portions of generating units that could be available to serve load for the period of peak demand for the season but do not meet the requirements of existing-certain.

Reserve Margin Descriptions

Planning Reserve Margin: This is the primary metric used to measure resource adequacy; it is defined as the difference in resources (anticipated or prospective) and net internal demand then divided by net internal demand and shown as a percentage.

Reference Margin Level: The assumptions and naming convention of this metric vary by assessment area. The Reference Margin Level can be determined using both deterministic and probabilistic (based on a 0.1/year loss of load study) approaches. In both cases, this metric is used by system planners to quantify the amount of reserve capacity in the system above the forecasted peak demand that is needed to ensure sufficient supply to meet peak loads. Establishing a Reference Margin Level is necessary to account for long-term factors of uncertainty involved in system planning, such as unexpected generator outages and extreme weather impacts that could lead to increase demand beyond what was projected in the 50/50 load forecasted. In many assessment areas, a Reference Margin Level is established by a state, provincial authority, ISO/RTO, or other regulatory body. In some cases, the Reference Margin Level is a requirement. Reference Margin Levels may be different for the summer and winter seasons. If a Reference Margin Level is not provided by an assessment area, NERC applies 15% for predominately thermal systems and 10% for predominately hydro systems.

Seasonal Risk Scenario Chart Description

Each assessment area performed an operational risk analysis that was used to produce the seasonal risk scenario charts in the **Regional Assessments Dashboards**. The chart presents deterministic scenarios for further analysis of different resource and demand levels: The left blue column shows anticipated resources, and the two orange columns at the right show the two demand scenarios of the normal peak net internal demand and the extreme summer peak demand—both determined by the assessment area. The middle red or green bars show adjustments that are applied cumulatively to the anticipated resources, such as the following:

- Reductions for typical generation outages (i.e., maintenance and forced, not already accounted for in anticipated resources)
- Reductions that represent additional outage or performance derating by resource type for extreme, low-probability conditions (e.g., drought condition impacts on hydroelectric generation, low-wind scenario affecting wind generation, fuel supply limitations, or extreme temperature conditions that result in reduced thermal generation output)
- Additional capacity resources that represent quantified capacity from operational procedures, if any, that are made available during scarcity conditions

Not all assessment areas have the same categories of adjustments to anticipated resources. Furthermore, each assessment area determined the adjustments to capacity based on methods or assumptions that are summarized below the chart. Methods and assumptions differ by assessment area and may not be comparable.

The chart enables evaluation of resource levels against levels of expected operating reserve requirement and the forecasted demand. Furthermore, the effects from extreme events can also be examined by comparing resource levels after applying extreme-scenario derates and/or extreme summer peak demand.

Resource Adequacy

The Anticipated Reserve Margin, which is based on available resource capacity, is a metric used to evaluate resource adequacy by comparing the projected capability of anticipated resources to serve forecast peak demand.[11] Large year-to-year changes in anticipated resources or forecast peak demand (net internal demand) can greatly impact Planning Reserve Margin calculations. All assessment areas have sufficient Anticipated Reserve Margins to meet or exceed their Reference Margin Level for the 2022 summer as shown in **Figure 9**.

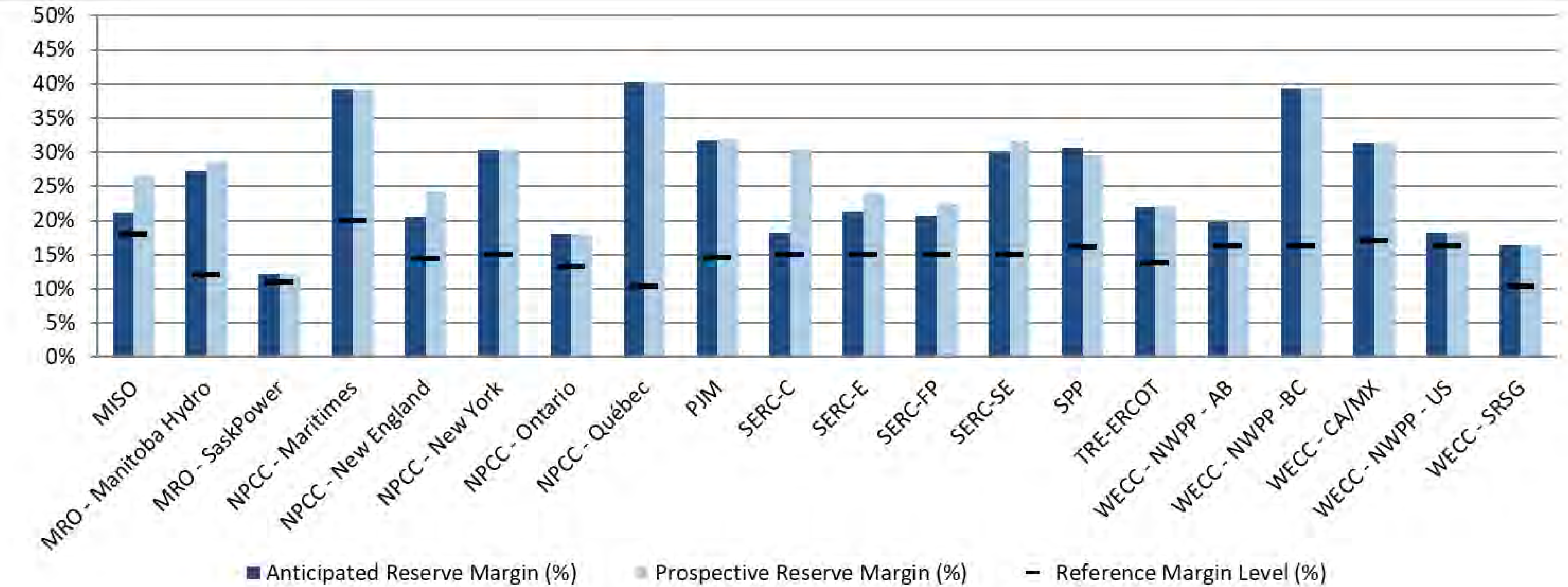
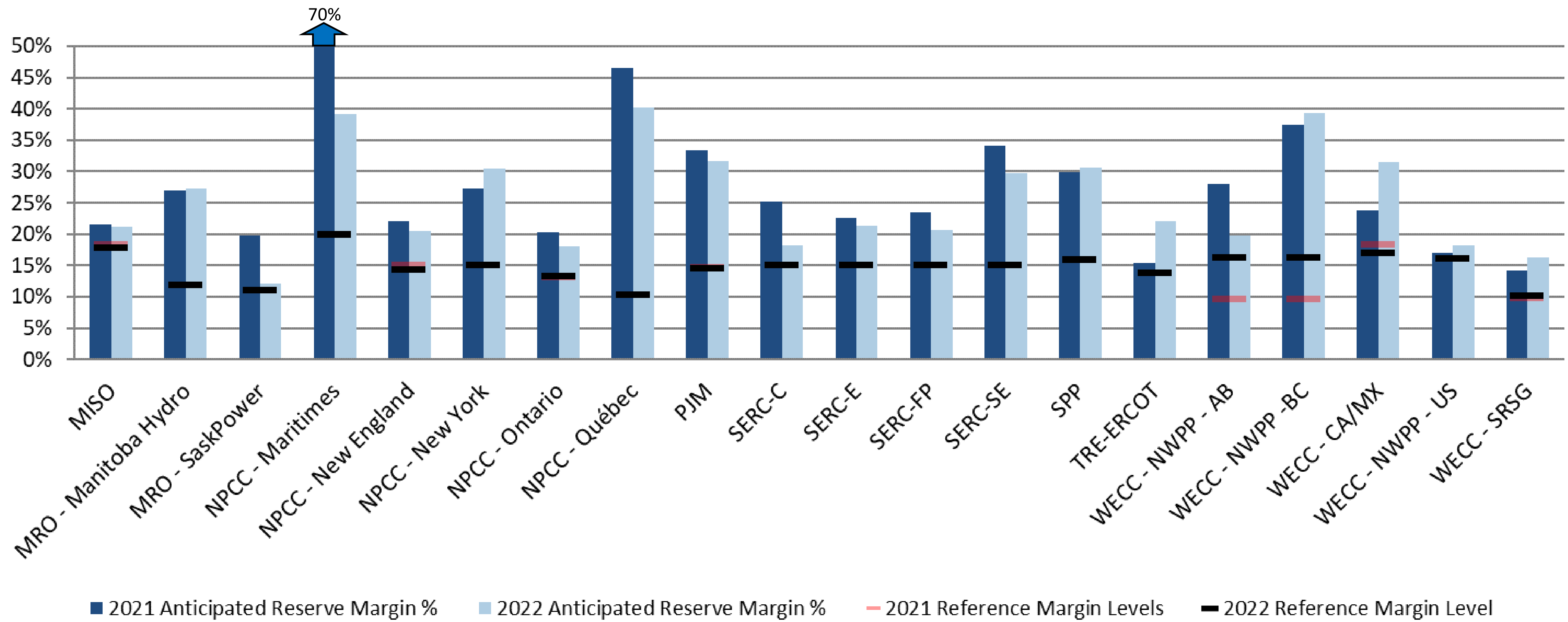


Figure 9: Summer 2022 Anticipated/Prospective Reserve Margins Compared to Reference Margin Level

[11] Generally, anticipated resources include generators and firm capacity transfers that are expected to be available to serve load during electrical peak loads for the season. Prospective resources are those that could be available but do not meet criteria to be counted as anticipated resources. Refer to the **Data Concepts and Assumptions** section for additional information on Anticipated/Prospective Reserve Margins, anticipated/prospective resources, and Reference Margin Levels.

Changes from Year-to-Year

Figure 10 provides the relative change in the forecast Anticipated Reserve Margins from the 2021 summer to the 2022 summer. A significant decline can indicate potential operational issues that emerge between reporting years. MRO-SaskPower, NPCC-Maritimes, NPCC-Québec, SERC-C, and WECC-AB have noticeable reductions in anticipated resources with MRO-SaskPower close to falling below its Reference Margin Level for the 2022 summer. MRO-SaskPower will rely on demand response and transfers from neighbors during a higher load scenario to avoid load interruption. The lower Anticipated Reserve Margins for NPCC-Maritimes, NPCC-Québec, SERC-C, and WECC-AB do not present reliability concerns on peak for this upcoming summer. Additional details for each assessment area are provided in the Data Concepts and Assumptions and Regional Assessments Dashboards sections.



Note: The areas that only have one bar have the same Reference Margin Level for both years.

Figure 10: Summer 2021 and Summer 2022 Anticipated Reserve Margins Year-to-Year Change

Net Internal Demand

The changes in forecasted Net Internal Demand for each assessment area are shown in **Figure 11**.[12] Assessment areas develop these forecasts based on historic load and weather information as well as other long-term projections.

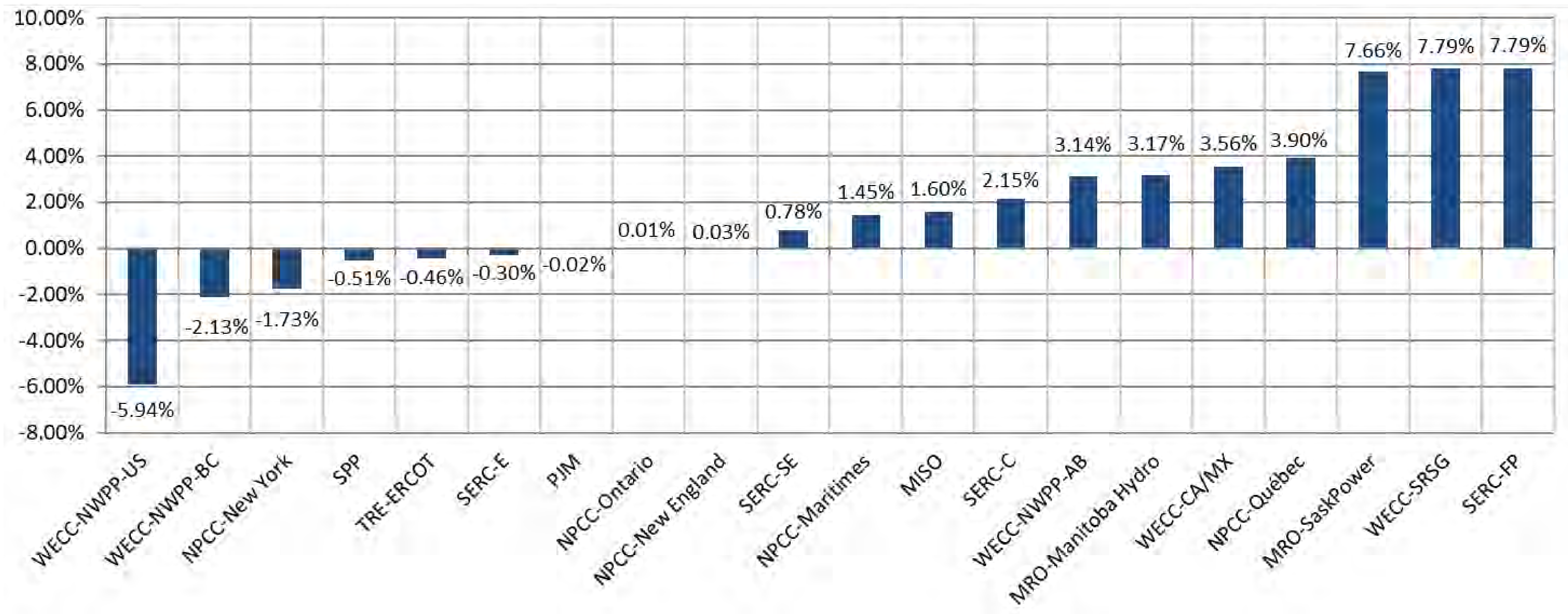


Figure 11: Change in Net Internal Demand: Summer 2021 Forecast Compared to Summer 2022 Forecast

[12] Changes in modeling and methods may also contribute to year-to-year changes in forecasted net internal demand projections.

Demand and Resource Tables

Peak demand and supply capacity data for each assessment area are provided below (in alphabetical order).

MISO Resource Adequacy Data

Demand, Resource, and Reserve Margins	2021 SRA	2022 SRA	2021 vs. 2022 SRA
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	122,398	124,506	1.7%
Demand Response: Available	6,038	6,287	4.1%
Net Internal Demand	116,360	118,220	1.6%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	138,464	141,844	2.4%
Tier 1 Planned Capacity	0	0	-
Net Firm Capacity Transfers	2,979	1,353	-54.6%
Anticipated Resources	141,443	143,197	1.2%
Existing-Other Capacity	633	669	5.7%
Prospective Resources	146,586	149,756	2.2%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	21.6%	21.1%	-0.5
Prospective Reserve Margin	26.0%	26.7%	0.7
Reference Margin Level	18.3%	17.9%	-0.4

MRO-Manitoba Hydro Adequacy Data

Demand, Resource, and Reserve Margins	2021 SRA	2022 SRA	2021 vs. 2022 SRA
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	2,965	3,059	3.2%
Demand Response: Available	0	0	-
Net Internal Demand	2,965	3,059	3.2%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	5,173	5,523	6.8%
Tier 1 Planned Capacity	186	186	0.0%
Net Firm Capacity Transfers	-1,596	-1,816	13.8%
Anticipated Resources	3,763	3,893	3.4%
Existing-Other Capacity	37	44	18.8%
Prospective Resources	3,800	3,937	3.6%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	26.9%	27.3%	0.4
Prospective Reserve Margin	28.2%	28.7%	0.5
Reference Margin Level	12.0%	12.0%	0.0

MRO-SaskPower Resource Adequacy Data

Demand, Resource, and Reserve Margins	2021 SRA	2022 SRA	2021 vs. 2022 SRA
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	3,400	3,656	7.5%
Demand Response: Available	60	60	0.0%
Net Internal Demand	3,340	3,596	7.7%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	3,863	3,743	-3.1%
Tier 1 Planned Capacity	13.5	0	-100.0%
Net Firm Capacity Transfers	125	290	132.0%
Anticipated Resources	4,002	4,033	0.8%
Existing-Other Capacity	0	0	-
Prospective Resources	4,002	4,033	0.8%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	19.8%	12.2%	-7.6
Prospective Reserve Margin	19.8%	12.2%	-7.6
Reference Margin Level	11.0%	11.0%	0.0

NPCC-Maritimes Resource Adequacy Data

Demand, Resource, and Reserve Margins	2021 SRA	2022 SRA	2021 vs. 2022 SRA
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	3,479	3,475	-0.1%
Demand Response: Available	305	255	-16.4%
Net Internal Demand	3,174	3,220	1.4%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	5,448	4,419	-18.9%
Tier 1 Planned Capacity	0	0	-
Net Firm Capacity Transfers	-57	64	-212.3%
Anticipated Resources	5,391	4,483	-16.8%
Existing-Other Capacity	0	0	-
Prospective Resources	5,391	4,483	-16.8%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	69.8%	39.2%	-30.6
Prospective Reserve Margin	69.8%	39.2%	-30.6
Reference Margin Level	20.0%	20.0%	0.0

NPCC-New England Resource Adequacy Data			
Demand, Resource, and Reserve Margins	**2021 SRA**	**2022 SRA**	**2021 vs. 2022 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	25,244	25,300	0.2%
Demand Response: Available	434	483	11.3%
Net Internal Demand	24,810	24,817	0.0%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	29,065	28,626	-1.5%
Tier 1 Planned Capacity	0	0	-
Net Firm Capacity Transfers	1,208	1,292	7.0%
Anticipated Resources	30,273	29,918	-1.2%
Existing-Other Capacity	1115	911	-18.3%
Prospective Resources	31,388	30,829	-1.8%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	22.0%	20.6%	-1.4
Prospective Reserve Margin	26.5%	24.2%	-2.3
Reference Margin Level	15.0%	14.3%	-0.7

NPCC-Ontario Resource Adequacy Data			
Demand, Resource, and Reserve Margins	**2021 SRA**	**2022 SRA**	**2021 vs. 2022 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	22,500	22,546	0.2%
Demand Response: Available	621	666	7.2%
Net Internal Demand	21,879	21,880	0.0%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	26,217	25,648	-2.2%
Tier 1 Planned Capacity	22	24	10.9%
Net Firm Capacity Transfers	80	150	87.5%
Anticipated Resources	26,319	25,822	-1.9%
Existing-Other Capacity	0	0	-
Prospective Resources	26,319	25,822	-1.9%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	20.3%	18.0%	-2.3
Prospective Reserve Margin	20.3%	18.0%	-2.3
Reference Margin Level	13.2%	13.3%	0.1

NPCC-New York Resource Adequacy Data			
Demand, Resource, and Reserve Margins	**2021 SRA**	**2022 SRA**	**2021 vs. 2022 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	32,333	31,765	-1.8%
Demand Response: Available	1,199	1,170	-2.4%
Net Internal Demand	31,134	30,595	-1.7%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	37,805	37,431	-1.0%
Tier 1 Planned Capacity	0	0	-
Net Firm Capacity Transfers	1,816	2,465	35.7%
Anticipated Resources	39,621	39,896	0.7%
Existing-Other Capacity	0	0	-
Prospective Resources	39,621	39,896	0.7%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	27.3%	30.4%	3.1
Prospective Reserve Margin	27.3%	30.4%	3.1
Reference Margin Level	15.0%	15.0%	0.0

NPCC-Québec Resource Adequacy Data			
Demand, Resource, and Reserve Margins	**2021 SRA**	**2022 SRA**	**2021 vs. 2022 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	21,436	22,271	3.9%
Demand Response: Available	0	0	-
Net Internal Demand	21,436	22,271	3.9%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	33,380	33,542	0.5%
Tier 1 Planned Capacity	0	0	-
Net Firm Capacity Transfers	-1,995	-2,304	15.5%
Anticipated Resources	31,385	31,238	-0.5%
Existing-Other Capacity	0	0	-
Prospective Resources	31,385	31,238	-0.5%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	46.4%	40.3%	-6.1
Prospective Reserve Margin	46.4%	40.3%	-6.1
Reference Margin Level	10.4%	10.3%	-0.1

PJM Resource Adequacy Data			
Demand, Resource, and Reserve Margins	**2021 SRA**	**2022 SRA**	**2021 vs. 2022 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	149,224	148,938	-0.2%
Demand Response: Available	8,779	8,527	-2.9%
Net Internal Demand	140,445	140,411	0.0%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	183,572	184,837	0.7%
Tier 1 Planned Capacity	2400	10	-99.6%
Net Firm Capacity Transfers	1,460	124	-91.5%
Anticipated Resources	187,431	184,971	-1.3%
Existing-Other Capacity	0	0	-
Prospective Resources	188,891	185,095	-2.0%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	33.5%	31.7%	-1.8
Prospective Reserve Margin	34.5%	31.8%	-2.7
Reference Margin Level	14.7%	14.9%	0.2

SERC-East Resource Adequacy Data			
Demand, Resource, and Reserve Margins	**2021 SRA**	**2022 SRA**	**2021 vs. 2022 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	42,680	42,883	0.5%
Demand Response: Available	970	1,298	33.8%
Net Internal Demand	41,710	41,585	-0.3%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	50,539	49,380	-2.3%
Tier 1 Planned Capacity	0	486	-
Net Firm Capacity Transfers	562	612	8.9%
Anticipated Resources	51,101	50,478	-1.2%
Existing-Other Capacity	766	1,097	43.2%
Prospective Resources	51,867	51,575	-0.6%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	22.5%	21.4%	-1.1
Prospective Reserve Margin	24.4%	24.0%	-0.4
Reference Margin Level	15.0%	15.0%	0.0

SERC-Central Resource Adequacy Data			
Demand, Resource, and Reserve Margins	**2021 SRA**	**2022 SRA**	**2021 vs. 2022 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	40,341	41,267	2.3%
Demand Response: Available	1,744	1,841	5.6%
Net Internal Demand	38,597	39,426	2.1%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	47,987	47,424	-1.2%
Tier 1 Planned Capacity	154	0	-100.0%
Net Firm Capacity Transfers	172	-795	-561.6%
Anticipated Resources	48,314	46,629	-3.5%
Existing-Other Capacity	4290	4,808	12.1%
Prospective Resources	52,604	51,437	-2.2%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	25.2%	18.3%	-6.9
Prospective Reserve Margin	36.3%	30.5%	-5.8
Reference Margin Level	15.0%	15.0%	0.0

SERC-Florida Peninsula Resource Adequacy Data			
Demand, Resource, and Reserve Margins	**2021 SRA**	**2022 SRA**	**2021 vs. 2022 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	48,710	52,172	7.1%
Demand Response: Available	3,030	2,932	-3.2%
Net Internal Demand	45,680	49,240	7.8%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	55,351	56,571	2.2%
Tier 1 Planned Capacity	0	2,540	-
Net Firm Capacity Transfers	1,007	300	-70.2%
Anticipated Resources	56,358	59,411	5.4%
Existing-Other Capacity	0	847	-
Prospective Resources	56,358	60,258	6.9%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	23.4%	20.7%	-2.7
Prospective Reserve Margin	23.4%	22.4%	-1.0
Reference Margin Level	15.0%	15.0%	0.0

SERC-Southeast Resource Adequacy Data			
Demand, Resource, and Reserve Margins	**2021 SRA**	**2022 SRA**	**2021 vs. 2022 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	46,631	47,258	1.3%
Demand Response: Available	1,671	1,946	16.5%
Net Internal Demand	44,960	45,312	0.8%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	61,263	59,828	-2.3%
Tier 1 Planned Capacity	142	1,514	964.9%
Net Firm Capacity Transfers	-1,115	-2,524	126.4%
Anticipated Resources	60,290	58,818	-2.4%
Existing-Other Capacity	783	859	9.7%
Prospective Resources	61,073	59,677	-2.3%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	34.1%	29.8%	-4.3
Prospective Reserve Margin	35.8%	31.7%	-4.1
Reference Margin Level	15.0%	15.0%	0.0

SPP Resource Adequacy Data			
Demand, Resource, and Reserve Margins	**2021 SRA**	**2022 SRA**	**2021 vs. 2022 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	52,249	52,040	-0.4%
Demand Response: Available	606	658	8.6%
Net Internal Demand	51,643	51,382	-0.5%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	66,600	67,245	1.0%
Tier 1 Planned Capacity	300	0	-100.0%
Net Firm Capacity Transfers	186	-144	-177.6%
Anticipated Resources	67,086	67,101	0.0%
Existing-Other Capacity	0	0	-
Prospective Resources	66,539	66,554	0.0%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	29.9%	30.6%	0.7
Prospective Reserve Margin	28.8%	29.5%	0.7
Reference Margin Level	16.0%	16.0%	0.0

Texas RE-ERCOT Resource Adequacy Data			
Demand, Resource, and Reserve Margins	**2021 SRA**	**2022 SRA**	**2021 vs. 2022 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	77,144	77,317	0.2%
Demand Response: Available	2,341	2,856	22.0%
Net Internal Demand	74,803	74,461	-0.5%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	80,569	89,603	11.2%
Tier 1 Planned Capacity	5489	1,199	-78.2%
Net Firm Capacity Transfers	210	20	-90.5%
Anticipated Resources	86,268	90,822	5.3%
Existing-Other Capacity	0	0	-
Prospective Resources	86,296	90,850	5.3%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	15.3%	22.0%	6.7
Prospective Reserve Margin	15.4%	22.0%	6.6
Reference Margin Level	13.75%	13.75%	0.0

WECC-NWPP-AB Resource Adequacy Data			
Demand, Resource, and Reserve Margins	**2021 SRA**	**2022 SRA**	**2021 vs. 2022 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	10,886	11,228	3.1%
Demand Response: Available	0	0	-
Net Internal Demand	10,886	11,228	3.1%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	12,205	11,926	-2.3%
Tier 1 Planned Capacity	1723	1,082	-37.2%
Net Firm Capacity Transfers	0	437	-
Anticipated Resources	13,928	13,445	-3.5%
Existing-Other Capacity	0	0	-
Prospective Resources	13,928	13,445	-3.5%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	27.9%	19.7%	-8.2
Prospective Reserve Margin	27.9%	19.7%	-8.2
Reference Margin Level	9.7%	10.1%	0.4

WECC-NWPP-BC Resource Adequacy Data			
Demand, Resource, and Reserve Margins	**2021 SRA**	**2022 SRA**	**2021 vs. 2022 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	8,264	8,088	-2.1%
Demand Response: Available	0	0	-
Net Internal Demand	8,264	8,088	-2.1%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	11,178	11,266	0.8%
Tier 1 Planned Capacity	185	3	-98.4%
Net Firm Capacity Transfers	0	0	-
Anticipated Resources	11,363	11,269	-0.8%
Existing-Other Capacity	0	0	-
Prospective Resources	11,363	11,269	-0.8%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	37.5%	39.3%	1.8
Prospective Reserve Margin	37.5%	39.3%	1.8
Reference Margin Level	9.7%	16.3%	6.5

WECC-CA/MX Resource Adequacy Data			
Demand, Resource, and Reserve Margins	**2021 SRA**	**2022 SRA**	**2021 vs. 2022 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	55,409	57,269	3.4%
Demand Response: Available	922	844	-8.4%
Net Internal Demand	54,487	56,425	3.6%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	63,396	70,791	11.7%
Tier 1 Planned Capacity	3358	3,381	0.7%
Net Firm Capacity Transfers	686	0	-100.0%
Anticipated Resources	67,440	74,172	10.0%
Existing-Other Capacity	0	0	-
Prospective Resources	67,440	74,172	10.0%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	23.8%	31.5%	7.7
Prospective Reserve Margin	23.8%	31.5%	7.7
Reference Margin Level	18.4%	16.9%	-1.5

WECC-SRSG Resource Adequacy Data			
Demand, Resource, and Reserve Margins	**2021 SRA**	**2022 SRA**	**2021 vs. 2022 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	24,751	26,720	8.0%
Demand Response: Available	332	399	20.0%
Net Internal Demand	24,419	26,321	7.8%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	26,850	28,249	5.2%
Tier 1 Planned Capacity	188	1,369	628.2%
Net Firm Capacity Transfers	866	1,002	15.7%
Anticipated Resources	27,904	30,620	9.7%
Existing-Other Capacity	0	0	-
Prospective Resources	27,904	30,620	9.7%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	14.3%	16.3%	2.0
Prospective Reserve Margin	14.3%	16.3%	2.0
Reference Margin Level	9.8%	10.2%	0.4

WECC-NWPP-US Resource Adequacy Data			
Demand, Resource, and Reserve Margins	**2021 SRA**	**2022 SRA**	**2021 vs. 2022 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	67,117	63,214	-5.8%
Demand Response: Available	1,087	1,104	1.5%
Net Internal Demand	66,030	62,110	-5.9%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	70,069	70,154	0.1%
Tier 1 Planned Capacity	1,002	798	-20.4%
Net Firm Capacity Transfers	6,139	2,517	-59.0%
Anticipated Resources	77,210	73,469	-4.8%
Existing-Other Capacity	0	0	-
Prospective Resources	77,210	73,469	-4.8%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	16.9%	18.3%	1.4
Prospective Reserve Margin	16.9%	18.3%	1.4
Reference Margin Level	14.3%	16.1%	1.8

Variable Energy Resource Contributions

Because the electrical output of variable energy resources (e.g., wind, solar) depends on weather conditions, on-peak capacity contributions are less than nameplate capacity. The table below shows the capacity contribution of existing wind and solar resources at the peak demand hour for each assessment area. Resource contributions are also aggregated by Interconnection and across the entire BPS. For NERC's analysis of risk periods after peak demand (i.e., U.S. assessment areas in WECC), lower contributions of solar resources are used because output is diminished during evening periods.

BPS Variable Energy Resources by Assessment Area									
	Wind			Solar			Hydro		
Assessment Area / Interconnection	Nameplate Wind	Expected Wind	Expected Share of Nameplate (%)	Nameplate Solar	Expected Solar	Expected Share of Nameplate (%)	Nameplate Hydro	Expected Hydro	Expected Share of Nameplate (%)
MISO	28,893	4,478	16%	2,441	1,221	50%	2,440	2,361	97%
MRO-Manitoba Hydro	259	41	16%	-	-	0%	5,917	5,255	89%
MRO-SaskPower	628	88	14%	-	-	0%	864	784	91%
NPCC-Maritimes	1,212	326	27%	2	-	0%	1,315	1,183	90%
NPCC-New England	1,421	201	14%	2,638	773	29%	4,059	2,812	69%
NPCC-New York	2,336	314	13%	76	35	46%	5,949	5,138	86%
NPCC-Ontario	4,943	751	15%	478	66	14%	8,918	4,716	53%
NPCC-Québec	3,820	-	0%	10	-	0%	41,346	32,789	79%
PJM	10,876	1,659	15%	4,852	2,878	64%	3,022	3,022	100%
SERC-Central	964	4	0%	450	287	64%	5,005	3,381	68%
SERC-East	-	-	0%	724	716	99%	3,052	3,002	98%
SERC-Florida Peninsula	-	-	0%	5,246	3,220	61%	-	-	0%
SERC-Southeast	-	-	0%	4,053	3,500	86%	3,242	3,288	101%
SPP	31,325	7,276	23%	306	245	80%	5,456	5,297	97%
Texas RE-ERCOT	35,454	9,423	27%	11,515	9,327	81%	571	475	83%
WECC-AB	3,177	232	7%	1,063	684	64%	894	378	42%
WECC-BC	717	142	20%	2	1	49%	16,378	10,115	62%
WECC-CA/MX	8,946	1,754	20%	19,457	13,634	70%	13,985	7,691	55%
WECC-NWPP-US	19,410	3,312	17%	7,479	4,735	63%	41,705	21,564	52%
WECC-NWPP-SRSG	3,245	516	16%	3,219	2,511	78%	3,532	2,765	78%
EASTERN INTERCONNECTION	82,856	14,425	17%	21,476	13,836	64%	50,846	41,776	82%
QUÉBEC INTERCONNECTION	3,820	-	0%	10	-	0%	41,346	32,789	79%
TEXAS INTERCONNECTION	35,454	9,423	27%	11,515	9,327	81%	571	475	83%
WECC INTERCONNECTION	35,495	5,956	17%	31,220	21,565	69%	76,494	42,513	56%
TOTAL:	157,626	29,804	19%	64,221	44,729	70%	169,257	117,554	69%

2023 Summer Reliability Assessment

May 2023

2023 Summer Reliability Assessment Video

Table of Contents

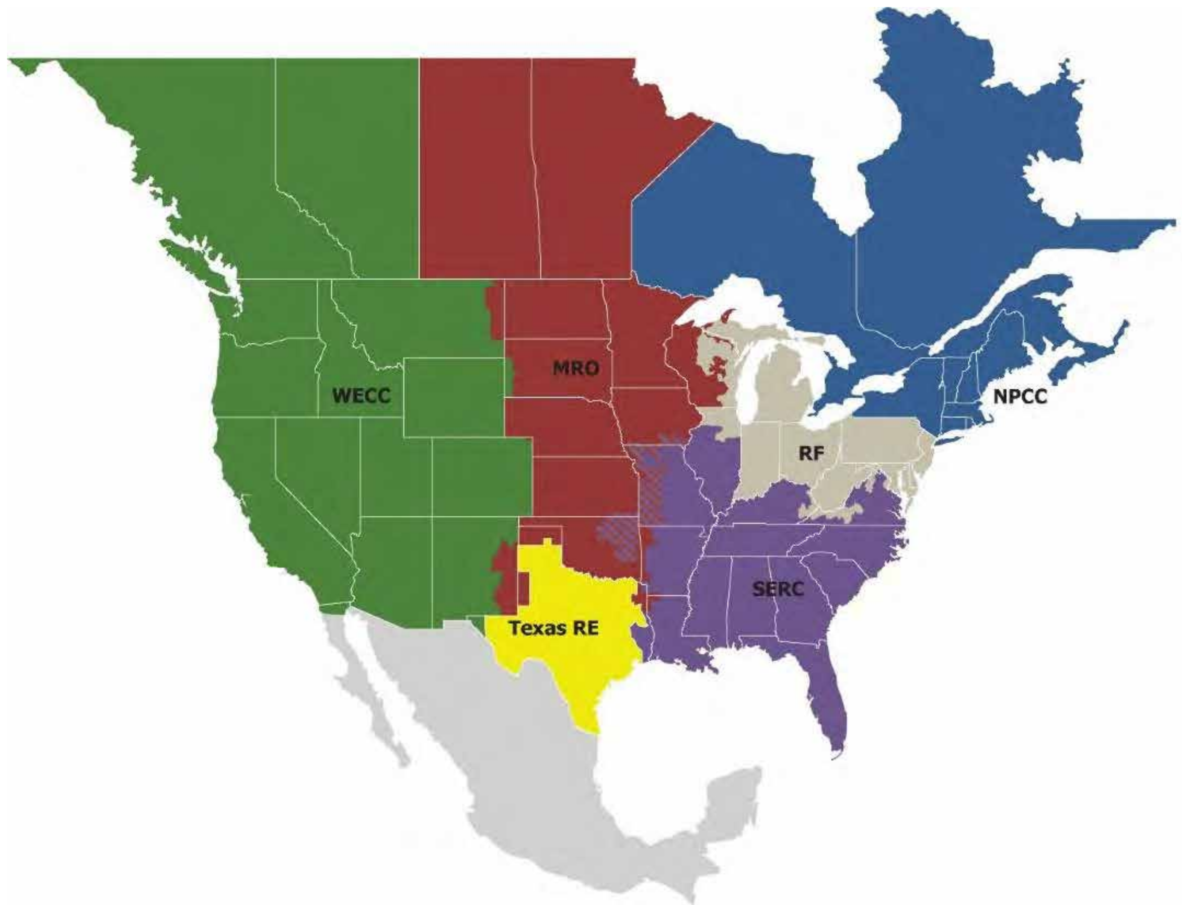
Preface

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

Reliability | Resilience | Security

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

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

About this Assessment

NERC's *2023 Summer Reliability Assessment* (*SRA*) identifies, assesses, and reports on areas of concern regarding the reliability of the North American BPS for the upcoming summer season. In addition, the *SRA* presents peak electricity demand and supply changes and highlights any unique regional challenges or expected conditions that might affect the reliability of the BPS. The reliability assessment process is a coordinated reliability evaluation between the NERC Reliability Assessment Subcommittee, the Regional Entities, and NERC staff with demand and resource projections obtained from the assessment areas. This report reflects an independent assessment by NERC and the ERO Enterprise and is intended to inform industry leaders, planners, operators, and regulatory bodies so that they are better prepared to take necessary actions to ensure BPS reliability. This report also provides an opportunity for the industry to discuss plans and preparations to ensure reliability for the upcoming summer period.

Key Findings

NERC's annual SRA covers the upcoming four-month (June–September) summer period. This assessment provides an evaluation of generation resource and transmission system adequacy as well as energy sufficiency to meet projected summer peak demands and operating reserves. This includes a deterministic evaluation of data submitted for peak net demand hour and peak risk hour as well as results from recently updated probabilistic analyses. Additionally, this assessment identifies potential reliability issues of interest and regional topics of concern. While the scope of this seasonal assessment is focused on the upcoming summer, the key findings are consistent with risks and issues that NERC has highlighted in the *2022 Long-Term Reliability Assessment* and other earlier reliability assessments and reports.

The following findings are NERC's and the ERO Enterprise's independent evaluation of electricity generation and transmission capacity as well as potential operational concerns that may need to be addressed for the 2023 summer.

Resource Adequacy Assessment and Energy Risk Analysis

All areas are assessed as having adequate anticipated resources for normal summer peak load and conditions (see **Figure 1**). However, the following areas face risks of electricity supply shortfalls during periods of more extreme summer conditions. This determination of elevated risk is based on analysis of plausible scenarios, including 90/10 demand forecasts and historic high outage rates as well as low wind, solar photovoltaic (PV), or hydro energy conditions:

- **Midcontinent ISO (MISO):** The risk of being unable to meet reserve requirements at peak demand this summer in MISO is lower than in 2022 due to additional firm import commitments and lower peak demand forecast. MISO is expected to have sufficient resources, including firm imports, for normal summer peak demand. Wind generator performance during periods of high demand is a key factor in determining whether there is sufficient electricity supply on the system to maintain reliability. MISO can face challenges in meeting above-normal peak demand if wind generator energy output is lower than expected. Furthermore, the need for external (non-firm) supply assistance during more extreme demand levels will depend largely on wind energy output. Results of MISO's capacity auction have not been released at the time of this assessment, and these could change MISO's firm resources for the summer.

- **NPCC-New England:** Anticipated resources in New England are projected to be lower than in 2022 but are expected to remain sufficient for meeting operating reserve requirements at normal peak demand. Operating procedures for obtaining emergency resources or non-firm supplies from neighboring areas are likely to be needed during more extreme demand or low resource conditions.

- **NPCC-Ontario:** Planned nuclear outage for refurbishment have reduced the electricity supply resources serving the province. Additionally, load growth is contributing to a constrained transmission network during high-demand conditions that may not be able to deliver sufficient supply to the Windsor-Essex area in the southwest part of the province. Additional generator outages or extreme demand can lead to reserve shortages and a need to seek non-firm imports. Ontario could potentially see a significant increase in reliance on imports this summer under both normal peak (50/50) and extreme (90/10) demand scenarios.

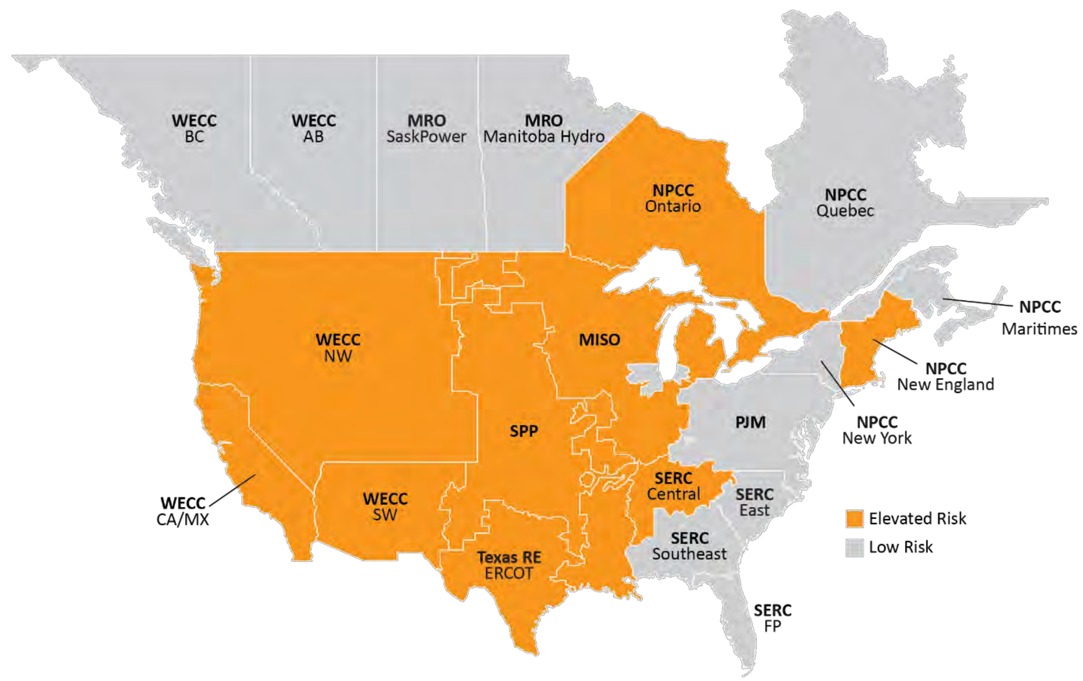
- **SERC-Central**: Compared to the summer of 2022, forecasted peak demand has risen by over 950 MW while growth in anticipated resources has been flat. The assessment area is expected to have sufficient supply for normal peak demand while demand-side management or other operating mitigations can be expected for above-normal demand or high generator-outage conditions.

- **Southwest Power Pool (SPP):** Reserve margins have also fallen in SPP as a result of increasing peak demand and declining anticipated resources. Like MISO, the energy output of SPP's wind generators during periods of high demand is a key factor in determining whether there is sufficient electricity supply on the system. SPP can face energy challenges in meeting extreme peak demand or managing periods of thermal or hydro generator outages if wind resource energy output is below normal.

- **Texas (ERCOT):** The area is experiencing strong growth in both resources and forecasted demand. ERCOT added over 4 GW of new solar PV nameplate capacity to the ERCOT grid since 2022. Additionally, load reductions from dispatchable demand response programs have grown by over 18% to total 3,380 MW. ERCOT's peak demand forecast has also risen by 6% as a result of economic growth. Resources are adequate for peak demand of the average summer; however, dispatchable generation may not be sufficient to meet reserves during an extreme heat-wave that is accompanied by low winds.

- **U.S. Western Interconnection:** Resources across the area are sufficient to support normal peak demand. However, wide-area heat events can expose the WECC assessment areas of California/Mexico (CA/MX), Northwest (NW), and Southwest (SW) to risk of energy supply shortfall as each area relies on regional transfers to meet demand at peak and the late afternoon to evening hours when energy output from the area's vast solar PV resources are diminished. Within the Western Interconnection, entities are planning to install over 2 GW of new battery energy storage systems, which can help reduce energy risks from resource variability. Wildfire risks to the transmission network, which often accompany these wide-area heat events, can limit electricity transfers and result in localized load shedding.

All other areas have sufficient resources to manage normal summer peak demand and are at low risk of energy shortfalls from more extreme demand or generation outage conditions. Anticipated Reserve Margins meet or surpass the Reference Margin Level, indicating that planned resources in these areas are adequate to manage the risk of a capacity deficiency under normal conditions. Furthermore, based on risk scenario analysis in these areas, resources and energy appear adequate. Figure 1 below summarizes the risk status for all assessment areas.



Seasonal Risk Assessment Summary	
High	Potential for insufficient operating reserves in normal peak conditions
Elevated	Potential for insufficient operating reserves in above-normal conditions
Low	Sufficient operating reserves expected

Figure 1: Summer Reliability Risk Area Summary

Other Reliability Issues

- **Stored supplies of natural gas and coal are at high levels, but industry is monitoring for potential generator fuel delivery risks.** The natural gas supply and infrastructure is vitally important to electric grid reliability, even as renewable generation satisfies more of our energy needs. Fuel supply and delivery infrastructure must be capable of meeting the ramp rates of natural-gas-fired generators as they balance the system when solar generation output declines. Likewise, owners and operators of some coal-fired generators in the U.S. Southeast report challenges in arranging coal replenishment due to mine closures and transport delays. Consequently, some Balancing Authorities (BA) continue to employ coal-conservation measures that began in late 2022 in order to maintain sufficient stocks for peak months.

- **New environmental rules that restrict power plant emissions will limit the operation of coal-fired generators in 23 states, including Nevada, Utah, and several states in the Gulf Coast, mid-Atlantic, and Midwest.** The U.S. Environmental Protection Agency's (EPA) Good Neighbor Plan, finalized on March 15, 2023, ensures that affected states meet the Clean Air Act's "Good Neighbor" requirements by reducing pollution that significantly contributes to problems attaining and maintaining the EPA's health-based air quality standard[1] for ground-level ozone (i.e., smog) in downwind states.[2] Coal and natural-gas-fired generators in states affected by the Good Neighbor Plan will likely meet tighter emissions restrictions primarily by limiting hours of operation in this first year of implementation rather than through adding emissions control equipment. RCs in summer-peaking areas typically are not able to authorize extended outages to upgrade systems during this summer season in order to ensure sufficient resources for high demand. The final rule approved by the EPA includes provisions designed to give grid owners and operators flexibility to help maintain reliability, including allowance-trading mechanisms. Consequently, RCs, BAs, and GOs will need to be vigilant for emissions rule constraints that affect generator dispatchability and the potential need for emission allowance trades or waivers to meet high demand or low resource conditions. State regulators and industry should have protocols in place at the start of summer for managing emergent requests.

- **Low inventories of replacement distribution transformers could slow restoration efforts following hurricanes and severe storms.** The electric industry continues to face a shortage of distribution transformers as a result of production not keeping pace with demand. A survey by the American Public Power Association revealed that many utilities have low levels of emergency stocks that are used for responding to natural disasters and catastrophic events.[3]

[1]This standard is known as the 2015 Ozone National Ambient Air Quality Standards (NAAQS)
[2]https://www.epa.gov/csapr/good-neighbor-plan-2015-ozone-naaqs#summary
[3]https://www.publicpower.org/periodical/article/appa-survey-members-shows-distribution-transformer-production-not-meeting-demand

Asset sharing programs used by utilities provide visibility and voluntary equipment sharing to maximize resources; however, electricity customers may experience delayed restoration of power following storms as crews must work to obtain new equipment. New efficiency standards for distribution transformers proposed by the U.S. Department of Energy could further exacerbate the transformer supply shortages.[4]

- **Supply chain issues present maintenance and summer preparedness challenges and are delaying some new resource additions.** Difficulties in obtaining sufficient labor, material, and equipment as a result of broad economic factors has affected preseason maintenance of transmission and generation facilities in North America. These supply chain issues have led some owners and operators to delay or cancel maintenance activities that are typically performed to ensure facilities are ready for summer conditions. Additionally, GOs in some areas that were preparing to interconnect new generation are facing delays that will prevent some from being available to meet expected peak summer demand. This includes areas in the U.S. Southeast and the U.S. part of the Western Interconnection (see **Regional Assessments Dashboards** for details). These supply chain issues can exacerbate concerns in elevated risk areas (**Figure 1**) and add challenges to operators across the BPS. Should project delays emerge, affected GOs and TOs must communicate changes to BAs, TOPs, and RCs so that impacts are understood and steps are taken to reduce risks of capacity deficiencies or energy shortfalls.
- **Winter precipitation is expected to improve the water supply for hydro generation in parts of the U.S. West, but low water levels on major reservoirs remain a concern for electricity generation.** Significant amounts of rainfall and high elevation snow are expected to help replenish reservoirs and maintain river flows that provide energy for most of California's hydroelectric facilities. However, reservoirs at the largest hydro facilities in the U.S. West, including Washington's Grand Coulee Dam and the Hoover Dam on the Arizona-Nevada border, remain at historic low levels, potentially limiting hydroelectric energy output. Power from these plants is used throughout the U.S. Western Interconnection.
- **Unexpected tripping of wind and solar PV resources during grid disturbances continues to be a reliability concern.** NERC has analyzed multiple large-scale disturbances on the BPS that involved widespread loss of inverter-based resources (IBR). In 2021 and 2022, the Texas Interconnection experienced widespread IBR loss events, like those previously observed in the California area. Similarly, four additional solar PV loss events occurred between June and August 2021 in California. In 2022, ERCOT required GOs to submit mitigation plans, and corrective measures are being implemented in 2023. In March 2023, NERC issued the *Inverter-Based Resource Performance Issues Alert* to GOs of Bulk Electric System (BES) solar PV generating resources.[5] As a Level 2 alert, it contains recommended actions for GOs of grid-connected solar PV resources, including steps to coordinate protection and controller settings, so that the resources will reliably operate during grid disturbances.
- **Curtailment of electricity transfers to areas in need during periods of high regional demand is a growing reliability concern.** During energy emergencies and periods of transmission system congestion, RCs and BAs may curtail area transfers for various reasons using established procedures and protocols. While the curtailments alleviate an issue in one part of the system, they can contribute to supply shortages or effect local transmission system operations in another area. Two recent extreme temperature events highlight the effect of transfer curtailments on area supply needs during energy emergencies. During the September 2022 wide-area heat dome, a BA in the WECC-SW assessment area declared an energy emergency when the neighboring assessment area, California Independent System Operator (CAISO), curtailed transfers in order to meet the high demand within their own area. During Winter Storm Elliott, firm exports were curtailed from PJM during a period of widespread energy emergencies in the U.S. Eastern Interconnection.

  For the summer of 2023, several areas identified as having capacity or energy risks are relying on imports of electricity supplies. These areas include MISO, NPCC-Ontario, SERC-Central, and the assessment areas in the U.S. Western Interconnection. A wide-area heat event that severely affects regional demand or generator availability presents an added concern in areas that are dependent on imports for managing high electricity demand.
- **In addition to the risk items identified in the Key Findings, resource outages will continue to present challenges in many areas during "near-peak" demand conditions that occur in spring and fall.** Many parts of North America experience elevated temperatures that extend beyond the summer (June–September) months into periods when BPS equipment owners and operators historically scheduled outages for maintenance. Increasingly, BAs are facing resource constrained periods during shoulder months as unseasonable temperatures coincide with generator unavailability. Careful attention to long-term weather forecasts and the potential for unusual heat patterns in the shoulder months is important to inform the need for more conservative outage coordination periods.

[4] https://www.energy.gov/articles/doe-proposes-new-efficiency-standards-distribution-transformers

[5] https://www.nerc.com/pa/rrm/bpsa/Alerts%20DL/NERC%20Alert%20R-2023-03-14-01%20Level%202%20-%20Inverter-Based%20Resource%20Performance%20Issues.pdf

Recommendations

To reduce the risk of electricity shortfalls on the BPS this summer, NERC recommends the following:

- RCs, BAs, and TOPs in the elevated risk areas identified previously in the key findings should take the following actions:
  - Review seasonal operating plans and the protocols for communicating and resolving potential supply shortfalls in anticipation of potentially extreme demand levels
  - Employ conservative generation and transmission outage coordination procedures commensurate with long-range weather forecasts to ensure adequate resource availability
  - Engage state or provincial regulators and policymakers to prepare for efficient implementation of demand side management mechanisms called for in operating plans
- GOs with solar PV resources should implement recommendations in the inverter-based resource performance issues alert that NERC issued in March 2023.
- RCs, BAs, and GOs in states affected by the new Good Neighbor Plan should be familiar with its provisions for ensuring electric reliability and have protocols in place to act to preserve generation resources when necessary to support periods of high demand. State regulators and industry should have protocols in place at the start of summer for managing emergent requests.

Discussion

Summer Temperature and Drought Forecasts

Peak electricity demand in most areas is directly influenced by temperature. Weather officials are expecting above normal temperatures for much of the United States while Canada is largely expected to see normal or below-normal average temperatures (see Figure 2). In addition, drought conditions continue across much of the western half of North America, resulting in unique challenges to area electricity supplies and potential impacts on demand.[6] Assessment area load forecasts account for many years of historical demand data, often up to 30 years, to predict summer peak demand and prepare for more extreme conditions. Above average seasonal temperatures can contribute to high peak demand as well as an increase in forced outages for generation and some BPS equipment. Effective preseason maintenance and preparations are particularly important to BPS reliability in severe or prolonged periods of above-normal temperatures.

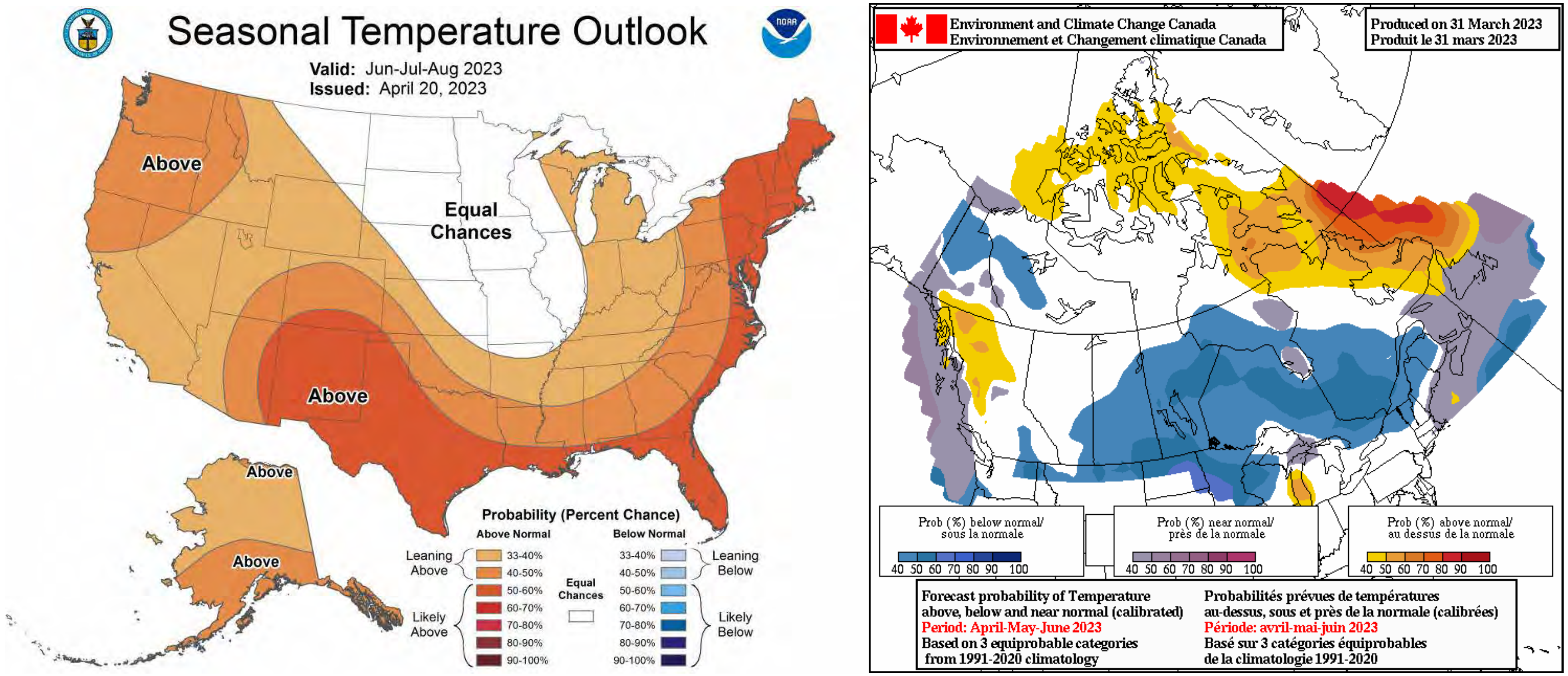


Figure 2: United States and Canada Summer Temperature Outlook[7]

[6] See North American Drought Monitor: https://www.ncdc.noaa.gov/temp-and-precip/drought/nadm/maps

[7] Seasonal forecasts obtained from U.S. National Weather Service and Natural Resources Canada: https://www.cpc.ncep.noaa.gov/products/predictions/long_range/ and https://weather.gc.ca/saisons/prob_e.html

Wildfire Risk Potential and BPS Impacts

Normal or below-normal fire risk is projected for much of the U.S. West at the beginning of the summer; in contrast, Florida, West Texas, and Central Canada project above-normal fire risks for the beginning of summer (see Figure 3). BPS operation can be impacted in areas where wildfires are active as well as areas where there is heightened risk of wildfire ignition due to weather and ground conditions. Above normal fire risk is projected for much of Canada throughout the summer.

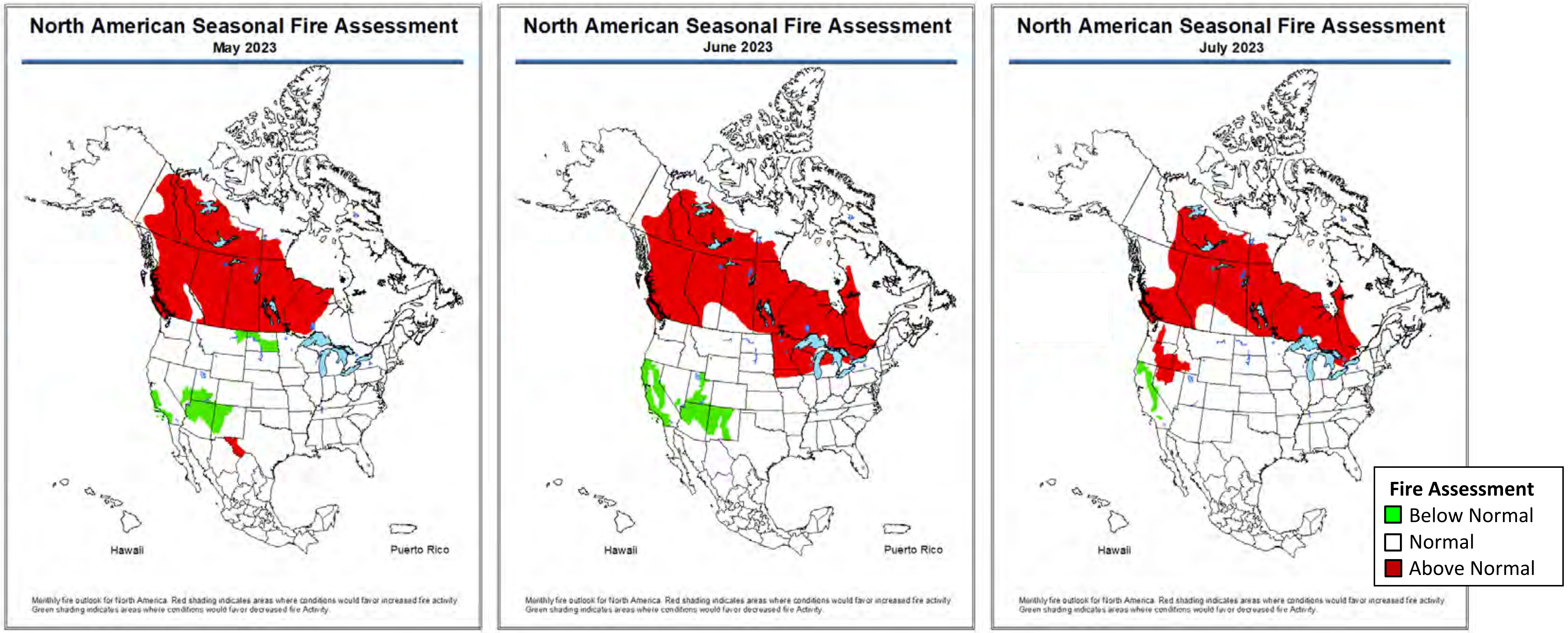


Figure 3: North American Seasonal Fire Assessment for May through July 2023[8]

Wildfire prevention planning in California and some states in the U.S. Northwest include power shut-off programs in high fire-risk areas. When conditions warrant implementing these plans, power lines (including transmission-level lines) may be preemptively de-energized in high fire-risk areas to prevent wildfire ignitions. Other wildfire risk mitigation activities include implementing enhanced vegetation management, equipment inspections, system hardening, and added situational awareness measures. In January 2021, the ERO published the *Wildfire Mitigation Reference Guide*[9] to promote preparedness within the North American electric power industry and share the experiences and practices from utilities in the Western Interconnection.

---

[8] *See North American Seasonal Fire Assessment and Outlook*, May 2023. Subsequent updates at this link will include August and September: https://www.predictiveservices.nifc.gov/outlooks/NA_Outlook.pdf

[9] See the NERC *Wildfire Mitigation Reference Guide*, January 2021: https://nerc.com/comm/RSTC/Documents/Wildfire%20Mitigation%20Reference%20Guide_January_2021.pdf

Risk Assessments of Resource and Demand Scenarios

Seasonal risk scenarios for each assessment area are presented in the **Regional Assessments Dashboards** section. The on-peak reserve margin and seasonal risk scenario chart in each dashboard provide potential summer peak demand and resource condition information. The reserve margins on the right side of the dashboard pages provide a comparison to the previous year's assessment. The seasonal risk scenario charts present deterministic scenarios for further analysis of different demand and resource levels with adjustments for normal and extreme conditions. The assessment areas determined the adjustments to capacity and peak demand based on methods or assumptions that are summarized in the seasonal risk scenario charts; see the **Data Concepts and Assumptions** for more information about these dashboard charts.

The seasonal risk scenario charts can be expressed in terms of reserve margins: In **Table 1**, each assessment area's Anticipated Reserve Margins are shown alongside the reserve margins for a typical generation outage scenario (where applicable) and the extreme demand and resource conditions in their seasonal risk scenario.

Highlighted in orange are the areas identified as having resource adequacy or energy risks for the summer in the **Key Findings** section's discussion. The typical outages reserve margin is comprised of anticipated resources minus the capacity that is likely to be in maintenance or forced outage at peak demand. If the typical maintenance or forced outage margin is the same as the Anticipated Reserve Margin, it is because an assessment area has already factored typical outages into the anticipated resources. The extreme conditions margin includes all components of the scenario and represents the most severe operating conditions of an area's scenario. Note that any reserve margin below zero indicates that the resources fall below demand in the scenario.

In addition to the peak demand and seasonal risk hour scenario charts, the assessment areas provided a resource adequacy risk assessment that was probability-based for the summer season. Results are included in the Highlights section of each assessment area's dashboard and summarized in the **Probabilistic Assessment** section. The risk assessments account for the hour(s) of greatest risk of resource shortfall. For most areas, the hour(s) of risk coincide with the time of forecasted peak demand; however, some areas incur the greatest risk at other times based on the varying demand and resource profiles. Various risk metrics are provided and include loss of load expectation (LOLE), loss of load hours (LOLH), expected unserved energy (EUE), and the probabilities of energy emergency alert (EEA) occurrence.

Table 1: Seasonal Risk Scenario On-Peak Reserve Margins

Assessment Area	Anticipated Reserve Margin	Anticipated Reserve Margin with Typical Outages	Anticipated Reserve Margin with Higher Demand, Outages, Derates in Extreme Conditions
MISO	23.0%	4.3%	-6.9%
MRO-Manitoba	29.1%	25.6%	13.1%
MRO-SaskPower	29.1%	12.8%	-1.9%
NPCC-Maritimes	49.7%	39.3%	20.2%
NPCC-New England	17.7%	7.0%	-3.9%
NPCC-New York	30.3%	17.0%	9.9%
NPCC-Ontario	14.0%	14.0%	8.6%
NPCC-Québec	37.1%	37.1%	37.1%
PJM	31.9%	23.4%	8.4%
SERC-Central	18.0%	9.6%	6.4%
SERC-East	19.1%	16.0%	9.0%
SERC-Florida Peninsula	26.6%	19.9%	12.8%
SERC-Southeast	39.6%	36.4%	33.8%
SPP	24.6%	14.3%	-4.0%
Texas RE-ERCOT	23.0%	16.5%	-1.6%
WECC-AB	24.8%	21.9%	8.1%
WECC-BC	28.9%	28.8%	-5.4%
WECC-CA/MX	35.0%	29.0%	-11.9%
WECC-NW	28.5%	22.5%	-12.9%
WECC-SW	19.5%	15.8%	-6.8%

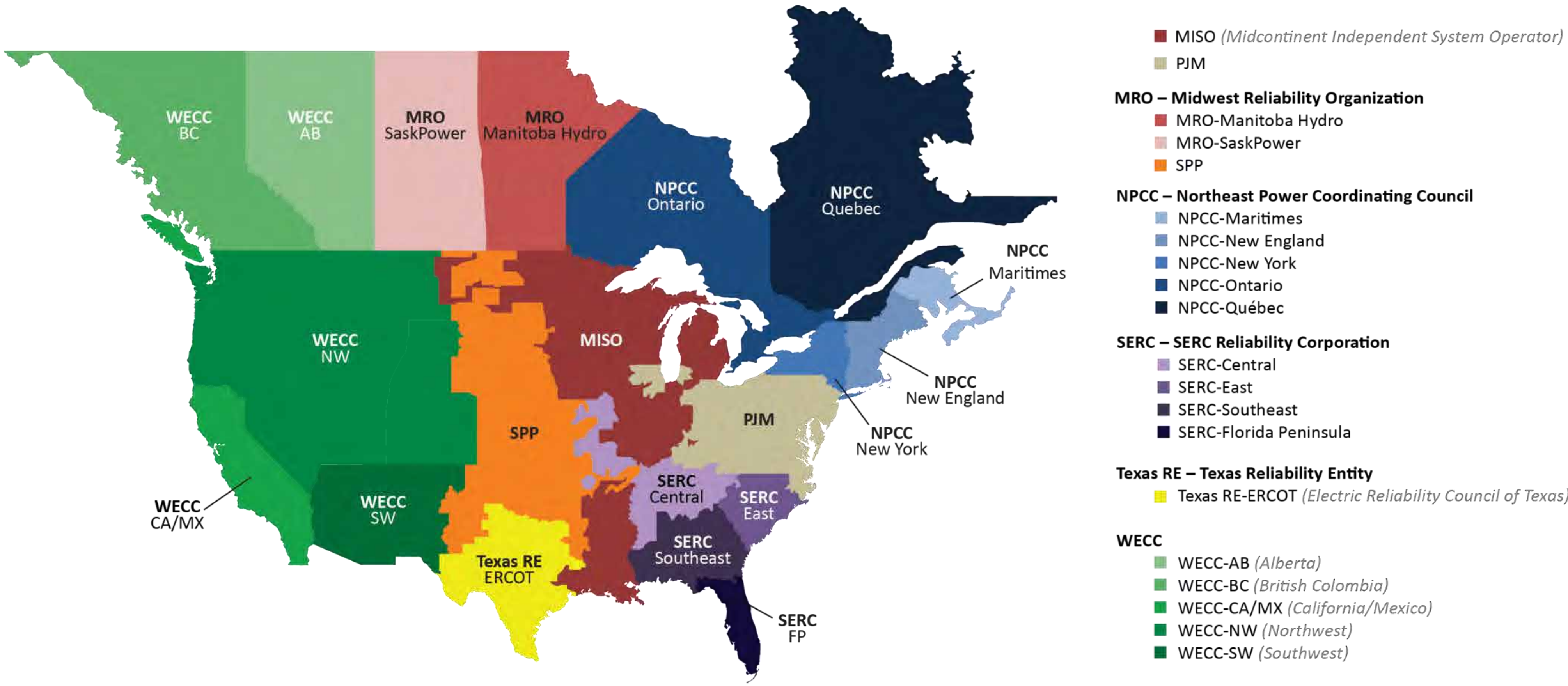
Extreme generation outages, low resource output, and peak loads similar to those experienced in wide area heat events and the heat domes experienced in western parts of North America during the last three summers are ongoing reliability risks in certain areas for the summer of 2023. When forecasted resources in an area fall below expected demand, BAs would need to employ operating mitigations or EEA to obtain the capacity and energy necessary to meet extreme peak demands. **Table 2** describes the various EEA levels and the circumstances for each.

Table 2: Energy Emergency Alert Levels

EEA Level	Description	Circumstances
EEA 1	All available generation resources in use	• The BA is experiencing conditions where all available generation resources are committed to meet firm load, firm transactions, and reserve commitments and is concerned about sustaining its required contingency reserves. • Non-firm wholesale energy sales (other than those that are recallable to meet reserve requirements) have been curtailed.
EEA 2	Load management procedures in effect	• The BA is no longer able to provide its expected energy requirements and is an energy deficient BA. • An energy deficient BA has implemented its operating plan(s) to mitigate emergencies. • An energy deficient BA is still able to maintain minimum contingency reserve requirements.
EEA 3	Firm Load interruption is imminent or in progress	• The energy deficient BA is unable to meet minimum contingency reserve requirements.

Regional Assessments Dashboards

The following assessment area dashboards and summaries were developed based on data and narrative information collected by NERC from the six Regional Entities on an assessment area basis. Guidelines and definitions are in the **Data Concepts and Assumptions** table. On-Peak Reserve Margin bar charts show the Anticipated Reserve Margin compared to a Reference Margin Level that is established for the areas to meet resource adequacy criteria. Prospective Reserve Margins can give an indication of additional on-peak capacity but are not used for assessing adequacy. The operational risk analysis shown in the following regional assessments dashboard pages provides a deterministic scenario for understanding how various factors that affect resources and demand can combine to impact overall resource adequacy. For each assessment area, there is a risk-period scenario graphic; the left blue column shows anticipated resources (from the **Demand and Resource Tables**), and the two orange columns at the right show the two demand scenarios of the normal peak net internal demand (from the **Demand and Resource Tables**) and the extreme summer peak demand determined by the assessment area. The middle red or green bars show adjustments that are applied cumulatively to the anticipated resources. Adjustments may include reductions for typical generation outages (maintenance and forced not already accounted for in anticipated resources) and additions that represent the quantified capacity from operational tools (if any) that are available during scarcity conditions but have not been accounted for in the SRA reserve margins. Resources throughout the scenario are compared against expected operating reserve requirements that are based on peak load and normal weather. The cumulative effects from extreme events are also factored in through additional resource derates or low-output scenarios. In addition, results from a probability-based resource adequacy assessment are shown in the Highlights section of each dashboard. Methods varied by assessment area and provided further insights into the risk conditions forecasted for the summer period.



MISO

MISO is a not-for profit, member-based organization that administers wholesale electricity markets that provide customers with valued service; reliable, cost-effective systems and operations; dependable and transparent prices; open access to markets; and planning for long-term efficiency. MISO manages energy, reliability, and operating reserve markets that consist of 36 local BA and 394 market participants, serving approximately 42 million customers. Although parts of MISO fall in three Regional Entities, MRO is responsible for coordinating data and information submitted for NERC's reliability assessments.

Highlights

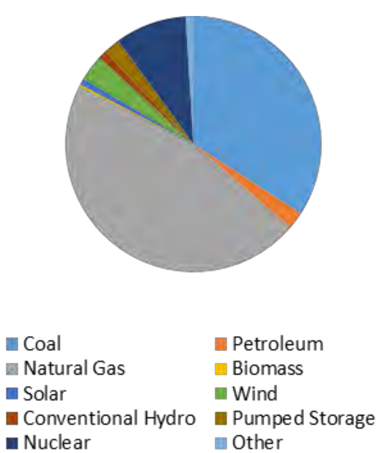
- Demand forecasts and preliminary resource data indicate that MISO is at risk of operating reserve shortfalls during periods of high demand or low resource output. MISO's resources are projected to be lower than in the summer of 2022 while net internal demand has also decreased. Firm transmission imports for this summer have significantly increased; this has resulted in a higher Anticipated Reserve Margin (ARM) of 23% (on an installed capacity basis) compared to 21% last summer. MISO's capacity auction has not concluded at the time of this assessment, which could lead to some change to MISO's firm resources for the summer.
- MISO conducted its annual probabilistic LOLE analysis and determined a 2023 Reference Margin Level (RML) of 15.9% results in an LOLE of 1 day in 10 years. MISO's RML declined from 17.9% in 2022 to 15.9% in 2023 based on the newly implemented seasonal capacity construct and associated modeling improvements that include seasonal outage rates and other enhancements. Comparing the increased ARM to the lower RML indicates improved reliability from the LOLE base case at 1 day in 10 years.
- Performance of wind generators during periods of high electricity demand is a key factor in determining whether system operators need to employ operating mitigations, such as maximum-generation declarations and energy emergencies. MISO has over 30,300 MW of installed wind capacity; however, the historically-based on-peak capacity contribution is 5,488 MW.

Risk Scenario Summary

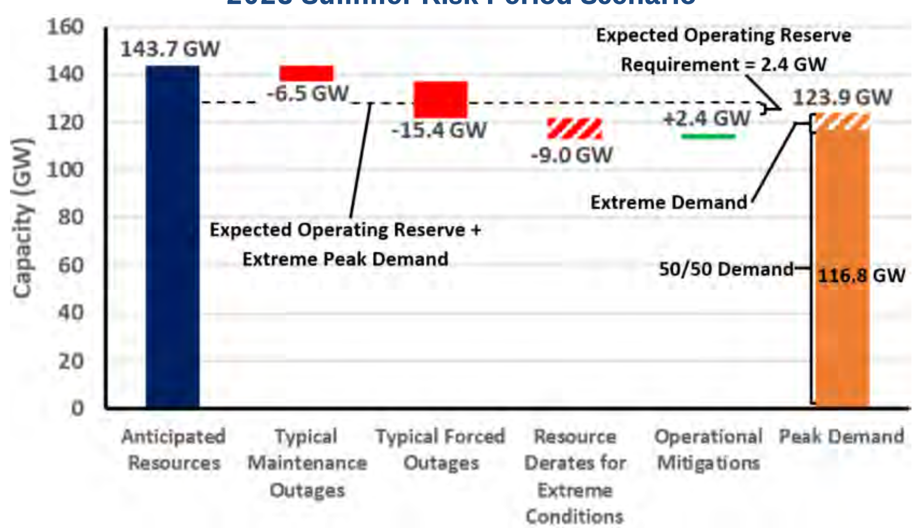
Expected resources meet operating reserve requirements under normal peak-demand scenarios. Above-normal summer peak load and outage conditions could result in the need to employ operating mitigations (i.e., load modifying resources and energy transfers from neighboring systems) and EEAs. Emergency declarations that can only be called upon when available generation is at maximum capability are necessary to access load modifying resources (demand response) when operating reserve shortfalls are projected.

On-Peak Reserve Margin

On-Peak Fuel Mix



2023 Summer Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: Net internal demand (50/50) and (90/10) demand forecast using 30 years of historical data

Maintenance Outages: Rolling five-year summer average of maintenance and planned outages

Forced Outages: Five-year average of all outages that were not planned

Extreme Derates: Maximum historical generation outages

Operational Mitigations: A total of 2.4 GW capacity resources available during extreme operating conditions

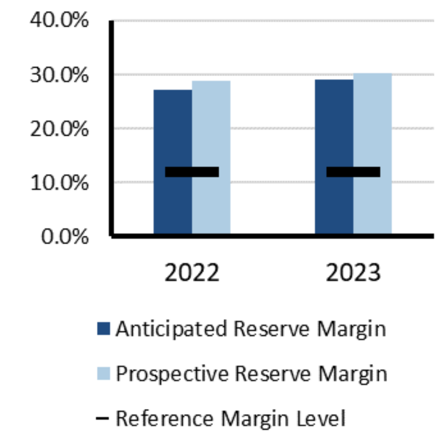
MRO-Manitoba Hydro

Manitoba Hydro is a provincial Crown Corporation and one of the largest integrated electricity and natural gas distribution utilities in Canada. Manitoba Hydro is a leader in providing renewable energy and clean-burning natural gas Manitoba Hydro provides electricity to approximately 608,500 electric customers in Manitoba and provides approximately 293,000 customers with natural gas in Southern Manitoba. The service area is the province of Manitoba which is 251,000 square miles Manitoba Hydro is winter peaking. Manitoba Hydro is its own Planning Coordinator (PC) and BA. Manitoba Hydro is a coordinating member of MISO. MISO is the RC for Manitoba Hydro.

Highlights

- Manitoba Hydro is not anticipating any operational challenges and/or emerging reliability issues in its assessment area for the summer of 2023.
- The Anticipated Reserve Margin for the summer of 2023 exceeds the 12% Reference Margin Level.
- Six of the seven units at Keeyask Generating Station (hydroelectric) have reached commercial operation status. The remaining unit (Keeyask Unit 6) is listed as a Tier 1 capacity resource as it is operating but awaiting official commercial operation status.
- The 2022 probabilistic work indicated the annual probabilistic indices for the Manitoba Hydro system for 2024 of 29 MWh per year of EUE. Given comparable supply and demand balance, the 2024 EUE is a reasonable estimate for all of 2023.

On-Peak Reserve Margin



Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed scenarios.

On-Peak Fuel Mix

2023 Summer Risk Period Scenario

Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: (50/50) Demand with allowance for Extreme Demand based on extreme summer weather scenario of 37 C (99 F)

Forced Outages: Typical forced outages

Extreme Derates: Summer wind capacity accreditation of 18.1% of nameplate rating based on MISO seasonal analysis

Normal hydro generation expected for this summer.

Operational Mitigations: Utilize Curtailable Rate Program to manage peak demand; utilize operating reserve if additional measures required

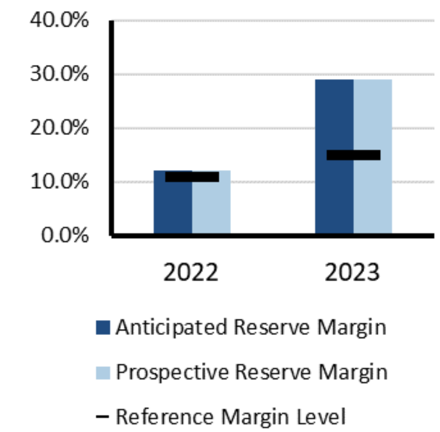
MRO-SaskPower

MRO-SaskPower is an assessment area in the Saskatchewan province of Canada. The province has a geographic area of 651,900 square kilometers (251,700 square miles) and a population of approximately 1.1 million. Peak demand is experienced in the winter. The Saskatchewan Power Corporation (SaskPower) is the PC and RC for the province of Saskatchewan and is the principal supplier of electricity in the province. SaskPower is a provincial crown corporation and, under provincial legislation, is responsible for the reliability oversight of the Saskatchewan BES and its Interconnections.

Highlights

- Summer reserve margins in Saskatchewan are higher than in 2022 due to the addition of new wind resources, fewer scheduled generator outages, and lower forecasted peak demand.
- Saskatchewan is a winter-peaking region but also experiences high load in summer during extreme hot weather.
- SaskPower conducts an annual summer joint operating study with Manitoba Hydro and prepares operating guidelines for any identified issues. Inputs from the Western Area Power Administration are included in the study.
- Results from SaskPower's probabilistic analysis indicate that the expected number of hours with operating reserve deficiency for the 2023 summer season (June to September) is 0.21 hours. The month with the highest probability of EEA is September (0.07 hours). The risk of operating reserve shortage during peak load times or EEAs could increase if large generation forced outage combined with planned maintenance outages occurs during peak load times in June, July, August, and September months.
- In case of extreme electricity demand from high temperatures combined with large generation forced outages, SaskPower would use available demand response programs, short-term power transfers from neighboring utilities, and short-term load interruptions if necessary.
- The Reference Reserve Margin was updated to adequately assess energy risks, such as due to changing resource mix, and to align with NERC recommended RRM.

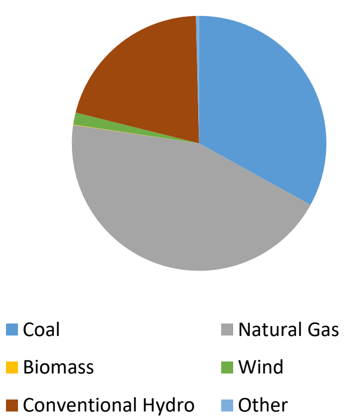
On-Peak Reserve Margin



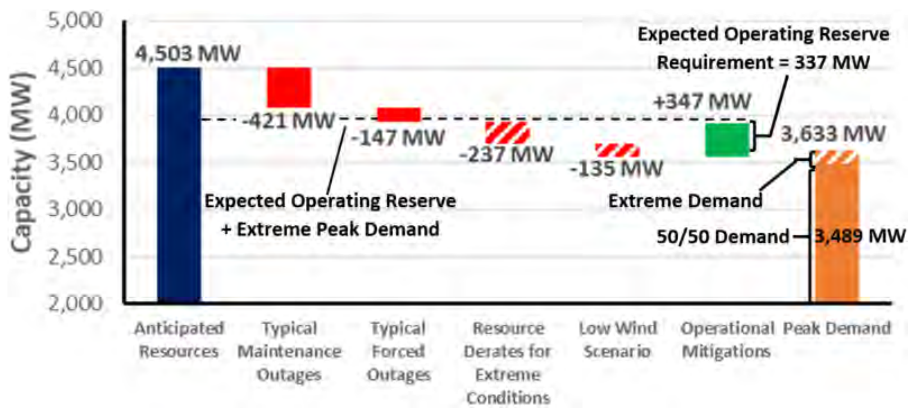
Risk Scenario Summary

Expected resources meet operating reserve requirements under normal peak-demand scenarios. Above-normal summer peak load and outage conditions could result in the need to employ operating mitigations (i.e., demand response and transfers) and EEAs.

On-Peak Fuel Mix



2023 Summer Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: Net internal demand (50/50) and above-normal scenario based on peak demand with lighting and all consumer loads

Maintenance Outages: Average of planned maintenance outages for the last three summers less future planned outages (already considered in Anticipated Resources)

Forced Outages: Estimated by using SaskPower forced outage model

Extreme Derates: Estimated resources unavailable in extreme conditions

Low Wind Scenario: 33% reduction in nameplate capacity for temperatures between 35° C and 40° C

Operational Mitigations: Estimated non-firm imports and stand-by generators on 2–7 day notice

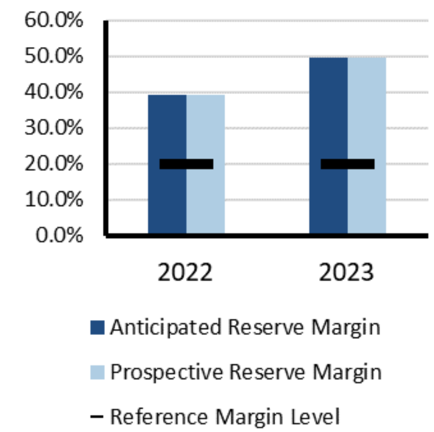
NPCC-Maritimes

The Maritimes assessment area is a winter-peaking NPCC area that contains two BAs. It is comprised of the Canadian provinces of New Brunswick, Nova Scotia, and Prince Edward Island, and the northern portion of Maine, which is radially connected to the New Brunswick power system. The area covers 58,000 square miles with a total population of 1.9 million.

Highlights

- The Maritimes area has not identified any operational issues that are expected to impact system reliability. If an event were to occur, there are emergency operations and planning procedures in place. All of the area's declared firm capacity is expected to be operational for the summer. As part of the planning process, dual-fuel units will have sufficient supplies of heavy fuel oil on-site to enable sustained operation in the event of natural gas supply interruptions.
- Based on an NPCC Probabilistic Assessment, minimal amounts of cumulative LOLE (<0.03 days/period), LOLH (<0.11 hours/period), or EUE (<5 MWh/period) were estimated over the May–September summer period for all modeled scenarios. The Maritimes area is winter peaking. The analysis included simulation of a base case (normal 50/50 demand and expected resources) and a highest peak load scenario as well as a low-likelihood, reduced resource case. This reduced resource case considered the impacts of wind capacity being derated by half during July and August due to calm weather, natural-gas-fired units being derated by half in July and August due to supply disruptions (dual-fuel units assumed to revert to oil) as well as reduced transfer capabilities. The highest load level results were based on the two highest load levels of the seven modeled, having approximately a combined 7% chance of occurring.

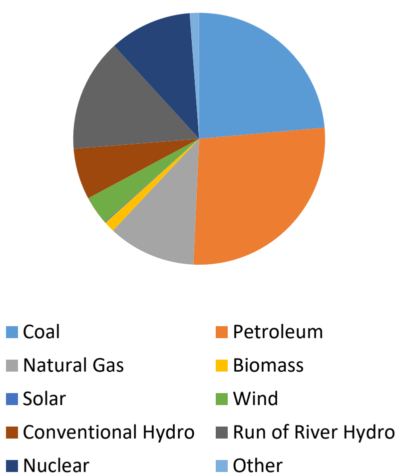
On-Peak Reserve Margin



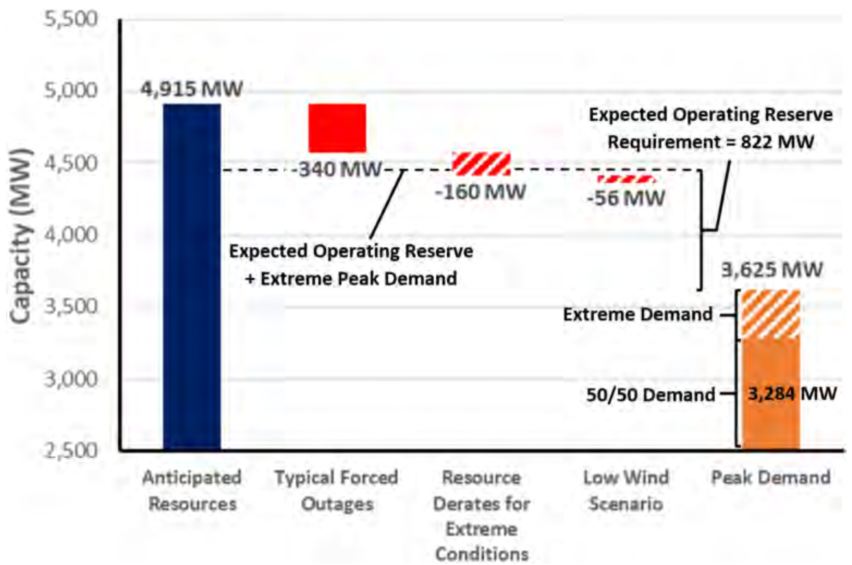
Risk Scenario Summary

Expected resources meet operating reserve requirements under normal peak-demand scenarios. Above-normal summer peak load and outage conditions could result in the need to employ operating mitigations (i.e., demand response and transfers) and EEAs.

On-Peak Fuel Mix



2023 Summer Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: Net internal demand (50/50) and (above 90/10) extreme demand forecast

Forced Outages: Based on historical operating experience

Extreme Derates: A low-likelihood scenario resulting in an additional 50% derate in the remaining capacity of both natural gas and wind resources under extreme conditions

NPCC-New England

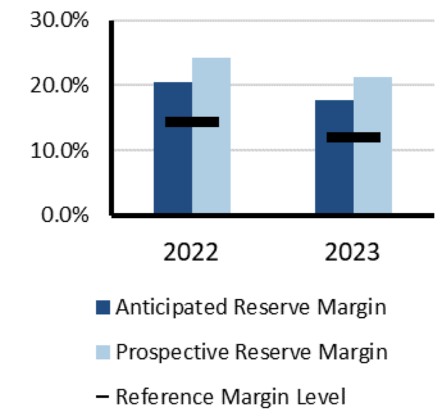
NPCC-New England is an assessment area consisting of the states of Connecticut, Maine, Massachusetts, New Hampshire, Rhode Island, and Vermont that is served by ISO New England (ISO-NE) Inc. ISO-NE is a regional transmission organization that is responsible for the reliable day-to-day operation of New England's bulk power generation and transmission system, administration of the area's wholesale electricity markets, and management of the comprehensive planning of the regional BPS.

The New England BPS serves approximately 14.5 million customers over 68,000 square miles.

Highlights

- Reserve margins in New England are projected to be lower this summer due to less existing-certain capacity and firm imports. The New England area expects to have sufficient capacity to meet the 2023 summer peak demand forecast. As of April 4, 2023, The New England area expects to have sufficient resources to meet the 2023 summer peak demand forecast of 24,664 MW, for the weeks beginning June 4 through week beginning September 10, 2023, with the lowest projected net margin of 231 MW (0.9%) during the week of June 25, 2023. The 2023 summer demand forecast takes into account the demand reductions associated with energy efficiency, load management, behind-the-meter photovoltaic (BTM-PV) systems, and distributed generation.
- Based on an NPCC Probabilistic Assessment, ISO-NE may rely on limited use of its operating procedures that are designed to mitigate resource and energy shortages during the summer. Negligible cumulative LOLE, LOLH, and EUE risks were estimated over the summer period for all modeled scenarios except the severe low-likelihood case. This reduced resource case with the highest peak load scenario resulted in a small estimated cumulative LOLE risk (0.12 days/period) with associated LOLHs (0.4 hours/period) and EUE (175 MWh/period) with the highest risk occurring in June. This scenario is based exclusively on the two highest load levels with a 7% chance of occurring and a low resource case consisting of extended summer maintenance across NPCC and reduced imports from PJM.

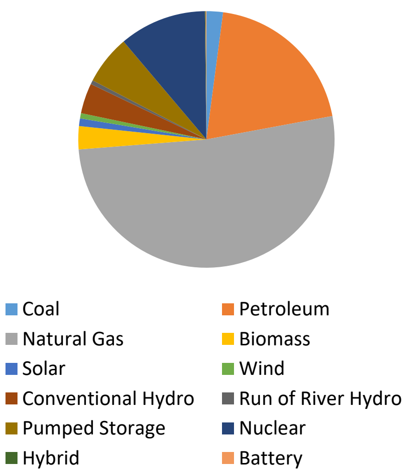
On-Peak Reserve Margin



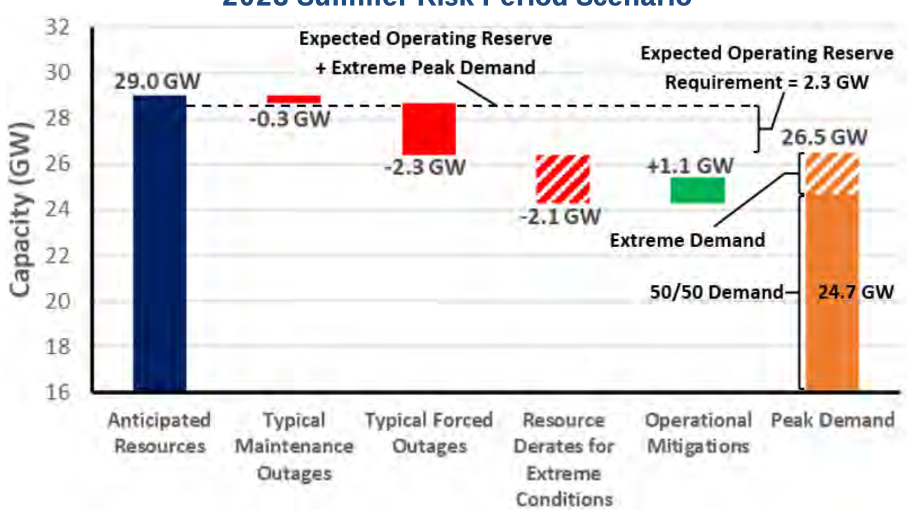
Risk Scenario Summary

Expected resources meet operating reserve requirements under normal peak-demand scenarios with local operating procedures. Extreme summer peak load and outage conditions could result in the need to employ operating mitigations (i.e., demand response, transfers, appeals) and EEAs. As noted above, the risk of load shedding is low.

On-Peak Fuel Mix



2023 Summer Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: Peak net internal demand (50/50) and (90/10) extreme demand forecast

Maintenance & Forced Outages: Based on historical weekly averages

Extreme Derates: Represent a case that is beyond the (90/10) conditions based on historical observation of force outages, additional reductions for generation at risk due to operating issues at extreme hot temperatures, and other outage causes reported by generators

Operational Mitigations: Based on load and capacity relief assumed available from invocation of ISO-NE operating procedures

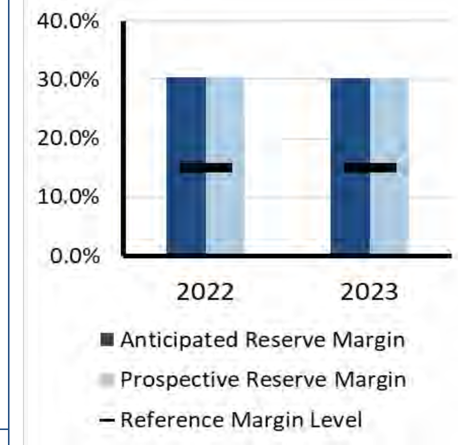
NPCC-New York

NPCC-New York is an assessment area consisting of the New York ISO (NYISO) service territory. 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 BPS encompasses over 11,000 miles of transmission lines, 760 power generation units, and serves 20.2 million customers. For this SRA, the established Reference Margin Level is 15%. Wind, grid-connected solar PV, and run-of-river totals were derated for this calculation. However, New York requires load-serving entities to procure capacity for their loads equal to their peak demand plus an Installed Reserve Margin (IRM). The IRM requirement represents a percentage of capacity above peak load forecast and is approved annually by the New York State Reliability Council. New York State Reliability Council approved the 2022–2023 IRM at 20.0%.

Highlights

- NYISO is not anticipating any operational issues in the New York control area for the upcoming summer. Adequate capacity margins are anticipated, and existing operating procedures are sufficient to handle any issues that may occur.
- A number of combustion turbine generators will be retiring before or during this summer as a result of the New York State Department of Environmental Conservation Peaker Rule. Retirements in 2023 include 16 MW of natural-gas-fired, 53 MW of oil-fired, and 558 MW of dual-fueled generation. New generation includes 556 MW of land-based wind, 90 MW of new solar PV (coming in the third quarter), and 136 MW of new offshore wind generation (coming in the third quarter). Overall, the rule is expected to lead to the retirement of approximately 1,600 MW of capacity by 2025.
- Based on an NPCC Probabilistic Assessment, NYISO may rely on limited use of its operating procedures that are designed to mitigate resource and energy shortages during the summer. Negligible cumulative LOLE, LOLH, and EUE risks were estimated over the summer period for all modeled scenarios except the severe low-likelihood case. This reduced resource case with highest peak load scenario resulted in a small estimated cumulative LOLE risk (0.5 days/period) with associated LOLH (1.1 hours/period) and EUE (525 MWh/period) with the highest risk in June and August. This scenario is based exclusively on the two highest load levels with a 7% chance of occurring and a low resource case consisting of extended summer maintenance across NPCC and reduced imports from PJM.

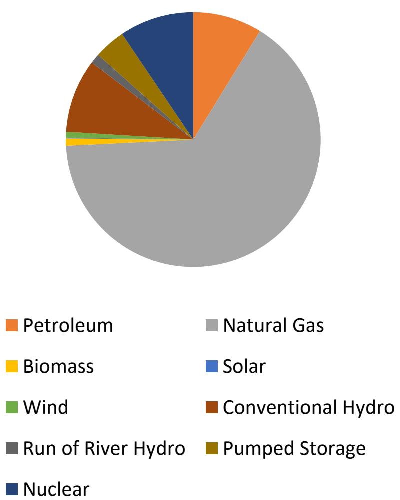
On-Peak Reserve Margin



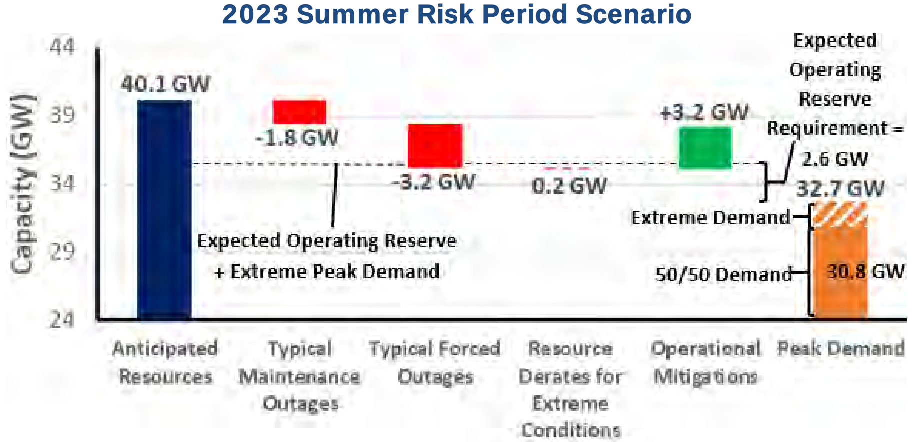
Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed scenarios.

On-Peak Fuel Mix



2023 Summer Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: Net internal demand (50/50) and (90/10) extreme demand forecast

Maintenance Outages:

Forced Outages: Based on historical 5-year averages

Extreme Derates: Estimated resources unavailable in extreme conditions

Operational Mitigations: A total of 3.3 GW based on operational/emergency procedures in area emergency operations manual

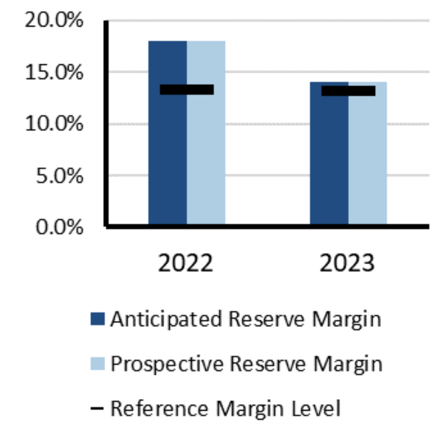
NPCC-Ontario

NPCC-Ontario is an assessment area in the Ontario province of Canada. The Independent Electricity System Operator (IESO) is the BA for the province of Ontario. The province of Ontario covers more than 1 million square kilometers (415,000 square miles) and has a population of more than 14 million. Ontario is interconnected electrically with Québec, MRO-Manitoba, states in MISO (Minnesota and Michigan), and NPCC-New York.

Highlights

- Ontario has entered a period during which generation and transmission outages will be increasingly difficult to accommodate. The IESO expects these conditions to persist for the foreseeable future. IESO is strongly encouraging market participants to plan ahead and coordinate with IESO to ensure planned outages can be appropriately scheduled.
- Under both normal and extreme weather conditions, Ontario may rely on imports and outage management for a significant number of weeks during the 2023 summer assessment period primarily as a result of coincident generator outages. Should market participants be unable to reschedule certain outages during this period, Ontario may have to rely on more than 2,000 MW of non-firm supply from other areas and/or additional operating actions to ensure reliability.
- Based on an NPCC Probabilistic Assessment, Ontario is expected to need only limited use of its operating procedures that are designed to mitigate resource and energy shortages during the summer. Negligible cumulative LOLE, LOLH, and EUE risks were estimated over the summer period for all modeled scenarios except the severe low-likelihood cases, which resulted in small LOLH (0.3 hours). These results model import availability and indicate that Ontario will be able to obtain the necessary supplies from neighbors over a range of most conditions, but there is a risk during extreme demand and low resource periods.
- The ongoing transmission outage at the New York–St. Lawrence interconnection continues to impact import and export capacity between Ontario and New York. This issue is expected to be resolved by the end of the fourth quarter of 2023.

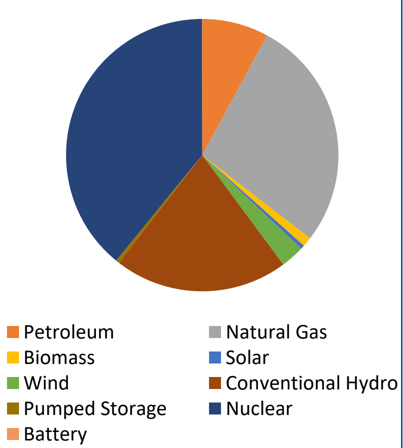
On-Peak Reserve Margin



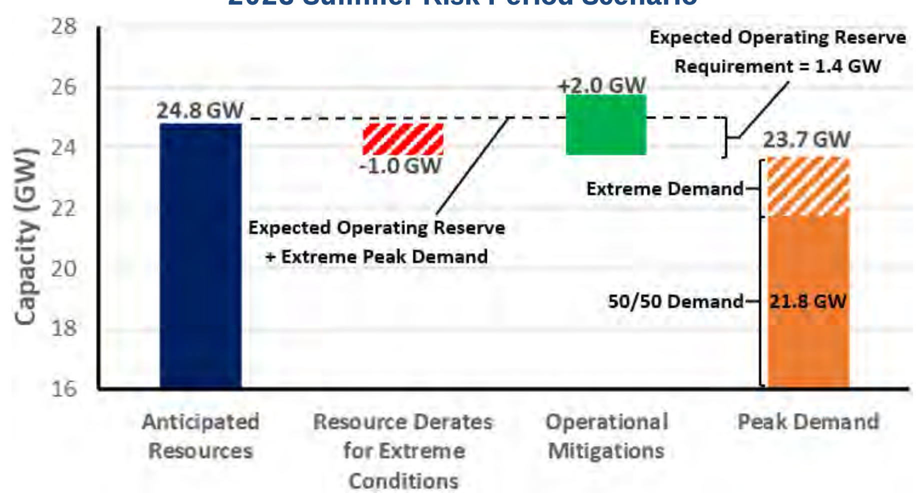
Risk Scenario Summary

Expected resources meet operating reserve requirements under normal peak-demand scenarios. Above-normal summer peak load or extreme outage conditions could result in the need to employ operating mitigations (i.e., demand response and non-firm transfers) and EEAs. Load shedding may be needed under extreme peak demand and outage scenarios.

On-Peak Fuel Mix



2023 Summer Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: Net internal demand (50/50 Forecast) and highest weather-adjusted daily demand based on 31 years of demand history

Extreme Derates: Derived from weather-adjusted temperature rating of thermal units and adjustments to expected hydro production for low water conditions

Operational Mitigations: Imports anticipated from neighbors during emergencies

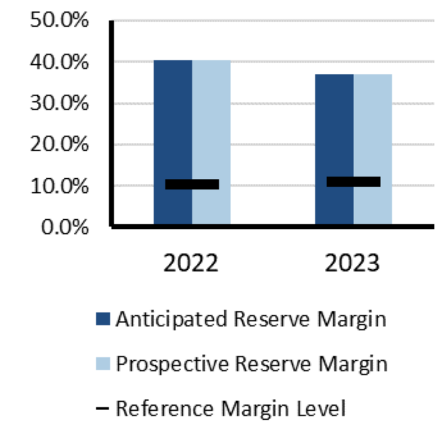
NPCC-Québec

The Québec assessment area (Province of Québec) is a winter-peaking NPCC area that covers 595,391 square miles with a population of 8 million. Québec is one of the four Interconnections in North America; it has ties to Ontario, New York, New England, and the Maritimes; consisting of either high voltage direct current ties, radial generation, or load to and from neighboring systems.

Highlights

- The Québec area forecasted summer peak demand (excluding April, May, and September) is 22,859 MW during the week of August 13, 2023, with a forecasted net margin of 7,202 MW (31.5%). No particular resource adequacy problems are forecasted, and the Québec area expects to be able to provide assistance to other areas up to the transfer capability available.
- In the Québec RC area, most transmission line, transformer, and generating unit maintenance is done during the summer period. Internal transmission outage plans are assessed to meet internal demand, firm sales, expected additional sales, and additional uncertainty margins. They should not impact inter-area transfer capabilities with neighboring systems. During the 2023 summer operating period, some maintenance outages are scheduled on the interconnections. Maintenance is coordinated with neighboring RC areas so as to leave maximum capability to summer-peaking areas.
- Based on an NPCC Probabilistic Assessment, Québec is expected to need only limited use of its operating procedures designed to mitigate resource and energy shortages during the summer. Negligible cumulative LOLE, LOLH, and EUE risks were estimated over the summer period for all modeled scenarios, including the severe low-likelihood cases.

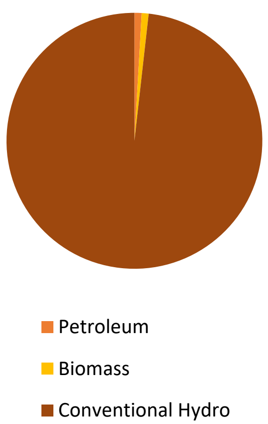
On-Peak Reserve Margin



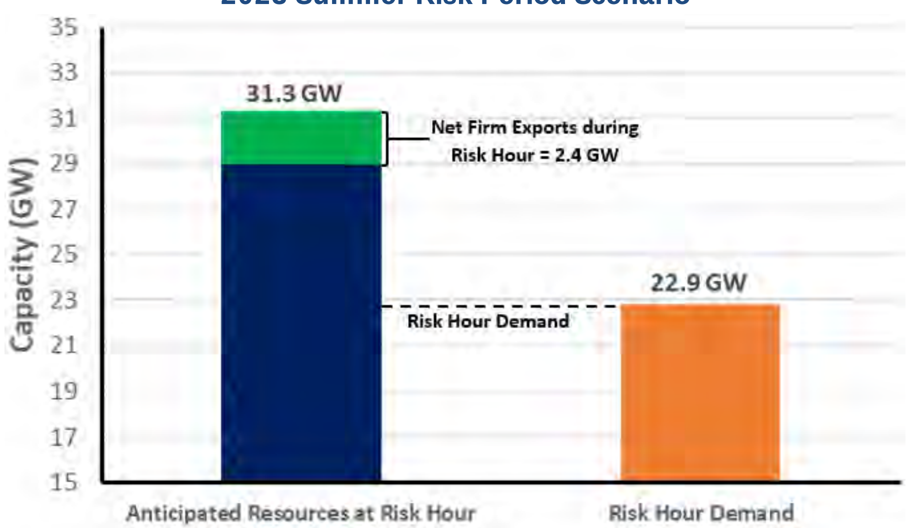
Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed scenarios.

On-Peak Fuel Mix



2023 Summer Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenario: Net internal demand (50/50) and (90/10) demand forecast

Net Firm Transfers: Anticipated exports to neighbors during the risk hour

PJM

PJM Interconnection is a regional transmission organization that coordinates the movement of wholesale electricity in all or parts of Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, West Virginia, and the District of Columbia. PJM serves 65 million customers and covers 369,089 square miles. PJM is a BA, PC, Transmission Planner, Resource Planner, Interchange Authority, TOP, Transmission Service Provider, and RC.

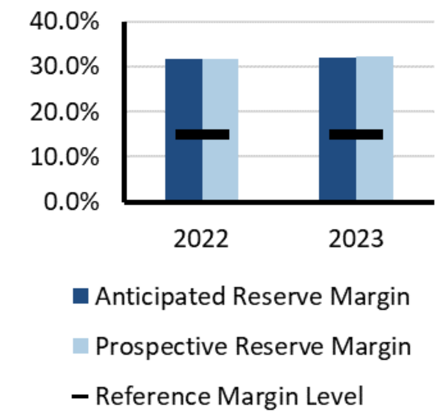
Highlights

- PJM expects no resource problems over the entire 2023 summer peak season. Installed capacity is over twice the PJM reserve requirement necessary to meet the 1-day-in-10-years LOLE criterion.
- The 2022 PJM reserve requirement study used to establish the target installed reserve margin of 14.9% analyzed a wide range of load scenarios (low, regular and extreme) as well as multiple scenarios for system-wide unavailable capacity due to forced outages, maintenance outages, and ambient derations. Due to the rather low penetration of limited and variable resources in PJM relative to PJM's peak load, the hour with most loss of load risk remains the hour with highest forecasted net peak demand.
- No other reliability issues are expected.

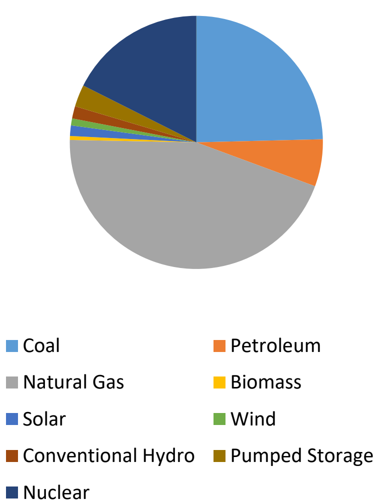
Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed scenarios.

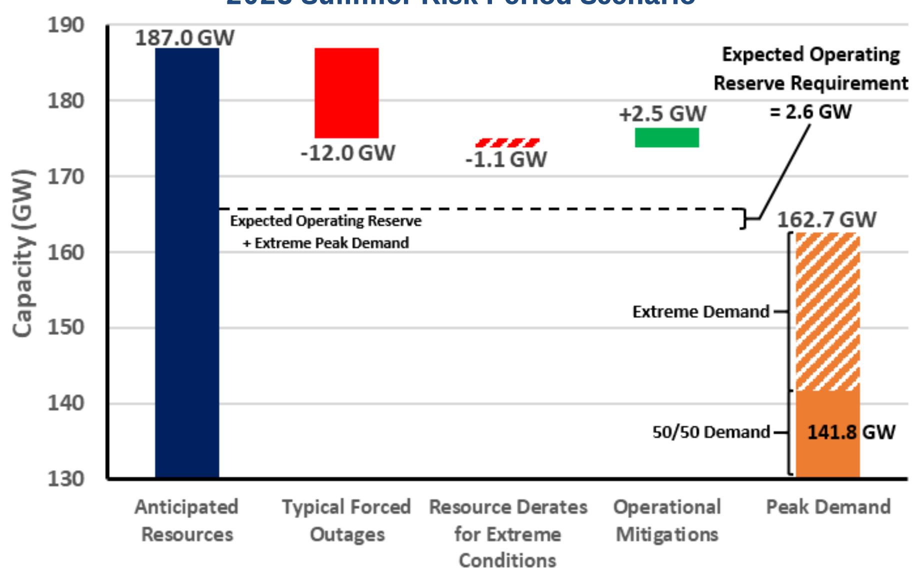
On-Peak Reserve Margin



On-Peak Fuel Mix



2023 Summer Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: Net internal demand (50/50) and (90/10) demand forecast

Forced Outages: Based on historical data and trending

Extreme Derates: Accounts for reduced thermal capacity contributions due to performance in extreme conditions

Operational Mitigations: A total of 2.5 GW based on operational/emergency procedures

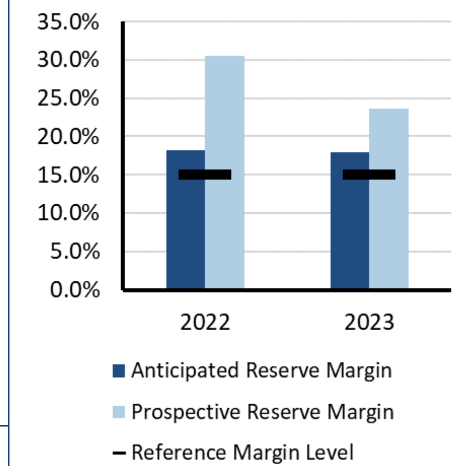
SERC-Central

SERC-Central is an assessment area within the SERC Regional Entity. SERC-Central includes all of Tennessee and portions of Georgia, Alabama, Mississippi, Missouri, and Kentucky. Historically a summer-peaking area, SERC-Central is beginning to have higher peak demand forecasts in winter. SERC is one of the six companies across North America that are responsible for the work under Federal Energy Regulatory Commission (FERC) approved delegation agreements with NERC. SERC-Central is specifically responsible for the reliability and security of the electric grid across the Southeastern and Central areas of the United States. This area covers approximately 630,000 square miles and serves a population of more than 91 million. The SERC Regional Entity includes 36 BAs, 28 Planning Authorities (PA), and 6 RCs.

Highlights

- Entities in SERC-Central have not identified any potential reliability issues for the upcoming summer season. Entities anticipate having adequate system capacity for the upcoming summer season and are equipped to address unexpected short-term issues by leveraging diverse generation portfolios and spot purchases from the power markets when necessary.
- Non-economic dispatch (out of merit) of available coal-fired generators ahead of the upcoming summer season is anticipated in order to build inventory and limit consumption of fuel and consumables for plant operations and mitigate supply and transportation challenges during the summer.
- Each entity continues to work collaboratively to ensure reliability for its area within SERC and to promote reliability and adequacy across the entire SERC Regional Entity.
- Entities continue to participate actively in the SERC Near-Term and Long-Term Working Groups among others. These working groups help the entities identify and address emerging and potential reliability impacts on transmission and resource adequacy along with transfer capability.
- Probabilistic analysis indicates negligible risk for resource shortfall. The 2022 study found negligible LOLH and EUE during summer months for a similar resource mix and demand levels.

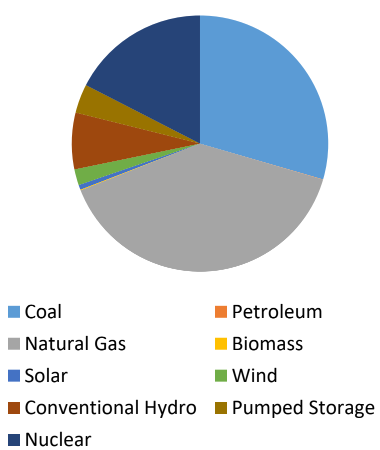
On-Peak Reserve Margin



Risk Scenario Summary

Expected resources meet operating reserve requirements under normal peak-demand scenarios. Above-normal summer peak load and outage conditions could result in the need to employ operating mitigations (i.e., demand response and transfers) and EEAs.

On-Peak Fuel Mix



2023 Summer Risk Period Scenario

Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: Net internal demand (50/50) and extreme demand forecast based on extreme summer weather (equals or exceeds the (90/10) demand forecast)

Maintenance Outages: Adjusted for higher outages resulting from extreme summer temperatures and aggregated on a SERC subregional level

Forced Outages: Accounts for reduced thermal capacity contributions due to performance in extreme conditions

Extreme Derates: Estimated resources unavailable in extreme conditions

Operational Mitigations: A total of 1.9 GW based on operational/emergency procedures

SERC-East

SERC-East is an assessment area within the SERC Regional Entity. SERC-East includes North Carolina and South Carolina. Historically a summer-peaking area, SERC-East is beginning to have higher peak demand forecasts in winter. SERC is one of the six companies across North America that are responsible for the work under FERC approved delegation agreements with NERC. SERC is specifically responsible for the reliability and security of the electric grid across the Southeastern and Central areas of the United States. This area covers approximately 630,000 square miles and serves a population of more than 91 million. The SERC Regional Entity includes 36 BAs, 28 PAs, and 6 RCs.

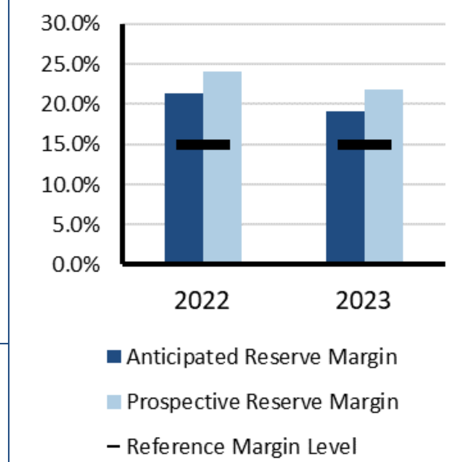
Highlights

- SERC-East is transitioning to a hybrid-peaking (both summer and winter peaking) area as solar PV reduces summer peak demand and electrification of heating drives up winter peak demand.
- Entities have not identified any emerging reliability issues or operational concerns for the upcoming summer season.
- Entities continue to perform resource studies to ensure resource adequacy to meet the summer peak demand and to maintain reliability to the system.
- Entities continue to participate actively in the SERC Near-Term and Long-Term Working Groups. These groups identify emerging and potential reliability impacts on transmission and resource adequacy along with transfer capability.
- Probabilistic analysis shows a low risk for resource shortfall during the months of July and August. The 2022 study found LOLH of 0.005 hours and EUE of 2.381 MWh during summer months for a similar resource mix and demand levels.

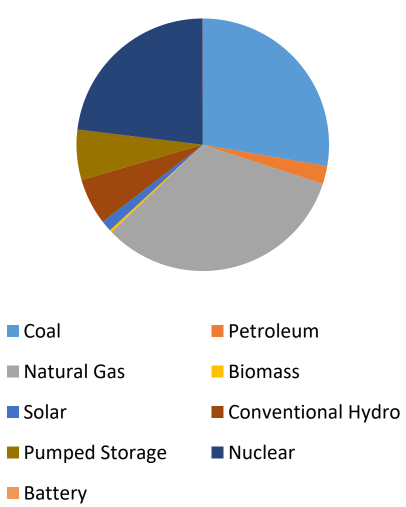
Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed scenarios.

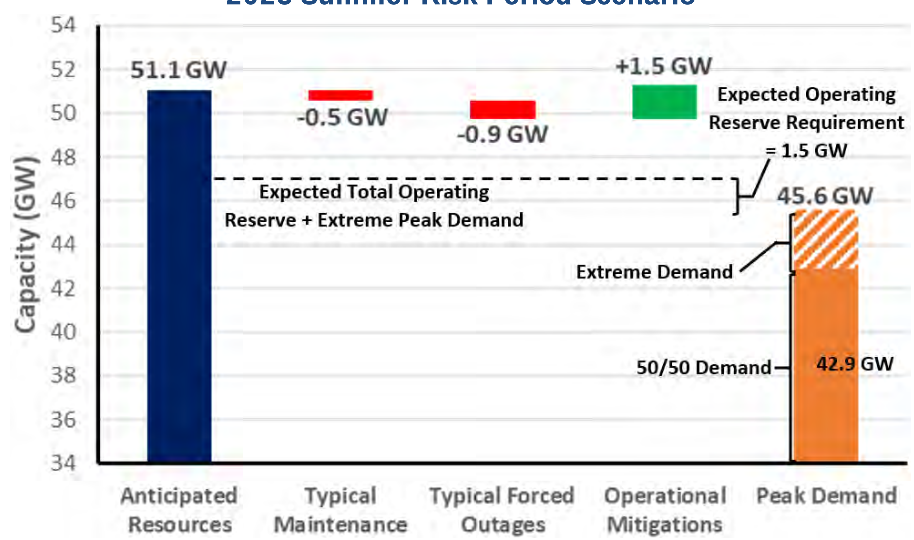
On-Peak Reserve Margin



On-Peak Fuel Mix



2023 Summer Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: Net internal demand (50/50) and extreme demand forecast based on extreme summer weather (equals or exceeds the (90/10) demand forecast)

Maintenance Outages: Adjusted for higher outages resulting from extreme summer temperatures and aggregated on a SERC subregional level

Forced Outages: Accounts for reduced thermal capacity contributions due to performance in extreme conditions

Operational Mitigations: A total of 1.5 GW based on operational/emergency procedures

SERC-Florida Peninsula

SERC-Florida Peninsula is a summer-peaking assessment area within SERC. SERC is one of the six companies across North America that are responsible for the work under FERC approved delegation agreements with NERC. SERC is specifically responsible for the reliability and security of the electric grid across the Southeastern and Central areas of the United States. This area covers approximately 630,000 square miles and serves a population of more than 91 million. The SERC Regional Entity includes 36 BAs, 28 PAs, and 6 RCs.

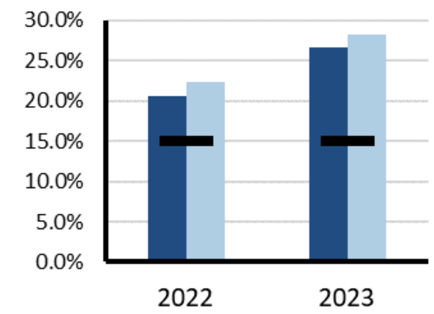
Highlights

- Entities have not identified any emerging reliability issues or operational concerns for the upcoming summer season.
- Entities continue to perform resource studies to ensure resource adequacy to meet the summer peak demand and to maintain system reliability.
- Entities continue to participate actively in the SERC Near-Term and Long-Term Working Groups. These groups identify emerging and potential reliability impacts on transmission and resource adequacy along with transfer capability.
- SERC probabilistic analysis indicates negligible risk for resource shortfall. The 2022 study found negligible LOLH and EUE during summer months for a similar resource mix and demand levels

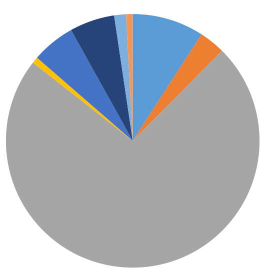
Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed scenarios.

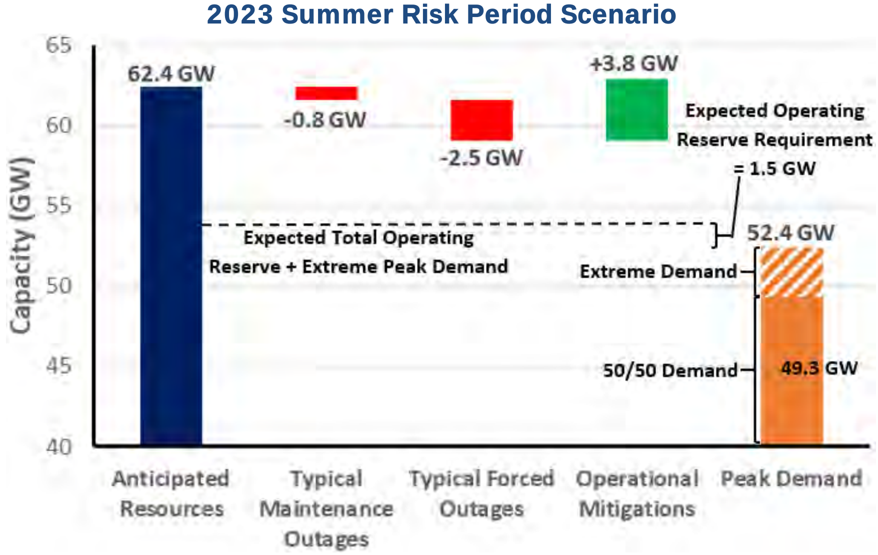
On-Peak Reserve Margin



On-Peak Fuel Mix



2023 Summer Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: Net internal demand (50/50) and extreme demand forecast based on extreme summer weather (equals or exceeds the (90/10) demand forecast)

Maintenance Outages: Adjusted for higher outages resulting from extreme summer temperatures and aggregated on a SERC subregional level

Forced Outages: Accounts for reduced thermal capacity contributions due to performance in extreme conditions

Operational Mitigations: A total of 3.8 GW based on operational/ emergency procedures

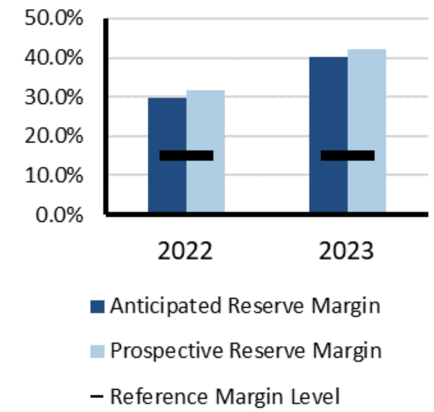
SERC-Southeast

SERC-Southeast is a summer-peaking assessment area within the SERC Regional Entity. SERC-Southeast includes all or portions of Georgia, Alabama, and Mississippi. SERC is one of the six companies across North America that are responsible for the work under FERC approved delegation agreements with NERC. SERC is specifically responsible for the reliability and security of the electric grid across the southeastern and central areas of the United States. This area covers approximately 630,000 square miles and serves a population of more than 91 million. The SERC Regional Entity includes 36 BAs, 28 Planning Authorities, and 6 RCs.

Highlights

- Entities have not identified any emerging reliability issues for the upcoming summer season that will impact resource adequacy.
- The available system capacity for the upcoming summer season meets or exceeds the reserve margin target. Reliability is supported by a diverse fuel mix, firm natural gas contracts, and power purchases.
- Entities continue to participate actively in the SERC near-term and long-term working groups. These groups identify emerging and potential reliability impacts on transmission and resource adequacy along with transfer capability.
- Probabilistic analysis indicates almost no risk for resource shortfall.

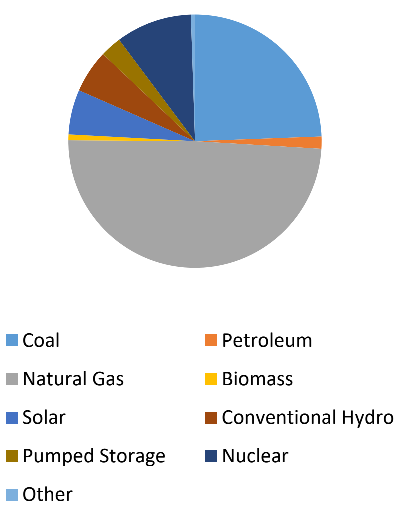
On-Peak Reserve Margin



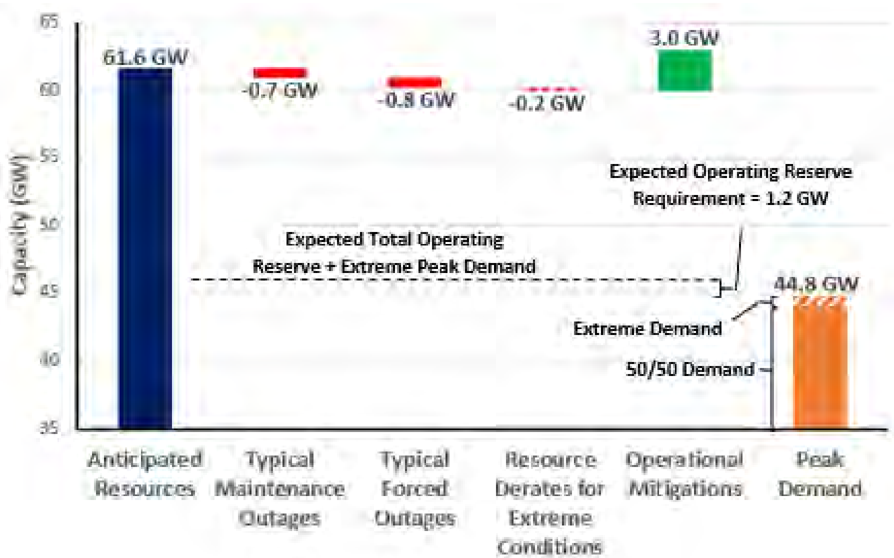
Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed scenarios.

On-Peak Fuel Mix



2023 Summer Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: Net internal demand (50/50) and extreme demand forecast based on extreme summer weather (equals or exceeds the (90/10) demand forecast)

Maintenance Outages: Adjusted for higher outages resulting from extreme summer temperatures and aggregated on a SERC subregional level

Forced Outages: Accounts for reduced thermal capacity contributions due to performance in extreme conditions

Extreme Derates: Estimated resources unavailable in extreme conditions

Operational Mitigations: A total of 3.0 GW based on operational/ emergency procedures

SPP

SPP PC 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 long-term assessment 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.

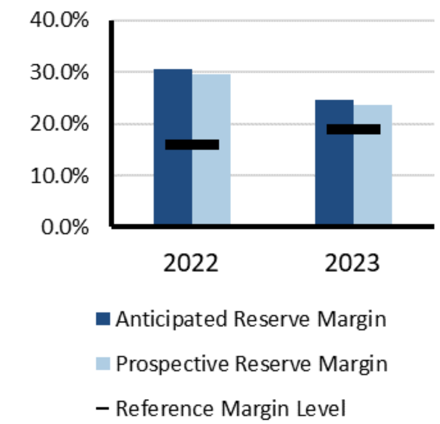
Highlights

- At this time, SPP projects a low likelihood of any emerging reliability issues impacting the area for the 2023 summer season.
- BA generation capacity deficiency risks remain depending on wind generation output levels and unanticipated generation outages in combination with high load periods.
- SPP performed a statistical analysis of risk of energy emergencies for the upcoming summer based on historical data. They found it likely that operators would use part of the 2 GW operating reserves and issue EEA1 and EEA2 level approximately one day each summer; it is likely that operators would deplete all operating reserves approximately once every five summers, resulting in an EEA3.
- Using the current operational processes and procedures, SPP will continue to assess the needs for the 2023 summer season and will adjust as needed to ensure that real-time reliability is maintained throughout the summer time frame.

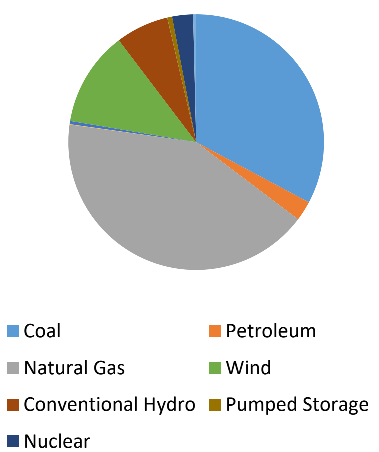
Risk Scenario Summary

Expected resources are sufficient to meet operating reserve requirements under normal peak-demand and outage scenarios. Above-normal summer peak load and outage conditions could result in the need to employ operating mitigations (i.e. demand response and transfers from neighboring systems) and EEAs.

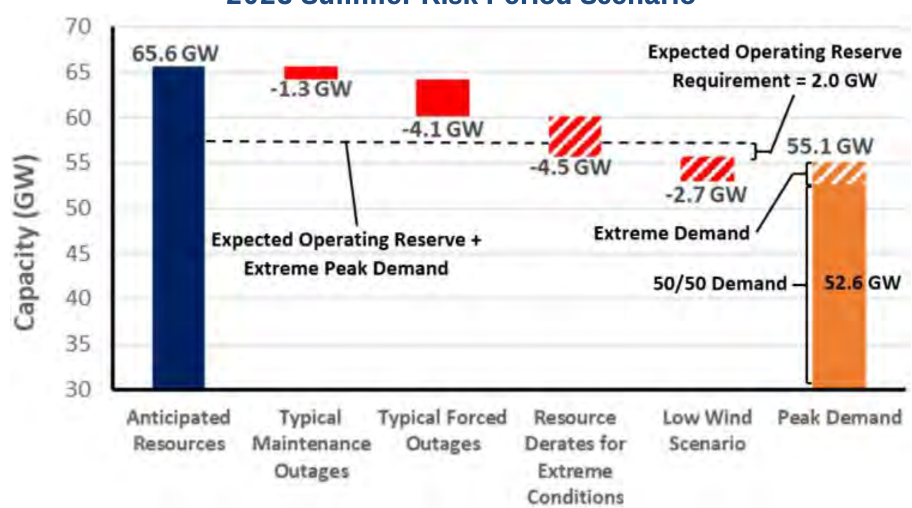
On-Peak Reserve Margin



On-Peak Fuel Mix



2023 Summer Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: Net internal demand (50/50) and extreme demand is a 5% increase from net internal demand

Maintenance & Forced Outages: Represent 5-year historical averages; calculated from SPP's generation assessment process

Extreme Derates: Additional unavailable capacity from operational data at high demand periods

Low Wind Scenario: Derates reflecting a low-wind day in the summer

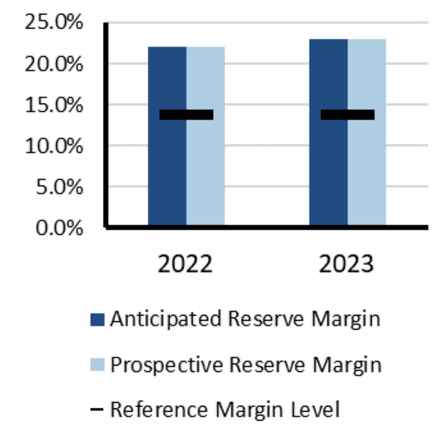
Texas RE-ERCOT

The Electric Reliability Council of Texas (ERCOT) is the ISO for the ERCOT Interconnection and is located entirely in the state of Texas; it operates as a single BA. It also performs financial settlement for the competitive wholesale bulk-power market and administers retail switching for nearly 8 million premises in competitive choice areas. ERCOT is governed by a board of directors and subject to oversight by the Public Utility Commission of Texas and the Texas Legislature. ERCOT is summer-peaking. It covers approximately 200,000 square miles, connects over 52,700 miles of transmission lines, has over 1,100 generation units, and serves more than 26 million customers. Texas RE is responsible for the RE functions described in the Energy Policy Act of 2005 for ERCOT. On November 3, 2022, the Public Utility Commission of Texas issued an order directing ERCOT to assume the duties and responsibilities of the Reliability Monitor for the Texas power grid.

Highlights

- Given an Anticipated Reserve Margin of 23% and Reference Reserve Margin of 13.75%, ERCOT expects to have sufficient operating reserves in expected normal summer system conditions.
- Solar PV nameplate capacity expected for the 2023 summer season is 4.4 GW higher than the forecast amount reported for the 2022 SRA.
- Several generator owners in the ERCOT area indicated they could run out of NOx emission allowances by July 2023 under U.S. EPA's Good Neighbor Plan. Texas filed a motion to stay the EPA's regulatory action. A delay in implementation has alleviated these concerns. ERCOT's probabilistic risk assessment indicates a low probability of energy emergency conditions during the summer peak load period, but the risk increases into the early evening hours due reductions of solar PV generation. There is a 4% probability that ERCOT will declare an EEA1 during the expected daily peak load hour increasing up to 19% probability at the highest risk hour ending at 8:00 p.m.
- System stability and strength stemming from the growth of IBRs remains a concern. ERCOT is also experiencing large increases in renewable production curtailments due to transmission constraints, and these curtailments are increasingly occurring at solar PV sites.

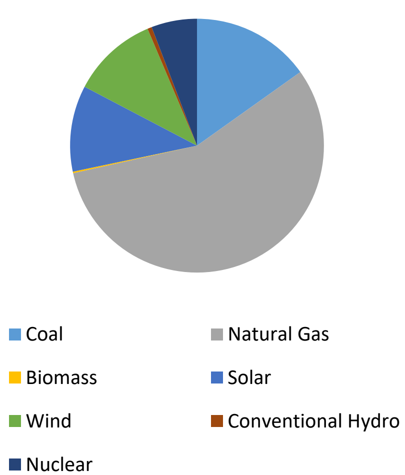
On-Peak Reserve Margin



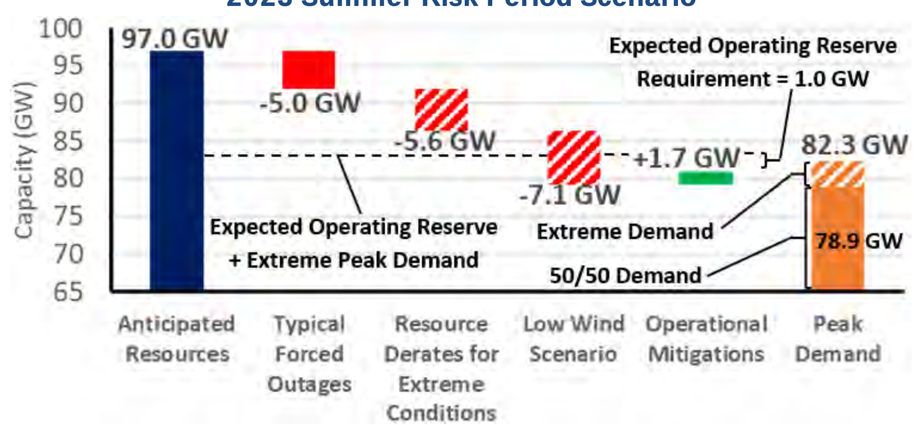
Risk Scenario Summary

Expected resources meet operating reserve requirements under normal and extreme peak-demand scenarios. Extreme generator outages combined with low-wind output during extreme peak demand could result in the need to employ operating mitigations such as demand response, EEAs, and localized load shedding.

On-Peak Fuel Mix



2023 Summer Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: Net internal demand (50/50) and extreme demand represents weather conditions 2% worse than summer peak in 2011

Forced Outages: Based on the 95th percentile of historical averages of forced outages for June through September weekdays, hours ending 3:00–8:00 p.m. local time for the last three (2019–2021) summer seasons

Low Wind Scenario: Based on the 10th percentile of historical averages of hourly wind for June through September, hours ending 1:00–9:00 p.m. local time

Extreme Derates: Based on the 95th percentile of historical averages of forced outages for June through September weekdays, hours ending 3:00–8:00 p.m. local time for the last five (2019–2021) summer seasons

Operational Mitigations: Additional capacity from switchable generation and additional imports

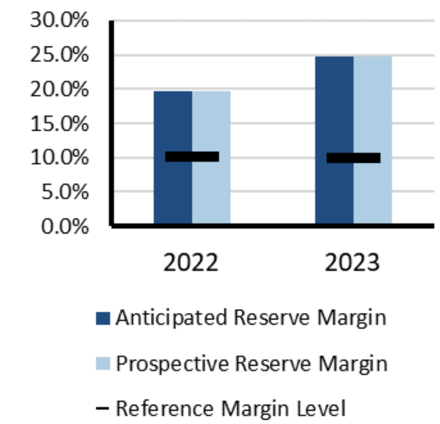
WECC-AB

WECC-AB (Alberta) is a winter-peaking assessment area in the WECC Regional Entity that consists of the province of Alberta, Canada. WECC is responsible for coordinating and promoting BES reliability in the Western Interconnection. WECC's 329 members include 39 BAs, representing a wide spectrum of organizations with an interest in the BES. Serving an area of nearly 1.8 million square miles and more than 82 million customers, it is geographically the largest and most diverse Regional Entity. WECC's service territory extends from Canada to Mexico. It includes the provinces of Alberta and British Columbia in Canada, the northern portion of Baja California in Mexico as well as all or portions of the 14 Western United States in between.

Highlights

- The Western Interconnection is experiencing heightened reliability risks heading into the summer of 2023 due to increased supply-side shortages along with the ongoing drought impacts in some areas, continued wildfire threats, and expanding heat wave events.
- There is 35% less coal-fired generator capacity in Alberta compared to last summer (446 MW). Resource additions include 554 MW of natural-gas-fired generation, 336 MW of new solar PV resources, and 1,350 MW of new wind generation.
- Based on a WECC Probabilistic Assessment, the WECC-AB assessment area had negligible LOLH and EUE.
- Alberta is expected to have sufficient resource availability to meet demand and cover reserves on the peak hour at 4:00 p.m. under a summer peak defined as a one-in-ten probability at the 90th percentile with any combination or accumulation of derates.

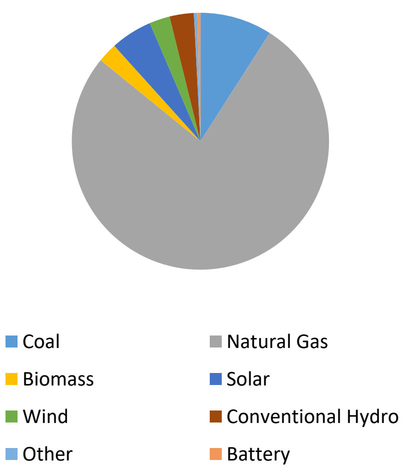
On-Peak Reserve Margin



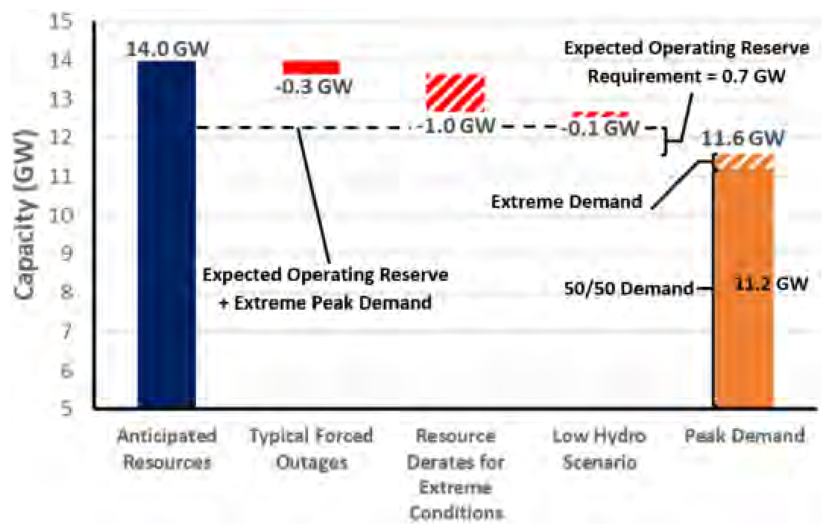
Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed scenarios

On-Peak Fuel Mix



2023 Summer Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: Net internal demand (50/50) and (90/10) demand forecast

Typical Forced Outages: Average seasonal outages

Extreme Derates: Using (90/10) point of resource performance distribution

Low Hydro Scenario: Reduced hydro availability resulting from drought conditions

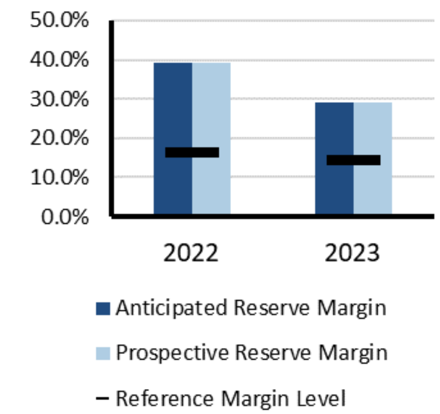
WECC-BC

WECC-British Columbia (BC) is a winter-peaking assessment area in the WECC Regional Entity that consists of the province of British Columbia, Canada. WECC is responsible for coordinating and promoting BES reliability in the Western Interconnection. WECC's 329 members include 39 BAs, representing a wide spectrum of organizations with an interest in the BES. Serving an area of nearly 1.8 million square miles and more than 82 million customers, it is geographically the largest and most diverse Regional Entity. WECC's service territory extends from Canada to Mexico. It includes the provinces of Alberta and British Columbia in Canada, the northern portion of Baja California in Mexico as well as all or portions of the 14 Western United States in between.

Highlights

- The Western Interconnection is experiencing heightened reliability risks heading into the summer of 2023 due to increased supply-side shortages along with the ongoing drought impacts in some areas, continued wildfire threats, and expanding heat wave events.
- BC shows adequate reserve margins to meet demand under extreme conditions.
- Based on a WECC Probabilistic Assessment, the WECC-BC assessment area had negligible LOLH and EUE.
- BC is expected to have sufficient resource availability to meet demand and cover reserves on the peak hour at 4:00 p.m., under a summer peak defined as a one-in-ten probability at the 90th percentile with any combination or accumulation of derates.

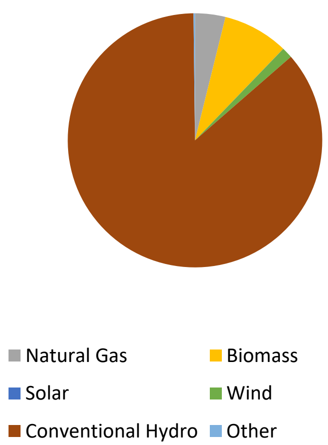
On-Peak Reserve Margin



Risk Scenario Summary

Expected resources meet operating reserve requirements under normal peak-demand scenarios. Above-normal summer peak load and outage conditions could result in the need to employ operating mitigations (i.e., demand response and transfers) and EEAs. Load shedding may be needed under the extreme peak demand and outage scenarios studied.

On-Peak Fuel Mix



2023 Summer Risk Period Scenario

Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: Net internal demand (50/50) and (90/10) demand forecast

Forced Outages: Average seasonal outages

Extreme Derates: Using (90/10) resource performance distribution at peak hour

Low Hydro Scenario: Reduced hydro availability resulting from drought conditions

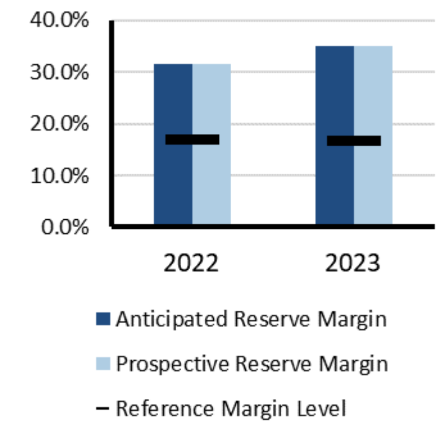
WECC-CA / MX

WECC-CA/MX is a summer-peaking assessment area in the WECC Regional Entity that includes parts of California, Nevada, and Baja California, Mexico. WECC is responsible for coordinating and promoting BES reliability in the Western Interconnection. WECC's 329 members include 39 BAs, representing a wide spectrum of organizations with an interest in the BES. Serving an area of nearly 1.8 million square miles and more than 82 million customers, it is geographically the largest and most diverse Regional Entity. WECC's service territory extends from Canada to Mexico. It includes the provinces of Alberta and British Columbia in Canada, the northern portion of Baja California in Mexico as well as all or portions of the 14 Western United States in between.

Highlights

- The Western Interconnection is experiencing heightened reliability risks heading into the summer of 2023 due to increased supply-side shortages along with the ongoing drought impacts in some areas, continued wildfire threats, and expanding heat wave events.
- CA/MX shows adequate reserve margins under expected conditions on the peak hour. However, increased risk occurs during the hours after peak demand and into the evening due to the variability of energy availability. CA/MX is typically reliant on imports during these periods.
- Based on a WECC Probabilistic Assessment, WECC-CA/MX is projected to have negligible-to-low amounts of LOLH (<0.5 hours) this summer. Variation in LOLH is attributable to the amount of Tier 1 resources that connect before the later months.
- CA/MX is expected to have sufficient resource availability to meet demand and cover reserves on the peak hour at 4:00 p.m. under a summer peak defined as a one-in-ten probability at the 90th percentile with any combination or accumulation of derates.
- For the peak riskiest hour ending 8:00 pm (four hours later than the peak) under an extreme summer peak load, CA/MX would need to rely on increased imports to maintain adequate reserves. Under expected net internal demand for the same riskiest hour (not an extreme summer peak for that hour), any of the typical outages or extreme derates would also cause a need for increased reliance on imports.

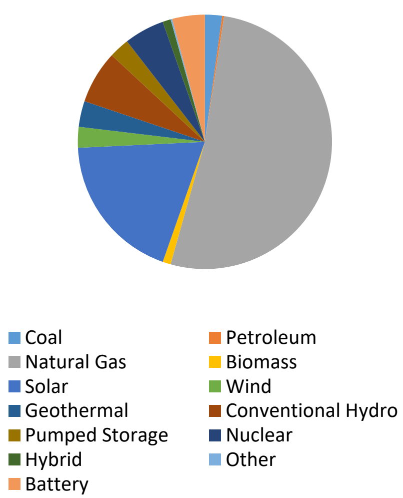
On-Peak Reserve Margin



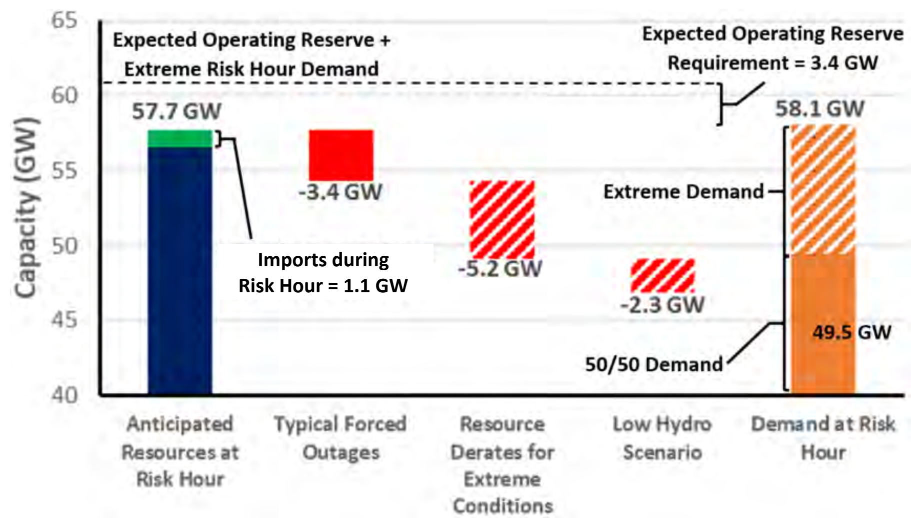
Risk Scenario Summary

Expected resources meet operating reserve requirements under normal peak-demand scenarios. Above-normal summer peak load and outage conditions could result in the need to employ operating mitigations (i.e., demand response and transfers) and EEAs. Load shedding may be needed under extreme peak demand and outage scenarios studied.

On-Peak Fuel Mix



2023 Summer Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at 8:00 p.m. local time as solar PV output is diminished and demand remains high

Demand Scenarios: Net internal demand (50/50) at risk hour and (90/10) demand forecast at risk hour

Forced Outages: Estimated using market forced outage model

Extreme Derates: On natural gas units based on historic data and manufacturer data for temperature performance and outages

Low Hydro Scenario: Reduced hydro availability resulting from drought conditions

WECC-NW

WECC-NW is a summer-peaking assessment area in the WECC Regional Entity. The area includes Colorado, Idaho, Montana, Oregon, Utah, Washington, Wyoming and parts of California, Nebraska, Nevada, and South Dakota. WECC is responsible for coordinating and promoting BES reliability in the Western Interconnection. WECC's 329 members include 39 BAs, representing a wide spectrum of organizations with an interest in the BES. Serving an area of nearly 1.8 million square miles and more than 82 million customers, it is geographically the largest and most diverse Regional Entity. WECC's service territory extends from Canada to Mexico. It includes the provinces of Alberta and British Columbia in Canada, the northern portion of Baja California in Mexico as well as all or portions of the 14 Western United States in between.

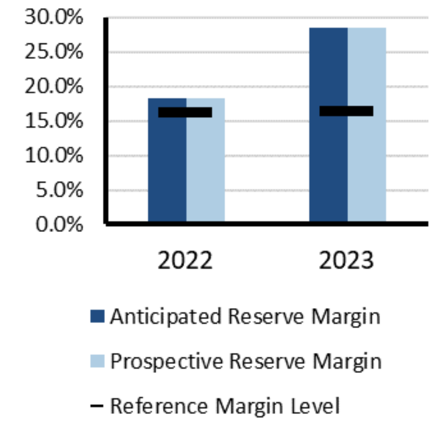
Highlights

- The Western Interconnection is experiencing heightened reliability risks heading into the summer of 2023 due to increased supply-side shortages along with the ongoing drought impacts in some areas, continued wildfire threats, and expanding heat wave events.
- NW shows adequate reserve margins under expected conditions on the peak hour. However, NW shows increased risk a few hours later during the peak riskiest hour, due to the variability of energy availability later in the evenings. NW would be reliant on increased imports.
- Based on a WECC Probabilistic Assessment, the WECC-NW assessment area had negligible LOLH and EUE.
- WECC-NW would need to rely on imports to maintain adequate reserves on the peak riskiest hour (five hours later at 9:00 p.m.) under an extreme summer peak load and either extreme thermal or extreme hydro derates or any combination of two other extreme derate scenarios.

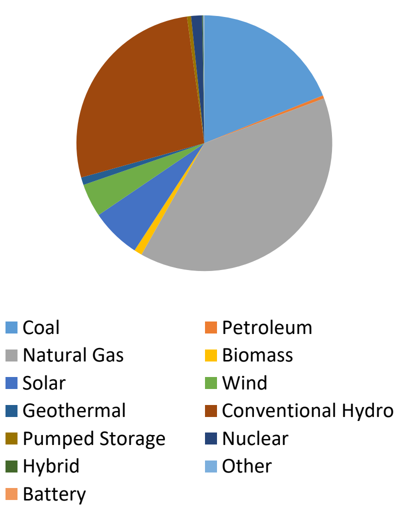
Risk Scenario Summary

Expected resources meet operating reserve requirements under normal peak-demand scenarios. Above-normal summer peak load and outage conditions could result in the need to employ operating mitigations (i.e., demand response and transfers) and EEAs. Load shedding may be needed under extreme peak demand and outage scenarios.

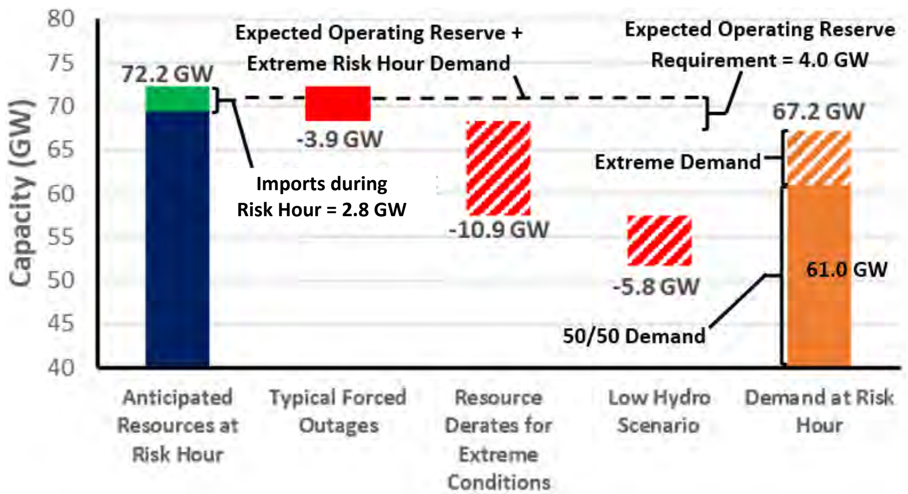
On-Peak Reserve Margin



On-Peak Fuel Mix



2023 Summer Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

- **Risk Period:** Highest risk for unserved energy at 9:00 p.m. local time as solar PV output is diminished and demand remains high
- **Demand Scenarios:** Net internal demand (50/50) at risk hour and (90/10) demand forecast at risk hour
- **Forced Outages:** Average seasonal outages
- **Extreme Derates:** Using (90/10) scenario
- **Low Hydro Scenario**: Reduced hydro availability resulting from drought conditions

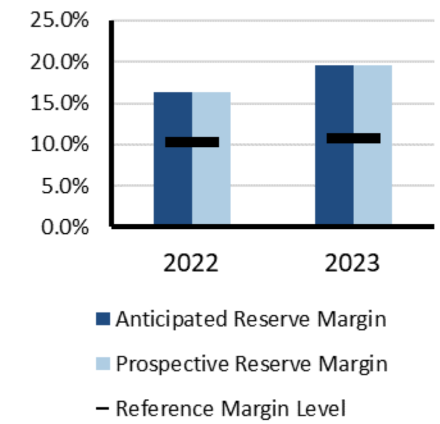
WECC-SW

WECC-SW is a summer-peaking assessment area in the WECC Regional Entity. It includes Arizona, New Mexico, and part of California and Texas. WECC is responsible for coordinating and promoting BES reliability in the Western Interconnection. WECC's 329 members include 39 BAs, representing a wide spectrum of organizations with an interest in the BES. Serving an area of nearly 1.8 million square miles and more than 82 million customers, it is geographically the largest and most diverse Regional Entity. WECC's service territory extends from Canada to Mexico. It includes the provinces of Alberta and British Columbia in Canada as well as the northern portion of Baja California in Mexico and all or portions of the 14 Western United States in between.

Highlights

- The Western Interconnection is experiencing heightened reliability risks heading into the summer of 2023 due to increased supply-side shortages along with the ongoing drought impacts in some areas, continued wildfire threats, and expanding heat wave events.
- WECC-SW shows adequate reserve margins to meet demand under extreme conditions.
- Based on a WECC Probabilistic Assessment, the WECC-SW assessment area had negligible LOLH and EUE.
- WECC-SW is expected to have sufficient resource availability to meet demand and cover reserves on the peak hour at 5:00 p.m. under a summer peak defined as a one-in-ten probability at the 90th percentile with any combination or accumulation of derates.

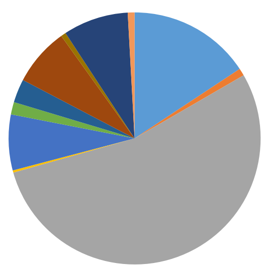
On-Peak Reserve Margin



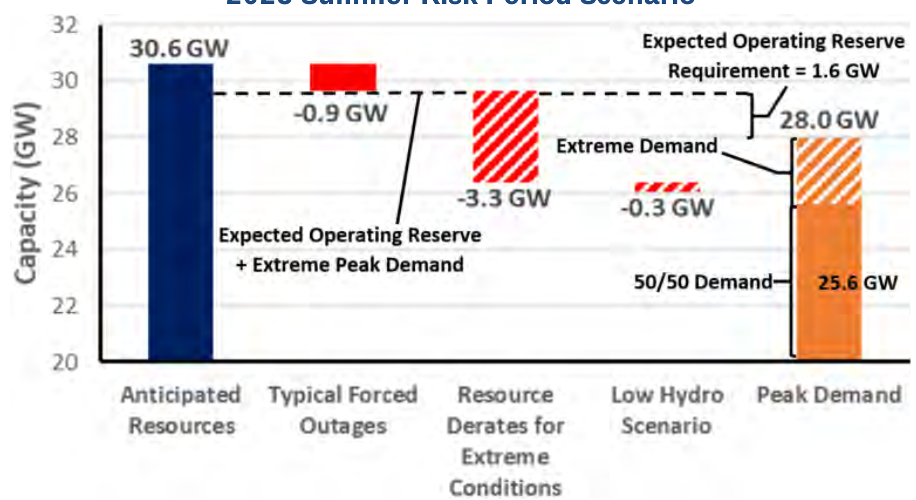
Risk Scenario Summary

Expected resources meet operating reserve requirements under normal peak-demand scenarios. Above-normal summer peak load and outage conditions could result in the need to employ operating mitigations (i.e., demand response and transfers) and EEAs. Load shedding may be needed under extreme peak demand and outage scenarios.

On-Peak Fuel Mix



2023 Summer Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy occurs at the hour of peak demand (5:00 p.m. local)

Demand Scenarios: Net internal demand (50/50) at risk hour and (90/10) demand forecast at risk hour

Forced Outages: Average seasonal outages

Extreme Derates: Using (90/10) scenario

Low Hydro Scenario: Reduced hydro availability resulting from drought conditions

Data Concepts and Assumptions

The table below explains data concepts and important assumptions used throughout this assessment.

General Assumptions
• Reliability of the interconnected BPS is comprised of both adequacy and operating reliability:
▪ Adequacy is the ability of the electricity system to supply the aggregate electric power and energy requirements of the electricity consumers at all times while taking into account scheduled and reasonably expected unscheduled outages of system components.
▪ Operating reliability is the ability of the electricity system to withstand sudden disturbances, such as electric short-circuits or unanticipated loss of system components.
• The reserve margin calculation is an important industry planning metric used to examine future resource adequacy.
• All data in this assessment is based on existing federal, state, and provincial laws and regulations.
• Differences in data collection periods for each assessment area should be considered when comparing demand and capacity data between year-to-year seasonal assessments.
• *2022 Long-Term Reliability Assessment* data has been used for most of this 2023 summer assessment period augmented by updated load and capacity data.
• A positive net transfer capability would indicate a net importing assessment area; a negative value would indicate a net exporter.
Demand Assumptions
• Electricity demand projections, or load forecasts, are provided by each assessment area.
• Load forecasts include peak hourly load[10] or total internal demand for the summer and winter of each year.[11]
• Total internal demand projections are based on normal weather (50/50 distribution[12]) and are provided on a coincident[13] basis for most assessment areas.
• Net internal demand is used in all reserve margin calculations, and it is equal to total internal demand then reduced by the amount of controllable and dispatchable demand response projected to be available during the peak hour.
Resource Assumptions
Resource planning methods vary throughout the North American BPS. NERC uses the categories below to provide a consistent approach for collecting and presenting resource adequacy. Because the electrical output of variable energy resources (e.g., wind, solar PV) depends on weather conditions, their contribution to reserve margins and other on-peak resource adequacy analysis is less than their nameplate capacity.
Anticipated Resources: • **Existing-Certain Capacity**: Included in this category are commercially operable generating unit or portions of generating units that meet at least one of the following requirements when examining the period of peak demand for the summer season: unit must have a firm capability and have a power purchase agreement with firm transmission that must be in effect for the unit; unit must be classified as a designated network resource; and/or where energy-only markets exist, unit must be a designated market resource eligible to bid into the market. • **Tier 1 Capacity Additions**: This category includes capacity that either is under construction or has received approved planning requirements. • **Net Firm Capacity Transfers (Imports minus Exports)**: This category includes transfers with firm contracts.

[10] *Glossary of Terms* used in NERC Reliability Standards
[11] The summer season represents June–September and the winter season represents December–February.
[12] Essentially, this means that there is a 50% probability that actual demand will be higher and a 50% probability that actual demand will be lower than the value provided for a given season/year.
[13] Coincident: This is the sum of two or more peak loads that occur in the same hour. Noncoincident: This is the sum of two or more peak loads on individual systems that do not occur in the same time interval; this is meaningful only when considering loads within a limited period of time, such as a day, a week, a month, a heating or cooling season, and usually for not more than one year. SERC and FRCC calculate total internal demand on a noncoincidental basis.

Prospective Resources: Includes all anticipated resources plus the following:

Existing-Other Capacity: Included in this category are commercially operable generating units or portions of generating units that could be available to serve load for the period of peak demand for the season but do not meet the requirements of existing-certain.

Reserve Margin Descriptions

Planning Reserve Margin: This is the primary metric used to measure resource adequacy; it is defined as the difference in resources (anticipated or prospective) and net internal demand then divided by net internal demand and shown as a percentage.

Reference Margin Level: The assumptions and naming convention of this metric vary by assessment area. The Reference Margin Level can be determined using both deterministic and probabilistic (based on a 0.1/year loss of load study) approaches. In both cases, this metric is used by system planners to quantify the amount of reserve capacity in the system above the forecasted peak demand that is needed to ensure sufficient supply to meet peak loads. Establishing a Reference Margin Level is necessary to account for long-term factors of uncertainty involved in system planning, such as unexpected generator outages and extreme weather impacts that could lead to increase demand beyond what was projected in the 50/50 load forecasted. In many assessment areas, a Reference Margin Level is established by a state, provincial authority, ISO/RTO, or other regulatory body. In some cases, the Reference Margin Level is a requirement. Reference Margin Levels may be different for the summer and winter seasons. If a Reference Margin Level is not provided by an assessment area, NERC applies 15% for predominately thermal systems and 10% for predominately hydro systems.

Seasonal Risk Scenario Chart Description

Each assessment area performed an operational risk analysis that was used to produce the seasonal risk scenario charts in the Regional Assessments Dashboards. The chart presents deterministic scenarios for further analysis of different resource and demand levels: The left blue column shows anticipated resources, and the two orange columns at the right show the two demand scenarios of the normal peak net internal demand and the extreme summer peak demand—both determined by the assessment area. The middle red or green bars show adjustments that are applied cumulatively to the anticipated resources, such as the following:

- Reductions for typical generation outages (i.e., maintenance and forced outages that are not already accounted for in anticipated resources)
- Reductions that represent additional outage or performance derating by resource type for extreme, low-probability conditions (e.g., drought condition impacts on hydroelectric generation, low-wind scenario affecting wind generation, fuel supply limitations, or extreme temperature conditions that result in reduced thermal generation output)
- Additional capacity resources that represent quantified capacity from operational procedures, if any, that are made available during scarcity conditions

Not all assessment areas have the same categories of adjustments to anticipated resources. Furthermore, each assessment area determined the adjustments to capacity based on methods or assumptions that are summarized below the chart. Methods and assumptions differ by assessment area and may not be comparable.

The chart enables evaluation of resource levels against levels of expected operating reserve requirement and the forecasted demand. Furthermore, the effects from extreme events can also be examined by comparing resource levels after applying extreme-scenario derates and/or extreme summer peak demand.

Resource Adequacy

The Anticipated Reserve Margin, which is based on available resource capacity, is a metric used to evaluate resource adequacy by comparing the projected capability of anticipated resources to serve forecast peak demand.[14] Large year-to-year changes in anticipated resources or forecast peak demand (net internal demand) can greatly impact Planning Reserve Margin calculations. All assessment areas have sufficient Anticipated Reserve Margins to meet or exceed their Reference Margin Level for the 2023 summer as shown in **Figure 4**.

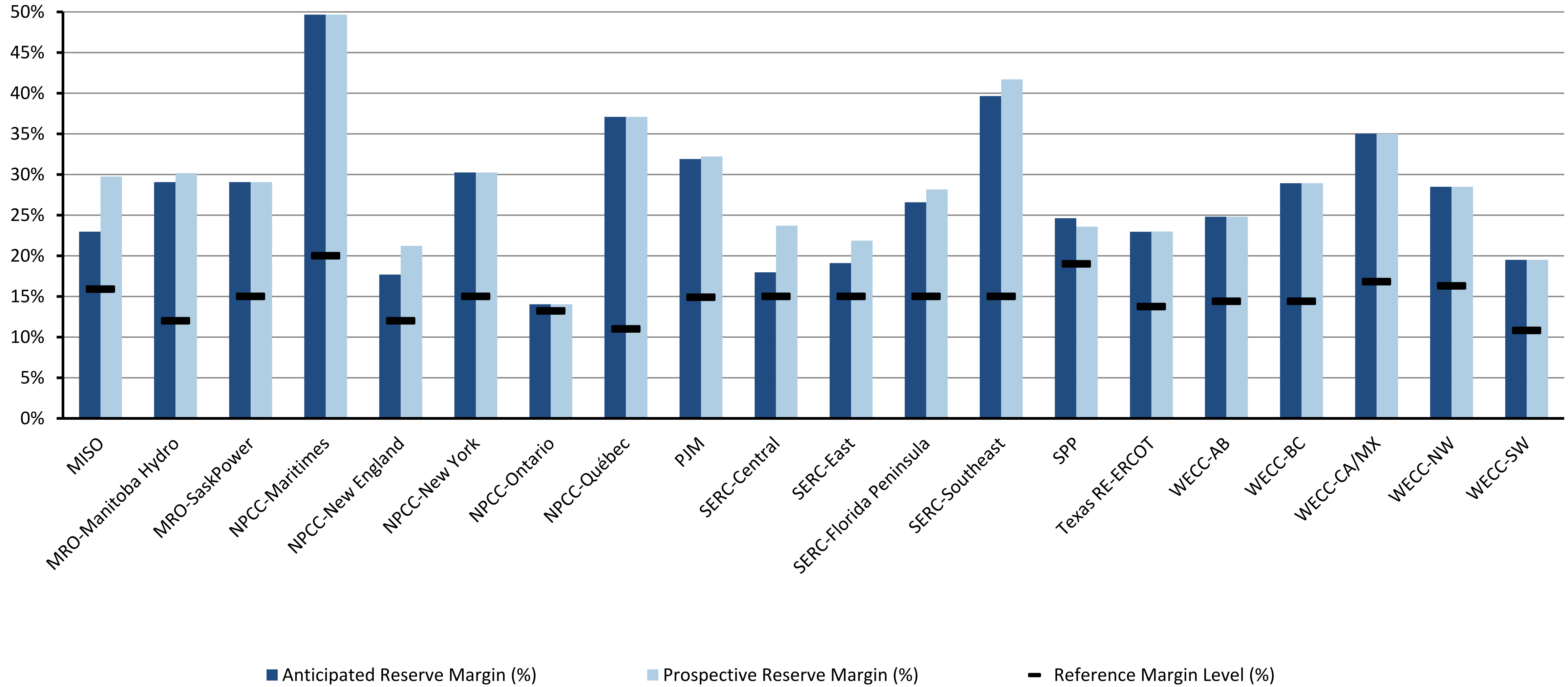
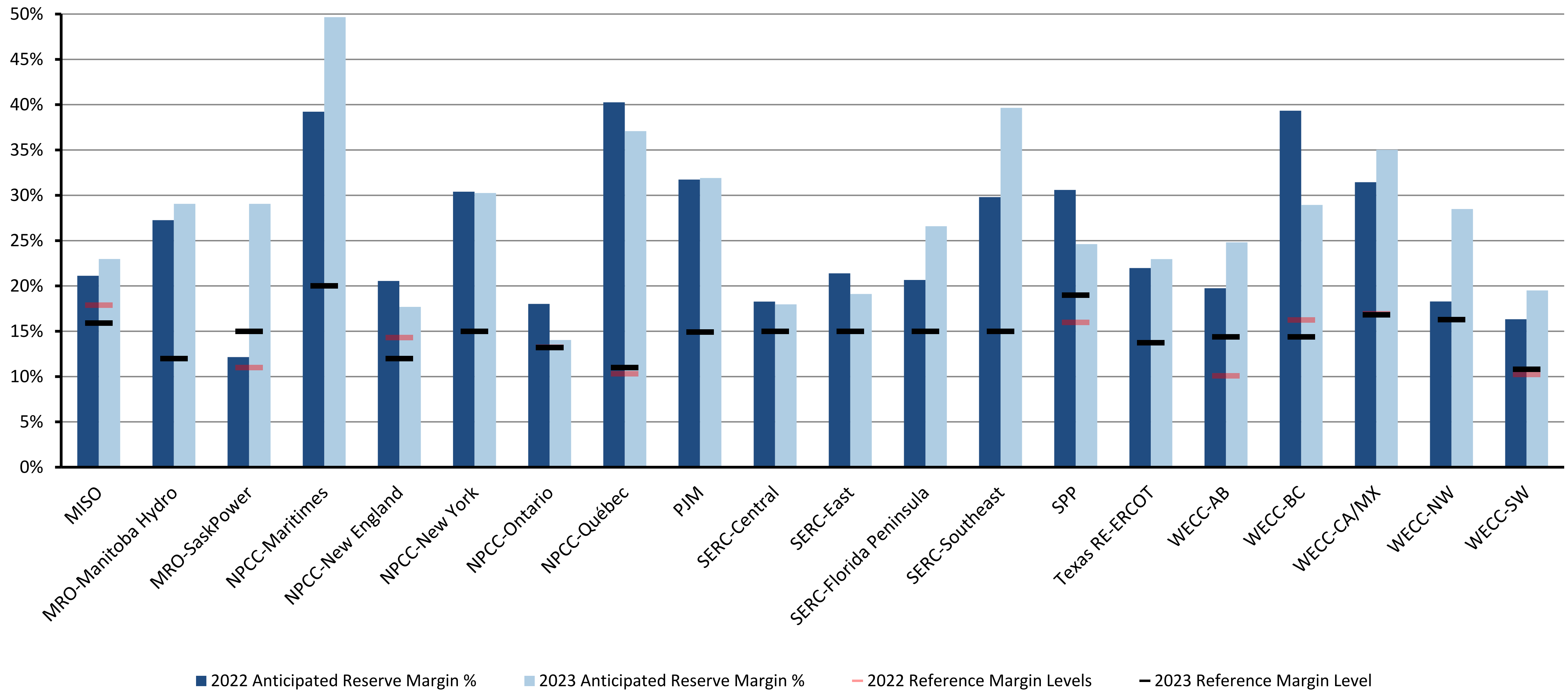


Figure 4: Summer 2023 Anticipated/Prospective Reserve Margins Compared to Reference Margin Level

[14] Generally, anticipated resources include generators and firm capacity transfers that are expected to be available to serve load during electrical peak loads for the season. Prospective resources are those that could be available but do not meet criteria to be counted as anticipated resources. Refer to the **Data Concepts and Assumptions** section for additional information on Anticipated/Prospective Reserve Margins, anticipated/prospective resources, and Reference Margin Levels.

Changes from Year-to-Year

Figure 5 provides the relative change in the forecast Anticipated Reserve Margins from the 2022 summer to the 2023 summer. A significant decline can indicate potential operational issues that emerge between reporting years. NPCC-Ontario, SPP and WECC-BC have noticeable reductions in anticipated resources with NPCC-Ontario close to falling below its Reference Margin Level for the 2023 summer. NPCC-Ontario is experiencing ongoing nuclear refurbishments and recent retirements will make it difficult to accommodate unplanned generator or transmission outages. NPCC-Ontario will rely on demand response and transfers from neighbors during a higher load scenario to avoid load interruption. The lower Anticipated Reserve Margins for NPCC-Maritimes, NPCC-Québec, SERC-C, and WECC-AB do not present reliability concerns on peak for this upcoming summer. Additional details for each assessment area are provided in the **Data Concepts and Assumptions** and **Regional Assessments Dashboards** sections.



Note: The areas that only have one bar have the same Reference Margin Level for both years.

Figure 5: Summer 2022 and Summer 2023 Anticipated Reserve Margins Year-to-Year Change

Net Internal Demand

The changes in forecasted Net Internal Demand for each assessment area are shown in Figure 6.[15] Assessment areas develop these forecasts based on historic load and weather information as well as other long-term projections.

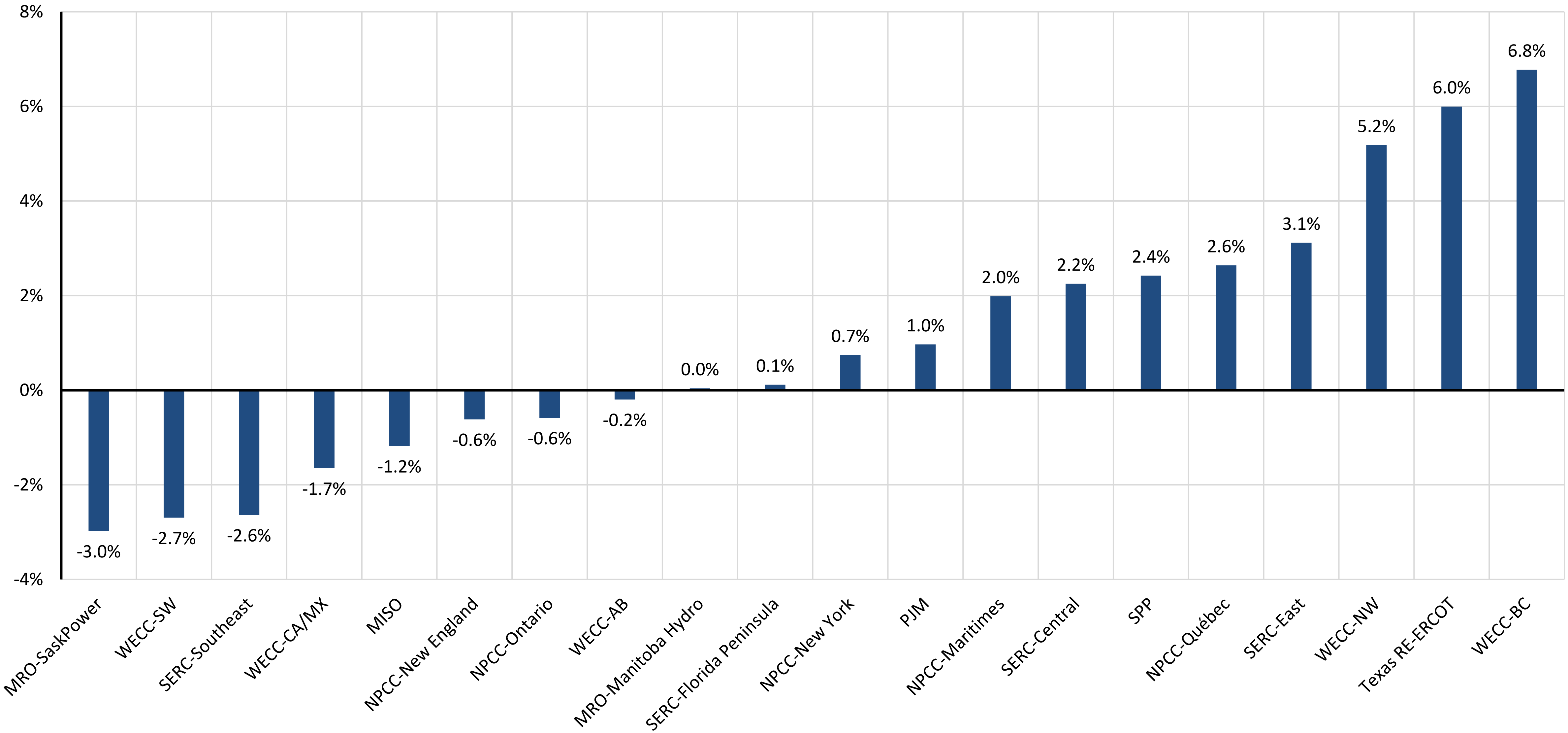


Figure 6: Change in Net Internal Demand—Summer 2022 Forecast Compared to Summer 2023 Forecast

[15] Changes in modeling and methods may also contribute to year-to-year changes in forecasted net internal demand projections.

Demand and Resource Tables

Peak demand and supply capacity data—resource adequacy data—for each assessment area are as follows in each table (in alphabetical order).

MISO			
Demand, Resource, and Reserve Margins	**2022 SRA**	**2023 SRA**	**2022 vs. 2023 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	124,506	123,728	-0.6%
Demand Response: Available	6,287	6,903	9.8%
Net Internal Demand	118,220	116,825	-1.2%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	141,844	140,650	-0.8%
Tier 1 Planned Capacity	0	0	-
Net Firm Capacity Transfers	1,353	3,018	123.1%
Anticipated Resources	143,197	143,668	0.3%
Existing-Other Capacity	669	668	-0.1%
Prospective Resources	149,756	151,579	1.2%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	21.1%	23.0%	1.8
Prospective Reserve Margin	26.7%	29.7%	3.1
Reference Margin Level	17.9%	15.9%	-2.0

MRO-Manitoba Hydro			
Demand, Resource, and Reserve Margins	**2022 SRA**	**2023 SRA**	**2022 vs. 2023 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	3,059	3,060	0.0%
Demand Response: Available	0	0	-
Net Internal Demand	3,059	3,060	0.0%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	5,523	5,731	3.8%
Tier 1 Planned Capacity	186	91	-50.9%
Net Firm Capacity Transfers	-1,816	-1,872	3.1%
Anticipated Resources	3,893	3,950	1.5%
Existing-Other Capacity	44	34	-23.4%
Prospective Resources	3,937	3,984	1.2%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	27.3%	29.1%	1.8
Prospective Reserve Margin	28.7%	30.2%	1.5
Reference Margin Level	12.0%	12.0%	0.0

MRO-SaskPower			
Demand, Resource, and Reserve Margins	**2022 SRA**	**2023 SRA**	**2022 vs. 2023 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	3,656	3,539	-3.2%
Demand Response: Available	60	50	-16.7%
Net Internal Demand	3,596	3,489	-3.0%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	3,743	4,213	12.6%
Tier 1 Planned Capacity	0	0	-
Net Firm Capacity Transfers	290	290	0.0%
Anticipated Resources	4,033	4,503	11.7%
Existing-Other Capacity	0	0	-
Prospective Resources	4,033	4,503	11.7%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	12.2%	29.1%	16.9
Prospective Reserve Margin	12.2%	29.1%	16.9
Reference Margin Level	11.0%	15.0%	4.0

NPCC-Maritimes			
Demand, Resource, and Reserve Margins	**2022 SRA**	**2023 SRA**	**2022 vs. 2023 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	3,475	3,612	3.9%
Demand Response: Available	255	328	28.6%
Net Internal Demand	3,220	3,284	2.0%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	4,419	4,834	9.4%
Tier 1 Planned Capacity	0	0	-
Net Firm Capacity Transfers	64	81	26.6%
Anticipated Resources	4,483	4,915	9.6%
Existing-Other Capacity	0	0	-
Prospective Resources	4,483	4,915	9.6%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	39.2%	49.7%	10.4
Prospective Reserve Margin	39.2%	49.7%	10.4
Reference Margin Level	20.0%	20.0%	0.0

NPCC-New England			
Demand, Resource, and Reserve Margins	**2022 SRA**	**2023 SRA**	**2022 vs. 2023 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	25,300	25,111	-0.7%
Demand Response: Available	483	447	-7.5%
Net Internal Demand	24,817	24,664	-0.6%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	28,626	27,997	-2.2%
Tier 1 Planned Capacity	0	0	-
Net Firm Capacity Transfers	1,292	1,030	-20.3%
Anticipated Resources	29,918	29,027	-3.0%
Existing-Other Capacity	911	872	-4.3%
Prospective Resources	30,829	29,899	-3.0%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	20.6%	17.7%	-2.9
Prospective Reserve Margin	24.2%	21.2%	-3.0
Reference Margin Level	14.3%	12.0%	-2.3

NPCC-Ontario			
Demand, Resource, and Reserve Margins	**2022 SRA**	**2023 SRA**	**2022 vs. 2023 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	22,546	22,439	-0.5%
Demand Response: Available	666	687	3.1%
Net Internal Demand	21,880	21,752	-0.6%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	25,648	24,575	-4.2%
Tier 1 Planned Capacity	24	9	-61.5%
Net Firm Capacity Transfers	150	223	48.5%
Anticipated Resources	25,822	24,807	-3.9%
Existing-Other Capacity	0	0	-
Prospective Resources	25,822	24,807	-3.9%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	18.0%	14.0%	-4.0
Prospective Reserve Margin	18.0%	14.0%	-4.0
Reference Margin Level	13.3%	13.2%	0.0

NPCC-New York			
Demand, Resource, and Reserve Margins	**2022 SRA**	**2023 SRA**	**2022 vs. 2023 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	31,765	32,049	0.9%
Demand Response: Available	1,170	1,226	4.8%
Net Internal Demand	30,595	30,823	0.7%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	37,431	37,216	-0.6%
Tier 1 Planned Capacity	0	0	-
Net Firm Capacity Transfers	2,465	2,932	18.9%
Anticipated Resources	39,896	40,148	0.6%
Existing-Other Capacity	0	0	-
Prospective Resources	39,896	40,148	0.6%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	30.4%	30.3%	-0.1
Prospective Reserve Margin	30.4%	30.3%	-0.1
Reference Margin Level	15.0%	15.0%	0.0

NPCC-Québec			
Demand, Resource, and Reserve Margins	**2022 SRA**	**2023 SRA**	**2022 vs. 2023 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	22,271	22,859	2.6%
Demand Response: Available	0	0	-
Net Internal Demand	22,271	22,859	2.6%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	33,542	33,690	0.4%
Tier 1 Planned Capacity	0	0	-
Net Firm Capacity Transfers	-2,304	-2,353	2.1%
Anticipated Resources	31,238	31,337	0.3%
Existing-Other Capacity	0	0	-
Prospective Resources	31,238	31,337	0.3%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	40.3%	37.1%	-3.2
Prospective Reserve Margin	40.3%	37.1%	-3.2
Reference Margin Level	10.3%	11.0%	0.7

PJM			
Demand, Resource, and Reserve Margins	**2022 SRA**	**2023 SRA**	**2022 vs. 2023 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	148,938	149,059	0.1%
Demand Response: Available	8,527	7,288	-14.5%
Net Internal Demand	140,411	141,771	1.0%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	184,837	186,540	0.9%
Tier 1 Planned Capacity	10	0	-100.0%
Net Firm Capacity Transfers	124	463	273.4%
Anticipated Resources	184,971	187,003	1.1%
Existing-Other Capacity	0	0	-
Prospective Resources	185,095	187,466	1.3%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	31.7%	31.9%	0.2
Prospective Reserve Margin	31.8%	32.2%	0.4
Reference Margin Level	14.9%	14.9%	0.0

SERC-East			
Demand, Resource, and Reserve Margins	**2022 SRA**	**2023 SRA**	**2022 vs. 2023 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	42,883	43,889	2.3%
Demand Response: Available	1,298	1,008	-22.3%
Net Internal Demand	41,585	42,881	3.1%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	49,380	50,452	2.2%
Tier 1 Planned Capacity	486	0	-100.0%
Net Firm Capacity Transfers	612	624	2.0%
Anticipated Resources	50,478	51,076	1.2%
Existing-Other Capacity	1,097	1,182	7.8%
Prospective Resources	51,575	52,258	1.3%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	21.4%	19.1%	-2.3
Prospective Reserve Margin	24.0%	21.9%	-2.2
Reference Margin Level	15.0%	15.0%	0.0

SERC-Central			
Demand, Resource, and Reserve Margins	**2022 SRA**	**2023 SRA**	**2022 vs. 2023 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	41,267	42,223	2.3%
Demand Response: Available	1,841	1,910	3.7%
Net Internal Demand	39,426	40,313	2.2%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	47,424	46,964	-1.0%
Tier 1 Planned Capacity	0	93	-
Net Firm Capacity Transfers	-795	1,068	-
Anticipated Resources	46,629	47,556	2.0%
Existing-Other Capacity	4,808	2,313	-51.9%
Prospective Resources	51,437	49,868	-3.0%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	18.3%	18.0%	-0.3
Prospective Reserve Margin	30.5%	23.7%	-6.8
Reference Margin Level	15.0%	15.0%	0.0

SERC-Florida Peninsula			
Demand, Resource, and Reserve Margins	**2022 SRA**	**2023 SRA**	**2022 vs. 2023 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	52,172	52,195	0.0%
Demand Response: Available	2,932	2,898	-1.2%
Net Internal Demand	49,240	49,297	0.1%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	56,571	60,074	6.2%
Tier 1 Planned Capacity	2,540	1,742	-31.4%
Net Firm Capacity Transfers	300	589	96.3%
Anticipated Resources	59,411	62,405	5.0%
Existing-Other Capacity	847	776	-8.4%
Prospective Resources	60,258	63,181	4.9%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	20.7%	26.6%	5.9
Prospective Reserve Margin	22.4%	28.2%	5.8
Reference Margin Level	15.0%	15.0%	0.0

SERC-Southeast			
Demand, Resource, and Reserve Margins	**2022 SRA**	**2023 SRA**	**2022 vs. 2023 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	47,258	46,127	-2.4%
Demand Response: Available	1,946	2,010	3.3%
Net Internal Demand	45,312	44,117	-2.6%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	59,828	59,559	-0.4%
Tier 1 Planned Capacity	1,514	2,865	89.3%
Net Firm Capacity Transfers	-2,524	-815	-67.7%
Anticipated Resources	58,818	61,609	4.7%
Existing-Other Capacity	859	908	5.7%
Prospective Resources	59,677	62,517	4.8%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	29.8%	39.6%	9.8
Prospective Reserve Margin	31.7%	41.7%	10.0
Reference Margin Level	15.0%	15.0%	0.0

SPP			
Demand, Resource, and Reserve Margins	**2022 SRA**	**2023 SRA**	**2022 vs. 2023 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	52,040	53,468	2.7%
Demand Response: Available	658	842	27.9%
Net Internal Demand	51,382	52,626	2.4%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	67,245	65,821	-2.1%
Tier 1 Planned Capacity	0	0	-
Net Firm Capacity Transfers	-144	-238	65.0%
Anticipated Resources	67,101	65,583	-2.3%
Existing-Other Capacity	0	0	-
Prospective Resources	66,554	65,036	-2.3%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	30.6%	24.6%	-6.0
Prospective Reserve Margin	29.5%	23.6%	-5.9
Reference Margin Level	16.0%	19.0%	3.0

Texas RE-ERCOT			
Demand, Resource, and Reserve Margins	**2022 SRA**	**2023 SRA**	**2022 vs. 2023 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	77,317	82,307	6.5%
Demand Response: Available	2,856	3,380	18.3%
Net Internal Demand	74,461	78,927	6.0%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	89,603	94,580	5.6%
Tier 1 Planned Capacity	1,199	2,445	103.9%
Net Firm Capacity Transfers	20	20	0.0%
Anticipated Resources	90,822	97,045	6.9%
Existing-Other Capacity	0	0	-
Prospective Resources	90,850	97,073	6.9%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	22.0%	23.0%	1.0
Prospective Reserve Margin	22.0%	23.0%	1.0
Reference Margin Level	13.75%	13.75%	0.0

WECC-AB			
Demand, Resource, and Reserve Margins	**2022 SRA**	**2023 SRA**	**2022 vs. 2023 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	11,228	11,206	-0.2%
Demand Response: Available	0	0	-
Net Internal Demand	11,228	11,206	-0.2%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	11,926	13,759	15.4%
Tier 1 Planned Capacity	1,082	227	-79.0%
Net Firm Capacity Transfers	437	0	-100.0%
Anticipated Resources	13,445	13,986	4.0%
Existing-Other Capacity	0	0	-
Prospective Resources	13,445	13,986	4.0%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	19.7%	24.8%	5.1
Prospective Reserve Margin	19.7%	24.8%	5.1
Reference Margin Level	10.1%	9.9%	-0.2

WECC-BC			
Demand, Resource, and Reserve Margins	**2022 SRA**	**2023 SRA**	**2022 vs. 2023 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	8,088	8,636	6.8%
Demand Response: Available	0	0	-
Net Internal Demand	8,088	8,636	6.8%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	11,266	11,135	-1.2%
Tier 1 Planned Capacity	3	0	-100.0%
Net Firm Capacity Transfers	0	0	-
Anticipated Resources	11,269	11,135	-1.2%
Existing-Other Capacity	0	0	-
Prospective Resources	11,269	11,135	-1.2%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	39.3%	28.9%	-10.4
Prospective Reserve Margin	39.3%	28.9%	-10.4
Reference Margin Level	16.3%	14.4%	-1.9

WECC-CA / MX			
Demand, Resource, and Reserve Margins	**2022 SRA**	**2023 SRA**	**2022 vs. 2023 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	57,269	56,356	-1.6%
Demand Response: Available	844	862	2.2%
Net Internal Demand	56,425	55,494	-1.7%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	70,791	69,408	-2.0%
Tier 1 Planned Capacity	3,381	5,522	63.3%
Net Firm Capacity Transfers	0	0	-
Anticipated Resources	74,172	74,930	1.0%
Existing-Other Capacity	0	0	-
Prospective Resources	74,172	74,930	1.0%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	31.5%	35.0%	3.6
Prospective Reserve Margin	31.5%	35.0%	3.6
Reference Margin Level	16.9%	16.8%	-0.1

WECC-SW			
Demand, Resource, and Reserve Margins	**2022 SRA**	**2023 SRA**	**2022 vs. 2023 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	26,720	25,992	-2.7%
Demand Response: Available	399	380	-4.7%
Net Internal Demand	26,321	25,612	-2.7%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	28,249	26,206	-7.2%
Tier 1 Planned Capacity	1,369	1,655	20.9%
Net Firm Capacity Transfers	1,002	2,747	174.2%
Anticipated Resources	30,620	30,608	0.0%
Existing-Other Capacity	0	0	-
Prospective Resources	30,620	30,608	0.0%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	16.3%	19.5%	3.2
Prospective Reserve Margin	16.3%	19.5%	3.2
Reference Margin Level	10.2%	10.8%	0.6

WECC-NW			
Demand, Resource, and Reserve Margins	**2022 SRA**	**2023 SRA**	**2022 vs. 2023 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	63,214	66,366	5.0%
Demand Response: Available	1,104	1,038	-6.0%
Net Internal Demand	62,110	65,328	5.2%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	70,154	76,587	9.2%
Tier 1 Planned Capacity	798	2,350	194.5%
Net Firm Capacity Transfers	2,517	5,004	98.8%
Anticipated Resources	73,469	83,941	14.3%
Existing-Other Capacity	0	0	-
Prospective Resources	73,469	83,941	14.3%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	18.3%	28.5%	10.2
Prospective Reserve Margin	18.3%	28.5%	10.2
Reference Margin Level	16.1%	16.3%	0.2

Variable Energy Resource Contributions

Because the electrical output of variable energy resources (e.g., wind, solar PV) depends on weather conditions, on-peak capacity contributions are less than nameplate capacity. The following table shows the capacity contribution of existing wind and solar PV resources at the peak demand hour for each assessment area. Resource contributions are also aggregated by Interconnection and across the entire BPS. For NERC's analysis of risk periods after peak demand (i.e., U.S. assessment areas in WECC), lower contributions of solar PV resources are used because output is diminished during evening periods.

BPS Variable Energy Resources by Assessment Area									
	Wind			Solar			Hydro		
Assessment Area / Interconnection	Nameplate Wind	Expected Wind	Expected Share of Nameplate (%)	Nameplate Solar PV	Expected Solar PV	Expected Share of Nameplate (%)	Nameplate Hydro	Expected Hydro	Expected Share of Nameplate (%)
MISO	30,373	5,488	18%	7,499	3,750	50%	4,884	4,688	96%
MRO-Manitoba Hydro	259	47	18%	-	-	0%	6,220	5,548	89%
MRO-SaskPower	615	203	33%	30	-	0%	851	797	94%
NPCC-Maritimes	1,212	255	21%	4	-	0%	1,315	1,183	90%
NPCC-New England	1,448	186	13%	2,914	1,163	40%	3,565	2,472	69%
NPCC-New York	2,879	331	12%	179	84	47%	6,731	5,067	75%
NPCC-Ontario	4,943	771	16%	478	126	26%	8,985	5,185	58%
NPCC-Québec	3,880	-	0%	10	-	0%	40,307	32,974	82%
PJM	10,923	1,688	15%	5,169	2,984	58%	3,027	3,027	100%
SERC-Central	1,206	564	47%	885	511	58%	4,967	3,315	67%
SERC-East	-	-	0%	1,475	1,473	99%	3,064	3,013	98%
SERC-Florida Peninsula	-	-	0%	7,724	4,534	59%	-	-	0%
SERC-Southeast	-	-	0%	5,305	4,647	88%	3,242	3,288	101%
SPP	32,028	4,500	14%	440	378	86%	5,465	4,996	91%
Texas RE-ERCOT	30,938	10,293	33%	15,958	12,509	78%	563	477	85%
WECC-AB	3,619	309	9%	1,165	763	65%	894	416	47%
WECC-BC	747	137	18%	2	1	50%	16,519	10,124	61%
WECC-CA/MX	9,362	1,111	12%	21,975	14,489	66%	13,957	4,606	33%
WECC-SW	2,994	593	20%	3,493	1,411	40%	1,202	844	70%
WECC-NW	20,296	3,968	20%	9,270	5,062	55%	41,860	22,752	54%
EASTERN INTERCONNECTION	85,886	14,032	16%	32,102	19,649	61%	52,316	42,578	81%
QUÉBEC INTERCONNECTION	3,880	-	0%	10	-	0%	40,307	32,974	82%
TEXAS INTERCONNECTION	30,938	10,293	33%	15,958	12,509	78%	563	477	85%
WECC INTERCONNECTION	37,018	6,118	17%	35,905	21,726	61%	74,432	38,742	52%
INTERCONNECTION TOTAL:	**157,722**	**30,443**	**19%**	**83,975**	**53,885**	**64%**	**167,618**	**114,771**	**68%**

Probabilistic Assessment

Regional Entities and assessment areas provided a resource adequacy risk assessment that was probability-based for the summer season. Results are included in the Highlights section of each assessment area's dashboard and summarized in the table below. The risk assessments account for the hour(s) of greatest risk of resource shortfall. For most areas, the hour(s) of risk coincide with the time of forecasted peak demand; however, some areas incur the greatest risk at other times based on the varying demand and resource profiles. Various risk metrics are provided and include LOLE, LOLH, EUE, and the probabilities of EEA occurrence.

Probability-Based Risk Assessment		
Assessment Area	**Type of Assessment**	**Results and Insight From Assessment**
MISO	Annual probabilistic LOLE study	MISO's RML decreased from 17.9% in 2022 to 15.9% for Summer 2023. The change results from implementing seasonal forced outages and probabilistic distributions of non-firm imports. Operating mitigations are needed in extreme peak summer conditions.
MRO-Manitoba	Verification of NERC 2022 Probabilistic Assessment (2022 ProbA)	The 2022 ProbA results indicate 29 MWh per year of EUE for 2024. Given comparable supply and demand balance, the 2024 EUE is a reasonable estimate for all of 2023. EUE for summer is less than the annual EUE.
MRO-SaskPower	Probability-based capacity adequacy assessment	Results indicate that the expected number of hours with operating reserve deficiency for the 2023 summer season (June to September) is 0.21 hours. September is the month with highest risk.
NPCC	NPCC conducted an all-hour Probabilistic Assessment that consisted of a base case and several more severe scenarios examining low resources, reduced imports, and higher loads. The highest peak load scenario has a 7% probability of occurring.	The assessment forecasts that the NPCC Regional Entity will have an adequate supply of electricity this summer. Necessary strategies and procedures are in place to deal with operational challenges and emergencies as they may develop. Results of the probabilistic analysis by assessment area are below.
NPCC-Maritimes		NPCC's assessment results indicate that Maritimes is likely to use a combination of imports and operating procedures to mitigate resource shortages this summer. Cumulative LOLE (<0.03 days/summer), LOLH (<0.11 hours/summer), or EUE (<5 MWh/summer) were estimated over the May–September summer for all modeled scenarios.
NPCC-New England		NPCC's assessment results indicate that ISO-NE may rely on limited use of its operating procedures to mitigate resource and energy shortages during the summer. The reduced resource case with the highest peak load scenario resulted in a small estimated cumulative LOLE risk (0.12 days/period) with associated LOLHs (0.4 hours/period) and EUE (175 MWh/period) with the highest risk occurring in June. This scenario is based exclusively on the two highest load levels with a 7% chance of occurring and a low resource case consisting of extended summer maintenance across NPCC and reduced imports from PJM.
NPCC-New York		NPCC's assessment results indicate that NYISO may rely on limited use of its operating procedures to mitigate resource and energy shortages during the summer. The reduced resource case with the highest peak load scenario resulted in a small estimated cumulative LOLE risk (0.5 days/summer) with associated LOLH (1.1 hours/summer) and EUE (525 MWh/summer). The highest risk is in June and August.
NPCC-Ontario		NPCC's assessment results indicate that Ontario is likely to use a combination of imports and operating procedures to mitigate resource shortages this summer. Negligible cumulative LOLE, LOLH, and EUE risks were estimated over the summer period for all modeled scenarios, including the severe low-likelihood cases. These results indicate that Ontario will be able to obtain necessary supplies from neighbors over a range of conditions.

Probability-Based Risk Assessment		
Assessment Area	**Type of Assessment**	**Results and Insight From Assessment**
NPCC-Québec		Québec is expected to need only limited use of its operating procedures designed to mitigate resource and energy shortages during the summer. Negligible cumulative LOLE, LOLH, and EUE risks were estimated over the summer period for all modeled scenarios, including the severe low-likelihood cases.
PJM	Based on 2022 PJM Reserve Requirement Study (RRS)	PJM is expecting a low risk of resources falling below required operating reserves. PJM forecasts a 29% installed reserve margin, well above the target of 14.9%. Due to the low penetration of variable energy resources in PJM relative to PJM's peak load, the hour with most loss of load risk remains the hour with highest forecasted demand.
SERC	Verification of NERC 2022 ProbA Results	The 2022 Base Case results indicated adequate resources for the SERC Region as a whole with an observed LOLE of 0.03 days/year for the year 2024. Trends from 2022 to 2023 indicate little change in study results, so SERC does not anticipate resource adequacy risk for the upcoming summer season.
SERC-Central		Probabilistic analysis indicates no risk for resource shortfall.
SERC-East		Probabilistic analysis shows low risk for July and August with EUE of 2.38 MWh and LOLH 0.005 hours.
SERC-Florida Peninsula		SERC Probabilistic analysis indicates no risk of resource shortfall.
SERC-Southeast		Probabilistic analysis indicates almost no risk of resource shortfall.
SPP	Statistical analysis of the Summer 2022 real time data; Operational process and procedures	Potential risk of using operating reserves and EEA1 or EEA2 is 1 day per summer. Risk of EEA3 is 0.2 days per summer. Risks is associated with low wind generation output levels or unanticipated generation outages in combination with high load periods.
Texas RE-ERCOT	ERCOT's Summer 2023 Probabilistic Assessment	There is a 4% probability that ERCOT will declare an EEA1 during the expected daily peak load hour; Increasing up to 19% probability at the highest risk hour and ending at 8:00 p.m.
WECC	The 2022 Western Assessment of Resource Adequacy provides the most recent probability-based resource adequacy risk assessment for Summer 2023 across WECC's areas.	The Western Interconnection is experiencing heightened reliability risks heading into Summer 2023 due to increased supply-side shortages and fuel constraints along with the ongoing drought impacts in some areas, continued wildfire threats, and expanding heat wave events. The installation of new resources for the summer and the availability of the imports, especially during wide-area heat events, affects resource adequacy for the U.S. assessment areas. The reliability and resource adequacy of the Western Interconnection depends on the ability to move power throughout the footprint.
WECC-AB		Alberta is expected to have sufficient resource availability to meet demand and cover reserves on the peak hour at 4:00 p.m. under a summer peak defined at the 90th percentile with any combination or accumulation of derates.
WECC-BC		BC is expected to have sufficient resource availability to meet demand and cover reserves on the peak hour at 4:00 p.m. under a summer peak defined at the 90th percentile with any combination or accumulation of derates.
WECC-CA/MX		WECC-CA/MX is projected to have negligible-to-low amounts of LOLH (<0.5 hours) this summer with variation attributable to the amount of Tier 1 resources that connect before the later months. Resources are sufficient to meet demand and cover reserves on the peak hour at 3:00

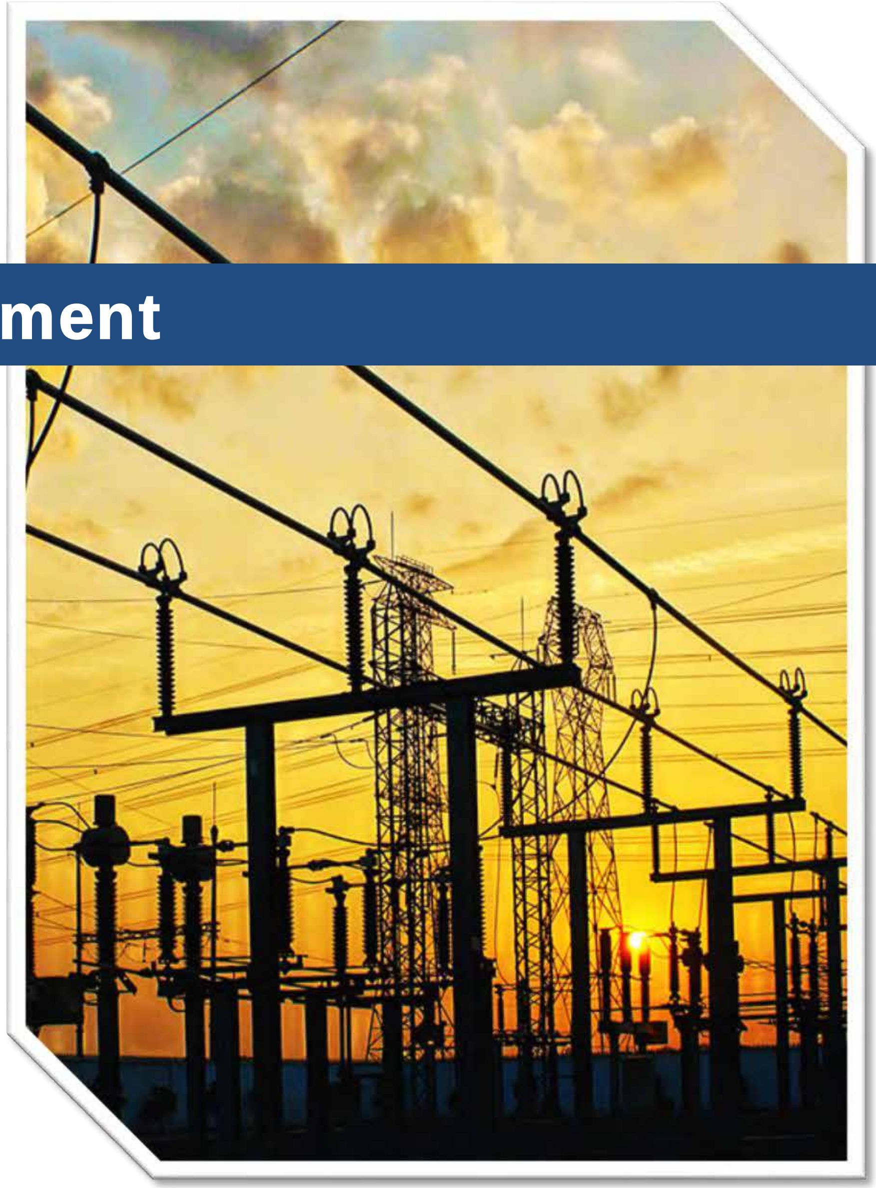
Probability-Based Risk Assessment		
Assessment Area	**Type of Assessment**	**Results and Insight From Assessment**
		p.m. under a summer peak defined at the 90th percentile with any combination or accumulation of derates. However, there is increased risk of insufficient reserves at later hours (up to 8:00 p.m.) due to the variability of energy resource output. Imports to the area are required to cover these risk periods; however, regional resource availability and transmission constraints can affect external assistance during wide area heat events.
WECC-NW		WECC-NW assessment area is projected to have negligible LOLH and EUE this summer with planned resource additions and normal transfer availability. However, some LOLH (<0.1) and EUE (<400 MWh) is anticipated during above-normal demand periods if new resource are delayed or external transfers are disrupted. WECC-NW would rely on imports to maintain adequate reserves on the during the risk hours from 4:00–9:00 p.m. under extreme summer peak load and low-resource conditions (e.g., extreme thermal or extreme hydro derates or combinations of other low energy output scenarios.)
WECC-SW		WECC-SW assessment area is projected to have negligible LOLH and EUE this summer with planned resource additions and normal transfer availability. However, some LOLH (<0.1) and EUE (<150 MWh) is anticipated during above-normal demand periods if new resource are delayed or external transfers are disrupted.

Errata

May 2023

- The Risk Scenario Summaries for SERC-Central and SERC-East were corrected (page 23 and page 24)

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION



2024 Summer Reliability Assessment

May 2024

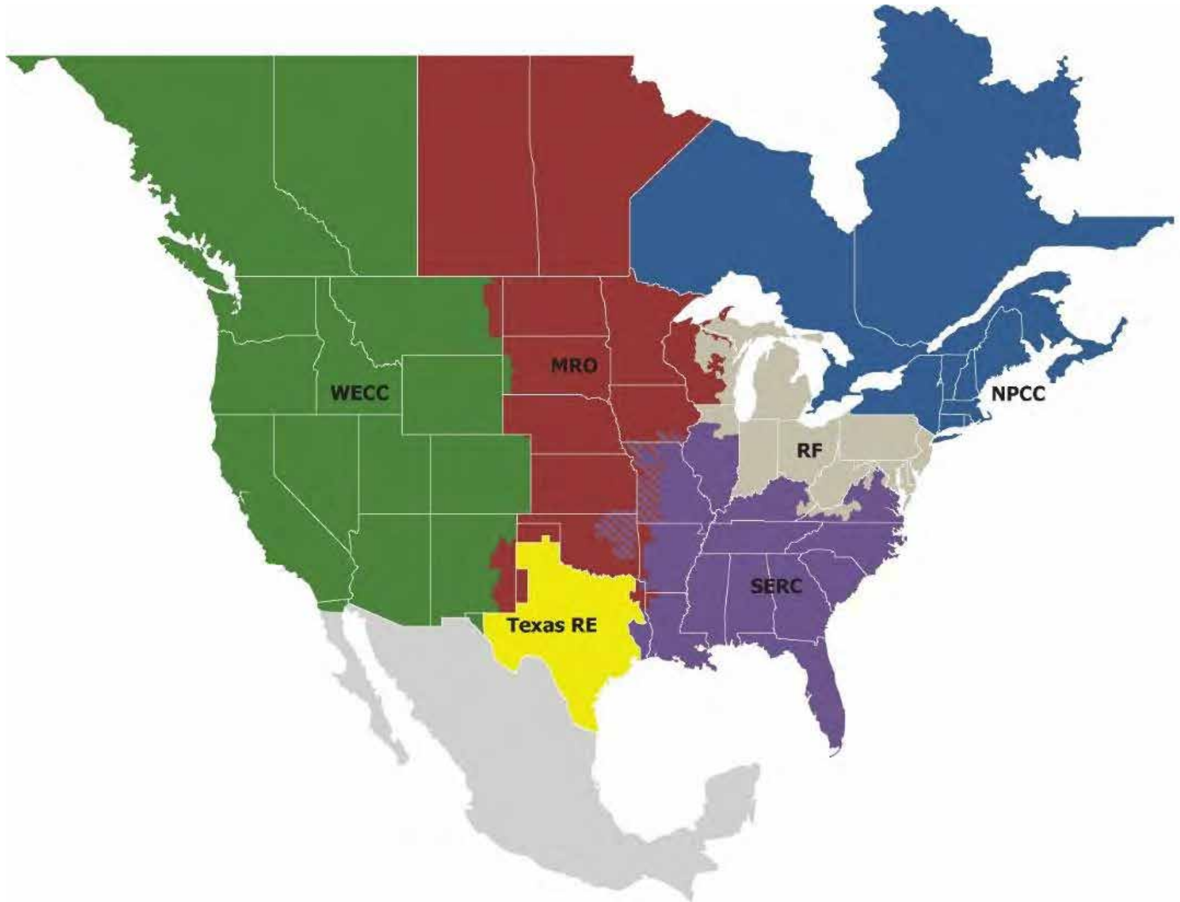
Table of Contents

Preface

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

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

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



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

About this Assessment

NERC's *2024 Summer Reliability Assessment* (*SRA*) identifies, assesses, and reports on areas of concern regarding the reliability of the North American BPS for the upcoming summer season. In addition, the *SRA* presents peak electricity demand and supply changes and highlights any unique regional challenges or expected conditions that might affect the reliability of the BPS. The reliability assessment process is a coordinated reliability evaluation between the NERC Reliability Assessment Subcommittee, the Regional Entities, and NERC staff with demand and resource projections obtained from the assessment areas. This report reflects an independent assessment by NERC and the ERO Enterprise and is intended to inform industry leaders, planners, operators, and regulatory bodies so that they are better prepared to take necessary actions to ensure BPS reliability. This report also provides an opportunity for industry to discuss plans and preparations to ensure reliability for the upcoming summer period.

Key Findings

NERC's annual *SRA* covers the upcoming four-month (June–September) summer period. This assessment evaluates generation resource and transmission system adequacy as well as energy sufficiency to meet projected summer peak demands and operating reserves. This includes a deterministic evaluation of data submitted for peak demand hour and peak risk hour as well as results from recently updated probabilistic analyses. Additionally, this assessment identifies potential reliability issues of interest and regional topics of concern. While the scope of this seasonal assessment is focused on the upcoming summer, the key findings are consistent with risks and issues that NERC highlighted in the *2023 Long-Term Reliability Assessment (LTRA*), covering a 10-year horizon, and other earlier reliability assessments and reports.[1]

The following findings are derived from NERC and the ERO Enterprise's independent evaluation of electricity generation and transmission capacity as well as potential operational concerns that may need to be addressed for the 2024 summer.

Resource Adequacy Assessment and Energy Risk Analysis

All areas are assessed as having adequate anticipated resources for normal summer peak load conditions (see **Figure 1**). However, the following areas face risks of electricity supply shortfalls during periods of more extreme summer conditions. This determination of elevated risk is based on analysis of plausible scenarios, including 90/10 demand forecasts and historical high outage rates as well as low wind or solar photovoltaic (PV) energy conditions:

- **Midcontinent Independent System Operator (MISO):** New solar and natural-gas-fired generation and additional demand response (DR) resources are offset by generator retirements, lower firm imports, and increased reserve requirements. MISO is expected to have sufficient resources, including firm imports, for normal summer peak demand. However, it can be challenging for MISO to meet above-normal peak demand if wind and solar resource output is lower than expected. Wind generator performance during periods of high demand is a key factor in determining whether there is sufficient electricity supply on the system or if external (non-firm) supply assistance is required to maintain reliability.
- **MRO-SaskPower:** Despite being primarily a winter-peaking area, Saskatchewan can face high electricity demand during hot summer weather conditions. Since 2023, both electricity demand and supply resources have increased, resulting in a 1.2% increase in reserve margin for the summer. Unanticipated generator outages that coincide with peak demand can result in insufficient reserves, a condition that operators will seek to alleviate through short-term transfers from neighbors and demand-side management.
- **NPCC-New England:** With the retirement of two natural-gas-fired generators at Mystic Generating Station in May 2024 (1,400 MW combined summer capacity), ISO New England will have less capacity this summer. This makes it more likely that ISO New England will need to resort to operating procedures for obtaining resources or non-firm supplies from neighboring areas during periods of above-normal peak demand or low-resource conditions. Summer heat waves that extend over the entire area can limit the availability of excess supplies and increase the risk of energy emergencies in New England.
- **Texas RE-ERCOT:** As a result of continued vigorous growth in both loads and solar and wind resources, there is a risk of emergency conditions in the summer evening hours when solar generation begins to ramp down. Contributing to the elevated risk is a potential need, under certain grid conditions, to limit power transfers from South Texas into the San Antonio region. These grid conditions can occur when demand is high and wind and solar output is low in specific areas, straining the transmission system and necessitating South Texas generation curtailments and potential firm load shedding to avoid cascading outages.
- **WECC-BC:** The peak demand forecast in the province of British Columbia has increased by over 600 MW since 2023 (7.4%), contributing to a drop in Anticipated Reserve Margin by over 10 percentage points. Much of the province is experiencing significant drought, and long-term precipitation deficits can challenge electricity production at some hydropower generators. Above-normal demand and low-resource conditions can result in the need for imports from neighboring areas. However, external assistance can be at risk during wide-area heat events.
- **WECC-CA/MX:** New solar and battery resources are contributing to higher on-peak reserve margins (46.7%, up over 11 percentage points since 2023) for the upcoming summer. Winter precipitation and snowpack have alleviated drought conditions across California, making more output from the area's hydropower resources available to balance variability in wind and solar output. Probabilistic assessments performed by WECC show that the risks of load loss are similar to Summer 2023, ranging from negligible to 0.8 loss of load hours (LOLH) depending on how much of the area's new solar and battery resources (totaling nearly 6 GW of nameplate capacity) are completed over the summer. The loss-of-load risk in this analysis occurs primarily under above-normal demand and low-resource conditions (e.g., low solar output, below-normal imports due to wide-area heat conditions or transmission limitations). Furthermore, risk is concentrated in the Baja (Mexico) portion of the WECC-CA/MX

[1] NERC's long-term, seasonal, and special reliability assessments are published on the Reliability Assessments web page.

assessment area. The assessment area has adequate resources for normal summer conditions.

- **WECC-SW:** Both forecasted peak demand and resources have risen since last summer, yielding a modest increase in the anticipated on-peak reserve margin (22.0%, up 2.5 percentage points since 2023.) The area has sufficient resources for normal summer demand. However, extreme demand or low resource output scenarios will likely require additional non-firm imports from neighboring areas, which may be unavailable during wide-area heat events. The ongoing severe drought in the Southwest increases the risk that extreme conditions could impact the BPS this summer.

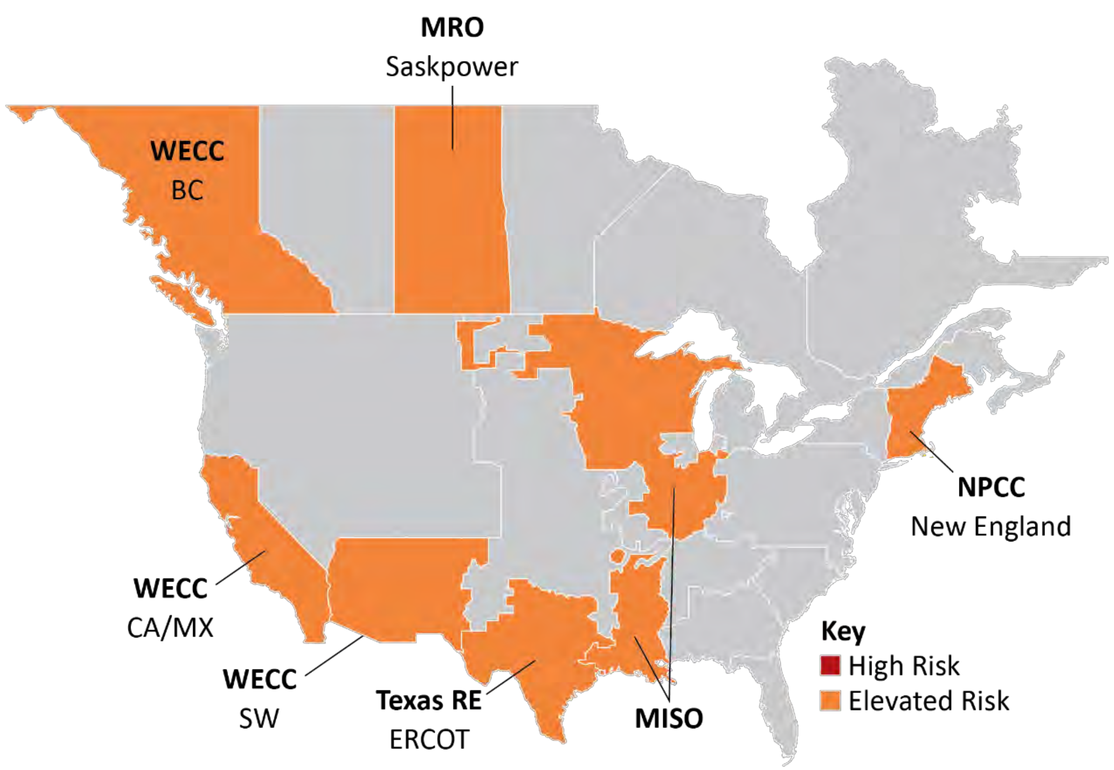


Figure 1: Summer Reliability Risk Area Summary

Seasonal Risk Assessment Summary	
High	Potential for insufficient operating reserves in normal peak conditions
Elevated	Potential for insufficient operating reserves in above-normal conditions
Normal	Sufficient operating reserves expected

New resources including 25 GW of nameplate solar capacity have been added to the BPS since last summer. Resource additions in assessment areas that were identified as at risk in the *2023 SRA* have largely outpaced rising demand forecasts and resulted in higher on-peak reserve margins. Four elevated-risk assessment areas from the *2023 SRA* are considered normal risk for the upcoming summer: NPCC-Ontario, SERC-Central, SPP, and WECC-NW. New firm transfer agreements, growth in DR, and postponed generator retirements are also contributing to an overall improved resource outlook for the upcoming summer. Details of each area are contained in the assessment area pages.

The findings in the *SRA* are consistent with conclusions reported in NERC's *2023 LTRA*. In assessing potential future electricity supply shortfalls over the 10-year horizon, NERC found that resource additions and delayed generator retirements have improved the outlook for 2024 in comparison to results reported in prior *LTRA*s. However, the *2023 LTRA* also found that a growing number of areas in North America face adequacy risks as early as 2025. NERC will publish the next *LTRA* in December 2024 based on demand forecasts, resource and transmission projections, and other information collected this year. NERC will also publish the 2024–2025 *Winter Reliability Assessment* in November to identify, assess, and report on BPS reliability issues for the next winter season.

Other Reliability Issues

- **Weather services are expecting above-average summer temperatures across much of North America, potentially creating challenging summer grid conditions.** Peak electricity demand in most areas is directly influenced by temperature. Above-average seasonal temperatures can contribute to high peak demand as well as an increase in forced outages for generation and some BPS equipment. Last summer brought record temperatures, extended heat waves, and wildfires to large parts of North America. Although few high-level energy emergency alerts were issued and no electricity supply disruptions occurred as a result of inadequate resources, operators at BAs, TOPs, and RCs faced significant challenges and drew upon procedures and protocols to obtain all available resources, manage system demand, and ensure that energy is delivered over the transmission network to meet the system demand. Additionally, load-serving entities and state and local officials in many parts of North America used mechanisms and public appeals to lower customer demand during periods of strained supplies. Operators should review lessons and experience from the prior summer and incorporate insights into their seasonal operations planning. The **Review of 2023 Capacity and Energy Performance** section describes actual demand and resource levels in comparison with NERC's *2023 SRA* and summarizes 2023 resource adequacy events.

- **Rising demand is challenging resource and transmission adequacy in several areas.** Most areas are forecasting increases in peak demand compared to last summer. The extent that demand forecasts have increased and the drivers affecting growth vary by area. In ERCOT, SPP, and British Columbia, the increases are among the highest and build on similar growth from the prior year. New data centers and cryptocurrency mining facilities are contributing to higher demand forecasts in ERCOT this summer, and some of these loads participate in demand-side management programs that can offset their impacts (see **Evolving Demand-Side Management Programs**). While resource additions in Texas, primarily solar PV, are outpacing demand increases, energy risks are growing during the hours when solar output is diminished. Further, transmission development is straining to connect new resources and deliver electricity supplies to growing load areas.

- **Occurrences involving the unexpected tripping of inverter-based resources (IBR) during grid disturbances continue to spread, underscoring the need for operator vigilance in the near term and urgent industry action on long-term solutions.** The tripping of BPS-connected solar PV generating units during grid faults has caused sudden loss of generation resources (over wide areas in some cases). Industry experience with unexpected tripping of BPS-connected solar PV generation units can be traced back to the 2016 Blue Cut fire in California. Similar events have occurred as recently as Summer 2023.[2] New event reports published by NERC analyzing the Southwest Utah disturbance (April 2023) and the California Battery Energy Storage disturbances (April and May 2022) illustrate that the reliability concern extends to more geographic areas and more than just solar PV resources. IBRs include most solar and wind generation as well as new battery energy storage systems (BESS) or hybrid generation and account for over 70% of the new generation in development for connecting to the BPS. IBRs respond to disturbances and dynamic conditions based on programmed logic and inverter controls. A common thread with these tripping events is the lack of IBR ride-through capability that causes a minor system disturbance to become a major disturbance. In March 2023, NERC issued the *Inverter-Based Resource Performance Issues Alert* to Generator Owners (GO) of Bulk Electric System (BES) solar PV generating resources.[3] As a Level 2 alert, it contains recommended actions for GOs of grid-connected solar PV resources, including steps to coordinate protection and controller settings, so that the resources will remain reliable during grid disturbances. NERC's comprehensive Inverter-Based Resources Strategy and FERC Order No. 901 describe additional steps for the ERO and industry to ensure that IBRs operate reliably and that the system is planned with due consideration for their characteristics.[4,5]
- **Stored supplies of natural gas are at high levels, but continued vigilance is needed to ensure the reliability of fuel delivery to natural-gas-fired-generators.[6]** The natural gas supply and infrastructure is vitally important to electric grid reliability, particularly as variable energy resources satisfy more of our energy needs. Fuel supply and delivery infrastructure must be capable of meeting the ramp rates of natural-gas-fired generators as they balance the system when wind and solar generation output declines. No specific reliability issues have been identified for the upcoming summer, but Reliability Coordinators (RC) and Balancing Authorities (BA) should be cognizant of natural gas supply infrastructure outage and maintenance plans that could affect generators in their areas.
- **Expanded demand-side management programs are an added resource for operators that should be carefully considered in operating plans and monitored during peak demand periods.** Formal DR programs involving commercial and industrial customers that have agreements with their load-serving entities to curtail load during high-demand periods have grown in many assessment areas. Additionally, some entities have launched programs with retail customers that also provide operator-controlled demand-side management capabilities. Operators will need to give special attention to new or expanded demand-side management programs in their planning if they are unfamiliar with protocols or uncertain about the amount of load relief that will be realized. These new mechanisms and protocols for controlling demand can support operating reliability and energy adequacy needs when they are effectively implemented and monitored.
- **Supply chain issues are delaying some new resource and transmission projects, raising concerns that some may not be completed prior to peak summer conditions.** Lead times for transformers, circuit breakers, transmission cables, switchgears, and insulators have increased significantly since 2020. Additionally, PV panels are more difficult to procure. These longer lead times can affect new project construction, existing asset upgrades, pre-seasonal maintenance, and the interconnection of new resources and customers. Long-term mitigation strategies include lengthening ongoing construction timelines and ordering surplus inventory in advance. In the near term, supply chain issues can exacerbate concerns in elevated risk areas and add operating challenges for the summer across the BPS. Should project delays emerge, affected GOs and Transmission Owners (TO) must communicate changes to BAs, Transmission Operators (TOP), and RCs so that impacts are understood and steps are taken to reduce risks of capacity deficiencies or energy shortfalls.
- **Wildfire risk areas cover a smaller portion of North America at the start of summer, lowering the likelihood that the BPS will be affected by fire conditions.** At the start of summer, Canadian wildfire information system officials assess that there is potential for above-average fire activity over a large region that extends from British Columbia to northwest Manitoba

[2] See the ERO's extensive IBR event reporting here: NERC Major Event Reports
[3] NERC Alert: Inverter Based Resource Performance Issues
[4] NERC IBR Activities
[5] FERC Order No. 901 - Final Rule Reliability Standards to Address Inverter-Based Resources
[6] Short-Term Energy Outlook - U.S. Energy Information Administration (EIA)

and includes Alberta and Saskatchewan. In the United States, Climate Prediction Center and Predictive Services outlooks for early summer indicate that above-normal significant fire potential is limited to portions of the U.S. Southwest and West Texas.[7] Nonetheless, wildfire risk in North America typically increases in later summer months as hotter and drier weather increases fire potential. BPS operation can be impacted in areas where wildfires are active as well as areas where there is heightened risk of wildfire ignition due to weather and ground conditions.

Recommendations

To reduce the risk of electricity shortfalls on the BPS this summer, NERC recommends the following:

- RCs, BAs, and TOPs in the elevated risk areas identified in the key findings should take the following actions:
  - Review seasonal operating plans and the protocols for communicating and resolving potential supply shortfalls in anticipation of potentially extreme demand levels
  - Employ conservative generation and transmission outage coordination procedures commensurate with long-range weather forecasts to ensure adequate resource availability
  - Engage state or provincial regulators and policymakers to prepare for efficient implementation of demand-side management mechanisms called for in operating plans
- GOs with solar PV resources should implement recommendations in the IBR performance issues alert that NERC issued in March 2023.[8]
- State regulators and industry should have protocols in place at the start of summer for managing emergent requests from generators for air-quality restriction waivers. If warranted, U.S. Department of Energy (DOE) action to exercise emergency authority under the Federal Power Act (FPA) section 202(c) may be needed to ensure that sufficient generation is available during extreme weather conditions.

[7] NIFC North American Outlook

[8] Industry Recommendation: Inverter-Based Resource Performance Issues

Discussion

Summer Temperature and Drought Forecasts

Peak electricity demand in most areas is directly influenced by temperature. Weather officials are expecting above-normal temperatures for much of the United States and Canada (see **Figure 2**). In addition, drought conditions continue across much of Canada and the U.S. Southwest, resulting in unique challenges to area electricity supplies and potential impacts on demand.[9] Assessment area load forecasts account for many years of historical demand data, often up to 30 years, to predict summer peak demand and prepare for more extreme conditions. Above-average seasonal temperatures can contribute to high peak demand as well as an increase in forced outages for generation and some BPS equipment. Effective preseason maintenance and preparations are particularly important to BPS reliability in severe or prolonged periods of above-normal temperatures.

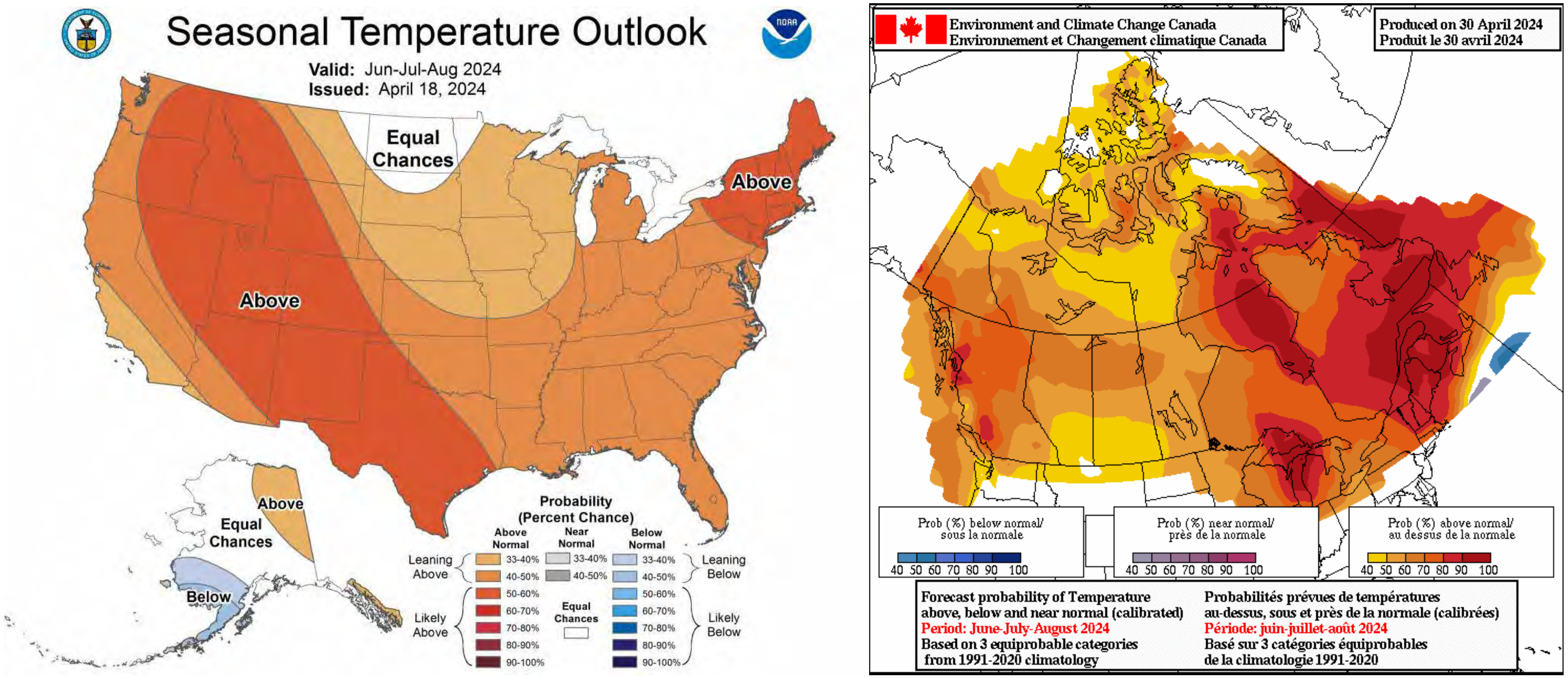


Figure 2: United States and Canada Summer Temperature Outlook[10]

[9] See North American Drought Monitor: https://www.ncdc.noaa.gov/temp-and-precip/drought/nadm/maps

[10] Seasonal forecasts obtained from U.S. National Weather Service and Natural Resources Canada: https://www.cpc.ncep.noaa.gov/products/predictions/long_range/ and https://weather.gc.ca/saisons/prob_e.html

Risk Assessment Discussion

NERC assesses the risk of electricity supply shortfall in each assessment area for the upcoming season by considering Planning Reserve Margins, seasonal risk scenarios, probability-based risk assessments, and other available risk information. NERC provides an independent assessment of the potential for each assessment area to have sufficient operating reserves under normal conditions as well as above-normal demand and low-resource output conditions selected for the assessment. A summary of the assessment approach is provided in **Table 1**.

Table 1: Seasonal Risk Assessment Summary

Category	Criteria[1]
High Potential for insufficient operating reserves in normal peak conditions	• Planning Reserve Margins do not meet Reference Margin Levels; or • Probabilistic indices exceed benchmarks (e.g., LOLH of 2.4 hours over the season); or • Analysis of the risk hour(s) indicates resources will not be sufficient to meet operating reserves under **normal peak-day demand and outage scenarios**[2]
Elevated Potential for insufficient operating reserves in above-normal conditions	• Probabilistic indices are low but not negligible (e.g., LOLH above 0.1 hours over the season); or • Analysis of the risk hour(s) indicates resources will not be sufficient to meet operating reserves under **extreme peak-day demand with normal resource scenarios** (i.e., typical or expected outage and derate scenarios for conditions);[2] or • Analysis of the risk hour(s) indicates resources will not be sufficient to meet operating reserves under **normal peak-day demand with reduced resources** (i.e., extreme outage and derate scenarios)[3]
Normal Sufficient operating reserves expected	• Probabilistic indices are negligible • Analysis of the risk hour(s) indicates resources will be sufficient to meet operating reserves under normal and extreme peak-day demand and outage scenarios[4]

Table Notes:

[1]The table provides general criteria. Other factors may influence a higher or lower risk assessment.

[2]**Normal resource scenarios** include planned and typical forced outages as well as outages and derates that are closely correlated to the extreme peak demand.

[3]**Reduced resource scenarios** include planned and typical forced outages and low-likelihood resource scenarios, such as extreme low-wind scenarios, low-hydro scenarios during drought years, or high thermal outages when such a scenario is warranted.

[4]Even in normal risk assessment areas, extreme demand and extreme outage scenarios that are not closely linked may indicate risk of operating reserve shortfall.

Assessment of Planning Reserve Margins and Operational Risk Analysis

Anticipated Reserve Margins, which provide the Planning Reserve Margins for normal peak conditions, as well as reserve margins for seasonal risk scenarios of more extreme conditions are provided in **Table 2**.

Table 2: Seasonal Risk Scenario On-Peak Reserve Margins

Assessment Area	Anticipated Reserve Margin	Anticipated Reserve Margin with Typical Outages	Anticipated Reserve Margin with Higher Demand, Outages, Derates in Extreme Conditions
MISO	26.1%	8.7%	-6.3%
MRO-Manitoba	15.7%	11.7%	5.1%
MRO-SaskPower	30.3%	26.5%	10.3%
MRO-SPP	27.8%	17.6%	-2.5%
NPCC-Maritimes	44.9%	34.5%	6.0%
NPCC-New England	15.9%	6.3%	3.3%
NPCC-New York	30.4%	11.4%	4.0%
NPCC-Ontario	26.2%	26.2%	19.8%
NPCC-Québec	44.1%	23.8%	18.2%
PJM	27.6%	17.9%	9.0%
SERC-C	24.3%	14.9%	14.7%
SERC-E	22.2%	16.3%	10.8%
SERC-FP	26.3%	19.3%	12.3%
SERC-SE	44.6%	41.1%	34.9%
TRE-ERCOT	25.6%	19.2%	11.5%
WECC-AB	30.5%	28.1%	8.6%
WECC-BC	18.8%	18.7%	-5.6%
WECC-CA/MX	46.7%	40.8%	5.4%
WECC-NW	35.5%	29.7%	1.1%
WECC-SW	22.0%	12.9%	-10.8%

Seasonal risk scenarios for each assessment area are presented in the **Regional Assessments Dashboards** section. The on-peak reserve margin and seasonal risk scenario charts in each dashboard provide potential summer peak demand and resource condition information. The reserve margins on the right side of the dashboard pages provide a comparison to the previous year's assessment. The seasonal risk scenario charts present deterministic scenarios for further analysis of different demand and resource levels with adjustments for normal and extreme conditions. The assessment areas determined the adjustments to capacity and peak demand based on methods or assumptions that are summarized in the seasonal risk scenario charts; more information about these dashboard charts is provided in the **Data Concepts and Assumptions** section.

The seasonal risk scenario charts can be expressed in terms of reserve margins: In **Table 2**, each assessment area's Anticipated Reserve Margins are shown alongside the reserve margins for a typical generation outage scenario (where applicable) and the extreme demand and resource conditions in their seasonal risk scenario.

Highlighted in **orange** are the areas identified as having resource adequacy or energy risks for the summer in the **Key Findings** section's discussion. The typical outage reserve margin includes anticipated resources minus the capacity that is likely to be in maintenance or forced outage at peak demand. If the typical maintenance or forced outage margin is the same as the Anticipated Reserve Margin, it is because an assessment area has already factored typical outages into the anticipated resources. The extreme conditions margin includes all components of the scenario and represents the most severe operating conditions of an area's scenario. Note that any reserve margin below zero indicates that the resources fall below demand in the scenario.

In addition to the peak demand and seasonal risk hour scenario charts, the assessment areas provided a resource adequacy risk assessment that was probability-based for the summer season. Results are summarized in **Table 3**. The risk assessments account for the hour(s) of greatest risk of resource shortfall. For most areas, the hour(s) of risk coincide with the time of forecasted peak demand; however, some areas incur the greatest risk at other times based on the varying demand and resource profiles. Various risk metrics are provided and include loss of load expectation (LOLE), LOLHs, expected unserved energy (EUE), and the probabilities of energy emergency alert (EEA) occurrence.

Energy Emergency Alerts

Extreme generation outages, low resource output, and peak loads similar to those experienced in wide-area heat events and the heat domes experienced in western parts of North America during the last three summers are ongoing reliability risks in certain areas for Summer 2024. When forecasted resources in an area fall below expected demand and operating reserve requirements, BAs may need to employ operating mitigations or EEAs to obtain the capacity and energy necessary for reliability. A description of each EEA level is provided below.

Energy Emergency Alert Levels

EEA Level	Description	Circumstances
EEA 1	All available generation resources in use	• The BA is experiencing conditions in which all available generation resources are committed to meet firm load, firm transactions, and reserve commitments and is concerned about sustaining its required contingency reserves. • Non-firm wholesale energy sales (other than those that are recallable to meet reserve requirements) have been curtailed.
EEA 2	Load management procedures in effect	• The BA is no longer able to provide its expected energy requirements and is an energy-deficient BA. • An energy-deficient BA has implemented its operating plan(s) to mitigate emergencies. • An energy-deficient BA is still able to maintain minimum contingency reserve requirements.
EEA 3	Firm load interruption is imminent or in progress	• The energy-deficient BA is unable to meet minimum contingency reserve requirements.

Table 3: Probability-Based Risk Assessment		
Assessment Area	**Type of Assessment**	**Results and Insight from Assessment**
MISO	NERC 2022 Probabilistic Assessment (2022 ProbA)	The 2022 ProbA results found 187 MWh EUE for Summer 2024 and <1 hour of LOLH. However, MISO has more resources and higher reserves for the summer than were considered in the 2022 ProbA, which should result in lower risk.
MRO-Manitoba	Verification of NERC 2022 Probabilistic Assessment (2022 ProbA)	The 2022 ProbA results indicate 29 MWh per year of EUE for 2024.
MRO-SaskPower	Probability-based capacity adequacy assessment	Results indicate that the expected number of hours with operating reserve deficiency for the 2024 summer season (June–September) is 0.68 hours. June is the month with highest risk.
MRO-SPP	Statistical analysis of the Summer 2022 real-time data and operating procedures	Potential risk of using operating reserves and EEA 1 or EEA 2 is 1 day per summer. Risk of EEA3 is 0.2 days per summer. Risk is associated with low wind generation output levels or unanticipated generation outages in combination with high-load periods.
NPCC	NPCC conducted an all-hour probabilistic assessment that consisted of a base case and several more severe scenarios examining low resources, reduced imports, and higher loads. The highest peak load scenario has a 7% probability of occurring.	NPCC Regional Entity assesses that there will be an adequate supply of electricity across the Regional Entity this summer. Necessary strategies and procedures are in place to deal with operational challenges and emergencies as they may develop. Preliminary results of the probabilistic analysis by assessment area are below. [NPCC anticipates releasing the assessment in early May].
NPCC-Maritimes		NPCC's assessment results indicate that Maritimes is unlikely to experience resource shortages that would require additional imports or operating procedures this summer. Negligible cumulative LOLE, LOLH, and EUE risks were estimated over the summer period for all modeled scenarios, including the severe low-likelihood cases.
NPCC-New England		NPCC's assessment results indicate that ISO-New England (ISO-NE) could experience resource shortages during high-demand and low-resource conditions and require limited use of operating procedures for mitigation. In NPCC's probabilistic assessment, the reduced resource case with the highest peak load scenario resulted in New England having a small estimated cumulative LOLE risk (0.66 days/summer) with associated LOLHs (2.7 hours/summer) and EUE (1,476 MWh/summer) with the highest risk occurring in June. This scenario is based exclusively on the two highest load levels with a 7% chance of occurring and a low-resource case consisting of extended summer maintenance across NPCC and reduced imports from PJM. Negligible cumulative LOLE (<0.022 days/summer), LOLH (<0.08hours/summer), and EUE (<17 MWh/summer) risks were estimated over the summer May–September period for the other scenarios modeled.
NPCC-New York		NPCC's assessment results indicate that New York ISO (NYISO) could experience resource shortages during high-demand conditions and require limited use of operating procedures for mitigation. In NPCC's probabilistic assessment, the highest peak load scenarios resulted in New York having a small estimated cumulative LOLE risk (1.6 days/summer) with associated LOLHs (5.9 hours/summer) and EUE (5,460 MWh/summer) with the highest risk occurring in July and August. Scenarios are based exclusively on the two highest load levels with a 7% chance of occurring. Negligible cumulative LOLE (<0.023 days/summer), LOLH (<0.07 hours/summer), and EUE (39 MWh/summer) were estimated over the summer period for the other scenarios modeled. Furthermore, the New York State Reliability Council conducts an annual study to determine the installed reserve margin (IRM) necessary to meet the 1 day in 10 years Loss of LOLE criterion. NYISO has procured capacity for the upcoming summer to meet the IRM requirement.

Table 3: Probability-Based Risk Assessment		
Assessment Area	**Type of Assessment**	**Results and Insight from Assessment**
NPCC-Ontario		NPCC's assessment results indicate that Ontario is unlikely to experience resource shortages that would require additional imports or operating procedures this summer. In NPCC's probabilistic assessment, the reduced resource case with the highest peak load scenario resulted in Ontario having a negligible cumulative LOLE risk (0.03 days/summer) with associated LOLHs (0.07 hours/summer) and EUE (33 MWh/summer) with the highest risk occurring in August. This scenario is based exclusively on the two highest load levels with a 7% chance of occurring and a low-resource case consisting of additional summer maintenance and low hydroelectric output. Negligible cumulative LOLE, LOLH, and EUE risks were estimated over the summer for the other scenarios modeled.
NPCC-Québec		NPCC's assessment results indicate that Québec is unlikely to experience resource shortages that would require additional imports or operating procedures this summer. Negligible cumulative LOLE, LOLH, and EUE risks were estimated over the summer period for all modeled scenarios, including the severe low-likelihood cases.
PJM	Based on 2023 PJM Reserve Requirement Study (RRS)	PJM is expecting a low risk of resources falling below required operating reserves. PJM forecasts a 29% IRM, well above the target of 17.7%. The RRS analyzed a wide range of load scenarios (low, regular, and extreme) as well as multiple scenarios for system-wide unavailable capacity due to forced outages, maintenance outages, and ambient derations. Due to the low penetration of variable energy resources in PJM relative to PJM's peak load, the hour with most loss of load risk remains the hour with highest forecasted demand.
SERC	Verification of NERC 2022 ProbA Results	The 2022 base case results indicated adequate resources for the SERC Regional Entity as a whole with an observed LOLE of 0.01 days/summer for 2024.
SERC-Central		Probabilistic analysis indicates no risk for resource shortfall.
SERC-East		Probabilistic analysis shows low risk for July and August with EUE of 2.38 MWh and LOLH 0.005 hours.
SERC-Florida Peninsula		SERC probabilistic analysis indicates no risk of resource shortfall.
SERC-Southeast		Probabilistic analysis indicates almost no risk of resource shortfall.
Texas RE-ERCOT	ERCOT probabilistic assessment using the Probabilistic Reserve Risk Model	The simulation indicates an elevated risk of having to declare an EEA during evenings on peak load days in August—the forecasted summer peak load month. The probability of declaring an EEA is 18.4% during the highest risk hour. The probability of firm load shedding is 14.6% during the highest risk hour. The model accounts for the risk of triggering the curtailment of coastal region wind generation due to transmission system constraints.
WECC	WECC performed a probabilistic assessment for Summer 2024 based on demand and resource forecasts provided by load-serving entities.	Resource adequacy remains a critical risk in the Western Interconnection and continues to challenge industry planners, operators, regulators, and partners. Resource adequacy risks over the medium and long terms have increased significantly compared to last year's assessment. Three risks merit particular attention: increasing variability, rate of demand growth and uncertainty of future load patterns, and the pace of new resource growth necessary to meet future energy demand.[11]
WECC-AB		Alberta is expected to have sufficient resource availability to meet demand and cover reserves on the peak hour at 5:00 p.m. under a summer peak defined at the 90th percentile with any combination or accumulation of derates.

[11] See 2023 Western Assessment of Resource Adequacy.pdf (wecc.org)

Table 3: Probability-Based Risk Assessment		
Assessment Area	**Type of Assessment**	**Results and Insight from Assessment**
WECC-BC		British Columbia is expected to have sufficient resource availability to meet reserves at the peak demand hour (5:00–6:00 p.m.) under most conditions. However, above-normal demand that coincides with low hydro output could result in a reserve shortage. This evaluation considers a 1-in-10 probability (90th percentile) level for peak demand and a combination of resource derates including low hydro output.
WECC-CA/MX		WECC-CA/MX is projected to have negligible-to-low amounts of LOLH (<1 hours) this summer, primarily forecast in the Baja (Mexico) part of CA/MX. Resources are sufficient to meet demand and cover reserves on the peak demand hour at 5:00 p.m. under a summer peak demand defined at the 90th percentile with any combination or accumulation of resource derates. There is increased risk of insufficient reserves at later hours (up to 7:00 p.m.) due to the variability of energy resource output. Imports to the area are required to cover these risk periods.
WECC-NW		The Northwest is expected to have sufficient resource availability to meet reserves at the peak demand hour at 5:00 p.m. under a summer peak defined at the 90th percentile with any combination or accumulation of derates.
WECC-SW		Results of WECC's probabilistic analysis indicate that the WECC-SW assessment area is projected to have negligible LOLH and EUE this summer under assessed scenarios. NERC's assessment of elevated risk is influenced by the deterministic risk scenario on page 36. The scenario shows that the assessment area would have insufficient resources to meet operating reserve requirements at a 90/10 demand level with typical generation outages and a scenario involving low-resource output and normal peak demand.

Evolving Demand-Side Management Programs

Demand-side management programs are expanding in many assessment areas, providing operators with additional resources to reduce electricity demand during periods when electricity supplies may not be sufficient. **Figure 3** shows the assessment areas with a DR exceeding 1.5% of the total internal demand. Formal DR programs involving commercial and industrial customers that have agreements with their load-serving entities to curtail load during high demand periods have grown in many assessment areas (see **Demand and Resource Tables**). Additionally, some entities have launched programs with retail customers that provide similar operator-controlled demand-side management capabilities. Programs in use by the independent system operators in Texas and the province of Ontario, discussed below, provide examples of the types of DR programs in use this summer and the contributions to meeting operating reliability and resource adequacy needs.

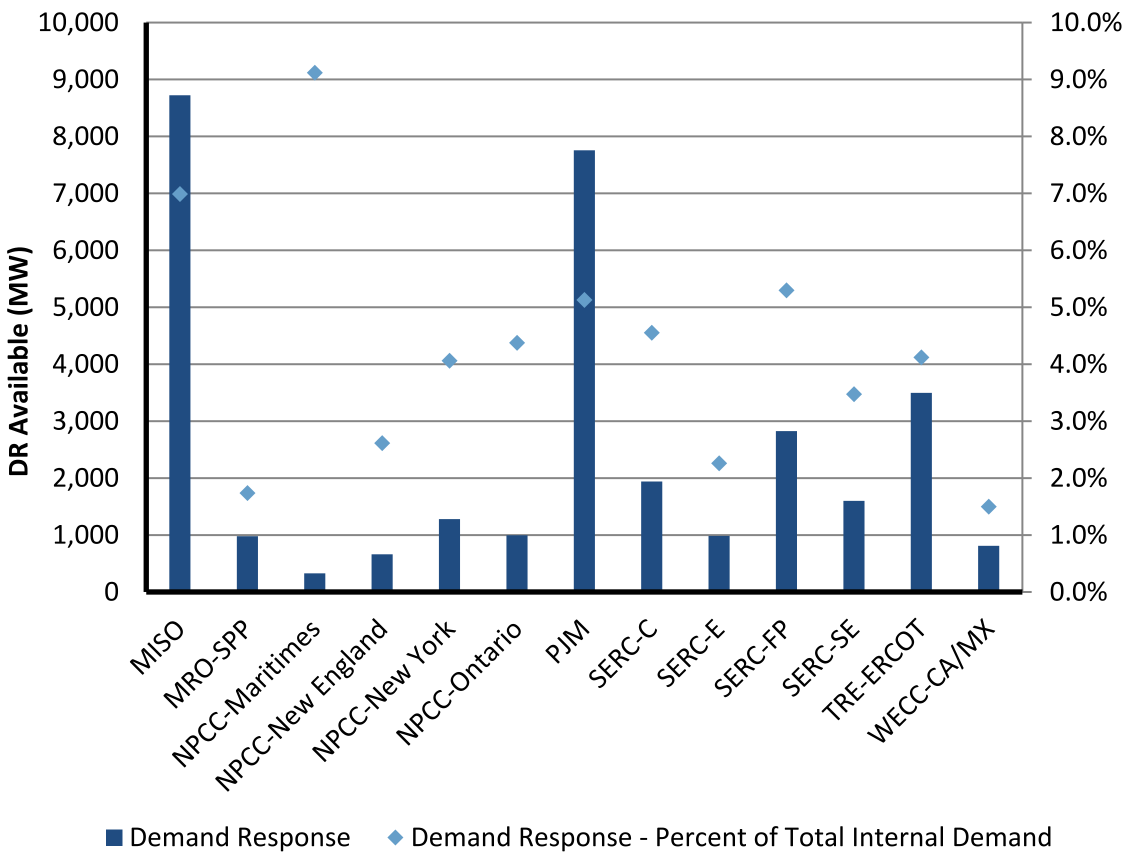


Figure 3: Demand Response in Assessment Areas Exceeding 1.5% Total Internal Demand

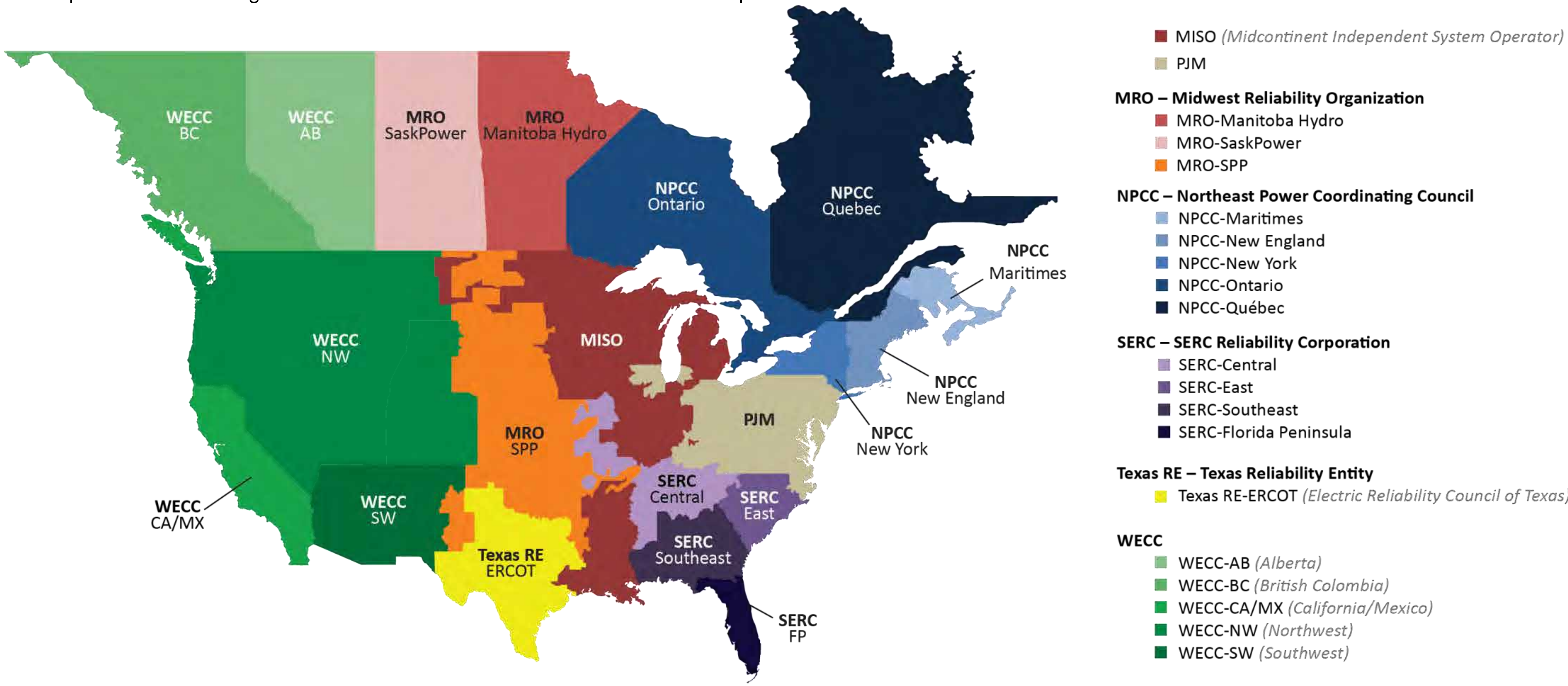
In ERCOT, nearly 3,500 MW of DR resources are expected for this summer, the equivalent of 4% of normal peak demand. Resources come from various programs, including several that are administered by ERCOT as well as those administered by other entities.

- ERCOT's controllable load resources (CLR) consist of large loads (e.g., data centers) and battery charging systems that can be dispatched by ERCOT to provide frequency regulation and short-notice resources for managing wind and solar ramps; 600 MW of CLRs are registered.
- Non-controllable load resources (NCLR) consist of "blocky" loads with both a 10-minute ramp capability for manual deployments and automatic deployment through underfrequency relay. NCLRs participate in ERCOT's Responsive Reserve Service market. ERCOT expects just over 1,100 MW of participation for the highest reserve risk hours for the upcoming summer.
- Some DR resources participate in ERCOT's Emergency Response Service (ERS), along with distributed generation. ERCOT's ERS consists of 10- and 30-minute-ramping DR and distributed generation that can first be deployed when physical responsive capability (PRC) drops to 3,000 MW to provide a contingency reserve. During the 2023 program year, ERS was deployed twice, once on August 17, and again on September 6 when ERCOT's PRC dropped below 3,000 MW. ERCOT expects approximately 1,000 MW to participate in ERS for the highest reserve risk hours for the upcoming summer.
- Transmission and distribution service provider (TDSP) load management programs provide price incentives for voluntary load reductions from commercial, industrial, and, most recently, residential loads during EEA Level 2 events. These programs have historically only been available for the months of June through September from 1:00–7:00 p.m. on weekdays (except holidays) and deployed via ERCOT instruction pursuant to agreements between ERCOT and the TDSPs. ERCOT forecasts that these programs can provide 330 MW in demand relief this summer. In addition, ERCOT Nodal Protocols allow ERCOT to instruct TDSPs to reduce customer load by using existing, in-service distribution voltage reduction measures to avoid an EEA. Conservation voltage reduction (CVR) can lower demand by nearly 575 MW.
- ERCOT accounts for load-reduction programs administered by retail entities in its load forecast. The 4-Coincident Peak (4CP) Load Reduction program incentivizes customers to reduce load during four anticipated 15-minute peak-load intervals, one each across the summer months of June, July, August, and September. The amount of load reduction for the four 4CP days in 2023 averaged 4,674 MW. Additionally, retail entities offer a variety of price-response programs that are factored into ERCOT's load forecast.

In the province of Ontario, the Independent Electricity System Operator (IESO) has expanded DR programs for summer. Overall, this summer, the effective capacity of Ontario's DR programs is 996 MW, the equivalent of 4% of normal peak demand. This includes 805 MW of DR from the capacity auction. The Peak Perks program, launched in June 2023, will contribute 92 MW of effective capacity this summer through enrolled residential customers with smart thermostats that may be controlled at peak times. The IESO also launched the Interruptible Rate Pilot in July 2023. The pilot is designed to provide large-load customers with an interruptible rate in exchange for agreeing to interrupt demand during up to 15 event periods, each up to four hours long. The pilot will run for a three-year period and has two participants that will provide 76 MW of interruptible demand.

Regional Assessments Dashboards

The following assessment area dashboards and summaries were developed based on data and narrative information collected by NERC from the six Regional Entities on an assessment area basis. Guidelines and definitions are in the **Data Concepts and Assumptions** table. On-peak reserve margin bar charts show the Anticipated Reserve Margin compared to a Reference Margin Level that is established for the areas to meet resource adequacy criteria. Prospective Reserve Margins can give an indication of additional on-peak capacity but are not used for assessing adequacy. The operational risk analysis shown in the following regional assessments dashboard pages provides a deterministic scenario for understanding how various factors that affect resources and demand can combine to impact overall resource adequacy. For each assessment area, there is a risk-period scenario graphic; the left **blue** column shows anticipated resources (from the **Demand and Resource Tables**), and the **orange** column at the right shows the two demand scenarios of the normal peak net internal demand (from the **Demand and Resource Tables**) and the extreme summer peak demand determined by the assessment area. The middle **red** or **green** bars show adjustments that are applied cumulatively to the anticipated resources. Adjustments may include reductions for typical generation outages (maintenance and forced not already accounted for in anticipated resources) and additions that represent the quantified capacity from operational tools (if any) that are available during scarcity conditions but have not been accounted for in the *SRA* reserve margins. Resources throughout the scenario are compared against expected operating reserve requirements that are based on peak load and normal weather. The cumulative effects from extreme events are also factored in through additional resource derates or low-output scenarios. In addition, results from a probability-based resource adequacy assessment are shown in the Highlights section of each dashboard. Methods varied by assessment area and provided further insights into the risk conditions forecasted for the summer period.



MISO

MISO is a not-for profit, member-based organization that administers wholesale electricity markets that provide customers with valued service; reliable, cost-effective systems and operations; dependable and transparent prices; open access to markets; and planning for long-term efficiency. MISO manages energy, reliability, and operating reserve markets that consist of 36 local BA and 394 market participants, serving approximately 42 million customers. Although parts of MISO fall in three Regional Entities, MRO is responsible for coordinating data and information submitted for NERC's reliability assessments.

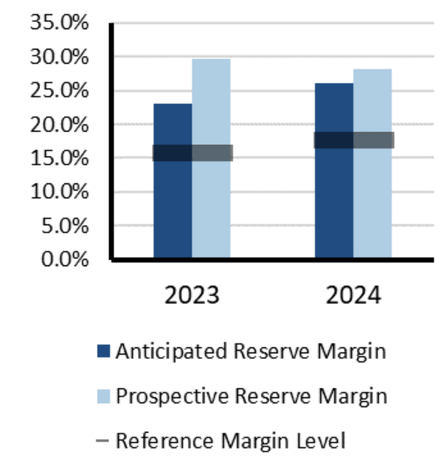
Highlights

- Demand forecasts and resource data indicate that MISO is at elevated risk of operating reserve shortfalls during periods of high demand or low resource output. MISO's resources are projected to be higher than in Summer 2023 while net internal demand decreased slightly. With increased resource availability for this summer, Anticipated Reserve Margin (ARM) of 31.6% (on an installed capacity basis) is higher than last summer's ARM of 23%.
- MISO conducted its annual probabilistic LOLE analysis and determined that a 2024 Reference Margin Level (RML) of 17.7% results in an LOLE of 1 day in 10 years. MISO's RML increased from 15.9% in 2023 to 17.7% in 2024 based on the summer seasonal capacity construct. A methodology change in the Planning Resource Auction (PRA) requesting GOs' seasonally corrected Generator Verification Test Capacity (GVTC), updated seasonal forced outage rates, and updated annualized planned maintenance outage rates as well as information on new units, retirements, suspensions, and changes in the resource mix contributed to the increase in reserve margin for the 2024 summer. Comparing the increased ARM to the lower RML indicates improved reliability from the LOLE base case at 1 day in 10 years.
- Performance of wind generators during periods of high electricity demand is a key factor in determining whether system operators need to employ operating mitigations, such as maximum-generation declarations and energy emergencies. MISO has over 31,000 MW of installed wind capacity; however, the historically based on-peak capacity contribution is 5,616 MW.

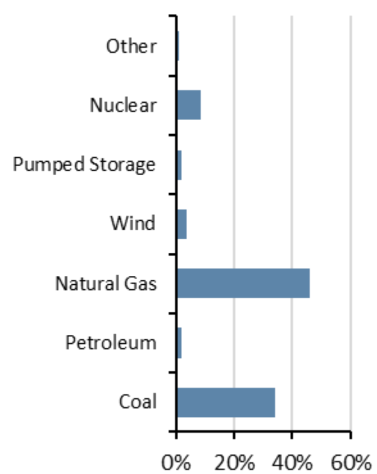
Risk Scenario Summary

Expected resources meet operating reserve requirements under normal peak-demand scenarios. Above-normal summer peak load and extreme generator outage conditions could result in the need to employ operating mitigations (e.g., load-modifying resources and energy transfers from neighboring systems) and EEAs. Emergency declarations that can only be called upon when available generation is at maximum capability are necessary to access load-modifying resources (DR) when operating reserve shortfalls are projected.

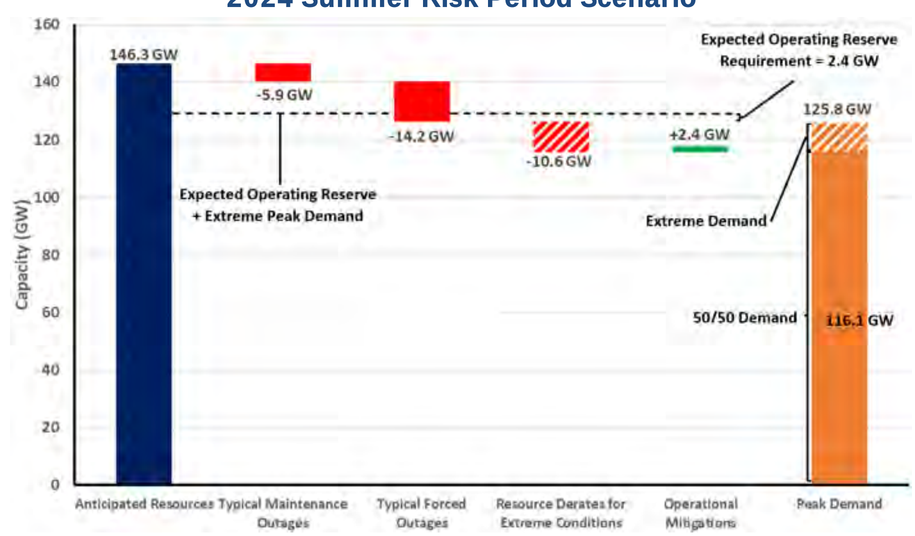
On-Peak Reserve Margin



On-Peak Fuel Mix



2024 Summer Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: Net internal demand (50/50) and (90/10) demand forecast using 30 years of historical data

Maintenance Outages: Rolling five-year summer average of maintenance and planned outages

Forced Outages: Five-year average of all outages that were not planned

Extreme Derates: Maximum historical generation outages

Operational Mitigations: A total of 2.4 GW capacity resources available during extreme operating conditions

MRO-Manitoba Hydro

Manitoba Hydro is a provincial Crown corporation and one of the largest integrated electricity and natural gas distribution utilities in Canada. Manitoba Hydro is a leader in providing renewable energy and clean-burning natural gas. Manitoba Hydro provides electricity to approximately 608,500 electric customers in Manitoba and natural gas to approximately 293,000 customers in southern Manitoba. Its service area is the province of Manitoba, which is 251,000 square miles. Manitoba Hydro is winter peaking. Manitoba Hydro is its own Planning Coordinator (PC) and BA. Manitoba Hydro is a coordinating member of MISO, which is the RC for Manitoba Hydro.

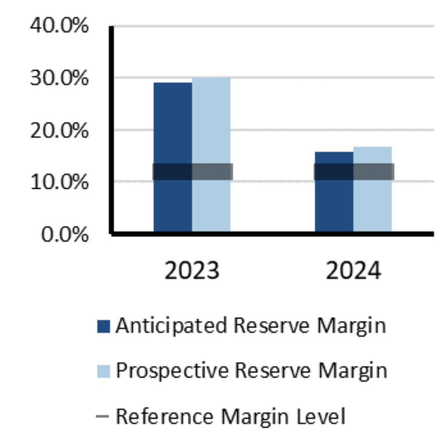
Highlights

- Manitoba Hydro is not anticipating any operational challenges and/or emerging reliability issues for Summer 2024.
- ARM has fallen since Summer 2023 due to higher peak demand forecast, more generator planned maintenance outages, and an increase in net firm capacity transfers. Nonetheless, ARM exceeds the 12% RML.
- Manitoba Hydro is experiencing below-average water supply conditions. However, above-average late-winter snowfall will favorably impact spring runoff. The Manitoba Hydro system is designed and operated such that reliable operations can be maintained under extreme drought. Manitoba Hydro expects to reliably supply its internal demand and export obligations even if drought continues through 2024/25.
- All units at Keeyask Generating Station have commercial operation status.

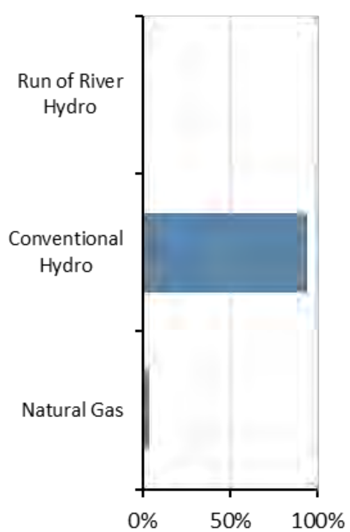
Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed scenarios.

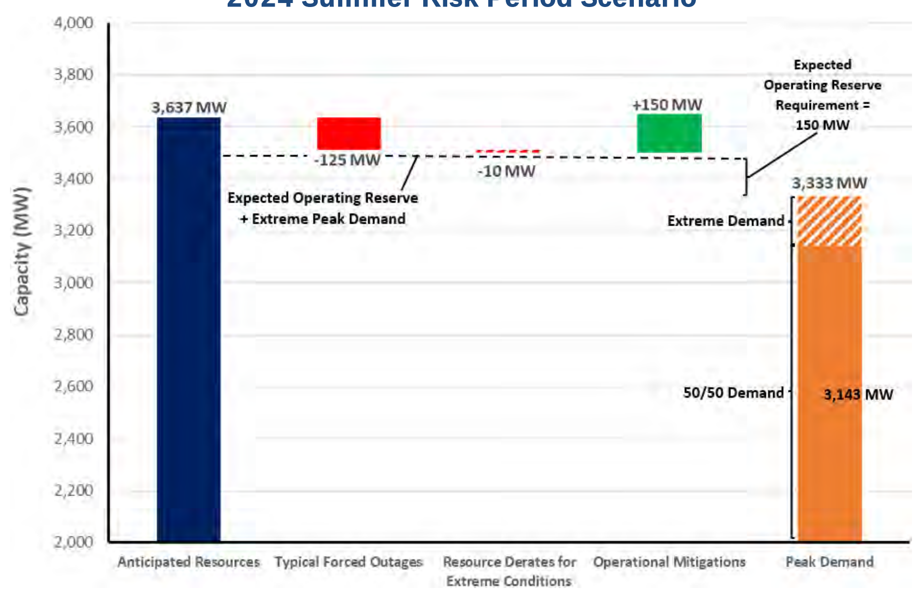
On-Peak Reserve Margin



On-Peak Fuel Mix



2024 Summer Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: (50/50) Demand with allowance for extreme demand based on extreme summer weather scenario of 35.4 C (96 F)

Forced Outages: Typical forced outages

Extreme Derates: Summer wind capacity accreditation of 18.1% of nameplate rating based on MISO seasonal analysis

Normal hydro generation expected for this summer.

Operational Mitigations: Utilize Curtailable Rate Program to manage peak demand; utilize operating reserve if additional measures required

MRO-SaskPower

MRO-SaskPower is an assessment area in the Saskatchewan province of Canada. The province has a geographic area of 651,900 square kilometers (251,700 square miles) and a population of approximately 1.1 million. Peak demand is experienced in the winter. The Saskatchewan Power Corporation (SaskPower) is the PC and RC for the province of Saskatchewan and is the principal supplier of electricity in the province. SaskPower is a provincial Crown corporation and, under provincial legislation, is responsible for the reliability oversight of the Saskatchewan BES and its Interconnections.

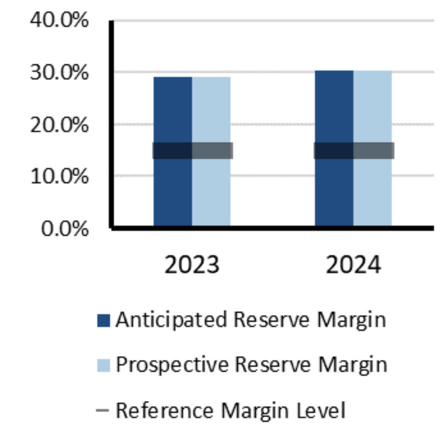
Highlights

- Despite being primarily a winter-peaking area, Saskatchewan also faces significant electricity demand in the summer during extremely hot weather conditions.
- SaskPower collaborates annually with Manitoba Hydro for a summer joint operating study, incorporating inputs from the Western Area Power Administration (WAPA) and Basin Electric to develop operational guidelines addressing any identified issues.
- The probability of experiencing a shortage in operating reserves during peak load periods, or EEAs, may increase if significant generation forced outages happen at the same time as planned maintenance outages during the high-demand months of June through September.
- If extreme thermal conditions align with significant generation outages, SaskPower will deploy available DR programs, engage in short-term power transfers from neighboring utilities, and implement temporary load interruptions as necessary to mitigate the situation.

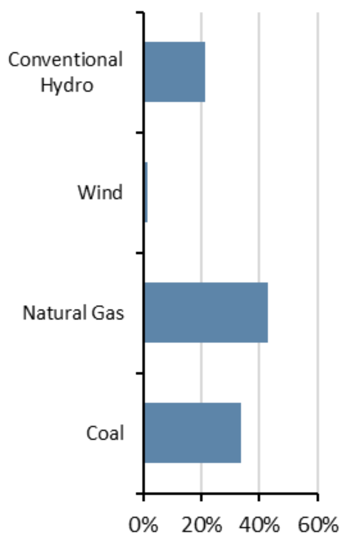
Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed scenarios. Above-normal summer peak load and outage conditions similar to those observed in Summer 2023 are likely to result in the need to employ operating mitigations (e.g., DR and transfers) and EEAs.

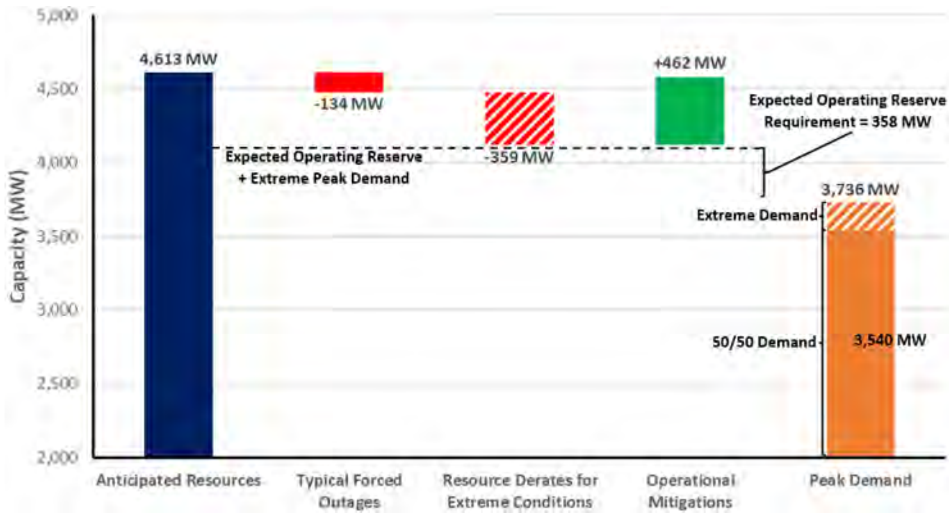
On-Peak Reserve Margin



On-Peak Fuel Mix



2024 Summer Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: Net internal demand (50/50) and above-normal scenario based on peak demand with lighting and all consumer loads

Forced Outages: Estimated by using SaskPower forced outage model

Extreme Derates: Estimated resources unavailable in extreme conditions

Operational Mitigations: Estimated non-firm imports and standby generators on 2–7-day notice

MRO-SPP

SPP PC's 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 long-term assessment is reported based on the PC footprint, which touches parts of the MRO 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.

Highlights

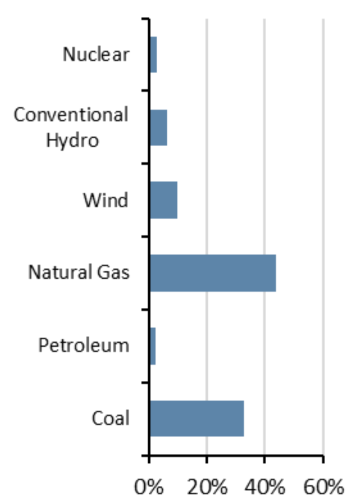
- ARMs are higher in SPP compared to Summer 2023. Increased capacity for the summer is coming from wind resource additions, higher expected wind contribution at peak demand, and commitments from switchable generators (i.e., resources capable of supplying SPP or a neighboring BA) to qualify as resources in SPP.
- SPP projects a low likelihood of any emerging reliability issues impacting the area for the 2024 summer season.
- BA generation capacity deficiency risks remain depending on wind generation output levels and unanticipated generation outages in combination with high-load periods.
- Using the current operational processes and procedures, SPP will continue to assess the needs for the 2024 summer season and will adjust as needed to ensure that real-time reliability is maintained throughout the summer time frame.

On-Peak Reserve Margin

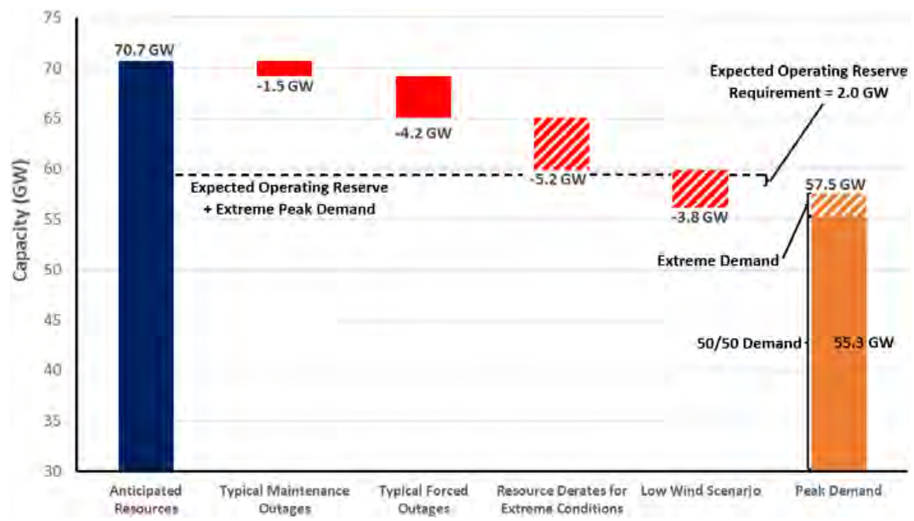
Risk Scenario Summary

Expected resources are sufficient to meet operating reserve requirements under normal peak-demand and outage scenarios. Above-normal summer peak load and outage conditions could necessitate operating mitigations (e.g., DR and transfers from neighboring systems) and EEAs.

On-Peak Fuel Mix



2024 Summer Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: Net internal demand (50/50) and extreme demand is a 5% increase from net internal demand

Maintenance and Forced Outages: Represent five-year historical averages; calculated from SPP's generation assessment process

Extreme Derates: Additional unavailable capacity from operational data at high-demand periods

Low Wind Scenario: Derates reflecting a low-wind day in the summer

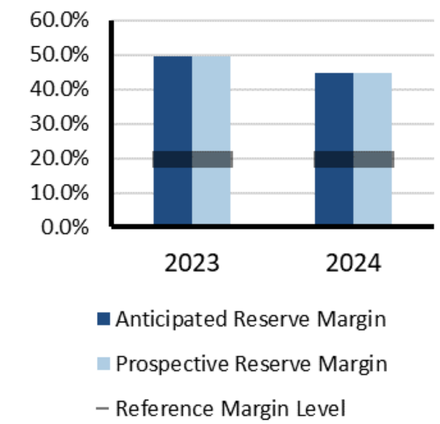
NPCC-Maritimes

The Maritimes assessment area is a winter-peaking NPCC area that contains two BAs. It is comprised of the Canadian provinces of New Brunswick, Nova Scotia, and Prince Edward Island and the northern portion of Maine, which is radially connected to the New Brunswick power system. The area covers 58,000 square miles with a total population of 1.9 million.

Highlights

- The Maritimes area has not identified any operational issues that are expected to impact system reliability. If an event were to occur, emergency operations and planning procedures are in place.
- All of the area's declared firm capacity is expected to be operational for the summer operating period.
- As part of the planning process, dual-fueled units will have sufficient supplies of heavy fuel oil (HFO) on site to enable sustained operation in the event of natural gas supply interruptions.

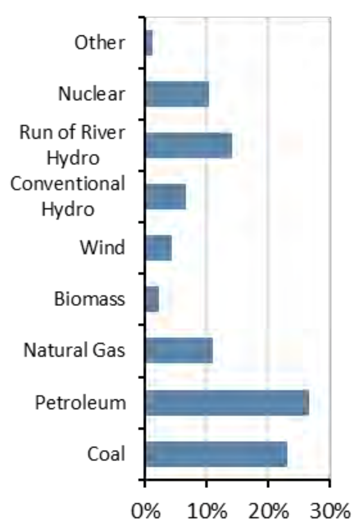
On-Peak Reserve Margin



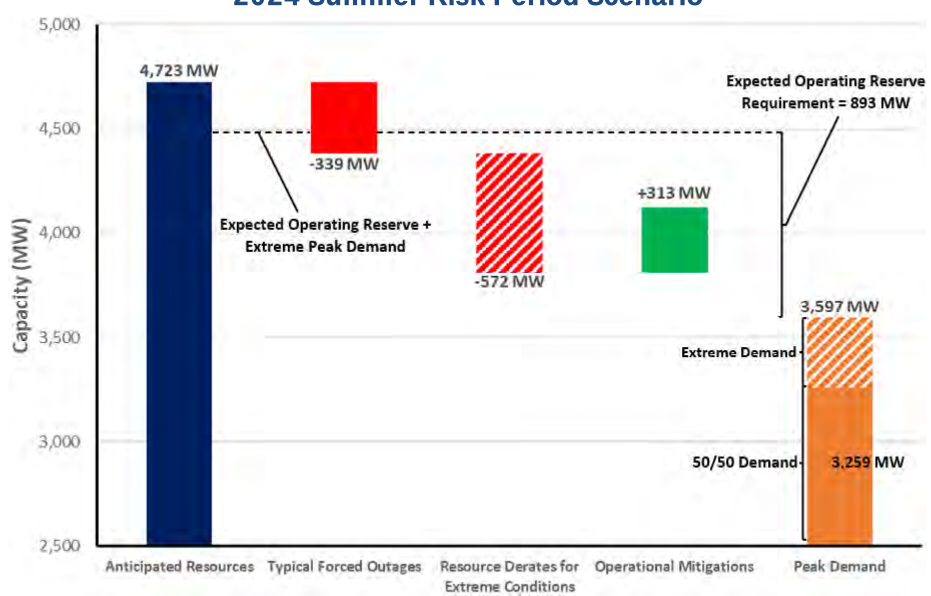
Risk Scenario Summary

Expected resources meet operating reserve requirements under normal peak-demand scenarios. Above-normal summer peak load or extreme outage conditions could necessitate operating mitigations (e.g., DR and non-firm transfers) and EEAs.

On-Peak Fuel Mix



2024 Summer Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: Net internal demand (50/50) and (above 90/10) extreme demand forecast

Forced Outages: Based on historical operating experience

Extreme Derates: A low-likelihood scenario resulting in an additional 50% derate in the remaining capacity of both natural gas and wind resources under extreme conditions

Operational Mitigations: Imports anticipated from neighbors during emergencies

NPCC-New England

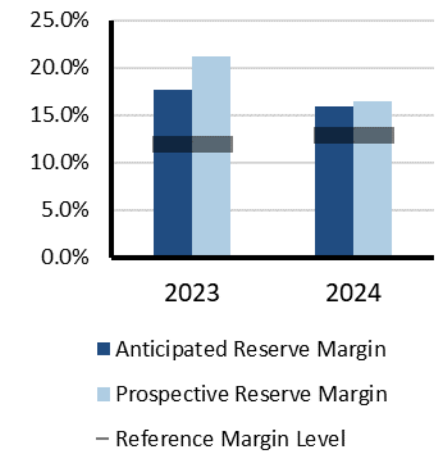
NPCC-New England is an assessment area consisting of the states of Connecticut, Maine, Massachusetts, New Hampshire, Rhode Island, and Vermont that is served by ISO New England (ISO-NE) Inc. ISO-NE is a regional transmission organization that is responsible for the reliable day-to-day operation of New England's bulk power generation and transmission system, administration of the area's wholesale electricity markets, and management of the comprehensive planning of the regional BPS.

The New England BPS serves approximately 14.5 million customers over 68,000 square miles.

Highlights

- The New England area expects to have sufficient resources to meet the 2024 summer peak demand forecast.
- 330 MW of resources are currently on emergency outage but are scheduled to be available during the summer operating period.
- The 50/50 peak summer demand is forecast to be 24,633 MW for the weeks beginning June 2, 2024, through September 15, 2024, with a lowest projected net margin of -401 MW (-1.6%). This margin assumes a net interchange of 1,297 MW, which is capacity backed. However, ISO-NE typically imports around 3,000 MW during summer peak load conditions. For this *SRA*, the established Reference Margin Level is 12.9%. Wind, grid-connected solar PV, and run-of-river totals were derated for this calculation.
- The 2024 summer demand forecast factors in demand reductions associated with energy efficiency, load management, behind-the-meter photovoltaic (BTM-PV) systems, and distributed generation.

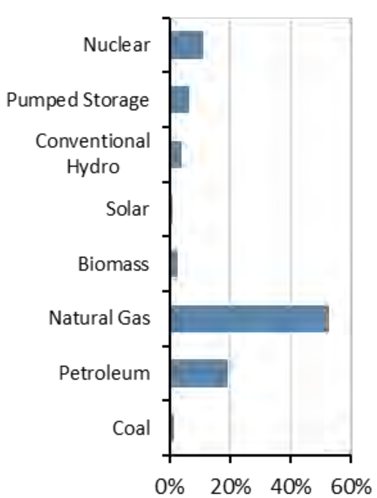
On-Peak Reserve Margin



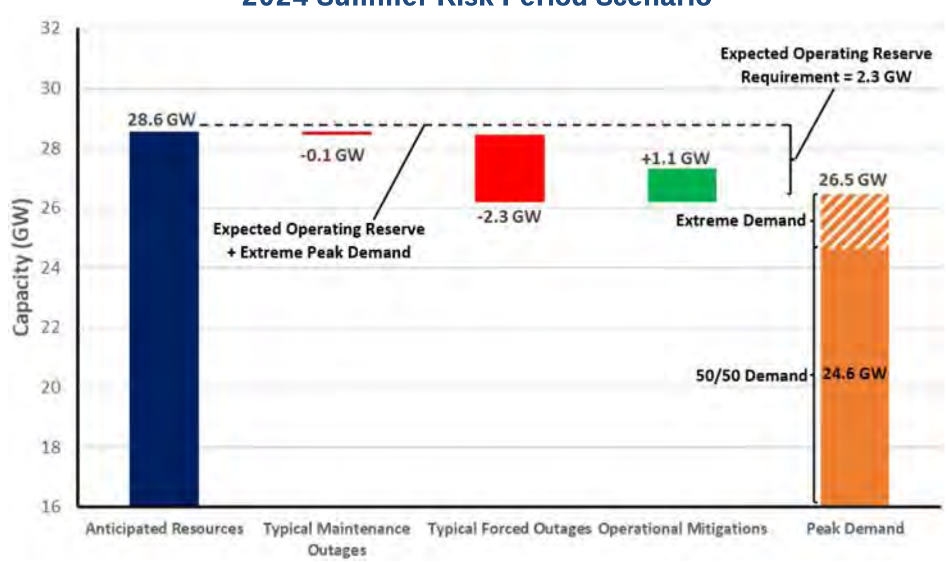
Risk Scenario Summary

Expected resources do not meet operating reserve requirements under normal peak-demand and outage scenarios. Operating mitigations (e.g., DR and transfers) are likely to be needed to meet peak demand. More severe conditions (e.g., above-normal summer peak load and outage conditions) could result in an EEA.

On-Peak Fuel Mix



2024 Summer Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: Peak net internal demand (50/50) and (90/10) extreme demand forecast

Maintenance Outages: Based on historical weekly averages

Typical Forced Outages: Based on seasonal capacity of each resource as determined by ISO-NE

Operational Mitigations: Based on load and capacity relief assumed available from invocation of ISO-NE operating procedures

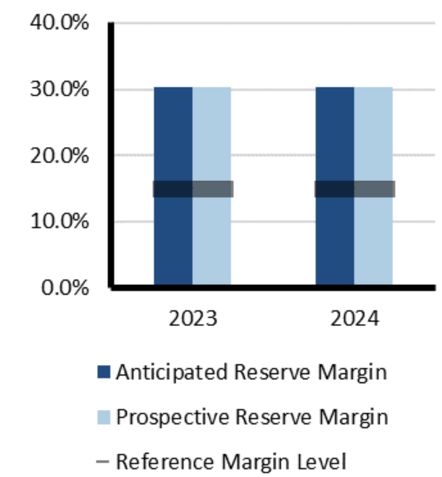
NPCC-New York

NPCC-New York is an assessment area consisting of the NYISO service territory. NYISO is responsible for operating New York's BPS, administering wholesale electricity markets, and conducting system planning. NYISO is the only BA within the state of New York. The BPS in New York encompasses over 11,000 miles of transmission lines and 760 power generation units and serves 20.2 million customers. For this *SRA*, the established RML is 15%. Wind, grid-connected solar PV, and run-of-river totals were derated for this calculation. However, New York requires load-serving entities to procure capacity for their loads equal to their peak demand plus an IRM. The IRM requirement represents a percentage of capacity above peak load forecast and is approved annually by the New York State Reliability Council. The council approved the 2024–2025 IRM at 22.0%.

Highlights

- NYISO is not anticipating any operational issues in the New York Control Area for the upcoming summer.
- No unanticipated operating conditions occurred during the summer 2023 season.
- Adequate capacity margins are anticipated, and existing operating procedures are sufficient to handle any issues that may occur.

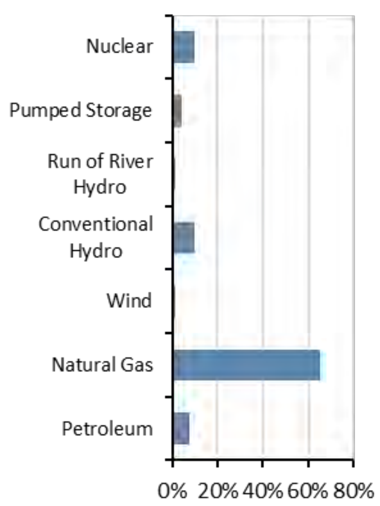
On-Peak Reserve Margin



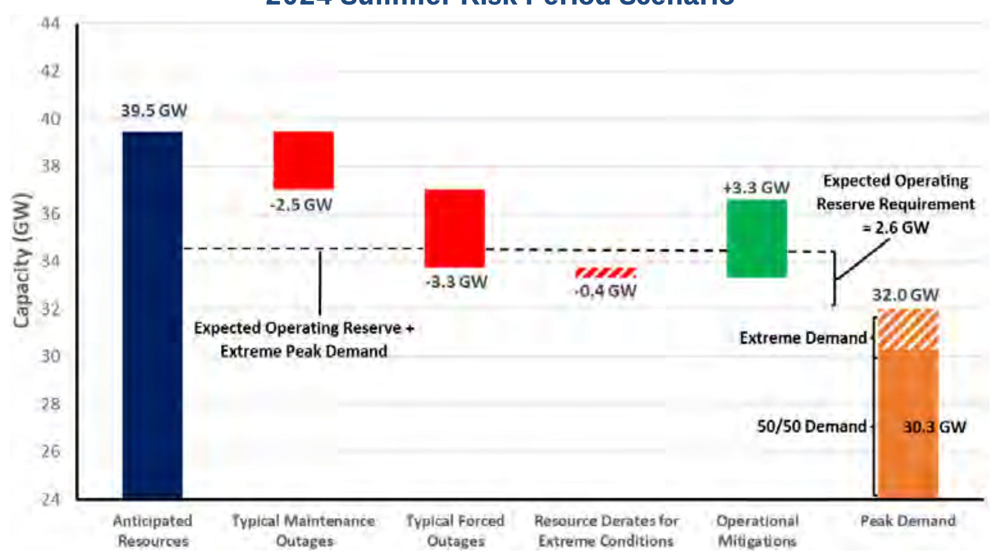
Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed scenarios. Operating mitigations (e.g., DR and transfers) may be needed to meet above-normal summer peak load and outage conditions.

On-Peak Fuel Mix



2024 Summer Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: Net internal demand (50/50) and (90/10) extreme demand forecast

Maintenance Outages: Based on historical performance and the new NYISO capacity accreditation process

Forced Outages: Based on historical five-year averages

Extreme Derates: Estimated resources unavailable in extreme conditions

Operational Mitigations: A total of 3.3 GW based on operational/emergency procedures in area emergency operations manual

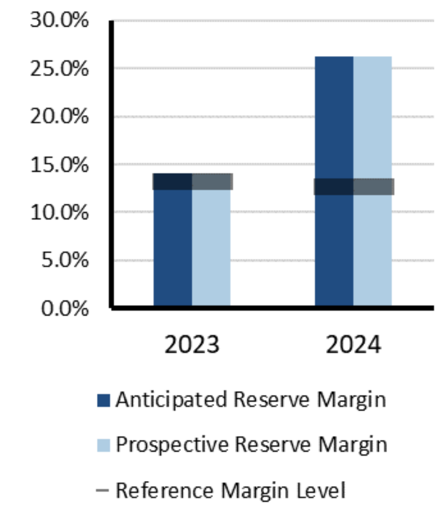
NPCC-Ontario

NPCC-Ontario is an assessment area in the Ontario province of Canada. The IESO is the BA for the province of Ontario. The province of Ontario covers more than 1 million square kilometers (415,000 square miles) and has a population of more than 15 million. Ontario is interconnected electrically with Québec, MRO-Manitoba, states in MISO (Minnesota and Michigan), and NPCC-New York.

Highlights

- Overall, Ontario is operating within a period in which generation and transmission outages are more challenging to accommodate. The IESO has been actively coordinating and planning with market participants to maintain reliability.
- The Ontario grid is better positioned for Summer 2024 than it was for Summer 2023.
- This season, the grid will benefit from fewer coincident planned generator outages, progress being made on nuclear refurbishments, increased capacity secured through the capacity auction, and new demand-side management programs, including the Interruptible Rate Pilot and Peak Perks.
- The system will be adequate in Summer 2024 under normal weather conditions. It is also expected to be adequate during extreme weather conditions with the availability of up to 2,000 MW of imports from neighboring jurisdictions or other operating actions to ensure reliability.

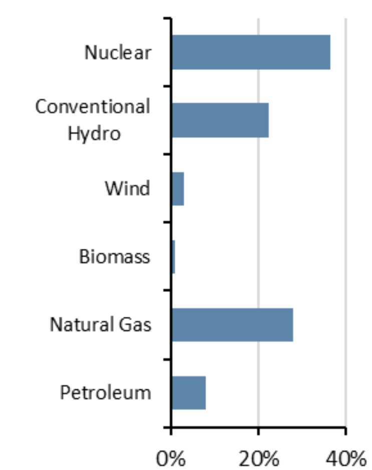
On-Peak Reserve Margin



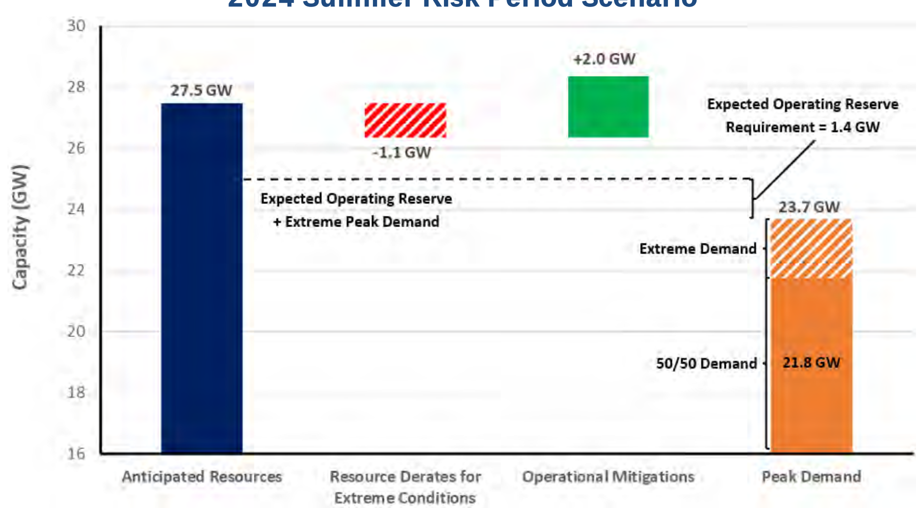
Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed scenarios.

On-Peak Fuel Mix



2024 Summer Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: Net internal demand (50/50 forecast) and highest weather-adjusted daily demand based on 31 years of demand history

Extreme Derates: Derived from weather-adjusted temperature rating of thermal units and adjustments to expected hydro production for low water conditions

Operational Mitigations: Imports anticipated from neighbors during emergencies

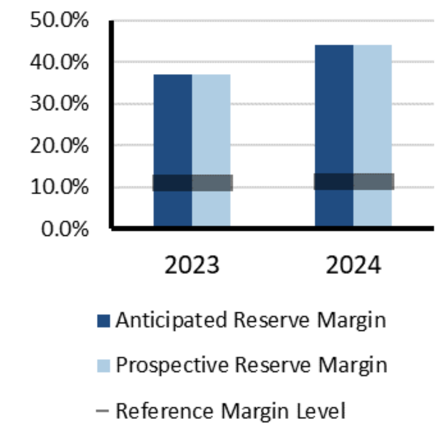
NPCC-Québec

The Québec assessment area (province of Québec) is a winter-peaking NPCC area that covers 595,391 square miles with a population of 8 million. Québec is one of the four Interconnections in North America; it has ties to Ontario, New York, New England, and the Maritimes consisting of either high-voltage direct current ties, radial generation, or load to and from neighboring systems.

Highlights

- The Québec area forecasted summer peak demand (excluding April, May, and September) is 22,922 MW during the week beginning August 11, 2024, with a forecasted net margin of 7,423 MW (32.4%).
- Resource adequacy issues are not expected this summer.
- The Québec area expects to be able to assist other areas, if needed, up to the transfer capability available.

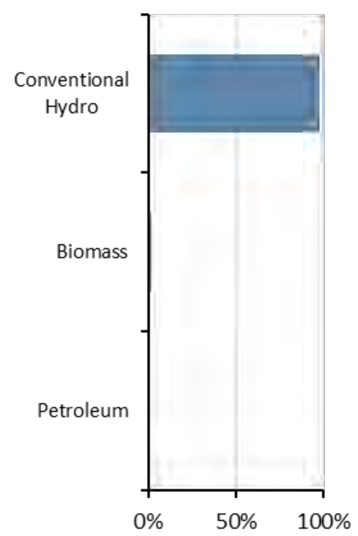
On-Peak Reserve Margin



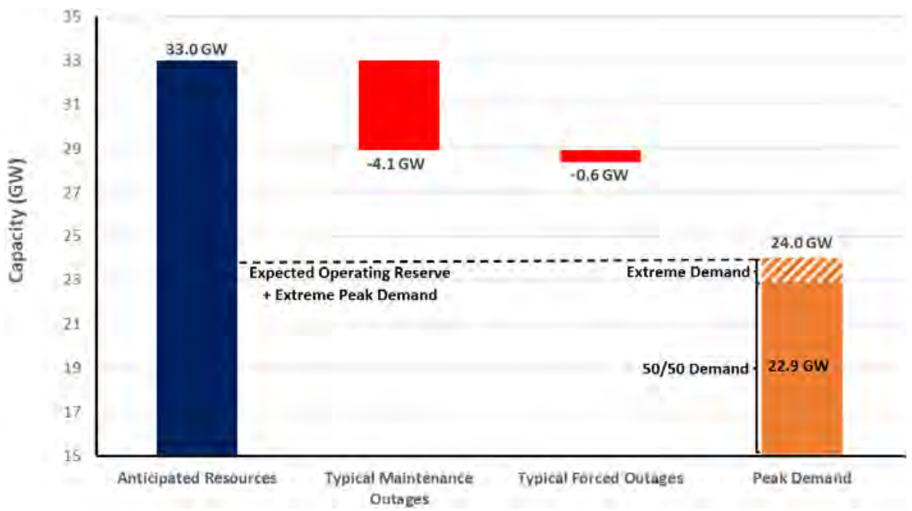
Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed scenarios.

On-Peak Fuel Mix



2024 Summer Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenario: Net internal demand (50/50) and (90/10) demand forecast

Net Firm Transfers: Anticipated exports to neighbors during the risk hour

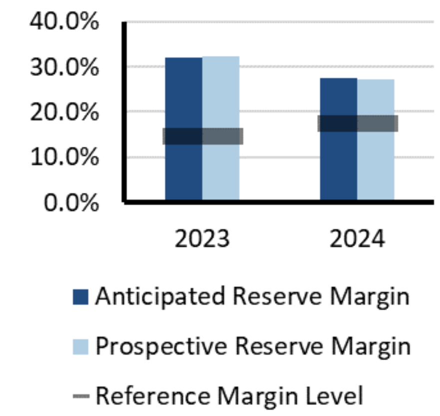
PJM

PJM Interconnection is a regional transmission organization that coordinates the movement of wholesale electricity in all or parts of Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, West Virginia, and the District of Columbia. PJM serves 65 million customers and covers 369,089 square miles. PJM is a BA, PC, Transmission Planner, Resource Planner, Interchange Authority, TOP, Transmission Service Provider, and RC.

Highlights

- PJM expects no resource problems over the 2024 summer peak season. PJM is forecasting around 29% installed reserves (including expected committed DR), which is well above the target IRM of 17.7%. The increase of 1.8 percentage points of the reserve requirement is driven by adjusted load forecast parameters.
- Rising demand, generator retirements, and slower-than-anticipated resource additions contribute to lower reserve margins compared to last summer.
- The greatest load-loss risk remains the hour with highest forecasted demand due to the low penetration of variable energy resources relative to PJM's peak load.

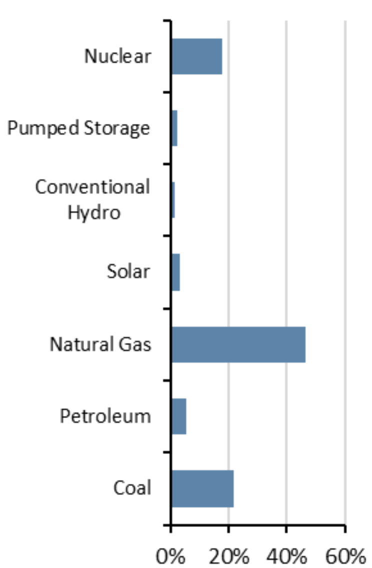
On-Peak Reserve Margin



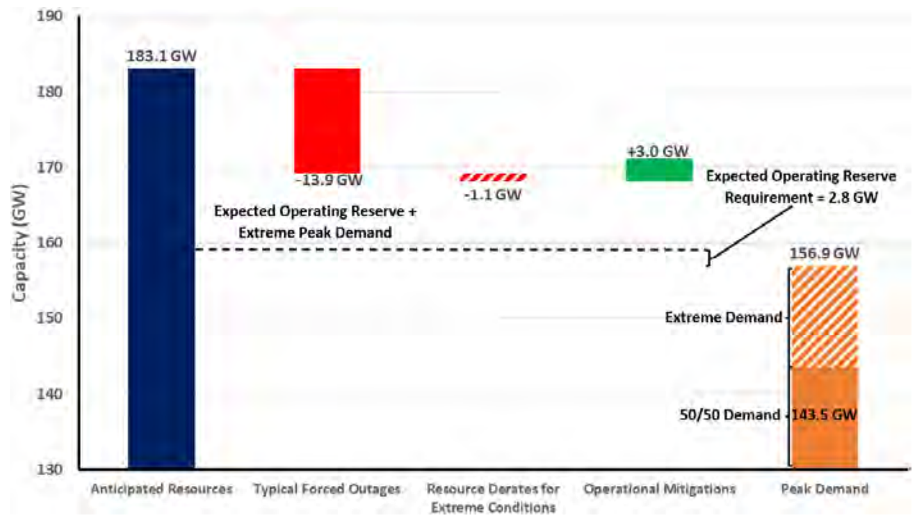
Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed scenarios.

On-Peak Fuel Mix



2024 Summer Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: Net internal demand (50/50) and (90/10) demand forecast

Forced Outages: Based on historical data and trending

Extreme Derates: Accounts for reduced thermal capacity contributions due to performance in extreme conditions

Operational Mitigations: A total of 3 GW based on operational/emergency procedures

SERC-Central

SERC-Central is an assessment area within the SERC Regional Entity. SERC-Central includes all of Tennessee and portions of Georgia, Alabama, Mississippi, Missouri, and Kentucky. Historically a summer-peaking area, SERC-Central is beginning to have higher peak demand forecasts in winter. SERC is one of the six companies across North America that are responsible for the work under Federal Energy Regulatory Commission (FERC)-approved delegation agreements with NERC. SERC-Central is specifically responsible for the reliability and security of the electric grid across the Southeastern and Central areas of the United States. This area covers approximately 630,000 square miles and serves a population of more than 91 million. The SERC Regional Entity includes 36 BAs, 28 planning entities, and 6 RCs.

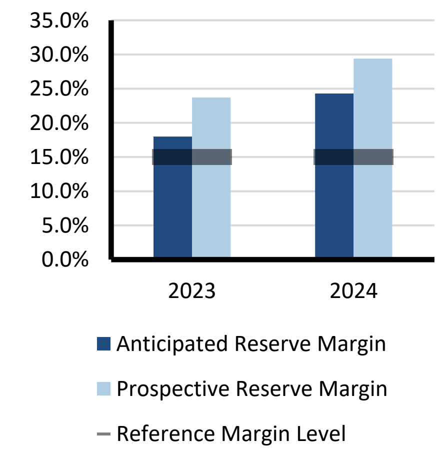
Highlights

- SERC-Central will have higher reserves compared to last summer due to increased firm imports and additions of gas and solar generation.
- Expected resources meet operating reserve requirements under the assessed scenarios.
- The probabilistic analysis metrics indicate adequate energy resources for the subregion.
- Entities perform resource studies to ensure resource adequacy to meet the summer peak demand and maintain the reliability of the system. They actively participate in the SERC Near-Term, Long-Term, and Resource Adequacy Working Groups, which identify emerging and potential reliability impacts on transmission and resource adequacy along with transfer capability.
- There is a moderate risk of transmission impacts due to severe weather. The advanced age and material condition of older coal- and gas-fired generators could result in potential reliability challenges. Entities are mitigating these risks through summer readiness processes, pursuing short-term market opportunities, and leveraging demand-side management programs as necessary.

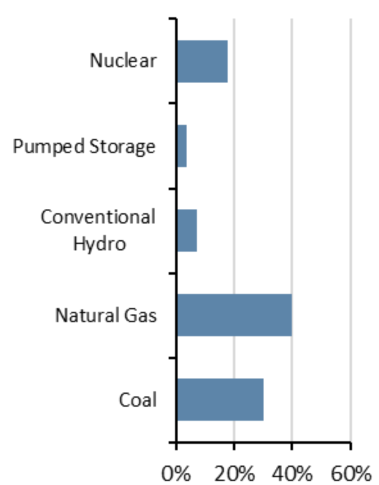
Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed scenarios.

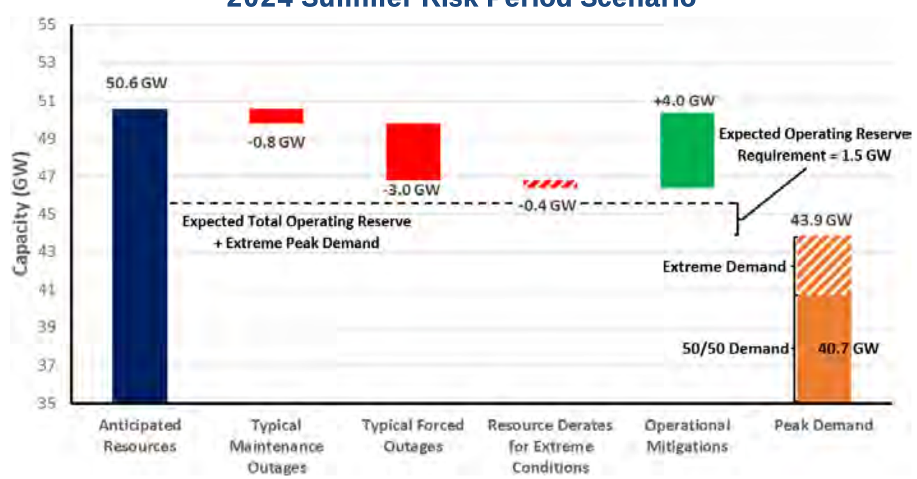
On-Peak Reserve Margin



On-Peak Fuel Mix



2024 Summer Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: Net internal demand (50/50) and extreme demand forecast based on extreme summer weather (equals or exceeds the (90/10) demand forecast)

Maintenance Outages: Adjusted for higher outages resulting from extreme summer temperatures and aggregated on a SERC subregional level

Forced Outages: Accounts for reduced thermal capacity contributions due to performance in extreme conditions

Extreme Derates: Estimated resources unavailable in extreme conditions

Operational Mitigations: A total of 1.9 GW based on operational/emergency procedures

SERC-East

SERC-East is an assessment area within the SERC Regional Entity. SERC-East includes North Carolina and South Carolina. Historically a summer-peaking area, SERC-East is beginning to have higher peak demand forecasts in winter. SERC is one of the six companies across North America that are responsible for the work under FERC-approved delegation agreements with NERC. SERC is specifically responsible for the reliability and security of the electric grid across the Southeastern and Central areas of the United States. This area covers approximately 630,000 square miles and serves a population of more than 91 million. The SERC Regional Entity includes 36 BAs, 28 planning entities, and 6 RCs.

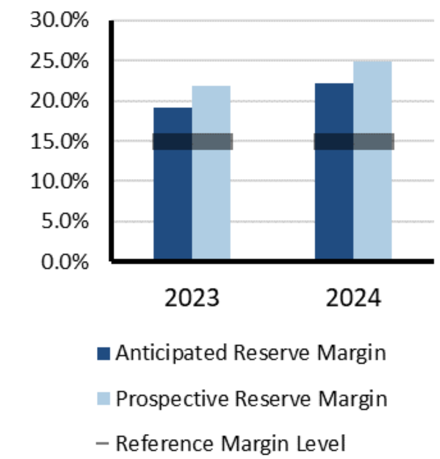
Highlights

- Expected resources meet operating reserve requirements under the assessed scenarios.
- The probabilistic analysis metrics show some risk for energy resource adequacy during the summer months of July and August in the afternoon hours.
- Entities perform resource studies to ensure resource adequacy to meet the summer peak demand and maintain the reliability of the system. They actively participate in the SERC Near-Term, Long-Term, and Resource Adequacy Working Groups, which identify emerging and potential reliability impacts on transmission and resource adequacy along with transfer capability.
- Entities have not identified any emerging reliability issues or operational concerns for the upcoming summer season.

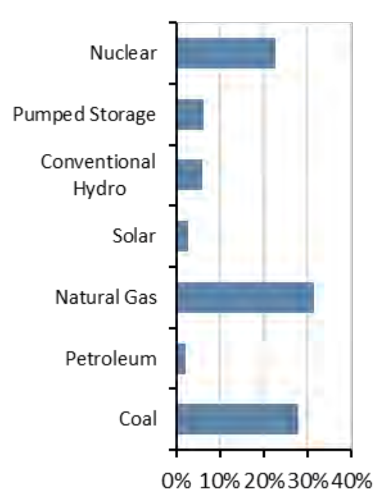
Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed scenarios.

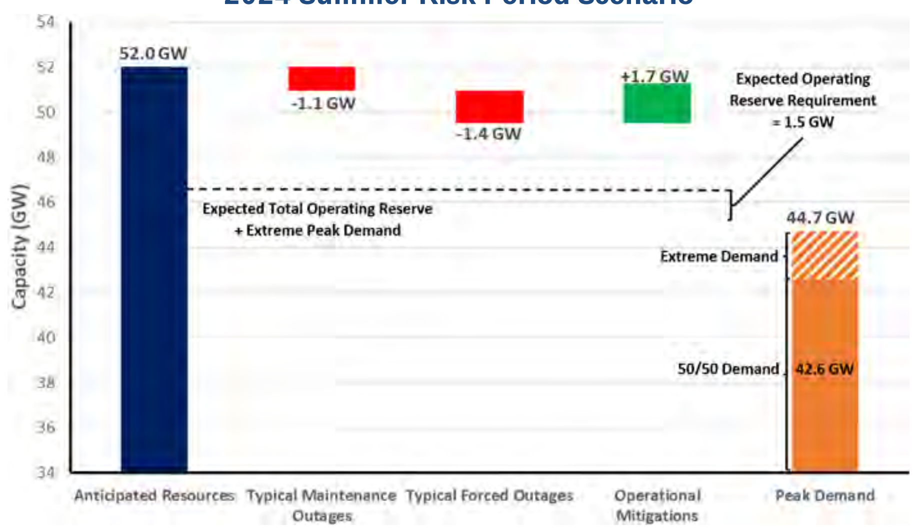
On-Peak Reserve Margin



On-Peak Fuel Mix



2024 Summer Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: Net internal demand (50/50) and extreme demand forecast based on extreme summer weather (equals or exceeds the (90/10) demand forecast)

Maintenance Outages: Adjusted for higher outages resulting from extreme summer temperatures and aggregated on a SERC subregional level

Forced Outages: Accounts for reduced thermal capacity contributions due to performance in extreme conditions

Operational Mitigations: A total of 1.5 GW based on operational/emergency procedures

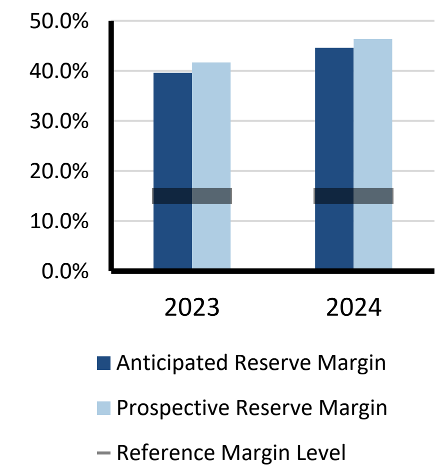
SERC-Florida Peninsula

SERC-Florida Peninsula is a summer-peaking assessment area within SERC. SERC is one of the six companies across North America that are responsible for the work under FERC-approved delegation agreements with NERC. SERC is specifically responsible for the reliability and security of the electric grid across the Southeastern and Central areas of the United States. This area covers approximately 630,000 square miles and serves a population of more than 91 million. The SERC Regional Entity includes 36 BAs, 28 planning entities, and 6 RCs.

Highlights

- Expected resources meet operating reserve requirements under the assessed scenarios.
- The probabilistic analysis metrics indicate adequate energy resources for the subregion.
- Entities perform resource studies to ensure resource adequacy to meet the summer peak demand and maintain the reliability of the system. They actively participate in the SERC Near-Term, Long-Term, and Resource Adequacy Working Groups, which identify emerging and potential reliability impacts on transmission and resource adequacy along with transfer capability.
- Entities have not identified any emerging reliability issues or operational concerns for the upcoming summer season.

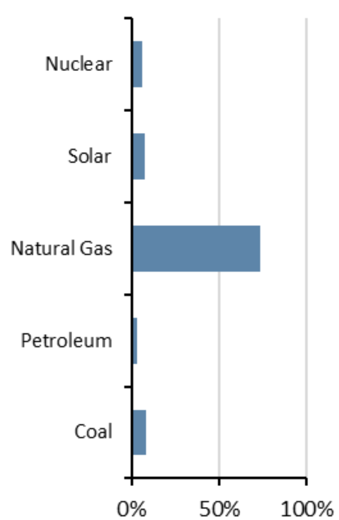
On-Peak Reserve Margin



Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed scenarios.

On-Peak Fuel Mix



2024 Summer Risk Period Scenario

Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: Net internal demand (50/50) and extreme demand forecast based on extreme summer weather (equals or exceeds the (90/10) demand forecast)

Maintenance Outages: Adjusted for higher outages resulting from extreme summer temperatures and aggregated on a SERC subregional level

Forced Outages: Accounts for reduced thermal capacity contributions due to performance in extreme conditions

Operational Mitigations: A total of 3.8 GW based on operational/emergency procedures

SERC-Southeast

SERC-Southeast is a summer-peaking assessment area within the SERC Regional Entity. SERC-Southeast includes all or portions of Georgia, Alabama, and Mississippi. SERC is one of the six companies across North America that are responsible for the work under FERC-approved delegation agreements with NERC. SERC is specifically responsible for the reliability and security of the electric grid across the Southeastern and Central areas of the United States. This area covers approximately 630,000 square miles and serves a population of more than 91 million. The SERC Regional Entity includes 36 BAs, 28 planning entities, and 6 RCs.

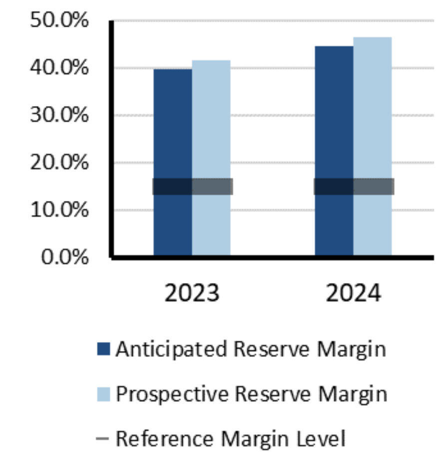
Highlights

- Expected resources meet operating reserve requirements under the assessed scenarios.
- A new 1,100 MW nuclear unit and additional solar generation will give SERC-Southeast higher reserves compared to last summer.
- The probabilistic analysis metrics indicate adequate energy resources for the subregion.
- With the increased penetration of variable energy resources (VER), the curtailment of VER during light-load conditions to support operations may become more prevalent. This, in combination with the retirement of resources, increases the operational challenges in managing the ramps in some areas of SERC-Southeast.
- Entities perform resource studies to ensure resource adequacy to meet the summer peak demand and maintain the reliability of the system. They actively participate in the SERC Near-Term, Long-Term, and Resource Adequacy Working Groups, which identify emerging and potential reliability impacts on transmission and resource adequacy along with transfer capability.

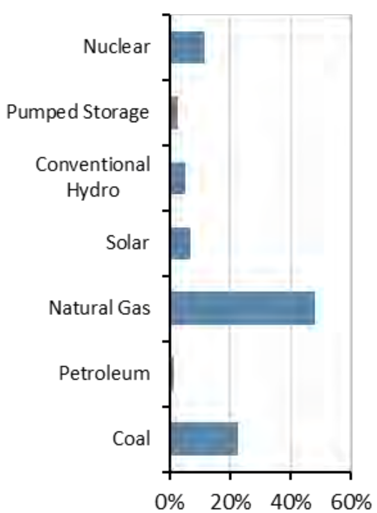
Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed scenarios.

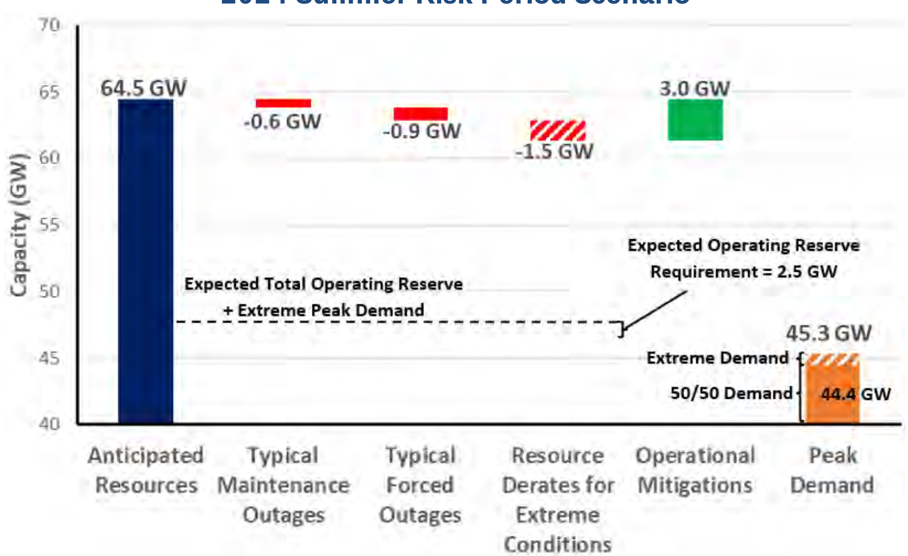
On-Peak Reserve Margin



On-Peak Fuel Mix



2024 Summer Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: Net internal demand (50/50) and extreme demand forecast based on extreme summer weather (equals or exceeds the (90/10) demand forecast)

Maintenance Outages: Adjusted for higher outages resulting from extreme summer temperatures and aggregated on a SERC subregional level

Forced Outages: Accounts for reduced thermal capacity contributions due to performance in extreme conditions

Extreme Derates: Estimated resources unavailable in extreme conditions

Operational Mitigations: A total of 3 GW based on operational/emergency procedures

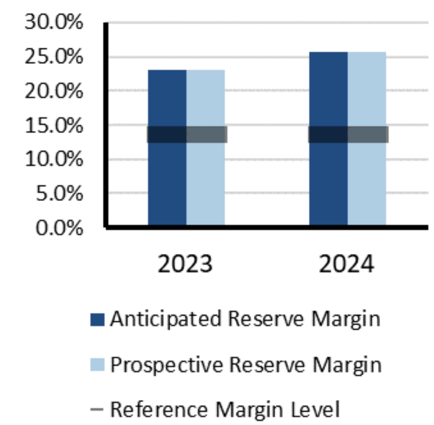
Texas RE-ERCOT

The Electric Reliability Council of Texas (ERCOT) is the independent system operator (ISO) for the ERCOT Interconnection and is located entirely in the state of Texas; it operates as a single BA. It also performs financial settlement for the competitive wholesale bulk-power market and administers retail switching for nearly 8 million premises in competitive choice areas. ERCOT is governed by a board of directors and subject to oversight by the Public Utility Commission of Texas and the Texas Legislature. ERCOT is summer-peaking, and the forecasted summer peak load month is August. It covers approximately 200,000 square miles, connects over 52,700 miles of transmission lines, has over 1,100 generation units, and serves more than 26 million customers. Texas RE is responsible for the Regional Entity functions described in the Energy Policy Act of 2005 for ERCOT. On November 3, 2022, the Public Utility Commission of Texas issued an order directing ERCOT to assume the duties and responsibilities of the reliability monitor for the Texas grid.

Highlights

- Given an ARM of 25.6% and Reference Reserve Margin of 13.75%, ERCOT expects to have sufficient operating reserves for the August peak load hour given expected normal summer system conditions.
- Solar and battery energy storage installed capacity has grown by about 4,500 and 1,600 MW, respectively, since last August.
- Continued robust growth in both loads and intermittent renewable resources has elevated the risk of emergency conditions in the evening hours when solar generation begins to ramp down.
- ERCOT's probabilistic risk assessment indicates an elevated risk of having to declare EEAs during hours ending 8:00–9:00 p.m. Central on the August peak load day. ERCOT judges an hour to have elevated risk (as opposed to low risk) when the probability of an EEA is greater than 10%. The EEA probability for these two hours is about 16% and 18%, respectively.
- Contributing to the elevated risk is a potential need, under certain grid conditions, to limit power transfers from South Texas into the San Antonio region. Conditions could cause overloads on the lines that make up the South Texas export and import interfaces, necessitating South Texas generation curtailments and potential firm load shedding to avoid cascading outages. The risk is greatest when ERCOT has extremely high net loads in the early evening hours. This issue will be addressed with mitigation measures including the construction of the San Antonio South Reliability Project, which is anticipated to be completed by Summer 2027.

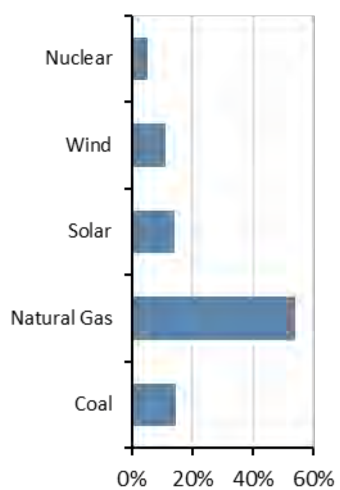
On-Peak Reserve Margin



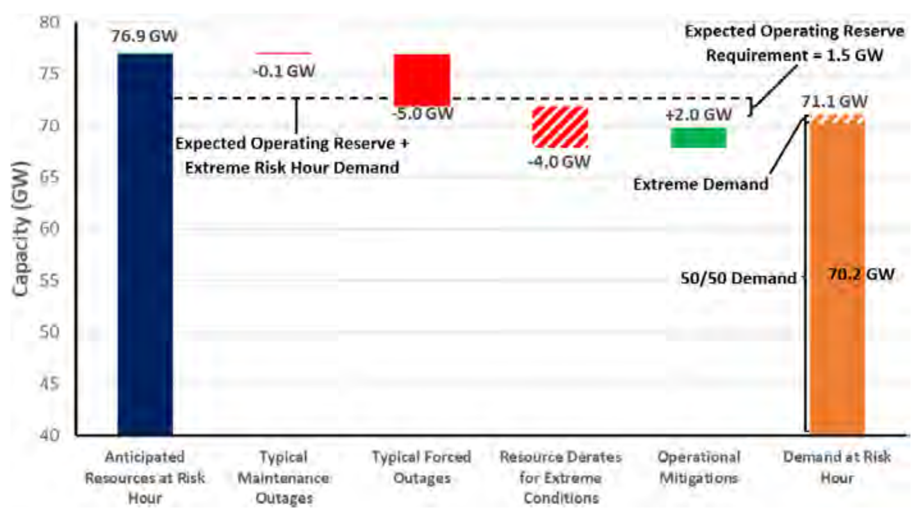
Risk Scenario Summary

Expected resources meet operating reserve requirements for the peak demand hour scenario. However, there is risk of supply shortages as solar generation ramps down during the early evening hours when system load is high and transmission constraints limit transfers.

On-Peak Fuel Mix



2024 Summer Risk Period Scenario (9:00 p.m. local time)



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at hour ending 9 p.m. local time as solar PV output is diminished and demand remains high

Demand Scenarios: Net internal demand (50/50) and extreme demand (95/5) based on August peak load

Forced Outages: Based on the 95th percentile of historical averages of forced outages for June through September weekdays, hours ending 3:00–8:00 p.m. local time for the last three summer seasons

Extreme Derates: Based on the 90th percentile of thermal forced outages for peak August load day

Low Wind Scenario: Based on the 10th percentile of historical averages of hourly wind for June through September, hours ending 1:00–9:00 p.m. local time

Operational Mitigations: Additional capacity from switchable generation and additional imports

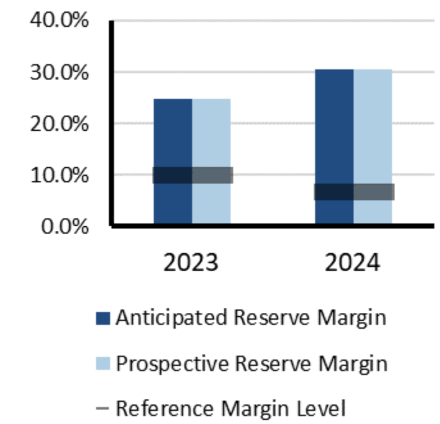
WECC-AB

WECC-AB (Alberta) is a winter-peaking assessment area in the WECC Regional Entity that consists of the province of Alberta. WECC is responsible for coordinating and promoting BES reliability in the Western Interconnection. WECC's 329 members include 39 BAs, representing a wide spectrum of organizations with an interest in the BES. Serving an area of nearly 1.8 million square miles and more than 82 million customers, it is geographically the largest and most diverse Regional Entity. WECC's service territory extends from Canada to Mexico. It includes the provinces of Alberta and British Columbia in Canada and the northern portion of Baja California in Mexico as well as all or portions of the 14 western U.S. states in between.

Highlights

- Thermal and renewable capacity are being added to the area to address rapid load growth, but supply chain issues causing project delays or cancellations may be an issue.
- Thermal tier 1 resources for this upcoming summer include a new 900 MW natural gas combined-cycle facility and the conversion of two existing coal units to two 1x1 natural gas combustion turbine sites with 932 MW (112 incremental MW) of capacity after the steam turbine tie in. The two coal sites undergoing conversion to natural gas are the only remaining coal facilities operating in the area.
- Issues maintaining rate of change of frequency (ROCOF) during islanded or near-islanded situations with high IBR output and low demand is also a concern.
- Alberta is expected to have sufficient resource availability to meet reserves at the peak demand hour (4:00–5:00 p.m.). This evaluation considers a 1-in-10 probability (90th percentile) level for peak demand and a combination of resource derates.
- Alberta shows no LOLH or EUE for the upcoming summer season.

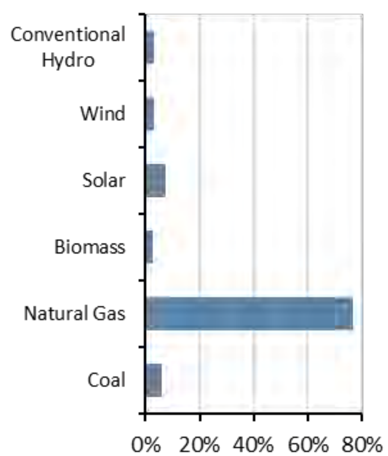
On-Peak Reserve Margin



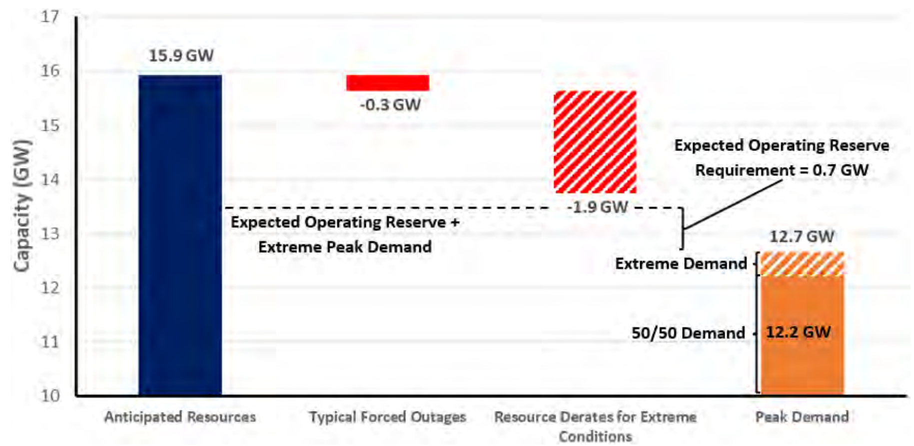
Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed scenarios.

On-Peak Fuel Mix



2024 Summer Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: Net internal demand (50/50) and (90/10) demand forecast

Typical Forced Outages: Average seasonal outages

Extreme Derates: Using (90/10) point of resource performance distribution

WECC-BC

WECC-British Columbia (BC) is a winter-peaking assessment area in the WECC Regional Entity that consists of the province of British Columbia. WECC is responsible for coordinating and promoting BES reliability in the Western Interconnection. WECC's 329 members include 39 BAs, representing a wide spectrum of organizations with an interest in the BES. Serving an area of nearly 1.8 million square miles and more than 82 million customers, it is geographically the largest and most diverse Regional Entity. WECC's service territory extends from Canada to Mexico. It includes the provinces of Alberta and British Columbia in Canada and the northern portion of Baja California in Mexico as well as all or portions of the 14 western U.S. states in between.

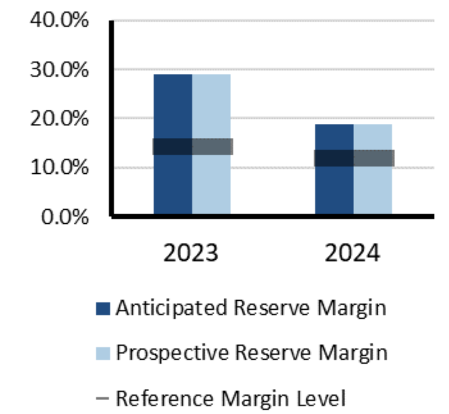
Highlights

- British Columbia faces operational challenges on multiple fronts, including drought, wildfires, and rapid electrification in the residential, commercial, industrial, and transportation sectors.
- British Columbia is expected to have sufficient resource availability to meet reserves at the peak demand hour (5:00–6:00 p.m.) under most conditions. However, above-normal demand that coincides with low hydro output could result in a reserve shortage. This evaluation considers a 1-in-10 probability (90th percentile) level for peak demand and a combination of resource derates including low hydro output.
- WECC's probabilistic analysis shows no LOLH or EUE for British Columbia during the upcoming summer season.

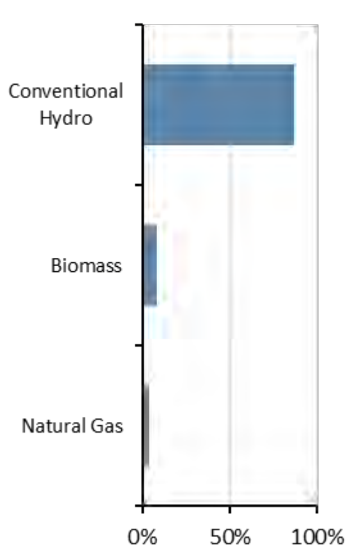
Risk Scenario Summary

Expected resources meet operating reserve requirements under normal peak-demand scenarios. Above-normal summer peak load and outage conditions could result in the need to employ operating mitigations (e.g., DR and transfers) and EEAs.

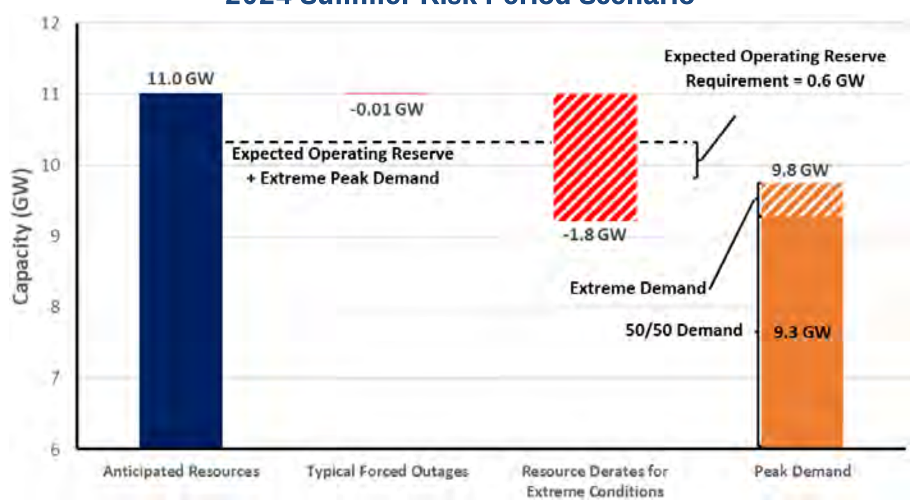
On-Peak Reserve Margin



On-Peak Fuel Mix



2024 Summer Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: Net internal demand (50/50) and (90/10) demand forecast

Forced Outages: Average seasonal outages

Extreme Derates: Using (90/10) resource performance distribution at peak hour

WECC-CA / MX

WECC-CA/MX is a summer-peaking assessment area in the WECC Regional Entity that includes parts of California, Nevada, and Baja California, Mexico. WECC is responsible for coordinating and promoting BES reliability in the Western Interconnection. WECC's 329 members include 39 BAs, representing a wide spectrum of organizations with an interest in the BES. Serving an area of nearly 1.8 million square miles and more than 82 million customers, it is geographically the largest and most diverse Regional Entity. WECC's service territory extends from Canada to Mexico. It includes the provinces of Alberta and British Columbia in Canada and the northern portion of Baja California in Mexico as well as all or portions of the 14 western U.S. states in between.

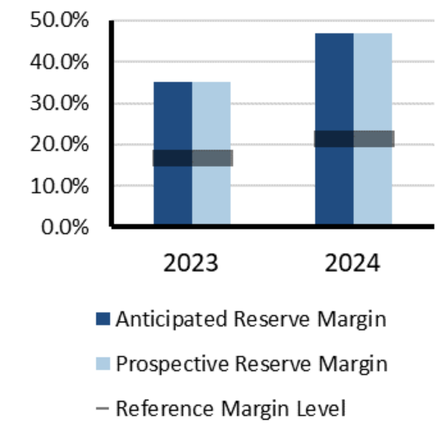
Highlights

- Drought conditions, which were a concern prior to 2023, have been alleviated for the upcoming summer.
- CA/MX is expected to have sufficient resource availability to meet reserves at the peak demand hour (4:00–5:00 p.m.). The riskiest hour for CA/MX is the hour ending 6:00–7:00 p.m. when solar output is low, causing the area to rely on imports to meet demand.
- In WECC's probabilistic analysis, CA/MX is projected to have LOLH ranging from negligible to 0.8 hours with the greatest risk of EUE and LOLH being in the Baja (Mexico) part of CA/MX. Variation in LOLH in the analysis is attributable to the amount of Tier 1 resource additions that connect before the later months. Supply chain issues resulting in the delay or cancellation of Tier 1 projects are a potential risk this summer for CA/MX.
- WECC's analysis considers a 1-in-10 probability (90th percentile) level for peak demand and a combination of resource derates.

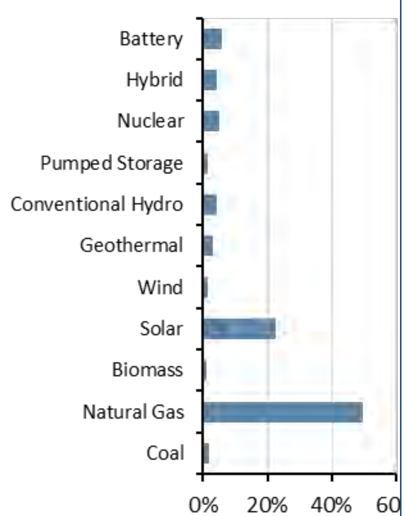
Risk Scenario Summary

Expected resources meet operating reserve requirements under normal peak-demand scenarios. Above-normal summer peak load and outage conditions could necessitate operating mitigations (e.g., DR and transfers) and EEAs.

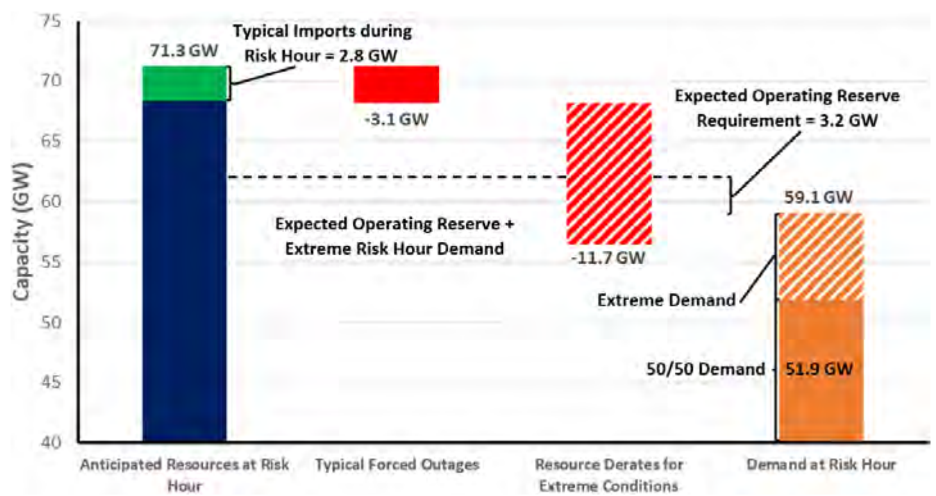
On-Peak Reserve Margin



On-Peak Fuel Mix



2024 Summer Risk Period Scenario (7 p.m. local time)



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at hour ending 7:00 p.m. local time as solar PV output is diminished and demand remains high

Demand Scenarios: Net internal demand (50/50) at risk hour and (90/10) demand forecast at risk hour

Forced Outages: Estimated using market forced outage model

Extreme Derates: On natural gas units based on historical data and manufacturer data for temperature performance and outages

WECC-NW

WECC-NW is a summer-peaking assessment area in the WECC Regional Entity. The area includes Colorado, Idaho, Montana, Oregon, Utah, Washington, and Wyoming and parts of California, Nebraska, Nevada, and South Dakota. WECC is responsible for coordinating and promoting BES reliability in the Western Interconnection. WECC's 329 members include 39 BAs, representing a wide spectrum of organizations with an interest in the BES. Serving an area of nearly 1.8 million square miles and more than 82 million customers, it is geographically the largest and most diverse Regional Entity. WECC's service territory extends from Canada to Mexico. It includes the provinces of Alberta and British Columbia in Canada and the northern portion of Baja California in Mexico as well as all or portions of the 14 western U.S. states in between.

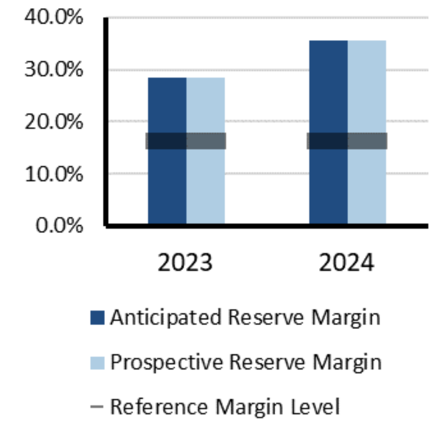
Highlights

- Operational challenges for the Northwest include supply chain issues potentially resulting in project delays or cancellations and unprecedented flow patterns associated with the expansion of IBRs.
- The Northwest is expected to have sufficient resource availability to meet reserves at the peak demand hour (4:00–5:00 p.m.). This evaluation considers a 1-in-10 probability (90th percentile) level for peak demand and a combination of resource derates.
- The Northwest shows no LOLH or EUE for the upcoming summer season.

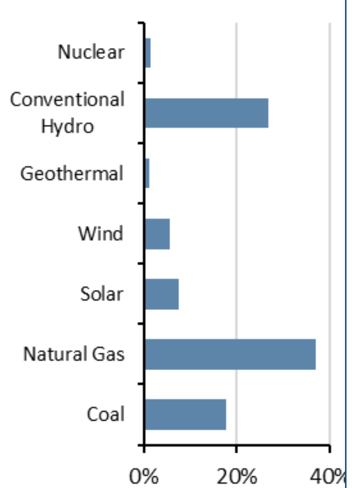
Risk Scenario Summary

Expected resources meet operating reserve requirements under normal peak-demand scenarios. Above-normal summer peak load and outage conditions could result in the need to employ operating mitigations (e.g., DR and transfers) and EEAs.

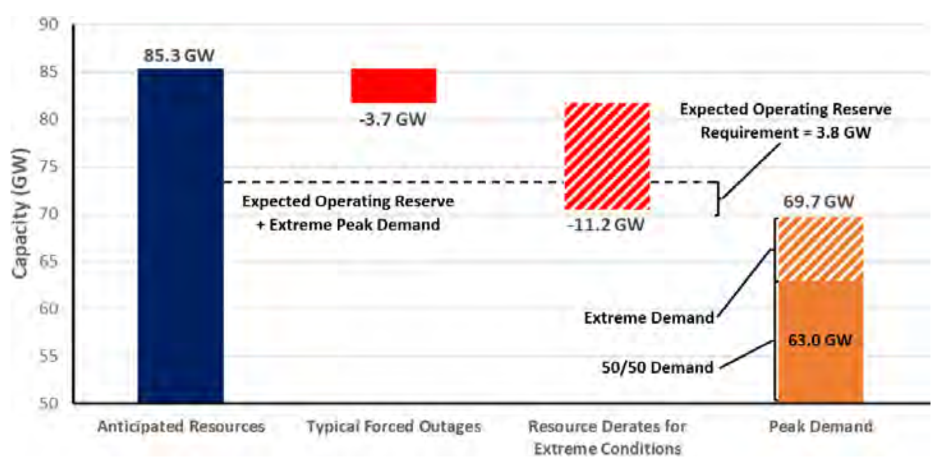
On-Peak Reserve Margin



On-Peak Fuel Mix



2024 Summer Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy occurs at the hour of peak demand

Demand Scenarios: Net internal demand (50/50) at risk hour and (90/10) demand forecast at risk hour

Forced Outages: Average seasonal outages

Extreme Derates: Using (90/10) scenario

WECC-SW

WECC-SW is a summer-peaking assessment area in the WECC Regional Entity. It includes Arizona, New Mexico, and parts of California and Texas. WECC is responsible for coordinating and promoting BES reliability in the Western Interconnection. WECC's 329 members include 39 BAs, representing a wide spectrum of organizations with an interest in the BES. Serving an area of nearly 1.8 million square miles and more than 82 million customers, it is geographically the largest and most diverse Regional Entity. WECC's service territory extends from Canada to Mexico. It includes the provinces of Alberta and British Columbia in Canada as well as the northern portion of Baja California in Mexico and all or portions of the 14 western U.S. states in between.

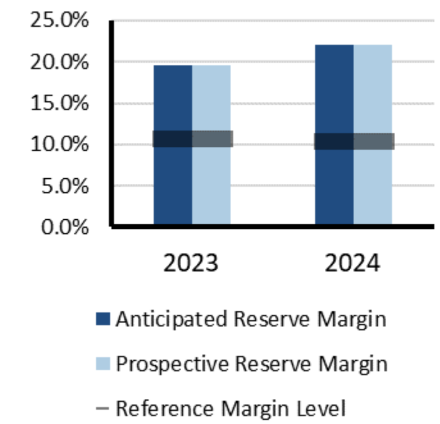
Highlights

- Operational challenges for the Southwest include drought, wildfires, derates of gas facilities due to extreme heat, and supply chain issues potentially affecting thermal resource return to service dates and CODs.
- The Southwest is expected to have sufficient resource availability to meet reserves at the peak demand hour (4:00–5:00 p.m.) under most conditions. However, above-normal demand that coincides with high generator forced outages or other low-resource conditions could result in a reserve shortage. This evaluation considers a 1-in-10 probability (90th percentile) level for peak demand and a combination of resource derates.
- The Southwest shows no LOLH or EUE for the upcoming summer season in WECC's probabilistic analysis.

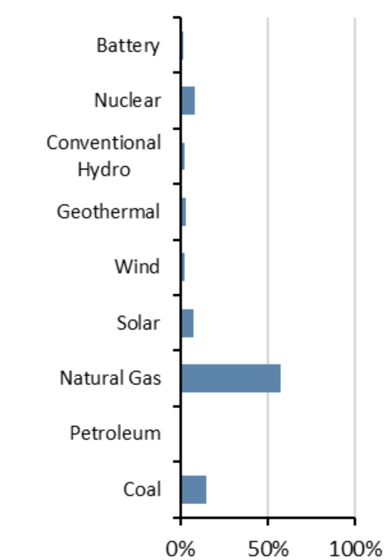
Risk Scenario Summary

Expected resources meet operating reserve requirements under normal peak-demand scenarios. Above-normal summer peak load and outage conditions could result in the need to employ operating mitigations (e.g., DR and transfers) and EEAs.

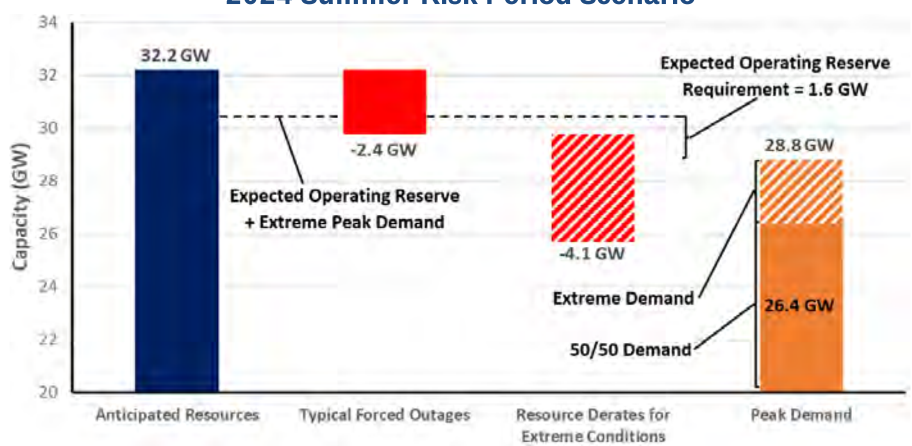
On-Peak Reserve Margin



On-Peak Fuel Mix



2024 Summer Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy occurs at the hour of peak demand (5:00 p.m. local)

Demand Scenarios: Net internal demand (50/50) at risk hour and (90/10) demand forecast

Forced Outages: Average seasonal outages

Extreme Derates: Using (90/10) scenario

Data Concepts and Assumptions

The table below explains data concepts and important assumptions used throughout this assessment.

General Assumptions

- Reliability of the interconnected BPS is comprised of both adequacy and operating reliability:
  - Adequacy is the ability of the electric system to supply the aggregate electric power and energy requirements of the electricity consumers at all times while taking into account scheduled and reasonably expected unscheduled outages of system components.
  - Operating reliability is the ability of the electric system to withstand sudden disturbances, such as electric short-circuits or unanticipated loss of system components.
- The reserve margin calculation is an important industry planning metric used to examine future resource adequacy.
- All data in this assessment is based on existing federal, state, and provincial laws and regulations.
- Differences in data collection periods for each assessment area should be considered when comparing demand and capacity data between year-to-year seasonal assessments.
- *2023 Long-Term Reliability Assessment* data has been used for most of this 2024 summer assessment period augmented by updated load and capacity data.
- A positive net transfer capability would indicate a net importing assessment area; a negative value would indicate a net exporter.

Demand Assumptions

- Electricity demand projections, or load forecasts, are provided by each assessment area.
- Load forecasts include peak hourly load[12] or total internal demand for the summer and winter of each year.[13]
- Total internal demand projections are based on normal weather (50/50 distribution)[14] and are provided on a coincident[15] basis for most assessment areas.
- Net internal demand is used in all reserve margin calculations, and it is equal to total internal demand then reduced by the amount of controllable and dispatchable DR projected to be available during the peak hour.

Resource Assumptions

Resource planning methods vary throughout the North American BPS. NERC uses the categories below to provide a consistent approach for collecting and presenting resource adequacy. Because the electrical output of variable energy resources (e.g., wind, solar PV) depends on weather conditions, their contribution to reserve margins and other on-peak resource adequacy analysis is less than their nameplate capacity.

Anticipated Resources:

- **Existing-Certain Capacity**: Included in this category are commercially operable generating units or portions of generating units that meet at least one of the following requirements when examining the period of peak demand for the summer season: unit must have a firm capability and have a power purchase agreement with firm transmission that must be in effect for the unit; unit must be classified as a designated network resource; and/or, where energy-only markets exist, unit must be a designated market resource eligible to bid into the market.
- **Tier 1 Capacity Additions**: This category includes capacity that either is under construction or has received approved planning requirements.
- **Net Firm Capacity Transfers (Imports minus Exports)**: This category includes transfers with firm contracts.

[12] *Glossary of Terms* used in NERC Reliability Standards
[13] The summer season represents June–September and the winter season represents December–February.
[14] Essentially, this means that there is a 50% probability that actual demand will be higher and a 50% probability that actual demand will be lower than the value provided for a given season/year.
[15] Coincident: This is the sum of two or more peak loads that occur in the same hour. Noncoincident: This is the sum of two or more peak loads on individual systems that do not occur in the same time interval; this is meaningful only when considering loads within a limited period of time, such as a day, a week, a month, a heating or cooling season, and usually for not more than one year. SERC calculates total internal demand on a noncoincidental basis.

Prospective Resources: Includes all anticipated resources plus the following:

Existing-Other Capacity: Included in this category are commercially operable generating units or portions of generating units that could be available to serve load for the period of peak demand for the season but do not meet the requirements of existing-certain.

Reserve Margin Descriptions

Planning Reserve Margin: This is the primary metric used to measure resource adequacy; it is defined as the difference in resources (anticipated or prospective) and net internal demand then divided by net internal demand and shown as a percentage.

Reference Margin Level: The assumptions and naming convention of this metric vary by assessment area. The RML can be determined using both deterministic and probabilistic (based on a 0.1/year loss of load study) approaches. In both cases, this metric is used by system planners to quantify the amount of reserve capacity in the system above the forecasted peak demand that is needed to ensure sufficient supply to meet peak loads. Establishing an RML is necessary to account for long-term factors of uncertainty involved in system planning, such as unexpected generator outages and extreme weather impacts that could lead to increase demand beyond what was projected in the 50/50 load forecasted. In many assessment areas, an RML is established by a state, provincial authority, ISO/Regional Transmission Organization (RTO), or other regulatory body. In some cases, the RML is a requirement. RMLs may be different for the summer and winter seasons. If an RML is not provided by an assessment area, NERC applies 15% for predominately thermal systems and 10% for predominately hydro systems.

Seasonal Risk Scenario Chart Description

Each assessment area performed an operational risk analysis that was used to produce the seasonal risk scenario charts in the Regional Assessments Dashboards. The chart presents deterministic scenarios for further analysis of different resource and demand levels: The left **blue** column shows anticipated resources, and the two **orange** columns at the right show the two demand scenarios of the normal peak net internal demand and the extreme summer peak demand—both determined by the assessment area. The middle **red** or **green** bars show adjustments that are applied cumulatively to the anticipated resources, such as the following:

- Reductions for typical generation outages (i.e., maintenance and forced outages that are not already accounted for in anticipated resources)
- Reductions that represent additional outage or performance derating by resource type for extreme, low-probability conditions (e.g., drought condition impacts on hydroelectric generation, low-wind scenario affecting wind generation, fuel supply limitations, or extreme temperature conditions that result in reduced thermal generation output)
- Additional capacity resources that represent quantified capacity from operational procedures, if any, that are made available during scarcity conditions

Not all assessment areas have the same categories of adjustments to anticipated resources. Furthermore, each assessment area determined the adjustments to capacity based on methods or assumptions that are summarized below the chart. Methods and assumptions differ by assessment area and may not be comparable.

The chart enables evaluation of resource levels against levels of expected operating reserve requirement and the forecasted demand. Furthermore, the effects from extreme events can also be examined by comparing resource levels after applying extreme scenario derates and/or extreme summer peak demand.

Resource Adequacy

The ARM, which is based on available resource capacity, is a metric used to evaluate resource adequacy by comparing the projected capability of anticipated resources to serve forecast peak demand.[16] Large year-to-year changes in anticipated resources or forecast peak demand (net internal demand) can greatly impact Planning Reserve Margin calculations. All assessment areas have sufficient ARMs to meet or exceed their RML for the 2024 summer as shown in **Figure 4**.

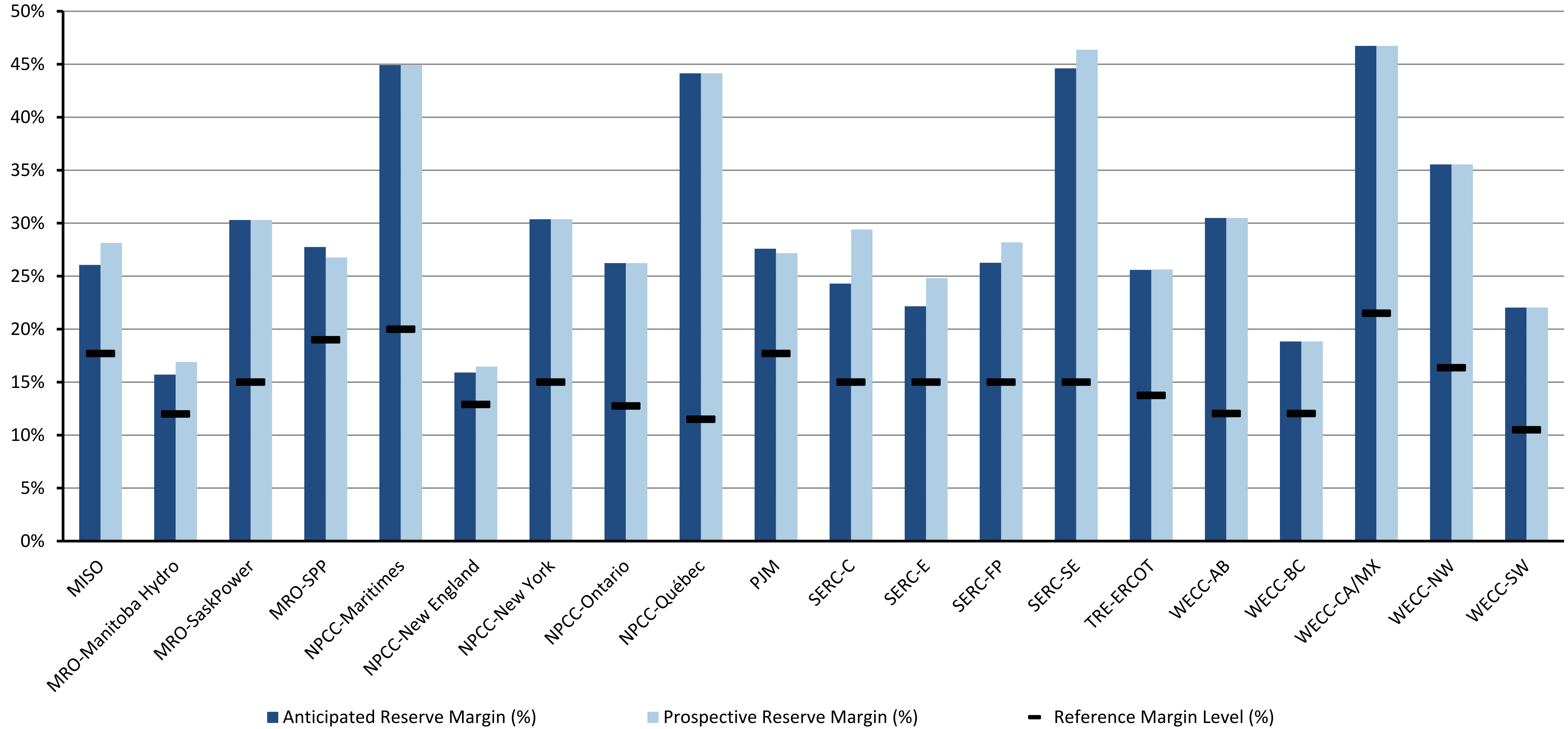


Figure 4: Summer 2024 Anticipated/Prospective Reserve Margins Compared to Reference Margin Level

[16] Generally, anticipated resources include generators and firm capacity transfers that are expected to be available to serve load during electrical peak loads for the season. Prospective resources are those that could be available but do not meet criteria to be counted as anticipated resources. Refer to the **Data Concepts and Assumptions** section for additional information on Anticipated/Prospective Reserve Margins, anticipated/prospective resources, and RMLs.

Changes from Year-to-Year

Figure 5 provides the relative change in the forecast ARMs from the 2023 summer to the 2024 summer. A significant decline can signal potential operational issues for the upcoming season. Both MRO-Manitoba Hydro and WECC-BC have noticeable reductions in their ARM levels for the 2024 summer. MRO-Manitoba Hydro does not anticipate elevated risk for the upcoming summer, but WECC-BC is experiencing increasing forecasted demand and drought conditions, increasing risk heading into the 2024 summer. Additional details for each assessment area are provided in the Data Concepts and Assumptions and Regional Assessments Dashboards sections.

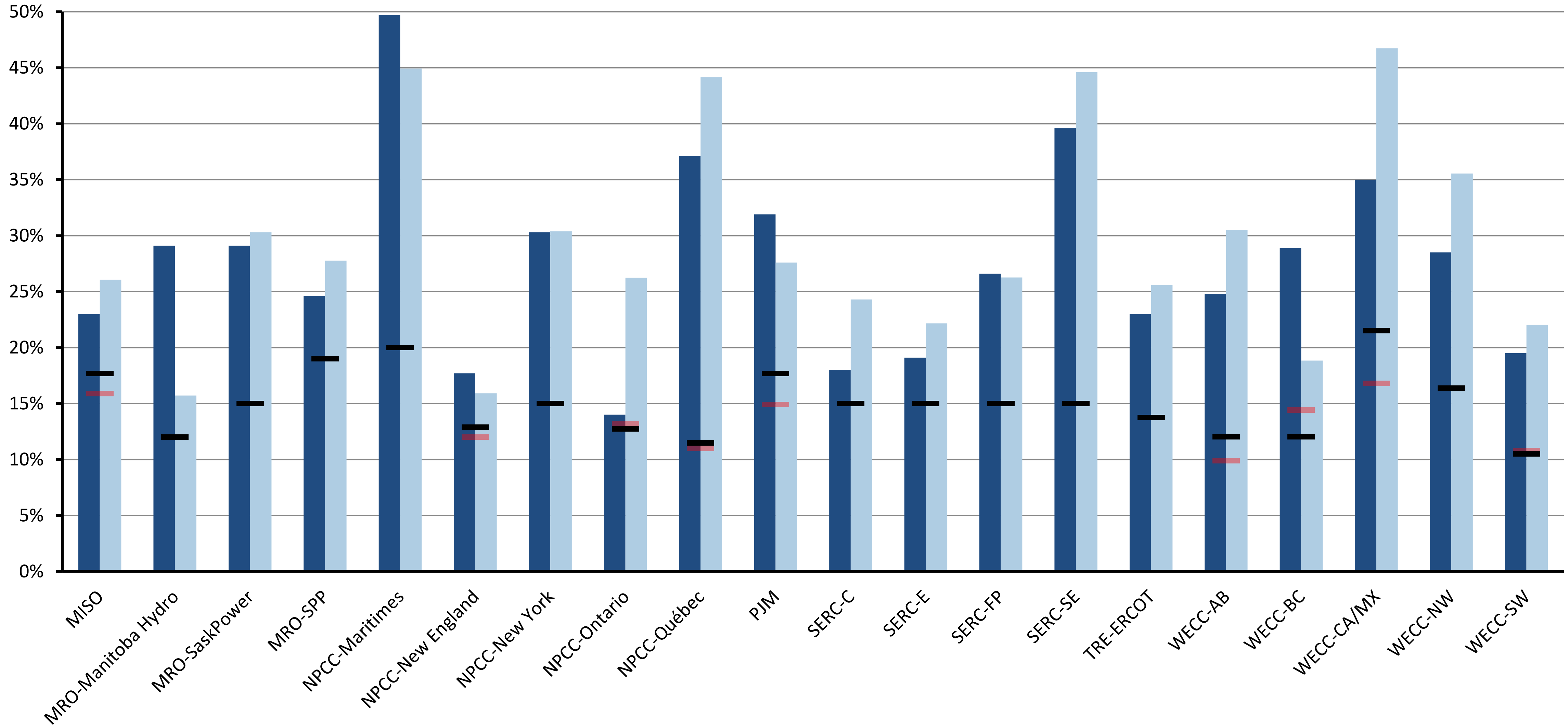


Figure 5: Summer 2023 and Summer 2024 Anticipated Reserve Margins Year-to-Year Change

Net Internal Demand

The changes in forecasted net internal demand for each assessment area are shown in **Figure 6**.[17] Assessment areas develop these forecasts based on historic load and weather information as well as other long-term projections.

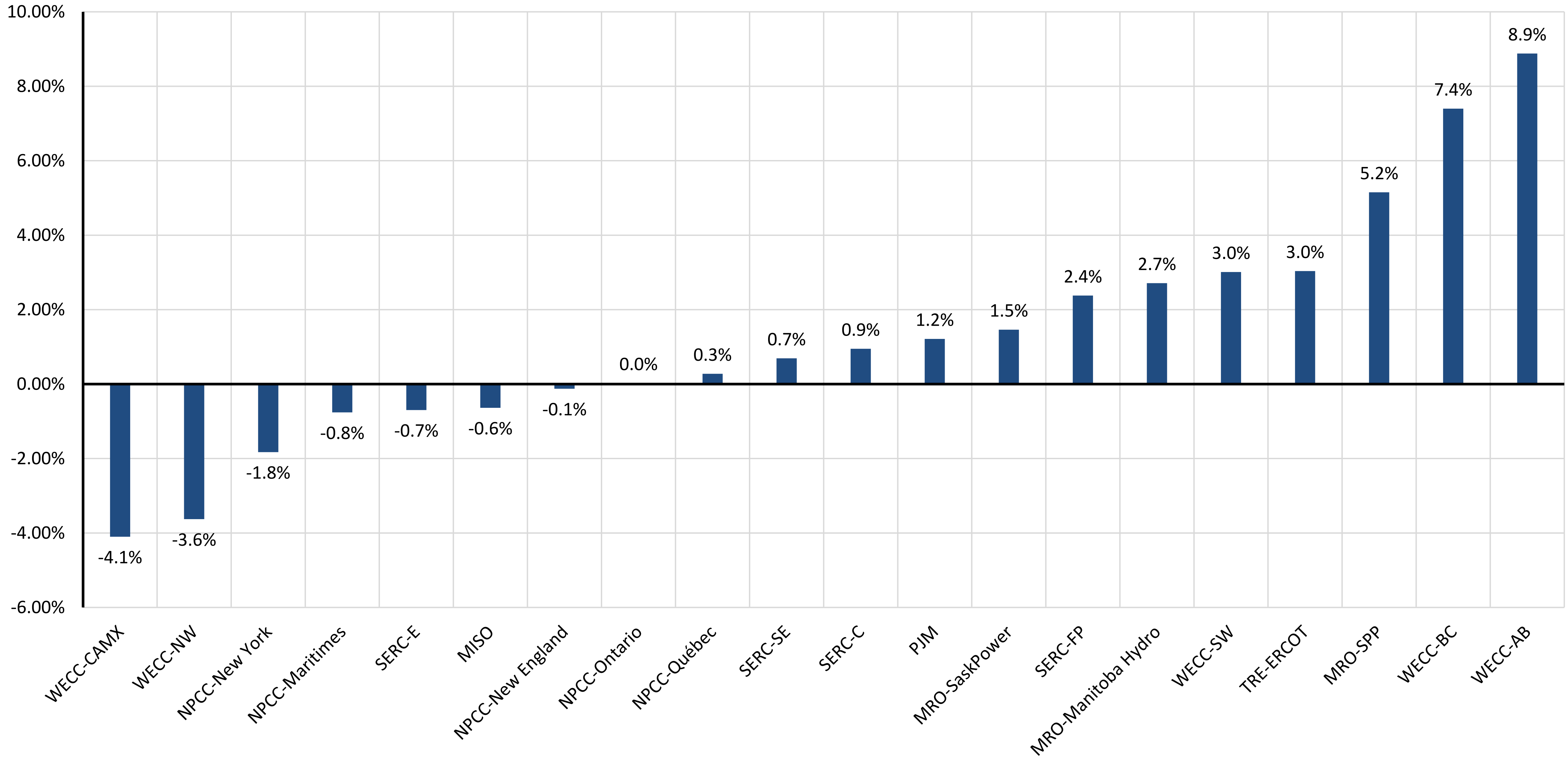


Figure 6: Changes in Net Internal Demand—Summer 2023 Forecast Compared to Summer 2024 Forecast

[17] Changes in modeling and methods may also contribute to year-to-year changes in forecasted net internal demand projections.

Demand and Resource Tables

Peak demand and supply capacity data—resource adequacy data—for each assessment area are as follows in each table (in alphabetical order).

MISO			
Demand, Resource, and Reserve Margins	**2023 SRA**	**2024 SRA**	**2023 vs. 2024 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	123,728	124,830	0.9%
Demand Response: Available	6,903	8,750	26.8%
Net Internal Demand	116,825	116,079	-0.6%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	140,650	143,866	2.3%
Tier 1 Planned Capacity	0	0	-
Net Firm Capacity Transfers	3,018	2,471	-18.1%
Anticipated Resources	143,668	146,337	1.9%
Existing-Other Capacity	668	1,833	174.4%
Prospective Resources	151,579	148,740	-1.9%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	23.0%	26.1%	3.1
Prospective Reserve Margin	29.7%	28.1%	-1.6
Reference Margin Level	15.9%	17.7%	1.8

MRO-Manitoba Hydro			
Demand, Resource, and Reserve Margins	**2023 SRA**	**2024 SRA**	**2023 vs. 2024 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	3,060	3,143	2.7%
Demand Response: Available	0	0	-
Net Internal Demand	3,060	3,143	2.7%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	5,731	5,615	-2.0%
Tier 1 Planned Capacity	91	0	-100.0%
Net Firm Capacity Transfers	-1,872	-1,978	5.7%
Anticipated Resources	3,950	3,637	-7.9%
Existing-Other Capacity	34	37	9.7%
Prospective Resources	3,984	3,674	-7.8%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	29.1%	15.7%	-13.4
Prospective Reserve Margin	30.2%	16.9%	-13.3
Reference Margin Level	12.0%	12.0%	0.0

MRO-SaskPower			
Demand, Resource, and Reserve Margins	**2023 SRA**	**2024 SRA**	**2023 vs. 2024 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	3,539	3,590	1.4%
Demand Response: Available	50	50	0.0%
Net Internal Demand	3,489	3,540	1.5%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	4,213	4,323	2.6%
Tier 1 Planned Capacity	0	0	-
Net Firm Capacity Transfers	290	290	0.0%
Anticipated Resources	4,503	4,613	2.4%
Existing-Other Capacity	0	0	-
Prospective Resources	4,503	4,613	2.4%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	29.1%	30.3%	1.2
Prospective Reserve Margin	29.1%	30.3%	1.2
Reference Margin Level	15.0%	15.0%	0.0

MRO-SPP			
Demand, Resource, and Reserve Margins	**2023 SRA**	**2024 SRA**	**2023 vs. 2024 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	53,468	56,316	5.3%
Demand Response: Available	842	979	16.3%
Net Internal Demand	52,626	55,337	5.2%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	65,821	70,855	7.6%
Tier 1 Planned Capacity	0	0	-
Net Firm Capacity Transfers	-238	-157	-33.9%
Anticipated Resources	65,583	70,698	7.8%
Existing-Other Capacity	0	0	-
Prospective Resources	65,036	70,151	7.9%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	24.6%	27.8%	3.2
Prospective Reserve Margin	23.6%	26.8%	3.2
Reference Margin Level	19.0%	19.0%	0.0

NPCC-Maritimes			
Demand, Resource, and Reserve Margins	**2023 SRA**	**2024 SRA**	**2023 vs. 2024 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	3,612	3,586	-0.7%
Demand Response: Available	328	327	-0.3%
Net Internal Demand	3,284	3,259	-0.8%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	4,834	4,660	-3.6%
Tier 1 Planned Capacity	0	0	-
Net Firm Capacity Transfers	81	63	-22.2%
Anticipated Resources	4,915	4,723	-3.9%
Existing-Other Capacity	0	0	-
Prospective Resources	4,915	4,723	-3.9%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	49.7%	44.9%	-4.8
Prospective Reserve Margin	49.7%	44.9%	-4.8
Reference Margin Level	20.0%	20.0%	0.0

NPCC-New York			
Demand, Resource, and Reserve Margins	**2023 SRA**	**2024 SRA**	**2023 vs. 2024 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	32,049	31,541	-1.6%
Demand Response: Available	1,226	1,281	4.5%
Net Internal Demand	30,823	30,260	-1.8%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	37,216	37,867	1.7%
Tier 1 Planned Capacity	0	0	-
Net Firm Capacity Transfers	2,932	1,585	-45.9%
Anticipated Resources	40,148	39,452	-1.7%
Existing-Other Capacity	0	0	-
Prospective Resources	40,148	39,452	-1.7%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	30.3%	30.4%	0.1
Prospective Reserve Margin	30.3%	30.4%	0.1
Reference Margin Level	15.0%	15.0%	0.0

NPCC-New England			
Demand, Resource, and Reserve Margins	**2023 SRA**	**2024 SRA**	**2023 vs. 2024 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	25,111	25,294	0.7%
Demand Response: Available	447	661	47.9%
Net Internal Demand	24,664	24,633	-0.1%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	27,997	27,255	-2.7%
Tier 1 Planned Capacity	0	0	-
Net Firm Capacity Transfers	1,030	1,297	25.9%
Anticipated Resources	29,027	28,552	-1.6%
Existing-Other Capacity	872	138	-84.2%
Prospective Resources	29,899	28,690	-4.0%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	17.7%	15.9%	-1.8
Prospective Reserve Margin	21.2%	16.5%	-4.7
Reference Margin Level	12.0%	12.9%	0.9

NPCC-Ontario			
Demand, Resource, and Reserve Margins	**2023 SRA**	**2024 SRA**	**2023 vs. 2024 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	22,439	22,753	1.4%
Demand Response: Available	687	996	45.0%
Net Internal Demand	21,752	21,757	0.0%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	24,575	26,856	9.3%
Tier 1 Planned Capacity	9	9	-1.6%
Net Firm Capacity Transfers	223	600	169.1%
Anticipated Resources	24,807	27,465	10.7%
Existing-Other Capacity	0	0	-
Prospective Resources	24,807	27,465	10.7%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	14.0%	26.2%	12.2
Prospective Reserve Margin	14.0%	26.2%	12.2
Reference Margin Level	13.2%	12.8%	-0.5

NPCC-Québec			
Demand, Resource, and Reserve Margins	**2023 SRA**	**2024 SRA**	**2023 vs. 2024 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	22,859	22,922	0.3%
Demand Response: Available	0	0	-
Net Internal Demand	22,859	22,922	0.3%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	33,690	35,731	6.1%
Tier 1 Planned Capacity	0	0	-
Net Firm Capacity Transfers	-2,353	-2,689	14.3%
Anticipated Resources	31,337	33,042	5.4%
Existing-Other Capacity	0	0	-
Prospective Resources	31,337	33,042	5.4%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	37.1%	44.1%	7.0
Prospective Reserve Margin	37.1%	44.1%	7.0
Reference Margin Level	11.0%	11.5%	0.5

SERC-Central			
Demand, Resource, and Reserve Margins	**2023 SRA**	**2024 SRA**	**2023 vs. 2024 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	42,223	42,636	1.0%
Demand Response: Available	1,910	1,941	1.6%
Net Internal Demand	40,313	40,695	0.9%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	46,964	48,677	3.6%
Tier 1 Planned Capacity	93	332	257.3%
Net Firm Capacity Transfers	1,068	2,592	142.7%
Anticipated Resources	47,556	51,601	8.5%
Existing-Other Capacity	2,313	2,074	-10.3%
Prospective Resources	49,868	51,083	2.4%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	18.0%	26.8%	8.8
Prospective Reserve Margin	23.7%	25.5%	1.8
Reference Margin Level	15.0%	15.0%	0.0

PJM			
Demand, Resource, and Reserve Margins	**2023 SRA**	**2024 SRA**	**2023 vs. 2024 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	149,059	151,247	1.5%
Demand Response: Available	7,288	7,756	6.4%
Net Internal Demand	141,771	143,491	1.2%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	186,540	183,690	-1.5%
Tier 1 Planned Capacity	0	0	-
Net Firm Capacity Transfers	463	-607	-231.1%
Anticipated Resources	187,003	183,083	-2.1%
Existing-Other Capacity	0	0	-
Prospective Resources	187,466	182,476	-2.7%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	31.9%	27.6%	-4.3
Prospective Reserve Margin	32.2%	27.2%	-5.0
Reference Margin Level	14.9%	17.7%	2.8

SERC-East			
Demand, Resource, and Reserve Margins	**2023 SRA**	**2024 SRA**	**2023 vs. 2024 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	43,889	43,567	-0.7%
Demand Response: Available	1,008	985	-2.3%
Net Internal Demand	42,881	42,582	-0.7%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	50,452	51,304	1.7%
Tier 1 Planned Capacity	0	122	-
Net Firm Capacity Transfers	624	593	-5.0%
Anticipated Resources	51,076	52,019	1.8%
Existing-Other Capacity	1,182	1,131	-4.3%
Prospective Resources	52,258	52,557	0.6%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	19.1%	22.2%	3.1
Prospective Reserve Margin	21.9%	23.4%	1.5
Reference Margin Level	15.0%	15.0%	0.0

SERC-Florida Peninsula			
Demand, Resource, and Reserve Margins	**2023 SRA**	**2024 SRA**	**2023 vs. 2024 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	52,195	53,293	2.1%
Demand Response: Available	2,898	2,824	-2.6%
Net Internal Demand	49,297	50,469	2.4%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	60,074	60,962	1.5%
Tier 1 Planned Capacity	1,742	34	-98.0%
Net Firm Capacity Transfers	589	200	-66.0%
Anticipated Resources	62,405	61,196	-1.9%
Existing-Other Capacity	776	985	27.0%
Prospective Resources	63,181	61,981	-1.9%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	26.6%	21.3%	-5.3
Prospective Reserve Margin	28.2%	22.8%	-5.4
Reference Margin Level	15.0%	15.0%	0.0

Texas RE-ERCOT			
Demand, Resource, and Reserve Margins	**2023 SRA**	**2024 SRA**	**2023 vs. 2024 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	82,307	84,818	3.1%
Demand Response: Available	3,380	3,496	3.4%
Net Internal Demand	78,927	81,323	3.0%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	94,580	99,541	5.2%
Tier 1 Planned Capacity	2,445	2,578	5.4%
Net Firm Capacity Transfers	20	20	0.0%
Anticipated Resources	97,045	102,139	5.2%
Existing-Other Capacity	0	0	-
Prospective Resources	97,073	102,167	5.2%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	23.0%	25.6%	2.6
Prospective Reserve Margin	23.0%	25.6%	2.6
Reference Margin Level	13.75%	13.75%	0.0

SERC-Southeast			
Demand, Resource, and Reserve Margins	**2023 SRA**	**2024 SRA**	**2023 vs. 2024 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	46,127	46,021	-0.2%
Demand Response: Available	2,010	1,599	-20.4%
Net Internal Demand	44,117	44,422	0.7%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	59,559	63,918	7.3%
Tier 1 Planned Capacity	2,865	1,738	-39.4%
Net Firm Capacity Transfers	-815	-1,192	46.3%
Anticipated Resources	61,609	64,463	4.6%
Existing-Other Capacity	908	785	-13.5%
Prospective Resources	62,517	66,441	6.3%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	39.6%	45.1%	5.5
Prospective Reserve Margin	41.7%	49.6%	7.9
Reference Margin Level	15.0%	15.0%	0.0

WECC-AB			
Demand, Resource, and Reserve Margins	**2023 SRA**	**2024 SRA**	**2023 vs. 2024 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	11,206	12,201	8.9%
Demand Response: Available	0	0	-
Net Internal Demand	11,206	12,201	8.9%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	13,759	13,941	1.3%
Tier 1 Planned Capacity	227	1,981	772.7%
Net Firm Capacity Transfers	0	0	-
Anticipated Resources	13,986	15,922	13.8%
Existing-Other Capacity	0	0	-
Prospective Resources	13,986	15,922	13.8%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	24.8%	30.5%	5.7
Prospective Reserve Margin	24.8%	30.5%	5.7
Reference Margin Level	9.9%	6.7%	-3.2

WECC-BC			
Demand, Resource, and Reserve Margins	**2023 SRA**	**2024 SRA**	**2023 vs. 2024 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	8,636	9,275	7.4%
Demand Response: Available	0	0	-
Net Internal Demand	8,636	9,275	7.4%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	11,135	11,022	-1.0%
Tier 1 Planned Capacity	0	0	-
Net Firm Capacity Transfers	0	0	-
Anticipated Resources	11,135	11,022	-1.0%
Existing-Other Capacity	0	0	-
Prospective Resources	11,135	11,022	-1.0%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	28.9%	18.8%	-10.1
Prospective Reserve Margin	28.9%	18.8%	-10.1
Reference Margin Level	9.7%	12.0%	-2.4

WECC-CA / MX			
Demand, Resource, and Reserve Margins	**2023 SRA**	**2024 SRA**	**2023 vs. 2024 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	56,356	54,029	-4.1%
Demand Response: Available	862	810	-6.0%
Net Internal Demand	55,494	53,219	-4.1%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	69,408	70,841	2.1%
Tier 1 Planned Capacity	5,522	6,906	25.1%
Net Firm Capacity Transfers	0	340	-
Anticipated Resources	74,930	78,087	4.2%
Existing-Other Capacity	0	0	-
Prospective Resources	74,930	78,087	4.2%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	35.0%	46.7%	11.7
Prospective Reserve Margin	35.0%	46.7%	11.7
Reference Margin Level	16.8%	21.5%	4.7

WECC-SW			
Demand, Resource, and Reserve Margins	**2023 SRA**	**2024 SRA**	**2023 vs. 2024 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	25,992	26,661	2.6%
Demand Response: Available	380	278	-26.8%
Net Internal Demand	25,612	26,383	3.0%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	26,206	28,336	8.1%
Tier 1 Planned Capacity	1,655	2,338	41.3%
Net Firm Capacity Transfers	2,747	1,523	-44.6%
Anticipated Resources	30,608	32,197	5.2%
Existing-Other Capacity	0	0	-
Prospective Resources	30,608	32,197	5.2%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	19.5%	22.0%	2.5
Prospective Reserve Margin	19.5%	22.0%	2.5
Reference Margin Level	10.8%	10.5%	-0.3

WECC-NW			
Demand, Resource, and Reserve Margins	**2023 SRA**	**2024 SRA**	**2023 vs. 2024 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	66,366	63,865	-3.8%
Demand Response: Available	1,038	907	-12.6%
Net Internal Demand	65,328	62,958	-3.6%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	76,587	78,057	1.9%
Tier 1 Planned Capacity	2,350	4,089	74.0%
Net Firm Capacity Transfers	5,004	3,192	-36.2%
Anticipated Resources	83,941	85,338	1.7%
Existing-Other Capacity	0	0	-
Prospective Resources	83,941	85,338	1.7%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	28.5%	35.5%	7.0
Prospective Reserve Margin	28.5%	35.5%	7.0
Reference Margin Level	16.3%	16.4%	0.1

Variable Energy Resource Contributions

Because the electrical output of variable energy resources (e.g., wind, solar PV) depends on weather conditions, on-peak capacity contributions are less than nameplate capacity. The following table shows the capacity contribution of existing wind and solar PV resources at the peak demand hour for each assessment area. Resource contributions are also aggregated by Interconnection and across the entire BPS. For NERC's analysis of risk periods after peak demand (e.g., U.S. assessment areas in WECC), lower contributions of solar PV resources are used because output is diminished during evening periods.

BPS Variable Energy Resources by Assessment Area												
	Wind			Solar			Hydro			Energy Storage Systems (ESS)		
Assessment Area / Interconnection	Nameplate Wind	Expected Wind	Expected Share of Nameplate (%)	Nameplate Solar PV	Expected Solar PV	Expected Share of Nameplate (%)	Nameplate Hydro	Expected Hydro	Expected Share of Nameplate (%)	Nameplate ESS	Expected ESS	Expected Share of Nameplate (%)
MISO	30,931	5,599	18%	10,169	4,981	49%	1,621	1,488	92%	2,678	2,591	97%
MRO-Manitoba Hydro	259	48	19%	–	-	0%	202	92	46%	-	-	0%
MRO-SaskPower	616	208	34%	30	6	21%	848	655	77%	-	-	0%
NPCC-Maritimes	1,209	262	22%	69	-	0%	1,312	1,181	90%	13	13	100%
NPCC-New England	1,546	122	8%	3,246	1,111	34%	550	367	67%	2,077	2,038	98%
NPCC-New York	2,590	340	13%	370	53	14%	984	386	39%	20	-	0%
NPCC-Ontario	4,883	720	15%	478	66	14%	8,922	5,171	58%	-	-	0%
NPCC-Québec	3,820	-	0%	10	-	0%	446	446	100%	-	-	0%
PJM	10,495	1,703	16%	10,990	5,694	52%	2,505	2,505	100%	190	151	79%
SERC-Central	1,220	172	14%	2,074	996	48%	4,966	3,332	67%	166	70	42%
SERC-East	-	-	-	2,769	2,405	87%	3,072	3,016	98%	24	10	43%
SERC-Florida Peninsula	-	-	0%	10,023	5,643	56%	-	-	0%	538	538	100%
SERC-Southeast	-	-	0%	7,887	7,217	91%	3,303	3,259	99%	115	105	92%
SPP	34,783	5,876	17%	756	486	64%	107	54	50%	12	2	13%
Texas RE-ERCOT	39,069	9,070	23%	24,463	17,797	73%	575	450	78%	7,876	2,661	34%
WECC-AB	4,482	666	15%	1,650	786	48%	894	450	50%	190	185	97%
WECC-BC	747	140	19%	2	0	22%	16,521	9,757	59%	-	-	0%
WECC-CA/MX	7,694	1,124	15%	21,790	13,147	60%	13,725	6,265	46%	7,295	6,858	94%
WECC-NW	19,709	2,964	15%	8,853	2,595	29%	41,705	24,147	58%	779	707	91%
WECC-SW	3,329	542	16%	2,690	1,294	48%	1,201	670	56%	988	893	90%
EASTERN INTERCONNECTION	88,702	15,220	17%	48,862	28,657	59%	28,394	21,507	76%	5,832	5,517	95%
QUÉBEC INTERCONNECTION	3,820	-	0%	10	-	0%	446	446	100%	-	-	0%
TEXAS INTERCONNECTION	39,069	9,070	23%	24,463	17,797	73%	575	450	78%	7,876	2,661	34%
WECC INTERCONNECTION	35,961	5,436	15%	34,985	17,822	51%	74,046	41,289	56%	9,252	8,643	93%
All INTERCONNECTIONS	**167,552**	**29,725**	**18%**	**108,320**	**64,277**	**59%**	**103,461**	**63,692**	**62%**	**22,960**	**16,821**	**73%**

Review of 2023 Capacity and Energy Performance

High temperatures, wildfires, and weather conditions challenged electric grid operators in many parts of North America to maintain a reliable supply of electricity during 2023. Prior to summer, NERC warned that much of North America was at risk of having insufficient resources to meet electricity demand if extreme temperatures and weather conditions were to develop. It is noteworthy that, after a summer of soaring temperatures, extended heat waves, and new electricity demand records, few high-level EEAs were issued, and no disruptions occurred as a result of inadequate resources. Nonetheless, operators at BAs, TOPs, and RCs faced significant challenges and drew upon procedures and protocols to obtain all available resources, manage system demand, and ensure the flow of supplies over the transmission network. Additionally, load-serving entities and state and local officials in many parts of North America used mechanisms and public appeals to lower customer demand during periods of strained supplies. The following section describes actual demand and resource levels in comparison with NERC's *2023 SRA* and summarizes 2023 resource adequacy events.

Eastern Interconnection–Canada and Québec Interconnection

Systems in parts of Canada experienced challenging conditions early in the summer from high electricity demand and wildfires over large areas. Electricity transfers from Québec to neighboring Maritimes and New England were curtailed or disrupted during periods in May and June when wildfires affected transmission facilities. Peak electricity demand in Ontario occurred in early September at a level near the 90/10 demand forecast. Additional imports helped the area meet the extreme demand.

Manitoba Hydro and SaskPower both experienced peak electricity demand in excess of 90/10 summer forecasts. Manitoba Hydro's peak occurred at the start of summer in June. Operators had sufficient reserves and were able to export supplies during the peak period to neighboring areas.

SaskPower peak electricity demand occurred in late July. A forced outage at a large thermal generator early in the summer contributed to operating challenges over much of the summer period. At the time of peak demand, forced outages were significantly higher than typical for summer peak periods.

Eastern Interconnection–United States

In SPP, summer electricity demand peaked in August and exceeded 90/10 forecasts. At the hour of peak demand, SPP experienced near-normal levels of forced thermal generation outages. Wind resource performance at the time of peak demand exceeded seasonal peak forecasts, helping to alleviate the strain on supplies. However, during periods in June and July, operators at SPP issued resource advisories during periods of forecasted high demand and low or uncertain wind resource output.

MISO also experienced peak electricity demand during the same period in August; however, demand was between the normal and 90/10 summer peak forecast levels. Wind and solar resource output at the time of peak demand were below expectations for summer on-peak contributions. Forced outages of thermal units, however, were lower than expected. An EEA (level 2) was issued in August due to high forecasted loads and wind uncertainty. MISO used operating procedures to ensure that sufficient reserves were maintained during periods of high electricity demand and high forced generator outages at times throughout the summer.

PJM experienced peak electricity demand in late July at a level between normal summer peak and the 90/10 forecast. Wind and solar resource output were below seasonal peak expectations, while low thermal generator outages were reported.

Peak electricity demand at NYISO and ISO-NE occurred in early September and fell below average summer peak forecasts.

Systems in the U.S. Southeast experienced peak demand above the 90/10 forecasts in mid to late August. Solar resource output exceeded the expected contributions for the peak demand period. Electricity imports into resource-constrained areas helped BAs maintain reserves during high demand periods.

Texas Interconnection–ERCOT

Extended heat waves led to record-setting system electricity demand in the ERCOT system throughout Summer 2023. Peak electricity demand occurred in mid-August at a level exceeding the 90/10 demand forecast. At the time of peak demand, wind and solar generation were slightly below expected levels for peak demand periods, and thermal generator outages were also slightly higher than normal for peak periods. Nonetheless, operators were able to maintain sufficient reserves. At various times throughout the summer, ERCOT issued public appeals for conservation to help manage high demand periods and evening periods when output from the solar resources is diminished. On September 6, ERCOT declared an EEA (level 2) to address a low-frequency condition on the system during a period of unusually high demand, declining solar output, and low wind output. Transmission system constraints led to the curtailment of some supply from wind resources in southern parts of the system. No load was shed during the event.

Western Interconnection–Canada

At the start of summer, the province of Alberta was in a state of emergency as a result of active wildfires and the threat of spreading from hot and dry conditions. A period of high demand from heat and humidity that coincided with generator forced outages and low wind conditions triggered an EEA. Alberta’s system peak demand occurred in late July at a level above normal summer peak demand forecasts but below the 90/10 level. Wind and solar resource outputs were above seasonal forecast levels for peak demand periods. High temperatures in late August led to high demand at a time of planned transmission system maintenance. An EEA (level 3) was triggered when low wind conditions and insufficient imports resulted in reserve shortage.

The BC Hydro system also experienced peak electricity demand in early August at a level near the 90/10 summer peak forecast.

Western Interconnection–United States

The California-Mexico assessment area, which consists of the CAISO, Northern California, and CENACE BAs, experienced system peak electricity demand in mid-August at a level between the average summer peak demand forecast and the 90/10 peak demand forecast. Public appeals to shift electricity use to off-peak hours were used during some high-demand periods. The Mexico portion of the assessment area faced reserve shortages during periods in July and August as a result of high demand, generator outages, and unavailability of imports.

System peak electricity demand in the U.S. Northwest also occurred in mid-August and was below normal summer peak demand forecasts.

The U.S. Southwest experienced extended heat conditions and demand levels that exceeded normal summer peak demand forecasts. Wind and solar output fell below expected levels during the peak demand period.

2023 Summer Demand and Generation Summary at Peak Demand							
Assessment Area	**Actual Peak Demand[1] (GW)**	**SRA Peak Demand Scenarios[2] (GW)**	**Wind – Actual[1] (MW)**	**Wind – Expected[3] (MW)**	**Solar – Actual[1] (MW)**	**Solar – Expected[3] (MW)**	**Forced Outages Summary[4] (MW)**
MISO	120.8	116.8 123.9	8,598	5,488	2,096	3,750	6,638
MRO-Manitoba Hydro	3.5	3.1 3.4	83	47	-		95
MRO-SaskPower	3.7	3.5 3.6	381	203	15		737
MRO-SPP	56.0	52.6 55.1	8,278	4,500	130	378	6,533
NPCC-Maritimes	3.5	3.3 3.6	131	255	40	-	1,690*
NPCC-New England	23.5	24.7 26.5	186	186	145	1,163	1,969
NPCC-New York	30.2	30.8 32.7	223	331	-	84	9,716
NPCC-Ontario	23.7	21.8 23.7	786	771	200	126	3,419*
NPCC-Québec	22.5	22.9 22.9	496	-	8		12,287*
PJM	147.6	141.8 162.7	1,278	1,688	1,826	2,984	8,020
SERC-C	44.0	40.3 43.0	15	564	673	511	1,225
SERC-E	43.3	42.9 45.6	-	-	3,032	1,473	2,129
SERC-FP	54.1	49.3 52.4	-	-	4,590	4,534	1,610
SERC-SE	45.6	44.8	-	-	2,781	4,647	2,334
TRE-ERCOT	85.4	78.9 82.3	9,557	10,293	10,431	12,509	6,699
WECC-AB	11.5	11.2 11.6	906	309	894	763	-
WECC-BC	9.2	8.6 9.2	373	137	0	1	-

2023 Summer Demand and Generation Summary at Peak Demand							
Assessment Area	Actual Peak Demand[1] (GW)	SRA Peak Demand Scenarios[2] (GW)	Wind – Actual[1] (MW)	Wind – Expected[3] (MW)	Solar – Actual[1] (MW)	Solar – Expected[3] (MW)	Forced Outages Summary[4] (MW)
WECC-CA/MX	52.3	49.5 58.1	1,074	1,111	6,930	14,489	2,444
WECC-NW	64.7	61.0 67.2	2,137	593	3,821	1,411	4,855
WECC-SW	27.3	25.6 28.0	835	3,968	1,731	5,062	2,507
Highlighting Notes:	Actual peak demand in the highlighted areas met or exceeded extreme scenario levels.		Actual wind output in highlighted areas was significantly below seasonal forecast.		Actual solar output in highlighted areas was significantly below seasonal forecast.		Actual forced outages above or below forecast by factor of two

Table Notes:

[1] Actual demand, wind, and solar values for the hour of peak demand in U.S. areas were obtained from EIA From 930 data. For areas in Canada, this data was provided to NERC by system operators and utilities.

[2] See NERC *2023 SRA* demand scenarios for each assessment area (pp. 14–33). Values represent the normal summer peak demand forecast and an extreme peak demand forecast that represents a 90/10, or once-per-decade, peak demand. Some areas use other basis for extreme peak demand.

[3] Expected values of wind and solar resources from the *2023 SRA*.

[4] Values from NERC Generator Availability Data System for the 2023 summer hour of peak demand in each assessment area. Highlighted areas had actual forced outages that were more than twice the value for typical forced outage rates used in the 2023 summer risk period scenarios in the *2023 SRA*.

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Midcontinent Independent System Operator (MISO)	)))))	Order No. 202-25-3

Exhibit to
Motion to Intervene and Request for Rehearing and Stay of
Public Interest Organizations

Filed June 18, 2025

Exhibit 43

Winter Storm Elliott System Operations Inquiry

Inquiry into Bulk-Power System Operations During December 2022 Winter Storm Elliott

FERC, NERC and Regional Entity Staff Report
October 2023

Inquiry into Bulk-Power System Operations During December 2022 Winter Storm Elliott

FERC, NERC and Regional Entity Staff Report
October 2023

FEDERAL ENERGY REGULATORY COMMISSION

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Regional Entities:
Midwest Reliability Organization, Northeast Power Coordinating Council, ReliabilityFirst Corporation, SERC Corporation, Texas Reliability Entity and Western Electricity Coordinating Council

Table of Contents

I. EXECUTIVE SUMMARY

This report describes how the extreme cold weather event occurring between December 21 and 26, 2022 (Winter Storm Elliott) impacted the reliability of the Bulk Electric System ("BES" or colloquially known as the grid) and the supporting natural gas infrastructure in the U.S. Eastern Interconnection[1] ("the Event").[2] During the Event, 1,702 individual BES[3] generating units in the Eastern Interconnection experienced 3,565 unplanned outages, derates, or failures to start.[4] Each individual unit could, and often did, have multiple outages from the same or different causes. At the worst point of the Event, there were 90,500 MW of coincident unplanned generating unit outages, derates and failures to start (meaning they all occurred at the same time). Including generation that was already out of service,[5] a total of over 127,000 MW of generation was unavailable, representing 18 percent of the U.S. portion of the anticipated resources in the Eastern Interconnection.

The Event was the **fifth** in the past **11** years in which

---

1 There are four nterconnect ons n North Amer ca, w th three of those nterconnect ons encompass ng the ower 48 states: the Eastern nterconnect on; the ERCOT nterconnect on; and the Western nterconnect on. NERC nterconnect ons, ava ab e at https://www.nerc.com/AboutNERC/keyp ayers/Pub sh ng mages/NERC%20 nterconnect ons.pdf. *See also*, FERC Re ab ty Pr mer, 11 (2020), https://www.ferc.gov/med a/2135.

2 Th s s a staff report, and does not speak for the Comm ss on, NERC or any of the Reg onal Ent t es. ***See*** Press Release, FERC, NERC to Open Jo nt nqu ry nto W nter Storm Ell ott (December 28, 2022) for a descr pt on of the nqu ry's commencement. *See* Append x A for l st of the W nter Storm Ell ott nqu ry jo nt team members (the "Team"). The Team of over 50 subject matter experts from the Comm ss on, NERC and all of ts Reg onal Ent t es: M dwest Rel ab l ty Organ zat on (MRO), Northeast Power Coord nat ng Counc l (NPCC), Rel ab l tyF rst Corporat on (RF), SERC Corporat on (SERC), Texas Rel ab l ty Ent ty (TRE) and the Western Electr c ty Coord nat ng Counc l (WECC); as well as the Nat onal Ocean c and Atmospher c Adm n strat on (NOAA), was formed shortly after the Event determ ne the causes of the Event and make recommendat ons to prevent recurrence of the effects that the extreme cold weather caused for the gr d. Append x B ncludes a l st of acronyms Used n the Report. The Report s wr tten for a reader who s already fam l ar w th pr nc ples of energy markets, electr c transm ss on operat ons, generat ng un t operat ons, and natural gas product on, process ng, and transportat on. For readers who are not as fam l ar, the staff Pr mers on Electr c and Natural Gas Markets deta l the essent al pr nc ples related to energy markets, electr c transm ss on operat ons, generat ng un t operat ons, and natural gas product on, process ng, and transportat on, *see* FERC Energy Pr mer (https://www.ferc.gov/med a/energy pr mer handbook energy market bas cs) and FERC Rel ab l ty Pr mer (https://www.ferc.gov/s tes/default/files/2020 04/rel ab l ty pr mer 1.pdf).

3 The Comm ss on's jur sd ct on extends to the Bulk Power System, defined by Sect on 215(a) (1) of the Federal Power Act as "fac l t es and control systems necessary for operat ng an nterconnected electr c energy transm ss on network (or any port on thereof), and electr c energy from generat ng fac l t es needed to ma nta n transm ss on system rel ab l ty." The mandatory Rel ab l ty Standards apply to owners and operators of the Bulk Electr c System (BES). n Order No. 773, the Comm ss on approved a defin t on of BES that generally covers all elements operated at 100 kV or h gher, w th a l st of spec fic nclus ons and exclus ons. Rev s ons to Electr c Rel ab l ty Organ zat on Defin t on of Bulk Electr c System and Rules of Procedure, Order No. 773, 141 FERC ¶ 61,236 (2012); order on reh'g, Order No. 773 A, 143 FERC ¶ 61,053 (2013), order on reh'g and clar ficat on, 144 FERC ¶ 61,174 (2013). Th s report w ll use BES because ts pr mary aud ence s most fam l ar w th that term. There were some non BES generat ng un ts (.e., that d d not meet the BES defin t on n the NERC Glossary of Terms) that exper enced outages, derates, or fa lures to start w th n the Eastern nterconnect on but the Team d d not request data from them and they are not ncluded n ts analys s. By defin t on these un ts would be less than 20 MW nd v dually or 75 MW n the aggregate w th a common po nt of connect on (e.g. a w nd or solar fac l ty). https://www.nerc.com/pa/Stand/Glossary%20of%20Terms/Glossary of Terms.pdf .

4 The Team obta ned generat ng un t data d rectly from the Generator Owners and/or Operators (GOs/GOPs).

5 Those un ts that were already out of serv ce ncluded generat ng un ts undergo ng planned ma ntenance outages and those un ts that ncurred forced outages before the Event, that had not yet returned to serv ce dur ng the worst po nt of the Event.

unplanned cold weather-related generation outages jeopardized grid reliability.[6] Several Balancing Authorities (BAs) (grid operators that balance demand and electric energy) in the southeast U.S. needed to shed firm load during the Event to maintain system reliability, which in total (at different points in time) exceeded 5,400 MW. This was the largest controlled firm load shed recorded in the history of the Eastern Interconnection. Just one year before, in 2021, the Winter Storm Uri event in Texas and the South Central U.S. saw the largest controlled firm load shed event in U.S. history, with over 20,000 MW of firm load shed (20,000 MW in ERCOT alone). In that event, more than 4.5 million people lost power in Texas, and some went without power for as long as four days, while exposed to below freezing temperatures for as long as six days. Estimates of those who died during that event, primarily from causes connected to the power outages including hypothermia, carbon monoxide poisoning, and medical conditions exacerbated by freezing conditions, range from over 200 to over 800.[7] The Federal Reserve Bank of Dallas estimated the direct and indirect losses to the Texas economy from that event to be between $80 and $130 billion.[8]

The quantity of firm load shed during Winter Storm Elliott was not as large as in the Winter Storm Uri event, but it is especially disconcerting that it happened in the Eastern Interconnection which normally has ample generation and transmission ties to other grid operators that allow them to import and export power. And yet, for reasons described more fully in Section IV of the Report, electric grid operators were faced with a generation capacity shortage that resulted in 5,400 MW of firm load shed.

6 n February 2011, an arct c cold front mpacted the southwest U.S. and resulted n 29,700 MW of generat on outages, natural gas fac l ty outages, and emergency power gr d cond t ons w th need for firm customer load shed. Report on Outages and Curta lments Dur ng the Southwest Cold Weather Event of February 1 5, 2011: Causes and Recommendat ons (Aug. 2011), Report on outages and curta lments dur ng the Southwest cold weather event (ferc.gov) (“2011 Report”). n January 2014, a polar vortex affected Texas, central and eastern U.S., tr gger ng 19,500 MW of generat on outages, and natural gas ava lab l ty ssues result ng n emergency cond t ons nclud ng voluntary load management. NERC “Polar Vortex Rev ew” (Sept. 2014), https://www.nerc.com/pa/rrm/January%202014%20Polar%20Vortex%20Rev ew/Polar Vortex Rev ew 29 Sept 2014 F nal.pdf (“Polar Vortex Rev ew”). n January 2018, an arct c h gh pressure system and below average temperatures n the South Central U.S. resulted n 15,800 MW of generat on outages and the need for voluntary load management emergency measures. South Central Un ted States Cold Weather Bulk Electr c Systems Event of January 17, 2018 (July 2019), https://www.ferc.gov/s tes/default/files/2020 07/SouthCentralUn tedStatesColdWeatherBulkElectr cSystemEventofJanuary17 2018.pdf (“2018 Report”). F nally, n February 2021, extreme cold weather and freez ng prec p tat on n Texas and the South Central U.S. resulted n generat ng outages of over 60,000 MW and over 20,000 MW of firm load shed. The February 2021 Cold Weather Outages n Texas and the South Central Un ted States FERC, NERC and Reg onal Ent ty Staff Report (Nov. 2021), The February 2021 Cold Weather Outages n Texas and the South Central Un ted States FERC, NERC and Reg onal Ent ty Staff Report Federal Energy Regulatory Comm ss on (“2021 Report”).

7 Recent “excess death” analyses of deaths n Texas dur ng the 2021 event range as h gh as 800. Amber Weber & Mose Buchele , *Texas has an official death count from the 2021 blackout. The true toll may never be known*., Texas Standard (Aug. 15, 2022),Texas has an off c al death count from the 2021 blackout. The true toll may never be known. Texas Standard.

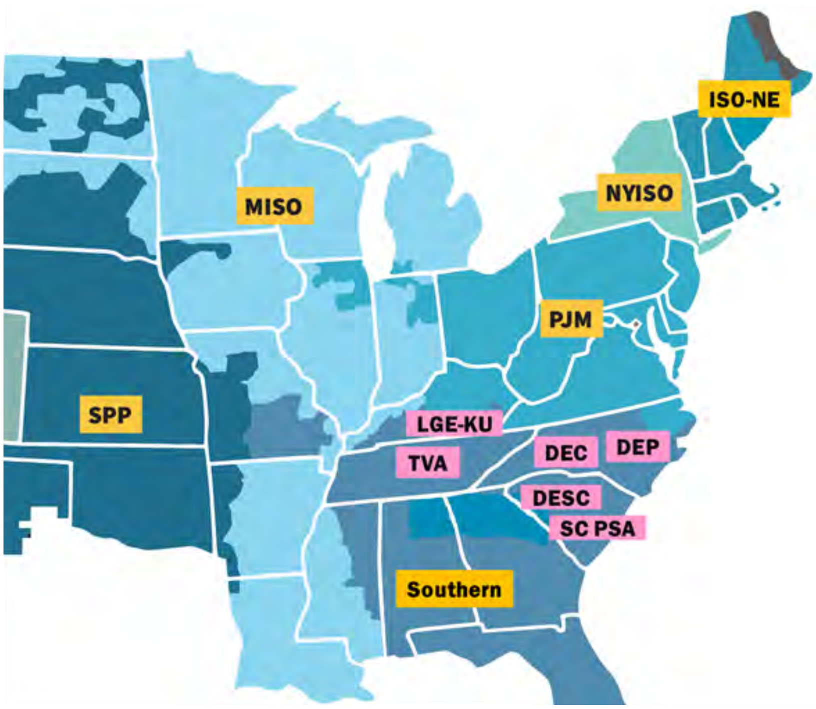
8 Garrett Gold ng et al., *Cost of Texas’ 2021 Deep Freeze Justifies Weatherization*, Dallas Fed. Econom cs (Apr. 15, 2021), https://www.dallasfed.org/research/econom cs/2021/0415.

A. Synopsis of Event

The storm that came to be known as Winter Storm Elliott, variously characterized as a bomb cyclone and an extra-tropical cyclone,[9] moved from the upper Plains states eastward. By Wednesday, December 21, 2022, it reached the central U.S., eventually blanketing most of the eastern United States on December 23 and 24, and did not subside until December 26. In an unacceptably familiar pattern, the cold temperatures ushered in electric generation outages that coincided with winter peak electricity demands (i.e., winter peak loads), and resulted in many BAs declaring energy emergencies. The amount of generation that failed during the Event was unprecedented—90,500 MW in coincident unplanned outages.[10] The coincident incremental[11] unplanned generation outages *alone* represented 13 percent of the U.S. portion of the winter 2022-2023 anticipated generation resources in the Eastern Interconnection.[12]

Figure 1, below, shows the entities in the U.S. Eastern Interconnection most affected by Winter Storm Elliott, referred to as the "Event Area." The entities represented by a pink box shed firm load at some point during the Event, including Tennessee Valley Authority (TVA), Louisiana Gas and Electric Company/Kentucky Utilities (LG&E/KU),

Figure 1: Bulk Electric System Map of Entities in the U.S. Eastern Interconnection Affected by the Extreme Cold Weather



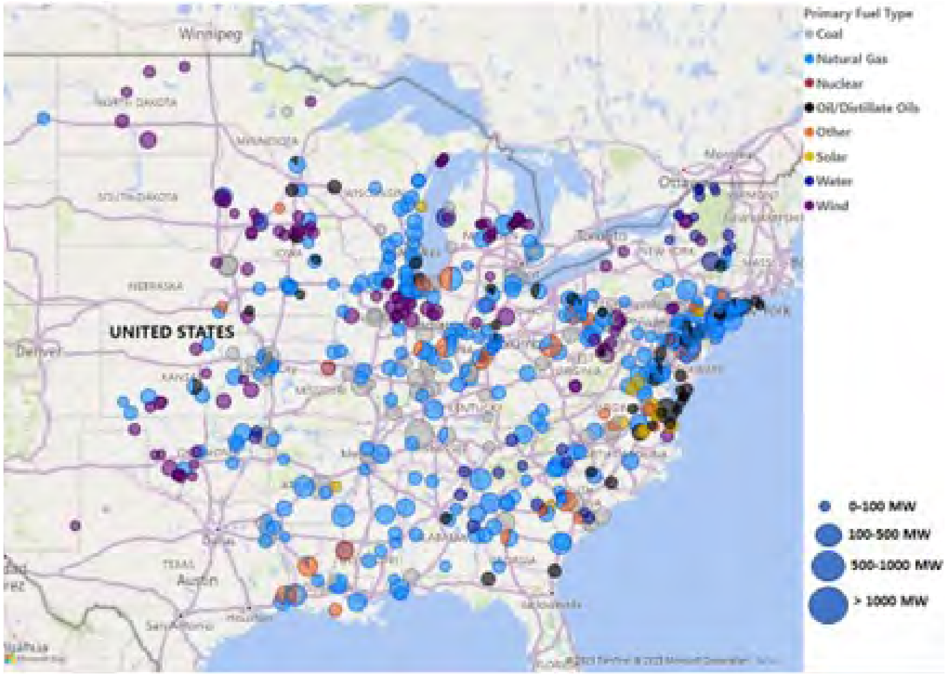
9 Both are terms that denote a storm assoc ated w th a rap d drop n pressure the more rap d the drop n pressure, the more ntense the storm. Pandora Dewan, *Bomb Cyclone Photos: What to Expect From Freezing Weather Forecast*., Newsweek (Dec. 20, 2022), https://www.newsweek.com/bomb cyclone photos freez ng weather forecast 1768515#:~:text Ell ott%20 s%20expected%20to%20arr ve%20 n%20the%20Pac fic,the%20M dwest%20and%20parts%20of%20the%20East%20Coast.

10 The 2021 W nter Storm Ur event had 65,622 MW co nc dent ncrementa unp anned generat ng un t outages, the most that occurred before the Event.

11 " ncremental" generat ng un t outages, derates, and fa lures to start refers to those wh ch occurred dur ng the Event (December 21 26, 2022), as compared to those wh ch occurred before the Event.

12 Based on data from the NERC 2022 2023 W nter Rel ab l ty Assessment. The 18 percent of Eastern nterconnect on resources reference earl er s for unplanned outages that occurred dur ng the Event at the moment when the most generat on was offl ne dur ng the Event ("the worst po nt"), plus unplanned and planned outages that were already n effect at the beg nn ng of the Event. NERC, *2022 2023 Winter Reliability Assessment* (Nov. 2022), https://www.nerc.com/pa/RAPA/ra/Rel ab l ty%20Assessments%20DL/NERC WRA 2022.pdf.

Figure 2: Location and Fuel Type of Unplanned Generation Outages and Derates During the Event (Bubble Size by MW for each Outage), as of December 24, 2022



Duke Energy Progress (DEP) and Duke Energy Carolinas (DEC), Dominion Energy SC (DESC), and South Carolina Public Service Authority (Santee Cooper). Other entities issued Energy Emergency Alerts (EEAs),[13] but did not need to shed firm load, including PJM Interconnection, LLC (PJM), Southern Company (Southern), Midcontinent Independent System Operator (MISO), Southwest Power Pool (SPP), and ISO New England (ISO-NE). All of the affected entities experienced significant unplanned generating unit outages, derates, or failures to start within their footprints. See Figure 2, above, shows the approximate locations of the generating unit outages during the Event and their fuel type.

The 2021 Report attributed the unplanned generating outages to generating units unprepared for the cold weather and natural gas fuel supply issues:

> A confluence of two causes, both triggered by cold weather, led to the [Uri] Event, part of a recurring pattern for the last ten years. First, generating units unprepared for cold weather failed in large numbers. Second, in the wake of massive natural gas production declines, and to a lesser extent, declines in natural gas processing, the natural gas fuel supply struggled to meet both residential heating load and generating unit demand for natural gas, exacerbated by the increasing reliance by generating units on natural gas. Natural gas pipeline capacity is for the most part designed, certificated and constructed to accommodate firm transportation commitments, while many natural gas-fired generating units rely on non-firm commodity and/or pipeline transportation contracts.[14]

13 New York ndependent System Operator (NY SO) d d not declare an EEA dur ng the Event.

14 2021 Report at 11 12.

The Event shows that, while some changes were implemented in response to previous cold weather events, generators and natural gas supply and infrastructure remain vulnerable to extreme cold weather.

Similar to other cold weather events,[15] the cold weather was forecast well in advance. Beginning with forecast colder weather mid-December, and with widespread warnings by December 20, grid operators knew that frigid weather was coming. Many issued cold weather preparation notices to their Generation and Transmission Owners and Operators. Temperatures were lower than normal during the Event, although not quite as far off normal lows as during the 2021 event. Winter Storm Elliott's departures from normal minimum lows were largely from 15 to 30 degrees lower than normal, though a small area was even lower. In Winter Storm Uri, departures from normal minimum lows ranged from 40 to 50 degrees lower than normal low temperatures. However, Winter Storm Elliott generally had higher winds than Uri, with gusts up to 60 miles per hour, which increased convective cooling. Rapid temperature drops to subfreezing levels across the eastern half of the U.S. occurred. For example, temperatures in Charleston, West Virginia dropped 42 degrees in six hours, and TVA reported a drop of 46 degrees in five hours. Some areas experienced blizzard conditions. Geographically, Winter Storm Elliott was a very large storm. At approximately 2,000 miles wide, its extreme cold and high winds covered the eastern two-thirds of the lower 48 U.S.

Winter Storm Elliott caused unplanned outages of natural gas wellheads due to wellhead freeze-offs and other frozen equipment. Weather-related poor road conditions prevented necessary maintenance.[16] This led to significant natural gas production decreases, which also occurred during the 2011 and 2021 events.[17] During the Event, "[d]ry natural gas production in the Lower 48 states dropped to a low of 82.5 Bcf on December 24, a 16 percent decrease (16.1 Bcf/d) from December 21...."[18] Gas production experienced the greatest declines in the Marcellus and Utica Shale formations, where it dropped by 23 to 54 percent during the Event.[19] Figure 3, below, shows the areas where production decreases occurred.

The affected grid operators, beginning with SPP and then MISO, saw rising load and increasing generating unit outages during the Event, which in many cases led to a reduction in their energy reserves. Neither SPP nor MISO needed to shed firm load throughout their footprints,[21] but, to combat the rising loads and generation outages, SPP twice curtailed non-firm exports on December 23 because its reserves were low. MISO and SPP closely coordinated on the Regional Directional Transfer Limit between MISO South and the rest of MISO (see Figures 41 and 42), twice lowering the limit at SPP's request.[22]

15 *See* F gure 4 below, for a s de by s de compar son of the past five extreme cold weather events n 11 years. For add t onal nformat on on extreme cold weather cond t ons dur ng the events, *see* the 2021 Report, Append x B: Compar son of S m lar Severe Weather Events, at 245.

16 The Team also obta ned natural gas product on and process ng data d rectly from owners of these fac l t es, unless otherw se stated. However, because these ent t es are not subject to the Comm ss on's jur sd ct on, the Team d d not rece ve all data requested.

17 The teams observed decreases n natural gas product on n the 2011 and 2021 cold weather events. The teams study ng the 2014 Polar Vortex and January 2018 events d d not quant fy natural gas product on losses or nvest gate any causes for such losses.

18 James Easton and Max Ober, *U.S. natural gas consumption reached record daily high in late December 2022*, Today n Energy (Jan. 31, 2023), https://www.e a.gov/today nenergy/deta l.php? d 55359.

19 Source: S&P Global Commod ty ns ghts, ©2023 by S&P Global nc.

20 Source: E A: Maps: O l and Gas Explorat on, Resources, and Product on Energy nformat on Adm n strat on (e a.gov), adapted from "Lower 48 Shale Plays."

21 SPP had a local zed voltage ssue caused by a comb nat on of unplanned generat ng un t outages and transm ss on outages. Local transm ss on system operators n t ated a br ef] firm load shed of 29 MW to allev ate ssue. *See section* .B.3.a), Thursday, December 22: Effects of Ell ott beg n to mpact U.S. port on of Eastern nterconnect on BES, for add t onal d scuss on.

22 Unplanned generat on outages and underest mated loads n M SO's "South" reg on led t to ncrease ts north to south power transfer to supply more power to that port on of ts system. M SO agreed to l m t ts north to south transfer by half of ts contractual l m t (1,500 MW)..

On December 23, MISO declared EEA 1 and 2,[23] due to congestion on its transmission system and diminished generation deliverability and used 3,000 MW of Load Modifying Resources.[24] MISO also had several local transmission emergencies but did not need to shed any firm load.

Figure 3: Areas of Shale Natural Gas Production Where Extreme Cold Weather Occurred[25]

TVA experienced rapidly-increasing generating unit outages in the early morning hours of December 23. By 6 a.m. Eastern Standard Time,[26] TVA had lost over 5,000 MW of generation and declared EEA 1 and EEA 2. By 6:12 a.m., TVA declared EEA 3, which indicated that firm load shed was imminent, and secured emergency power from Duke, Southern, PJM, and MISO, but this solution was short-lived. As TVA continued to experience significant unplanned generation outages and increasing electricity demands, PJM needed to reduce the emergency power it was supplying to TVA, due to a transmission operating limit in PJM.[27] By 10:31 a.m., now faced with well over

23 *See* Rel ab l ty Standard EOP 011 2 Emergency Preparedness and Operat ons, “Attachment 1 EOP 011 2 Energy Emergency Alerts” for the levels of alerts and energy emergenc es, at https://www.nerc.com/pa/Stand/Rel ab l ty%20Standards/EOP 011 2.pdf. EEA levels nd cate to ne ghbor ng Balanc ng Author t es that a Balanc ng Author ty s exper enc ng an energy emergency and the level of sever ty. The Rel ab l ty Coord nator s respons ble for declar ng EEAs for ts Balanc ng Author t es w th n ts footpr nt per EOP 011 2, Requ rement R6, and as deta led n Attachment 1.

24 Load Mod fy ng Resources, or LMRs, are demand resources or beh nd the meter generat on.

25 Source: E A: Maps: O l and Gas Explorat on, Resources, and Product on Energy nformat on Adm n strat on (e a.gov), adapted from “Lower 48 Shale Plays.”

26 All t mes stated w th n the Report, unless otherw se spec fied, are Eastern Standard T me (EST). f the ent ty s located n the Central T me Zone, all t mes were converted to EST.

27 PJM operators curta led the emergency power schedule to TVA due to a System Operat ng L m t (SOL). The transm ss on fac l ty at ssue was exceed ng ts emergency l m t n real t me. *See also* s debar on N 1 at 60.

6,000 MW of unplanned generating unit outages since midnight, continually rising system load, and depleted generation reserves, TVA ordered firm load shed of over 1,500 MW, which represented five percent of its peak system load.[28]

LG&E/KU also experienced significant unplanned generation derates during winter peak load conditions on the evening of December 23. To offset the generation derates, LG&E/KU was able to import 400 MW from PJM. At 4:29 p.m., PJM BA curtailed the 400 MW import due to experiencing rapidly increasing levels of unplanned generation outages coincident with increasing system load in its own footprint. In response, LG&E/KU requested emergency energy from the TVA Contingency Reserve Sharing Group, which TVA was able to supply. With its system load increasing, LG&E/KU entered into EEA 3 at 4:45 p.m. Following TVA's return at 5:18 p.m. to EEA 3, by 6:00 p.m. it also could no longer spare its 400 MW emergency power to LG&E/KU. With the loss of the import power to offset the unplanned generation derates, LG&E/KU began over 300 MW firm load shed at 5:58 p.m. This was the first time LG&E/KU had ever ordered firm load shed in response to an energy emergency (EEA) event.

Through the morning of December 24, PJM was providing emergency energy to neighboring Balancing Authorities, but as unplanned outages multiplied and its load increased, it needed to curtail those emergency energy export schedules and declared EEA 1 and EEA 2. PJM benefitted from a Simultaneous Activation of Ten-Minute Reserve (SAR) agreement with the Northeast Power Coordinating Council Balancing Authorities, which allowed PJM to call on reserves of up to 1,500 MW during the Event. PJM requested assistance under the SAR agreement five times between December 23 and 24. Although PJM said it was "close" to needing to shed firm load, it did not.[29]

Southern, like PJM, at first was able to provide emergency energy to other Balancing Authorities. By 6:25 a.m. on December 24, it declared EEA 2, having declared EEA 1 in the early morning hours. Southern obtained emergency energy from Florida Power and Light. The emergency energy import assisted Southern in meeting its all-time December record peak load early that morning and enabled it to provide emergency energy to DESC. DEC, DEP, DESC and Santee Cooper, Balancing Authorities in the Carolinas which form the Carolinas Reserve Sharing Group,[30] experienced escalating unplanned generating unit outages in the face of early morning peak load conditions. Combined with their inability to obtain import power from surrounding Balancing Authorities experiencing the same conditions, at worst points the four Balancing Authorities had to shed a combined total of over 2,000 MW firm load.

---

28 Th s was the first of two nstances dur ng W nter Storm Ell ott where TVA needed to shed firm load. The other nstance was dur ng the early morn ng hours of December 24. From 6:12 a.m. on December 23 to m dday December 24, TVA was at EEA 3, other than for a br ef per od the afternoon of December 23, when t was at EEA 2. Early the morn ng of December 24, TVA first ordered firm load shed of five percent of ts peak system load, followed by an add t onal five percent reduct on of firm load (n total, 10 percent of ts peak system load wh ch was **over 3,000 MW**). Dur ng those hours, most of TVA's ne ghbor ng BAs were faced w th h gh electr c ty demands and escalat ng unplanned generat ng un t outages of the r own and as a result, could not prov de emergency power to TVA.

29 Although PJM was at an ncreased r sk of load shedd ng approach ng the morn ng peak on December 24, PJM st ll had opt ons before shedd ng firm load, f t had lost another large generat ng un t or f NY SO had to cut ts mports. PJM could have n t ated a Voltage Reduct on Act on, wh ch could have prov ded approx mately 1,700 MW of rel ef. f necessary, PJM could have followed the Voltage Reduct on w th a Manual Load Dump Warn ng (prov d ng Transm ss on Operators w th the r load allocat ons). F rm load shed would occur, f necessary, v a Manual Load Dump Act on, followed by ssuance of EEA 3. PJM Report at 63.

30 *See*, CRSG, Dom n on Energy South Carol na, nc. OATT & SA, § SA No. 239, CRSG Operat ng Manual (0.0.0), https://etar ff.ferc.gov/Tar ffSect onDeta ls.aspx?t d 6293&s d 312207.

B. Recurrence of Cold Weather Events with Unplanned Generating Unit Outages and Implications

The 2021 Report noted, “the [2021 Winter Storm Uri event] was the fourth cold-weather-related event in the last ten years to jeopardize BES reliability,” and that “in each of the four BES events, planned and unplanned generating unit outages caused energy emergencies and in 2011, 2014 and 2021 they triggered the need for firm load shed.”[31] Each event’s report made recommendations to reduce the likelihood of similar consequences in the future.

In several of the previous events, there have been close calls, meaning, that if conditions worsened, it could have resulted in widespread firm load shed or outages. During Uri, for example, ERCOT came within four minutes of a potential complete blackout of the ERCOT Interconnection if the interconnection frequency had not recovered. During the January 2018 cold weather event, had the worst contingency generating unit forced outage occurred in MISO South, its electric grid operators would have needed to rely on post-contingency manual firm load shed to maintain voltages within limits, while faced with potential additional firm load shedding to maintain system balance and restore reserves. The Event, too, had its share of close calls. The natural gas provider for Manhattan, The Bronx, and portions of Queens and Westchester County, Consolidated Edison (Con Edison), faced reliability-threatening low pressures at its citygate[32] on all the interstate natural gas pipelines that it relies upon. Con Edison maintained its natural gas local distribution system pressure by using its own liquified natural gas (LNG) facility, among other measures. Had Con Edison not activated its LNG facility and taken its other emergency measures, or had the cold weather lasted longer, it could have faced large scale outages. System outages for a local natural gas distribution company generally take longer to restore than firm load shed, or even cascading outages, on the electric grid. Once electricity is restored to a circuit, all of the homes[33] can return to their normal functioning—lights turn back on, heating or air conditioning systems return to normal function, etc. By contrast, for the natural gas local distribution system to return system outages to normal operation, workers must go house-to-house and individually light every pilot light. Con Edison estimated it would have taken months to restore service, even with mutual assistance from other utilities, had it experienced a complete loss of its system.

In addition to the close call with Con Edison, the Eastern Interconnection’s normally robust electric grid one-minute average frequency dropped to 59.936 Hz, slightly below its low frequency trigger limit of 59.95 Hz.[34] The frequency began declining on the morning of December 24 at 3:25 a.m. and over the next hour steadily decreased

---

31 2021 Report at 9.

32 C tygate a po nt or measur ng stat on at wh ch a d str but ng gas ut l ty rece ves gas from a natural gas p pel ne company or transm ss on system. *See* E A Defin t ons, Sources and Explanatory Notes, at https://www.e a.gov/dnav/ng/TblDefs/ng_pr_sum_tbldef2.asp.

33 For those that do not have secondary outage causes.

34 Frequency as a measure of the rel ab l ty status of a power system prov des a key nd cator of the overall ntegr ty of operat ons. 60.000 Hz s the nom nal frequency for the Eastern nterconnect on, and ma nta n ng t requ res generat ng un ts to automat cally respond to dev at ons, BAs to perform moment to moment balanc ng of the system’s aggregate generat on output to ts load and ma nta n suff c ent respons ve reserves ava lable to w thstand the sudden tr pp ng of the largest generator on the system. The Low Frequency Tr gger L m t s approx mately 59.95 Hz for the Eastern nterconnect on and s used by BAs to calculate the r requ red response to frequency dev at ons that are below 60 Hz. *See* NERC Rel ab l ty Standard BAL 001 2 Real Power Balanc ng Control Performance, Attachment 2. RSCompleteSet.pdf (nerc.com)

from 60.00 Hz, reaching its lowest point by 4:25 a.m. At that time, the composite ACE[35] for the Core Event Area[36] was -2,754 MW, and PJM BA's portion of the composite ACE was -2,162 MW (due in part to PJM experiencing an additional 1,400 MW in unplanned generation outages from 4:20 a.m. to 4:25 a.m.). Although the Eastern Interconnection frequency recovered to its normal range[37] as PJM and several other Balancing Authorities concurrently initiated more severe emergency energy actions (including firm load shed for some Balancing Authorities), total unplanned generation outages continued to increase over and above generation that was already out of service, reaching a combined total of over 127,000 MW by 10:00 a.m. This left 18 percent of the winter 2022-2023 anticipated generation resources in the U.S. portion of the Eastern Interconnection offline during winter peak conditions.[38] Including this occasion, as well as the evening of December 23, there were four points during the Event at which the one-minute average frequency declined below 59.95 Hz, coinciding with lower online responsive reserves[39] within the Core Event Area due to generation outages. Ultimately on the morning of December 24, grid operators maintained frequency by reducing electricity demand, including by shedding over 5,400 MW of firm load, leaving hundreds of thousands of customers[40] without electricity to heat homes for several hours during the extreme cold weather conditions.

35 ACE stands for Area Control Error, wh ch s the m nute to m nute measure of how well the BA s perform ng ts balanc ng funct on; .e., balanc ng ts scheduled power outputs to meet actual nputs and outputs. f ACE s less than zero, then the BA needs to ncrease generat on supply/output n ts footpr nt to balance; or f add t onal generat on ncrease s not poss ble, the BA may need to curta l export power schedules, or worst case, reduce demand by shedd ng firm load.

36 The "Core Event Area" refers to the ocat on where concurrent EEA 2 and EEA 3 energy emergency measures were taken by e ectr c gr d ent t es the morn ng of December 24, 2022 (.e., concurrent EEA 2 oad management and EEA 3 firm oad shed measures) to ma nta n BES re ab ty. These gr d ent t es are NERC reg stered Ba anc ng Author t es. They are referred to as Core Ent t es or Core BAs n the Report, and are dep cted n F gure 9, be ow.

37 For the Eastern nterconnect on, the normal range s 59.95 60.05 Hz.

38 Th s exceeds NERC's 2022 2023 W nter Rel ab l ty Assessment "worst case" low generat on cond t on for the U.S. port on of the Eastern nterconnect on (worst case s calculated by comb n ng MW outage shortfall scenar os of: extreme low gen low w nd natural gas r sk scenar o) by 32,500 MW of add t onal generat on reduct ons.

39 Respons ve reserves are those onl ne reserves that are capable of respond ng and recover ng from frequency dev at ons.

40 On December 24, 2022, TVA ordered ts 153 oca power compan es (LPCs) serv ng 10 m on peop e n Tennessee and parts of s x surround ng states to nterrupt 10 percent of the r firm oad. Tennessee Va ey Author ty After Act on Report, at 20 21, ((https://www.tva.com/about tva/reports)), and https://www.tva.com/about tva#:~:text The%20Tennessee%20Va ey%20Author ty%20prov des, ndustr a %20customers%20and%20federa %20 nsta at ons. Duke Energy reported to the North Caro na Ut t es Comm ss on that on December 24, approx mate y 15 percent of customers overa rough y 500,000 n tota were mpacted by the company's rotat ng outages. (https://news.duke energy.com/re eases/duke energy updates north caro na ut t es comm ss on on w nter storm e ott emergency outage event#:~:text CHARLOTTE%2C%20N.C.%20%E2%80%93%20 Leaders%20from%20Duke,from%20occurr ng%20that%20way%20aga n.) Dur ng ro ng b ackouts firm oad shed] nst tuted by LG&E/KU, 54,637 customers were affected. *Kentucky Utilities Co. & Louisville Gas and Electric Co. Response* (Mar. 10, 2023), https://psc.ky.gov/pscecf/2022 00402/r ck. ovekamp%40 ge ku.com/03102023103319/02 AG DR1 LGE KU Responses.pdf.

Figure 4: Comparison of Events' Effects on Bulk Electric System Generation and Resulting Need for Load Shed

Event Date/ Duration:	SW U.S. Event/ Feb. 1-5, 2011	Polar Vortex/ Jan 6-8, 2014	2018 Event/ Jan 15-19, 2018	2021 Event/ Feb 8-20, 2021	2022 Event/ Dec 21-26, 2022
Deviation from Average Daily Temperature	17 to 36 deg. below average	20 to 30 deg. below average	12 to 28 deg. below average	40 to 50 deg. below average	20 to 30 deg. below average
Geographic Area of Event	Texas and Southwest U.S.	M dwest, South Central, and East Coast reg ons	South Central U.S.	Texas and South Central U.S.	Central, M dwest, and large parts of Southeast and Northeast U.S.
Event Area Sq. Miles (approx.)	656,300	1,923,000	418,000	869,600	1,517,000
Unavailable Generation Due to Cold Weather, at Worst Point (MW)	14,702	9,800	15,600	65,622	90,500
Causes of Unavailable Generation (in alphabetical order)	Freez ng ssues, Mechan cal/ Electr cal ssues, Natural Gas Fuel ssues	Freez ng ssues (cold weather), Natural Gas Fuel ssues	Freez ng ssues, Mechan cal/ Electr cal ssues, Natural Gas Fuel ssues	Freez ng ssues, Natural Gas Fuel ssues, Mechan cal/ Electr cal ssues	Freez ng ssues, Mechan cal/ Electr cal ssues, Natural Gas Fuel ssues
Energy Emergency Declared/ Highest Level	Yes/ EEA 3	Yes/ EEA 3	Yes/ EEA 2	Yes/ EEA 3	Yes/ EEA 3
Maximum Level of Firm Load Shed (MW)	5,411.6	300	0	23,418 (ERCOT 20,000, SPP 2,718, M SO South 700)	Over 5,400[41] Tota (TVA over 3,000, DEC 1,000, DEP 961, LG&E/ KU 317,[42] DESC 94.7,[43] Santee Cooper 86.4)
Overall Duration of Firm Load Shed	ERCOT: 7 hours, 24 m nutes	3 hours	N/A	ERCOT: over 70 hours, SPP: over 4 hours M SO South: over 2 hours	TVA: 7 hours, DEC: 3 hours, DEP: 2 hours, LG&E/KU: 4 hours, DESC and Santee Cooper: 9, and 17 m n., respect vely

41 Total of ent t es' max mum load shed ordered, wh ch occurred on December 23 and 24, 2022 at d fferent t mes. Sect on .B.3. of the report descr bes more deta ls on the magn tudes and t meframes of firm load shed for each ent ty.

42 317 MW was n t al level of firm load shed. Load shed levels were decreased over durat on.

43 94.7 MW was n t al magn tude of firm load shed. After 2 m nutes, load shed levels were decreased over durat on.

Figure 5: Similarities to Past Extreme Cold Weather Events

	2011 Event	2014 Event	2018 Event	2021 Event	2022 Event
S gn ficant levels of ncremental unplanned electr c generat ng un t losses w th top causes found to be mechan cal/electr cal, freez ng, and fuel ssues.	✓	✓	✓	✓	✓
S gn ficant natural gas product on decreases occurred, w th some areas of the country more severely affected.	✓			✓	✓
Short range forecasts of peak electr c ty demands were less than actual demands for BAs n event area.	✓		✓	✓	✓
S gn ficant natural gas LDC outages or near m ss.	✓				✓

As demonstrated by Figure 4, above, the Event was the fifth in the past 11 years in which unplanned cold-weather-related generation outages jeopardized grid reliability, and the fourth that triggered the need for firm load shed. Twice in 11 years the reliability of natural gas delivery to homes and businesses has been jeopardized. These recurring failures make clear that America's natural gas infrastructure and electric grid continue to be severely challenged during extreme cold weather events, repeatedly jeopardizing reliability during life-threatening conditions, even when technology exists to protect the vulnerable components.[44] Multiple extreme cold weather event reports, including the 2021 Report issued less than two years ago, have detailed the same three primary causes of the unplanned generating outages: Freezing Issues; Fuel Issues; and Mechanical/Electrical issues which are correlated with temperature, increasing in number as temperatures fall.[45]

Multiple extreme cold weather event reports made recommendations aimed at preventing recurrence of these events, and some progress has been made.[46] But some key drivers of these events remain unaddressed, especially the freezing of natural gas infrastructure. As noted in the NAESB Gas-Electric Harmonization Forum Report ("NAESB Report"):

> "In the last two decades, natural gas' fuel share for power generation has doubled: today it represents almost 40 percent of total resources. Both sectors of the American energy system have become highly interdependent economically and technically: natural gas represents the largest fuel resource for power generation, while power generation is the largest consumer of natural gas."[47]

44 *See* 2011 Report at 206 208 (recommendat ons on spec fic freeze protect on ma ntenance measures); note 119 (methods to protect natural gas nfrastructure), 2021 Report at 194 95 (Key Recommendat on 6) (same).

45 Append x E of the Report updates the progress on the recommendat ons from the 2021 Report.

46 Freez ng related generat ng un t outages are recogn zed as a s gn ficant dr ver of these events. As d scussed below, Rel ab l ty Standards requ r ng appropr ate generator w nter zat on are currently n development or soon to be n effect.

47 North Amer can Energy Standards Board Gas Electr c Harmon zat on Forum Report ("NAESB Report"), July 28, 2023, at 1. https://www.naesb.org/pdf4/geh_final_report_072823.pdf.

2014 Polar Vortex Event

On January 5 through 8, 2014, "the Midwest, South Central, and East Coast regions of North America experienced a weather condition known as a polar vortex, where extreme cold weather conditions occurred in lower latitudes than normal, resulting in temperatures 20 to 30 [degrees] below average. Some areas faced days that were 35 [degrees] or more below their average temperatures. These temperatures resulted in record high electrical demand for these areas on January 6 and again on January 7, 2014."[48] Demand for natural gas also increased, and significant amounts of natural gas-fired generating units were unavailable because they did not have natural gas.[49] "By properly and appropriately communicating through the NERC [EEA][50] process using interruptible load, demand-side management tools, and voltage reduction, only one BA was required to shed firm load. The amount shed was less than 300 MW, representing less than 0.1 percent of the total load for the Eastern and ERCOT Interconnections."[51] The "lower temperatures had a drastic impact on load, with many of the Reliability Coordinators [e.g., MISO, PJM, TVA, VACAR-South, and Southeastern RC] reporting record or near-record winter peak demands. PJM exceeded its historic winter peak on both January 7 and January 8, 2014, and MISO reported that [it] exceeded [its] historic winter peak for three straight days (January 6–8, 2014)."[52]

NERC staff reviewed and validated the Generating Availability Data Systems (GADS)[53] data covering the Polar Vortex event. Analysis of these data identified two principal causes of generating unit outages: curtailment or interruption of natural gas fuel supply and over 17,700 MW of lost generating capacity due to frozen equipment.[54] The majority of forced outages, 55 percent, were natural gas-fired generating units, although they only represented 40 percent of capacity in the Polar Vortex event area (Eastern and ERCOT Interconnections).[55] Although the Polar Vortex Review stated that "many generator outages" occurred as a result of entities exceeding the design basis of their plants, it did not quantify the percentage. The Review identified associations between temperature and increasing outages in most of the Regional Entity footprints.[56]

The Review's ten recommendations included the following: that the electric industry work with the gas industry "to allow generators to be able to secure firm supply and transportation at a reasonable rate;" to review and update generating units' weatherization plans; to implement periodic site reviews of generating units' winter preparedness; to reconsider forced outage rate assumptions in winter assessments, as well as assumptions about natural gas outage rates and heating oil replenishment; to limit planned outages during winter peak periods; to improve BAs' awareness of generating units' fuel status; to protect stored fuel against effects of cold weather; to review generating units' design basis and protect against outages that occur within design basis; and to prepare to apply for necessary environmental (or other) waivers during emergencies.

48 Polar Vortex Rev ew at .

49 d.

50 *See* note 21.

51 Polar Vortex Rev ew at .

52 Polar Vortex Rev ew at v .

53 Generat ng Ava lab l ty Data System (GADS) s a mandatory ndustry program for track ng nformat on about outages of BES generat ng un ts. Generat ng Ava lab l ty Data System (GADS) (nerc.com).

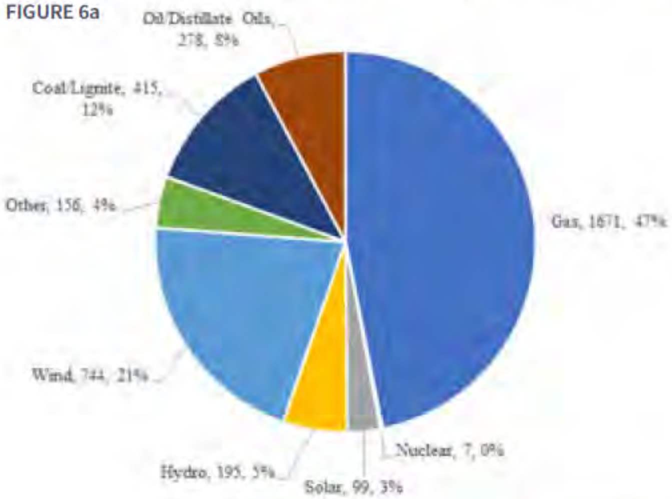
54 Polar Vortex Rev ew at 2.

55 Polar Vortex Rev ew at 13.

56 Polar Vortex Rev ew at 4 12.

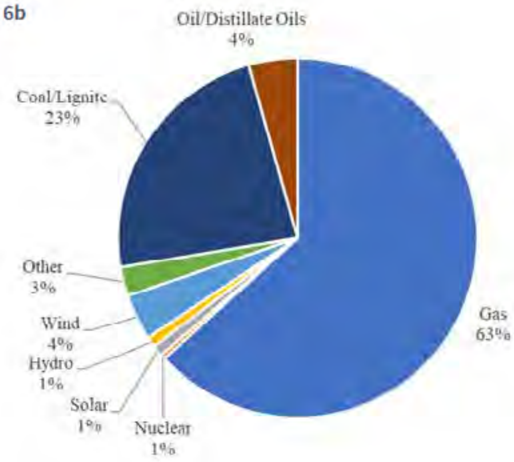
Figures 6a, 6b: Event Area Incremental Unplanned Generating Unit Outages, Derates and Failures to Start by Fuel Type: Percentages by Number of Outages, and Percentages by Unavailable MW[57]

FIGURE 6a



1,702 Generating Units   3,565 Outages/Derates

FIGURE 6b



1,702 Generating Units   3,565 Outages/Derates

57 Add t onal F gures of unplanned generat on outages by other fuel types can be found n Append x C: Add t onal Charts and F gures for Unplanned Generat on Outages Dur ng Event.

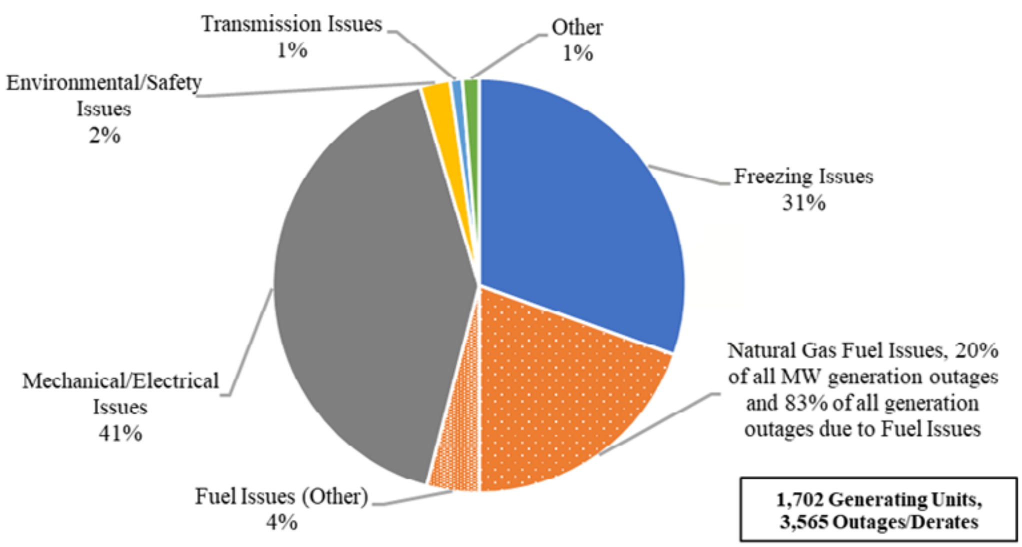
C. Key Findings and Causes

From December 21 to 26, 2022, in the Event Area, a total of 1,702 individual generating units—47 percent natural gas-fired, 21 percent wind, 12 percent coal, 3 percent solar, 0.4 percent nuclear, 17 percent other (oil, hydroelectric and biomass)—experienced 3,565 outages, derates, or failures to start (see Figures 6a & 6b, below).

Ninety-six percent of all outages, derates, and failures to start were attributed to three causes: Freezing Issues (31 percent), Fuel Issues (24 percent) and Mechanical/Electrical Issues (41 percent). Of those outages, derates, and failures to start, 55 percent were caused by either Freezing Issues or Fuel Issues, as shown in Figure 7 below. Natural Gas Fuel Issues[58] (a subset, but the majority, of Fuel Issues) were 20 percent of all causes, and issues with other fuels were four percent.

In addition to the outages, derates, and failures to start caused by Freezing Issues, those caused by Mechanical/Electrical Issues also indicated a clear pattern related to cold temperatures—as temperatures decreased, the number of generating units experiencing an outage, derate or failure to start due to Mechanical/Electrical Issues increased.

Figure 7: Incremental Unplanned Generating Unit MW Outages, Derates and Failures to Start, Total Event Area: by Cause



Prior to the Event, Generator Owners had ample reminders, guidance and opportunities to prepare for the extreme cold weather, and most did have plans in place. For example, FERC and NERC had provided

58 Natural Gas Fuel ssues nclude the comb ned effects of decreased natural gas product on; cold weather mpacts and mechan cal problems at product on, gather ng, process ng and p pel ne fac l t es result ng n gas qual ty ssues and low p pel ne pressure; supply and transportat on nterrupt ons; curta lments and fa lure to comply w th contractual obl gat ons. Add t onally, t ncludes sh ppers' nab l ty to procure natural gas due to t ght supply, proh b t ve, scarc ty nduced market pr ces, or m smatches between the t m ng of the natural gas and energy markets.

multiple prior recommendations and follow-up activities regarding steps for winter preparedness.[59] In addition, Generator Owners received annual reminders via Regional Entity workshops to prepare for winter (which provide detailed suggestions for how to protect generating units from freezing). Yet, despite these reminders, guidance, and their own preparation, over 75 percent of the generating unit failures caused by Freezing Issues[60] occurred at temperatures above the units' documented operating temperatures.[61] Over 150 blackstart-designated generating units,[62] totaling 19,000 MW, incurred outages during the Event, 119 of which were natural-gas-fueled generating units (accounting for just under 75 percent of all MW of blackstart-designated generation outages).

During the Event, natural gas production experienced its greatest decline since 2021's Winter Storm Uri, in which Texas production dropped by 70 percent. The Marcellus Shale[63] and Utica Shale[64] formations (combined, the Appalachia Region, which produced more natural gas than any other U.S. region in 2022) production dropped by 23 to 54 percent during the Event.[65] Wellhead freeze-offs, other natural gas supply chain equipment freezing and weather-related poor road conditions that prevented necessary maintenance were the top causes.

59 For examples of other act v t es to publ c ze the need for, and how, generators can protect the r un ts from cold weather, *see* FERC, NERC and Reg onal Ent t es Techn cal Conference: mprov ng W nter read ness of Generat ng Un ts; NERC Alerts and Cold Weather Preparat ons for Extreme Weather Events; Cold Weather Preparat ons for Extreme Weather Events ; NERC annual web nars on preparat on for cold weather (https://www.nerc.com/pa/rrm/Pages/Web nars.aspx); NERC Compl ance Mon tor ng and Enforcement Program pract ce gu de (quest ons for BAs, RCs, and other ent t es for understand ng the r cold weather preparedness r sk m t gat on) https://www.nerc.com/pa/comp/gu dance/CMEPPract ceGu desDL/CMEP%20Pract ce%20Gu de%20 %20Cold%20Weather%20Preparedness.pdf.

60 ncludes unplanned outages, derates, and fa lures to start caused by Freez ng ssues. Th s analys s s l m ted to generat ng un ts that prov ded outage data, amb ent temperature data, and data concern ng that un ts' operat ng parameters. Not all GOs prov ded data for each of these data sources n a manner and format wh ch the Team was able to analyze.

61 GOs were g ven opt ons for document ng the r generat ng un ts' temperature l m ts n the r data responses: des gn temperature, h stor cal operat ng temperature, or current cold weather performance temperature determ ned by an eng neer ng analys s. Many GOs prov ded the Team w th more than one of these temperatures; f so, the Team used the h ghest of the temperatures to calculate the 75 percent figure. Us ng one of the lower temperatures prov ded for all GOs would have y elded a h gher figure. The Team w ll use the phrase "documented operat ng temperatures" to refer to these temperatures.

62 Blackstart ("blackstart") refers to restart ng the power gr d after a major port on of the electr cal network has been de energ zed, and generators that have blackstart capab l ty are those that can be started ndependently and w thout external power. *See* NERC Glossary of Terms for NERC defin t on of Blackstart Resource, and NERC Rel ab l ty Standard EOP 005 3 System Restorat on from Blackstart Resources.

63 The Marcellus Shale format on spreads across Pennsylvan a, New York, West V rg n a, Maryland, Tennessee, Kentucky, Oh o, and V rg n a.

64 The Ut ca Shale format on covers parts of Pennsylvan a, New York, West V rg n a, Maryland, Tennessee, Kentucky, Oh o, New York, and Canada.

65 " n 2022, the Appalach a reg on produced more natural gas than any other U.S. reg on, account ng for 29 percent] of U.S. gross natural gas w thdrawals." U.S. Energy nformat on Adm n strat on E A ndependent Stat st cs and Analys s

D. Recommendations

In response to the continued failures of generating units due to Freezing Issues, the Team[66] urges prompt development and implementation of the remaining revisions to the Reliability Standards recommended by Key Recommendation 1 from the 2021 Report to strengthen generators' ability to maintain extreme cold weather performance. Additionally, the Team suggests robust monitoring of the implementation of currently-effective and approved cold weather Reliability Standards to determine if reliability gaps exist. The Team includes several recommendations to prevent generating unit freeze issues, one targeted at those units that failed above their designated operating limits, and three applicable to all units. Another recommendation suggests that Generation Owners communicate changes in their operating limits to the BA in real time. The Team also recommends a technical review of the individual causes of cold-related mechanical/electrical generation outages to reduce the frequency of these outages and inform whether additional Standards are needed. Finally, the Team recommends another blackstart study, like the one currently being conducted for the ERCOT Interconnection in response to Recommendation 26 from the 2021 Report, but focusing on the Eastern and Western Interconnections.

In response to the natural gas production, processing and pipeline issues, the Team recommends that Congress and state legislatures (or state regulatory entities that have jurisdiction over natural gas infrastructure reliability) take action to establish reliability rules for natural gas infrastructure necessary to support the grid and natural gas LDCs in three areas: cold weather preparedness/freeze protection; regional natural gas situational awareness, coordination and information sharing (similar to the grid's Reliability Coordinators); and the designation of critical natural gas infrastructure (for prioritization during load shed).

The Team makes several recommendations concerning natural gas-electric coordination, including consideration of whether to require a one-time report to the Commission from FERC-jurisdictional natural gas entities describing how they are assessing and responding to their vulnerabilities to extreme cold weather; a NAESB effort to enhance situational awareness through communication during extreme cold weather events (both among natural gas infrastructure entities, and with grid entities); and a study to analyze whether additional natural gas infrastructure, including interstate pipelines and storage, is needed to support the reliability of the electric grid and meet the needs of natural gas LDCs.

Finally, the Team recommends several potential improvements for grid operations, including Balancing Authorities improving their short-term load forecasts for extreme cold weather periods by implementing and sharing effective practices with peers for continuous improvement; Balancing Authorities assessing whether new or modified processes such as multi-day risk assessment or reliability commitments are needed to mitigate the risk of capacity shortages or other reliability issues during extreme cold weather events; resource planners and entities serving load sponsoring joint-regional reliability assessments of electric grid conditions that could occur during extreme cold weather; and a study to examine potential Eastern Interconnection stability risks on December 23 and 24 during periods of decreased frequency and low responsive reserves.

66 *See* note 1 for defin t on of the Team.

II. EVENT OVERVIEW AND RELEVANT BACKGROUND INFORMATION

A. Event Overview: Both the Electric Grid and the Natural Gas Pipeline System Experienced a Supply Shortage Event, Leaving Some System Operators with No Choice but to Take the Extreme Step of Shedding or Curtailing Firm Customers in Order to Maintain System Reliability

Both the electric grid and the interstate natural gas pipeline system must account for situations where there is too little supply to maintain system reliability. Insufficient supply can create the risk of dangerously low voltage on the grid or pressure on the pipelines, respectively. This event was a supply shortage event for both the electric grid and the natural gas pipeline system.

During the Event, natural gas supply shortages began with freezing issues and weather-related access issues associated with production facilities and equipment, which rippled throughout the natural gas infrastructure system. Natural gas pipelines faced decreased supply flowing into the pipelines at the same time that shippers requested increased volumes of gas, with some shippers taking volumes of gas in excess of their entitlement. The reduced supply relative to higher volumes of delivered gas (a situation known as a draft condition) resulted in lower line pressures and reduced line pack. Pipeline system operators faced not only draft conditions but also freezing issues that affected important equipment like compressor stations. While they deployed line pack and storage, and dispatched personnel to respond to these conditions, most pipelines also needed to issue critical notices and Operational Flow Orders (OFOs), and some issued force majeures (which curtail even firm transportation).[67] Eventually pressures on some pipelines reached reliability-threatening levels. Con Edison, which provides local distribution of natural gas to over a million customers in Manhattan, The Bronx, and portions of Queens and Westchester County, New York, established an internal Gas System Emergency to preserve its system reliability due to rapidly decreasing pipeline pressures at its citygate that were not recovering. Had pipeline pressures not recovered, Con Edison could have faced an unprecedented loss of its entire system that, in this worst case scenario, would have taken months to restore, even with mutual assistance. WE Energies, a local gas distribution utility in Wisconsin, had to resort to consumer appeals to drop thermostats to 60 degrees on the night of December 23 when one of the interstate pipelines it relied upon experienced an unexpected compressor outage and curtailed natural gas flow to WE Energies by 30 percent.[68]

On the electric grid, natural gas production declines reduced the supply available for natural gas-fired generating units. Many natural gas-fired generating units either do not contract for firm gas supply or transportation, or contract for only a portion of the firm supply or transportation needed to meet their winter peak needs.[69] They are then unable to obtain natural gas when natural gas supply and available pipeline capacity become scarce-to-unobtainable in extreme cold weather. On top of the natural gas-related fuel outages, the grid experienced

67 *See* p. 76 for s debar on p pel ne commun cat ons for explanat ons of these terms.

68 Karl Ebert, "*On a bitter cold night, We Energies begged customers to turn down their thermostats. How close did the natural gas supply system come to failure?*" M lwaukee Journal Sent nel, (Jan. 20, 2023), https://www. sonl ne.com/story/money/bus ness/energy/2023/01/20/what caused we energ es natural gas cr s s on dec 23/69785899007/.

69 *See* F gure 85 for contractual arrangements held by some of the GOs/GOPs n the Event.

generating unit outages, derates and failures to start due to Freezing Issues and Mechanical/Electrical Issues that were closely correlated with falling temperatures. Total unplanned coincident generating unit outages, derates and failures to start during the Event exceeded 90,000 MW, the most ever observed compared to other extreme cold weather events that impacted the U.S.

While interstate pipeline and electric grid operators used every tool (e.g., EEA 1 or 2 for the grid, OFOs for pipelines) to avoid disruptions in service, some operators were forced to make difficult decisions such as curtailing firm natural gas customers or shedding firm electricity customers, to allow the system to recover from reliability-threatening conditions rather than deteriorate into an uncontrolled loss of an entire pipeline or the electric grid.

The coldest areas in Winter Storm Elliott did not deviate from normal lows as much as the coldest areas in 2021's Winter Storm Uri (comparing the NOAA-produced graphics of deviation from normal lows). In Uri, the coldest areas were between 40 and 50 degrees below the normal low, while in Elliott the coldest areas, on the peaks of the Appalachian Mountains, were between 30 and 35 degrees below the normal low. However, temperature alone is not the only factor in determining the extent to which extreme cold weather will wreak havoc on generating units and natural gas infrastructure. Wind and precipitation exacerbate the effects of temperature.[70] In the Event, TVA noted that rain followed by extreme cold weather and wind created an environment that was beyond the design basis of some TVA generating sites. Freezing rain can coat wind turbine blades, rendering them out of service until the icing is removed, while snow causes the largest performance drops at solar facilities.[71] Rain can also soak insulation, limiting or eliminating its ability to protect against cold. Another factor, which played a strong role in the Event, is how quickly the winter temperatures dropped. An extremely rapid drop (for example, temperatures in Charleston, West Virginia, ranged from 45 degrees at 2:43 a.m. to 3 degrees[72] at 8:43 a.m., a drop of 42 degrees in six hours), increases system load as it challenges the ability of home heating systems to maintain consistent temperatures.

The Event had the largest footprint of any examined in a joint FERC-NERC-Regional Entity inquiry. As shown in Figure 8, below, the extreme cold weather covered most of the eastern half of the lower 48 United States, except for some of Florida. The Team focused on affected entities that either shed firm load or lost larger percentages of their generating unit capacity. All were located within the Eastern Interconnection and had multiple tie lines to other entities within the Eastern Interconnection.

Entities that were more severely affected (Core Entities)[73] included PJM, (represented by the blue box below in Figure 9); TVA and LG&E/KU BAs, within TVA's Reliability Coordinator footprint (represented by red and white striped boxes); Southern (represented by an aqua box); and DEP, DEC/VACAR-South RC, DESC and Santee Cooper, represented by pink boxes). Within the Event Area, the Team also examined MISO, SPP, ISO New England and NYISO (collectively represented by gold boxes) to better understand how their generating unit outages and flows exchanged with Core Entities impacted Event outcomes.

70 The effects of a lower dry bulb temperature s equ valent to those of a h gher dry bulb temperature w th h gh w nds or assoc ated prec p tat on.

71 N cole D. Jackson & Thushara Gunda, Evaluat on of extreme weather mpacts on ut l ty scale photovolta c plant performance n the Un ted States, 302, Appl ed Energy, 1:7 (2021) Sand a Nat onal Labs.

72 The Report ncludes temperature references only n Fahrenhe t.

73 See note 35 for defin t on of Core Event Area, wh ch ncludes defin t on of Core Ent t es.

B. Background on Affected Systems and Entities

1. RELIABILITY ROLES

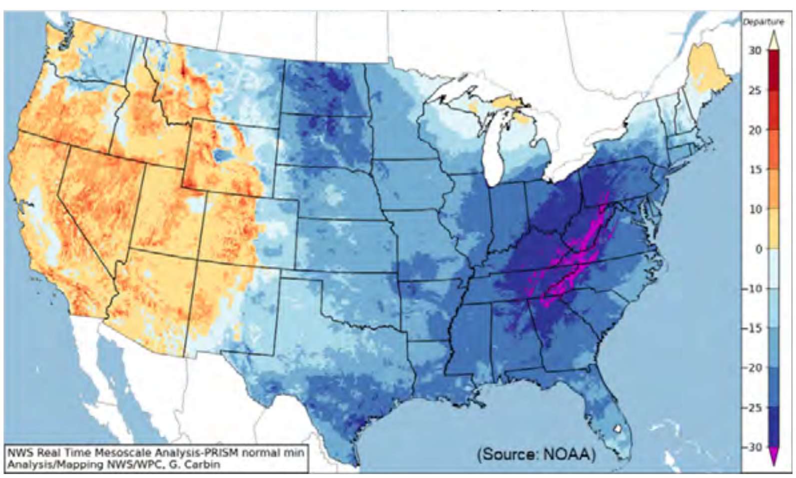
NERC categorizes the entities responsible for planning and operating the BES in a reliable manner into multiple categories of functional entity types. The NERC roles most relevant to the Event are Reliability Coordinators (RCs), Balancing Authorities (BAs), Generator Owners (GOs), Generator Operators (GOPs), Transmission Owners (TOs), Transmission Operators (TOPs), Planning Authority/Planning Coordinators (PA/PCs), and Transmission Planners (TPs). Several of the Core Entities (also referred to as "Core BAs"), especially PJM, TVA, Southern, DEC/VACAR-South RC, and DESC, served multiple reliability roles during the Event.

2. INTERCONNECTIONS BETWEEN AFFECTED ENTITIES AND OTHER PARTS OF THE ELECTRIC GRID

In North America, there are four separate power grids or "interconnections." The Eastern interconnection includes the eastern two-thirds of the continental United States and Canada from Saskatchewan east to the Maritime Provinces (see Figure 10, below), and is electrically independent from the other interconnections.

The Eastern Interconnection is the largest of the four interconnections, and by itself has been called the largest machine in the world.[74] The Eastern Interconnection is electrically connected to the Western, ERCOT and Quebec Interconnections by means of Direct Current (DC) asynchronous transmission tie lines.[75] Within each interconnection, power generally flows without barriers (subject to operational limits) from one utility's system to another across the entire grid via alternating current (AC) tie lines. A significant enough imbalance of generation and demand can cause instability of one utility's system to affect the stability of all utility systems operating in that interconnection.[76]

Figure 8: Extreme Cold Weather Conditions – December 24, 2022

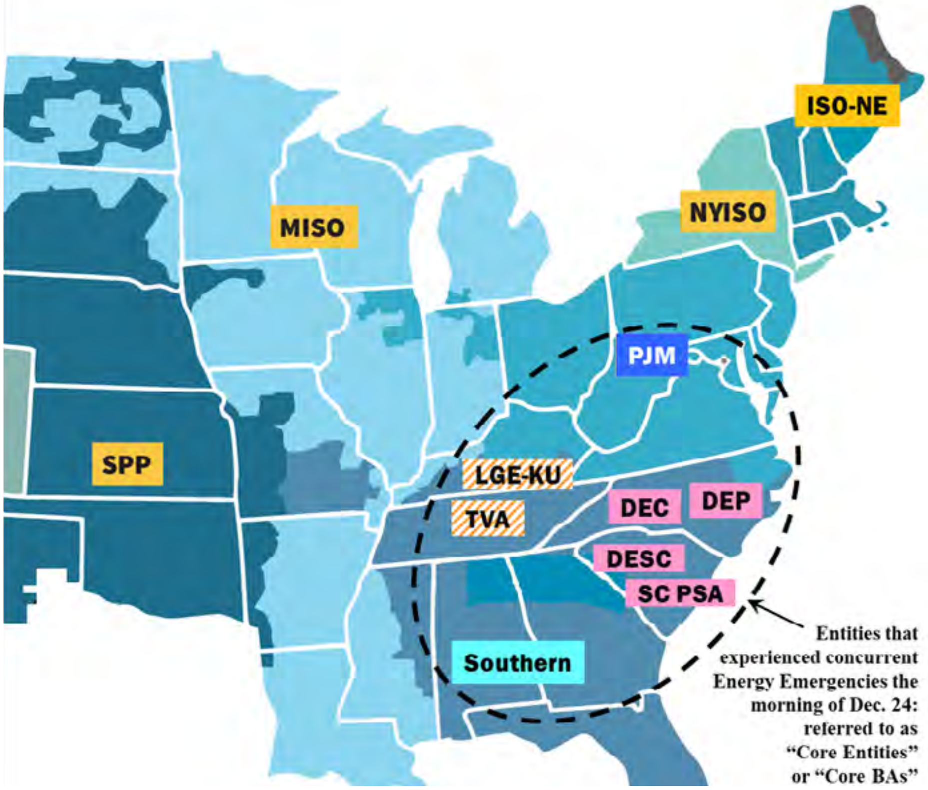


74 "Mult D mens onal ssues n nternat onal Electr c Power Gr d nterconnect ons," 15 (2006), https://www.un.org/esa/sustdev/publ cat ons/energy/ nterconnect ons.pdf.

75 For DC transm ss on l nes, the flow of power s controlled (.e., scheduled), rather than flow ng cont nuously as on synchronous t es.

76 *See* generally, U.S. Canada Power System Outage Task Force, F nal Report on the August 14, 2003 Blackout n the Un ted States and Canada: Causes and Recommendat ons, 5 10 (Apr l 2004), https://www.ferc.gov/s tes/default/files/2020 05/ch1 3 0.pdf.

Figure 9: Bulk Electric System Map of Affected Entities



3. DESCRIPTION OF U.S. BES ENTITIES IN THE EASTERN INTERCONNECTION AFFECTED BY WINTER STORM ELLIOTT

a. PJM and other RTOs/ISOs in the Eastern Interconnection[77]

PJM (Core Entity). PJM is a regional transmission organization (RTO) covering 13 states (Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, West Virginia)[78] and Washington, DC for a total of 368,906 square miles.[79] PJM is NERC-registered as a BA, RC, PA/PC, and TOP, and in the latter capacity, operates 88,115 miles of transmission lines.[80] It monitors over 1,400 generating units. In 2022, PJM obtained energy from 40 percent gas generation, 20 percent coal, 32.3 percent nuclear, 1.9 percent hydroelectric, 3.7 percent wind, and 2.2 percent other (all calculated on a MWh basis). Its total installed capacity at the end of December 2022 was 183,385 MW.[81] PJM has historically been a summer-peaking region, and its all-time peak load was 165,563 MW during the summer of 2006. PJM operates an energy and ancillary services market that includes both day-ahead and real-time markets.

MISO. MISO is an RTO that operates the grid across 15 states and the Canadian province of Manitoba, and

77 Wh le both New York SO (NY SO) and SO NE ncurred s gn ficant d str but on power outages from W nter Storm Ell ott, both exper enced less severe BES mpacts dur ng the Event. These SOs are d scussed n Sect on of the Report.

78 https://www.p m.com/about p m/who we are.

79 https://www.p m.com/about p m, https://serv ces.p m.com/annualreport2022/.

80 https://learn.p m.com/ /med a/about p m/newsroom/fact sheets/p m at a glance.ashx.

81 http://www.mon tor nganalyt cs.com/reports/PJM State of the Market/2022/2022 som p m press br efing.pdf.

serves as a BA and RC, among other reliability roles.[82] MISO operates 75,000 miles of transmission lines, is a summer-peaking region, and experienced its highest peak load to date, 130,917 MW, on July 20, 2011. MISO's generating capacity is 198,933 MW, comprised of 42 percent natural gas-fired generation, 29 percent coal, 19 percent renewables and eight percent nuclear generation. Currently, MISO operates one of the largest energy and operating reserve markets, with annual gross transactions of $22 billion, as well as an ancillary services market, and includes both day-ahead and real-time markets.

SPP. SPP is an RTO and serves as a BA and RC, among other reliability roles. It operates a 552,885-square-mile area that includes all or portions of 14 states, including: Arkansas, Iowa, Kansas, Louisiana, Minnesota, Missouri, Montana, Nebraska, New Mexico, North Dakota, Oklahoma, South Dakota, Texas and Wyoming.[83] SPP operates 70,025 miles of transmission lines. It is a summer-peaking region and although it experienced its highest peak load of 56,184 MW on August 21, 2023, it experienced a new all-time winter peak load of 47,157 MW during Winter Storm Elliott. SPP's generating fleet is 38.5 percent (nameplate) natural gas, 29 percent wind, and 24.3 percent coal. However, coal accounts for the majority of the generated energy with 38.6 percent of the total, while wind and natural gas produce about 29.5 percent and 22.7 percent respectively.[84] SPP operates an energy and ancillary services market that includes both day-ahead and real-time markets.

b. Grid Operators in the Southeast U.S.

TVA (Core Entity). TVA is a federally-owned electric utility corporation, the largest public power provider in the U.S., and serves as a BA, RC, GO, GOP, TO and TOP, among others. TVA's service area covers most of Tennessee, portions of Alabama, Mississippi, and Kentucky, and small areas of Georgia, North Carolina and Virginia. TVA owns and operates approximately 16,200 miles of transmission lines and serves 12 million customers. TVA's generation fleet consists of 33 percent natural gas, 39 percent nuclear, 14 percent coal, 10 percent hydro, and four percent wind and solar. TVA is a dual (both summer and winter) peaking region and set a new record winter peak of 33,425 MW during the Event on December 23, 2022.

LG&E/KU (Core Entity). LG&E and KU are subsidiaries of PPL Corporation. They are regulated public utilities that serve more than 1 million electric customers combined. LG&E/KU operate their combined transmission systems as a joint BA Area, PC Area, and TOP Area. LG&E/KU are also registered as a GO, GOP, TSP, TP, and TO. TVA serves as LG&E/KU's RC. LG&E serves approximately 333,000 natural gas and 429,000 electric customers in Louisville and 16 surrounding counties.[85] KU serves approximately 566,000 electric customers in 77 Kentucky counties and five counties in Virginia operating as Old Dominion Power Company.[86] Together, the companies own approximately 5,400 miles of electric transmission lines.[87] Their combined generation fleet includes 37.5 percent natural gas, 59.6 percent coal, and 2.9 percent hydro and other. LG&E/KU is dual peaking, and its all-time winter peak BA load was 7,336 MW on January 6, 2014.

DEP and DEC (both Core Entities). DEP and DEC are subsidiaries of Duke Energy. DEP operates as a BA, GO, GOP, PA/PC, TO, and TOP. DEC is the agent for the VACAR-South RC, and operates as a BA, GO, GOP, PA/PC, TO, and TOP.[88] DEP has 16,390 megawatts of generation

82 M SO Corporate Fact Sheet, https://www.m soenergy.org/about/med a center/corporate fact sheet/.

83 SPP Fact Sheet https://www.spp.org/about us/fast facts/.

84 *Id.*

85 About LG&E and KU LG&E and KU (lge ku.com); https://lgeku.com/ nvestments#:~:text The%20same%20type%20of%20deta led,gas%20 storage%20fields%20that%20enable .

86 https://lge ku.com/about.

87 https://lge ku.com/about.

88 https://www.nerc.com/comm/OC/Operat ng%20Rel ab l ty%20Subcomm ttee%20ORS%202013/ORS Presentat on Nov 6 7 2019.pdf pg 15

capacity within its footprint, 1.7 million residential, commercial and industrial electricity customers across a 29,000-square-mile service area in North Carolina and South Carolina, and operates 6,300 miles of transmission lines. Generation within its footprint includes 38.1 percent natural gas, 19.4 percent coal, 22.8 percent nuclear, 1.5 percent hydro and other. DEC has 25,848 megawatts of generation capacity within its footprint (34.2 percent natural gas, 23.7 percent coal, 28.5 percent nuclear, 13.2 percent hydro and other), 2.8 million residential, commercial and industrial electricity customers across a 24,000-square-mile service area in North Carolina and South Carolina,[89] and operates 13,000 miles of transmission lines. DEP's and DEC's record winter peak loads were 15,569 MW and 21,620 MW, respectively.

DESC (Core Entity). DESC (formerly known as South Carolina Electric & Gas Company) is a vertically integrated electric utility for the central, southern, and southwestern portions of South Carolina. DESC serves as a BA, GO, GOP, PA/PC, TO, and TOP. VACAR-South is its RC. DESC also purchases and distributes natural gas.[90] DESC's generating fleet is 40 percent natural gas,[91] 25 percent coal, 14 percent solar,[92] and 9 percent nuclear energy for a total net winter capacity of 6,821 MW. DESC is dual peaking, and its record winter peak load was 4,970 MW.

Santee Cooper (Core Entity). Santee Cooper (shown as "SC PSA" in Figures 1 and 9 above) is South Carolina's state-owned electric utility. It provides power to approximately two million people,[93] and operates as a BA, GO, GOP, PA/PC, TO, and TOP. VACAR-South is its RC. Santee Cooper sells electricity to Central Electric Power Cooperative, a wholesale power provider, which in turn provides power to South Carolina's 20 electric cooperatives.[94] It also provides power to the cities of Bamber and Georgetown, 27 large industrial customers including Joint Base Charleston, the Alabama Municipal Electric Authority, and the 10 member cities that form the Piedmont Municipal Power Agency.[95] Santee Cooper schedules power over 5,223 miles of transmission lines.[96] Its generation consists of 66.5 percent coal, 22.0 percent natural gas, 6.1 percent nuclear, 2.7 percent hydro, and 2.8 percent other. Santee Cooper is a winter-peaking region, and its highest winter peak demand was 5,342 MW in 2022.

Southern (Core Entity). Southern provides energy to nine million customers through its family of companies, including Alabama Power, Southern Power, Georgia Power, and Mississippi Power.[97] Southern also serves as a BA, PA/PC, and TOP, among others, and its RC is Southeastern RC.[98] Southern has electric operating companies in three states and natural gas distribution companies in four.[99] The Southern BA Area had 57,895 MW of projected generating capacity prior to Winter Storm Elliott and more than 27,000 miles of transmission lines.[100] The Southern BA Area generating fleet consisted of 53.5 percent natural gas, 20.3 percent coal, 11.5 percent nuclear, 8.7 percent hydro, 5.3 percent solar and wind, and 0.7 percent other. The Southern BA footprint is

89 https://p cd.duke energy.com/ /med a/pdfs/our company/duke energy fast facts.pdf?rev 77d14a34d96f449493f89595285d4d57.

90 https://www.dom n onenergy.com/pro ects and fac l t es/natural gas fac l t es/south carol na natural plants.

91 Th rty of the 40 percent of DESC's natural gas generat ng fleet s dual fuel.

92 Accord ng to DESC, "Most of the t me, DESC gets c ose to zero percent so ar at t me of morn ng w nter peak oads s nce they occur before the sun r ses."

93 https://www.santeecooper.com/about/.

94 https://www.fl psnack.com/santeecooper/fingert p facts 2022/full v ew.html.

95 https://www.fl psnack.com/santeecooper/fingert p facts 2022/full v ew.html.

96 https://www.fl psnack.com/santeecooper/fingert p facts 2022/full v ew.html.

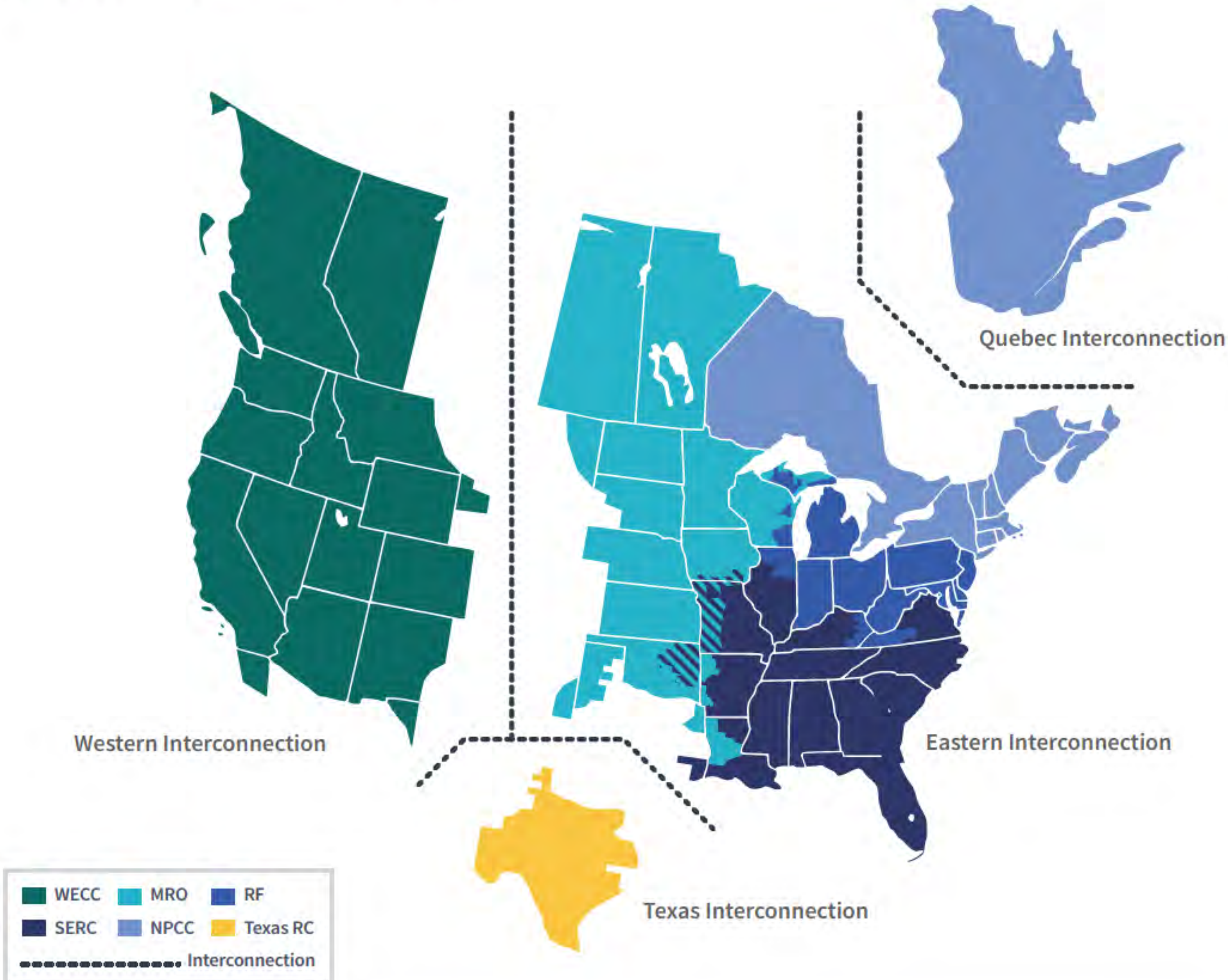
97 https://www.southerncompany.com/about/our compan es.html#:~:text We%20support%209%20m ll on%20customers,w reless%20commun cat ons%20across%20the%20country.

98 SERC recogn zes Southern Company Serv ces as the Rel ab l ty Coord nator for the Southeastern RC area.

99 https://www.southerncompany.com/about/our compan es.html#:~:text We%20support%209%20m ll on%20customers,w reless%20commun cat ons%20across%20the%20country.

100 https://www.southerncompany.com/about/our bus ness.html#:~:text Southern%20Company%20operat ons%20has%20respons b l ty,a%20safe%20and%20rel able%20gr d.

Figure 10: Electric Interconnections Map



generally dual peaking (summer and winter), with its all-time peak load being 48,008 MW.[101] Southern set a new December peak record during the Event of 45,153 MW on December 24.[102]

Figure 11, below, lists the capacity of BES generation resources for the Core Entities by fuel type, at the time of the Event. Natural gas-fueled generation comprised the largest percentage (41.90 percent) of generation across the core entities, followed by coal-fired generation at 24.19 percent. Renewable BES generation capacity was relatively low (1.94 percent solar and 1.12 percent wind, respectively) in the Core Event Area.

101 https://www.southerncompany.com/content/dam/southerncompany/susta nab l ty/pdfs/2022 Year n Rev ew.pdf.

102 https://www.southerncompany.com/content/dam/southerncompany/susta nab l ty/pdfs/2022 Year n Rev ew.pdf. For the Southern Company BA area, ts all t me w nter peak load was 45,887 MW.

Figure 11: Total Installed Net Capacity of BES Generation Resources Located within Core Entity Footprints During Event, and Resource Fuel Type Composition for Combined Core Entity Footprints

Core Entity Footprint	Capacity
	(MW)
DEC	25,848
DEP	16,390
DESC	6,821
LG&E/KU	7,973
PJM	186,270
Santee Cooper	5,237
Southern	57,895
TVA	36,456
TOTAL MW	**342,890**

Fuel Type	Combined Core Entity Footprints	
	(MW)	(Percent)
Coal	82,954	24.19%
Hydro*	34,455	10.05 %
Natural Gas	143,658	**41.90 %**
Nuclear	59,963	17.49 %
Solar	6,653	1.94 %
Wind	3,857	1.12 %
Other	11,350	3.31 %
TOTAL MW	**342,890**	**100%**
* ncludes Pumped Storage		

c. Tie Lines Between Entities

The affected entities, each operating as BAs, have AC transmission tie lines which connect one BA to another, and enable power transfers to be routinely scheduled between them (resulting in power imports and exports) when generation reserves in the exporting BA and available transmission capacity are sufficient to accommodate the power transfers. All BAs in the Eastern Interconnection have multiple tie lines connecting them to neighboring BAs (BAs that are directly connected via tie lines are often referred to as "adjacent BAs").

In general, there is an extensive network of transmission tie lines between the Core BAs in the Eastern Interconnection, which under normal conditions allow for significant imports and exports among them. Figure 12, below shows the number of tie lines, by voltage level, between the Core BAs. ISO-NE, NYISO, MISO, and SPP also have tie lines with Canadian BES BAs (not shown on Figure 12).

Figure 12: Total Number of AC Transmission Tie lines, Number of Tie Lines between Adjacent Core BAs, and with other BAs Affected by Elliott, by Voltage Level

	DEC			DEP			DESC			LG&E/KU			PJM			Santee Cooper			Southern			TVA		
Totals:	29			41			31			85			201			35			55			61		
Voltage Level	DEC DESC	DEC PJM	DEC Santee Cooper	DEC Southern	DEP DEC	DEP PJM	DEP DESC	DEP Santee Cooper	DESC Santee Cooper	DESC Southern	LG&E/KU M SO	LG&E/KU PJM	PJM M SO	PJM NY SO	Santee Cooper Southern	Southern Flor da BAs	Southern M SO	TVA LG&E\KU	TVA M SO	TVA PJM	TVA Southern	TVA DEC	TVA DEP	TVA AEC
<100 kV											1	33	4	7		2	0	2	1	1				
100 to 150 kV	2	1			3	4	1	2	10	3	7	17	33	6		12	1		1	2	1			
150 to 300 kV	2		4		11	7	2	8	9	2	5	6		4	2	10	7	4	15	7	7	2	1	1
300 kV and Higher		1		1	1	1					7	2	51	11		2	1	1	7	3	4	1		
TOTAL	4	2	4	1	15	12	3	10	19	5	20	58	88	28	2	26	9	7	24	13	12	3	1	1

C. Background on Preparation for 2022-2023 Winter Peak Operations

1. SEASONAL PROJECTIONS AND ASSESSMENTS BY AFFECTED GRID ENTITIES

In general, BAs and RCs (which included both RTO and non-RTO entities) performed 2022-2023 winter season demand forecasts and projections of adequacy for both generation resources and transmission performance for their respective footprints.

a. Season Peak Load Forecasts

Figure 13, below, provides a summary of peak load forecasts that were made by the Core BAs in advance of the 2022-2023 winter season (typically developed by entities during the third calendar quarter in advance of the subsequent winter). Figure 13 compares the forecast peak loads against the actual peak loads that occurred within each Core BA footprint during the Event (as well as, where available, against the estimated peak if firm load shed or demand response had not reduced the actual peak load).

Figure 13: Winter 2022-2023 Season BA Peak Load Forecasts and Actual Hourly Winter Peak Loads for the Core Event Area (in MW)

		DEC	DEP	DESC	LG&E/KU	PJM	Santee Cooper	Southern	TVA
Previous All-Time Hourly Winter Peak		21,620	15,569	4,970	7,336	143,225	5,869*	45,887	33,352
Date of Occurrence		01/05/18	02/20/15	02/20/15	01/06/14	02/20/15	02/20/15	01/07/14	01/24/14
Winter 2022-2023 50/50 Forecast		20,246	14,454	4,169	6,453	132,980	5,481	41,300	30,295
Winter 2022-2023 90/10 Forecast		22,147	16,911	4,726	7,051	143,782	6,000	45,462	34,363
December 2022 Actual Hourly Peak		20,568	13,819	4,678	6,891	134,189	5,342	45,153	33,427
Date		12/24/22	12/24/22	12/24/22	12/23/22	12/23/22	12/24/24	12/24/22	12/23/22
December 2022 Estimated Peak without Load Management		21,800	14,800	N/A	6,986	134,951	5,900	46,000	35,000
Percent 2022 Actual Peak was Above Forecasts:	50/50	1.59%	4.39%	12.21%	6.79%	0.91%	2.54%	9.33%	10.34%
	90/10	7.13%	18.28%	1.02%	2.27%	6.67%	10.97%	0.68%	2.72%
Percent 2022 Estimated Peak was Above Forecasts:	50/50	7.68%	2.39%	N/A	8.26%	1.48%	7.64%	11.38%	15.53%
	90/10	1.57%	12.48%	N/A	0.92%	6.14%	1.67%	1.18%	1.85%

(a) DEC, DEP values l sted for 90/10 forecasts were projected super peak loads, ncluded Super Peak study as part of DEP and DEC w nter 2022 2023 season transm ss on capab l ty assessment. Super Peak values range from 9 (DEC) to 17 percent (DEP) to 17 percent (DEP) above 50/50 forecasts.

(b) DESC developed monthly 50/50 and extreme weather demand r sk peak values. Jan 2023 forecasts were 50/50, 4,902 MW; extreme, 5,459 MW.
(c) PJM: prev ous All T me Hourly W nter Peak value accounts for allocated 500 kV transm ss on losses. W nter 2022 2023 50/50 Forecast value represents the co nc dent peak 50/50 forecast and accounts for allocated 500 kV transm ss on losses (PJM uses the non co nc dent peak 50/50 forecast (136,867 MW for W nter 2022 2023, not l sted above) n ts Operat ons Assessment Task Force seasonal stud es). W nter 2022 2023 90/10 Forecastvalue accounts for allocated 500 kV transm ss on losses. 2022 Actual Hourly Peak and Est mated Hourly Peak w thout Load Management values account for allocated 500 kV transm ss on losses, and d ffer from peaks PJM reported elese where (135, 296) MW for actual and 136,010 MW for est mated peak w/o load management) due to a sl ght d fference n the way load s defined for the long term and short term forecast ng appl cat ons.
(d) *Santee Cooper 2015 / prev ous all t me w nter peak load ncluded load that s no longer served by Santee Cooper.
(e) Southern developed an extreme peak value based on stat st cal analys s.

Most of the BAs' actual winter peak loads during Winter Storm Elliott's extreme cold weather fell between their winter 2022-2023 50/50 and their 90/10 (or extreme forecast) winter season forecast peak loads.[103] A few BAs, such as TVA and Southern, would have exceeded both their 50/50 and 90/10 forecast peaks had they not implemented load management (Southern) or firm load reduction (TVA). Both BAs commented that winter peak load conditions do not exhibit a saturation point like summer peak air-conditioning-driven loads do, because electric heating (auxiliary backup heating for heat pumps, electric strip heating and electric space heaters) increases winter peak load in a non-linear manner as temperatures decrease.[104]

b. Capacity/Resource Reserves Projections

The Core BAs performed seasonal resource assessments in advance of the 2022/2023 winter to determine available generation reserves during winter peak conditions. The assessments included forecast peak loads, generation capacity, and projected reserves. Most of the Core BAs performed their respective winter season assessments assuming a 50/50 load forecast, although LG&E/KU's winter assessment assumed a 90/10 load forecast.[105] The paragraphs below summarize each BA's respective assessment.

Figure 14, below, depicts the winter 2022-2023 seasonal resource assessments for the Core BAs to meet their respective 50/50 and 90/10 forecast peak loads.

Figure 14: 2022-2023 Winter Season Resource Assessment Reserve Margins - Core BAs

		Without Demand Response		With Demand Response	
Balancing Authority	**NERC Region/Area**	50/50 Forecast W nter Peak Load (Percent)	90/10 Forecast W nter Peak Load (Percent)	50/50 Forecast W nter Peak Load (Percent)	90/10 Forecast W nter Peak Load (Percent)
DEC	SERC East	21.1	10.7	23.5	12.9
DEP	SERC East	9.0	6.8	10.6	5.5

103 A 50/50 peak load forecast s based on a 50 percent chance that the actual system peak load w ll exceed the forecast value, wh le a 90/10 peak load forecast s based on a 10 percent chance that the actual system peak load w ll exceed the forecast value.

104 *See* Recommendat on 16 and F gure 108 from the 2021 Report, wh ch shows how home heat ng demand due to electr c aux l ary heat ng ncreases from two to four t mes once temperatures drop below 14 degrees (as compared to the demand at 32 degrees).

105 For more about how BAs conduct these assessments, *see* page 30 of the 2021 Report.

		Without Demand Response		With Demand Response	
Balancing Authority	**NERC Region/Area**	50/50 Forecast W nter Peak Load (Percent)	90/10 Forecast W nter Peak Load (Percent)	50/50 Forecast W nter Peak Load (Percent)	90/10 Forecast W nter Peak Load (Percent)
DESC	SERC East	18.7	6.6	23.5	10.9
LG&E/KU	SERC Central	15.1	5.4	15.1	5.4
PJM	RF/PJM	14.9	9.4	20.5	14.7
Santee Cooper	SERC East	4.1	12.4	7.3	2.0
Southern	SERC Southeast	30.2	18.3	30.2	18.3
TVA	SERC Central	9.2	3.7	14.6	1.0

DESC. DESC performed a Winter 2022/2023 resource assessment assuming a 50/50 load forecast. Based on its winter assessment, DESC believed that it could meet its projected winter peak demand of 4,902 MW with available generation and imports (based on normal weather conditions). DESC's extreme winter forecast[106] was 5,459 MW, higher than its previous all-time winter peak demand record of 4,970 MW, set in 2015. To meet that extreme peak demand, DESC projected a seasonal resource capacity of 5,819 MW, once 1,147 MW of planned and forced outages were deducted from available resources. This resulted in estimated reserves of 917 MW assuming the 50/50 load forecast and 360 MW for an extreme weather demand risk scenario.

Duke/DEC and DEP. Based on its winter resource reserves projection, Duke believed that it could meet its projected winter peak demand of 20,246 MW for DEC and 14,454 MW for DEP, for a combined load of 34,700 MW, with available generation and imports (based on normal weather conditions). To meet the projected winter demand, DEC projected a resource capacity of 24,510 MW, once 1,338 MW of planned and forced outages were deducted from available resources. DEP projected a resource capacity of 15,754 MW, once 636 MW of planned and forced outages were deducted from available resources. Duke assumed a forced outage rate of 2.5 percent based on recent historical performance. Duke adjusts reserves by third party imports/exports, projected demand response and units in extended reserve shutdown. This resulted in estimated reserves of 2,246 MW for DEC and 1,648 MW for DEP for the 50/50 load forecast.[107]

Duke's extreme winter forecast was 22,147 MW for DEC and 16,911 MW for DEP (39,058 MW combined), which was higher than its previous all-time winter peak demand record of 21,620 MW, set on January 5, 2018 for DEC and 15,569 MW, set on February 20, 2015 for DEP. Duke performed this super peak study to determine potential transfer capability limitations. The DEC transmission system would be capable of serving load of 24,457 MW before seeing any significant issues. The DEP transmission system would be capable of serving load of 17,491 MW before seeing any significant issues.

Santee Cooper. Santee Cooper performed a Winter 2022/2023 resource assessment assuming a 50/50 load forecast. Santee Cooper's winter load forecast is prepared using 20 years of monthly peak demand and energy usage each year around April. This forecast is composed of several component forecasts, including forecasts for different customer classes. Based on its winter

106 DESC uses a stat st cal regress on techn que to quant fy an extreme w nter weather demand level, based on ts h stor cally coldest w nter days.

107 DEC and DEP also expla ned that there are no add t onal sub areas, reg ons, or load pockets w th n the DEC and DEP BA areas where reserves are mon tored to ensure suff c ent resource reserves and/or del verab l ty of reserves for the reg ons or sub areas.

assessment, Santee Cooper believed that it could meet its projected winter peak demand of 5,481 MW with available generation and imports (based on normal weather conditions).[108] Santee Cooper's extreme (i.e., 90/10) winter forecast was 6,000 MW, slightly higher than its previous all-time winter peak demand record of 5,869 MW, set on February 20, 2015.[109] To meet that extreme peak demand, Santee Cooper projected resource capacity of 5,237 MW and 626 MW of demand response. Without demand response, Santee Cooper projected a resource deficiency of up to 743 MW to meet its extreme load forecast of 6,000 MW. Santee Cooper relied on the Carolinas Reserve Sharing Group to recover from typical single-contingency outages of generating units and relied on import power purchases as needed for other scenarios such as multi-unit outage conditions.

LG&E/KU. LG&E/KU performed its Winter 2022/2023 resource assessment using the 90/10 load forecasts provided by the four load-serving entities in the LG&E/KU BA area: (1) LG&E/KU; (2) Owensboro Municipal Utilities; (3) Kentucky Municipal Power Agency; and (4) Kentucky Municipal Energy Agency. Although LG&E/KU used the 90/10 load forecast for their winter assessment, LG&E/KU also performed a 50/50 load forecast using the forecasts provided by the four load-serving entities (LSEs) in the BA area.[110] Based on the winter assessment, LG&E/KU believed that it could meet its projected winter peak demand of 6,453 MW with available generation and imports (based on normal weather conditions). LG&E/KU's extreme winter forecast demand was 7,051 MW. To meet that extreme peak demand, LG&E/KU projected resource capacity of 7,430 MW, assuming a 3.66 percent forced outage rate for coal units and 6.36 percent forced outage rate for natural gas units. LG&E/KU's assessment also considered multiple contingencies (e.g., analysis required in Reliability Standard TPL-001-5.1). This resulted in estimated reserves of 977 MW assuming the 50/50 load forecast and 379 MW for the 90/10 extreme load scenario.

TVA. TVA performed a Winter 2022/2023 resource assessment assuming a 50/50 load forecast. TVA uses 24 hourly regression models trained over the prior three years to estimate response of load to temperature (i.e., the corresponding MW increase from a one-degree increase or decrease of temperature). TVA's models use calendar factor variables (e.g., holidays, day of week, month, and year), seasonal weighted aggregate dry bulb temperatures based on the five largest cities in the TVA region,[111] and a 72-hour weighted average of the dry bulb temperature, where the more recent observations are more heavily weighted to estimate the impacts of thermal buildup. TVA uses these models to estimate load for its hourly temperature history (going back to 1960) as if the load had occurred with the current system size, in order to ensure a wide sample of load and temperature values. TVA uses the estimated loads to build a probability distribution to mitigate issues with a regression model. The models assume that the most extreme winter weather will occur in January and assume that the prior three years of hourly temperatures approximate current temperature response.

Based on its winter assessment, TVA believed that it could meet its projected winter peak demand of 30,295 MW with available generation and imports (based on normal weather conditions). TVA's extreme winter forecast was 34,363 MW, slightly higher than its previous all-time winter peak demand record of 33,352 MW, set on January 24, 2014. To meet that extreme peak demand, TVA projected resource capacity of 33,079 MW, once 577 MW of planned and 2,800 MW of unplanned outages were deducted from available resources. This resulted in estimated reserves of 2,784 MW for the 50/50 load forecast and 1,284 MW deficiency for the 90/10 extreme load scenario.

---

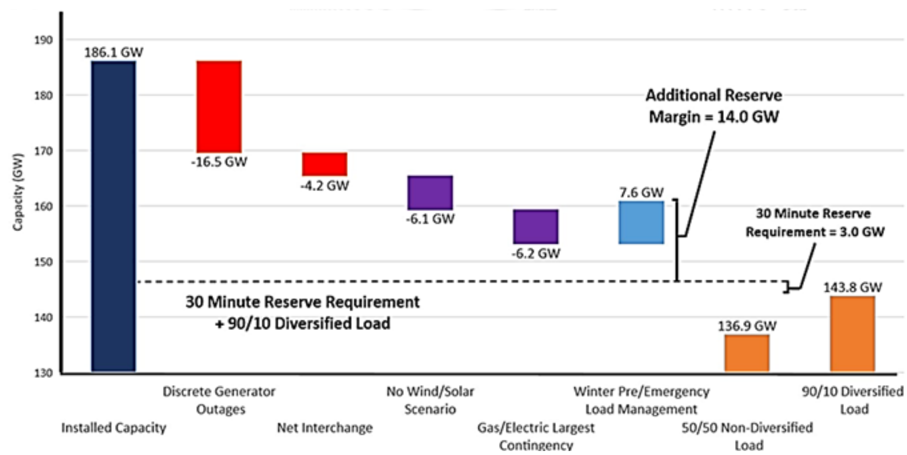
108 Based on ts 50/50 forecast reserve marg n w thout demand response, magn tude of mports to meet load and ma nta n operat ng reserves w thout deployment of demand response would have been n the range of 350 400 MW.

109 A port on of the load Santee Cooper was serv ng on February 20, 2015 s no longer served by Santee Cooper.

110 Accord ng to LG&E/KU, " t]he LG&E/KU] LSE forecasts the 50/50 w nter peak load us ng the average temperature on the peak day over the last 20 years. To assess generat on rel ab l ty and develop extreme weather load scenar os, the LG&E/KU] LSE develops hourly demand forecasts based on the actual weather n each year s nce 1973. Degree days are the pr mary var able used to develop these forecasts."

111 .e., Huntsv lle, Alabama; Memph s, Tennessee; Nashv lle, Tennessee; Chattanooga, Tennessee; and Knoxv lle, Tennessee.

Figure 15: PJM's Winter 2022-2023 Capacity Projections



However, TVA projected approximately 1,626 MW of load management available to respond to additional unplanned resource outages.

Southern. The Southern BA performed a winter 2022/2023 resource assessment assuming a 50/50 load forecast. Based on its winter assessment, the Southern BA believed that it could meet its projected winter peak demand of 41,300 MW with available generation and imports (based on normal weather conditions). The Southern BA's extreme winter forecast was 45,462 MW, slightly lower than its previous all-time winter peak demand record of 45,887 MW, which was set on January 7, 2014. To meet that extreme peak demand, Southern projected resource capacity of 53,759 MW, once 4,136 MW of planned and forced outages were deducted from available resources. This resulted in estimated reserves of 12,459 MW assuming the 50/50 load forecast and 8,297 MW for the 90/10 extreme load scenario. Southern BA also projected approximately 2,510 MW of load management available to respond to additional unplanned resource outages.

For assessing transmission system performance for the upcoming winter season, SERC (members include DESC, DEC, DEP, Santee Cooper, LG&E/KU, TVA, and Southern) conducted a 2022-2023 winter reliability study. The assessment studied an N-1 contingency analysis on the initial base case to determine whether there was adequate transmission for the upcoming winter season. SERC members also studied an "extreme weather" scenario under which a 12 GW power transfer was simulated from PJM to MISO South. A third study simulated what was termed as a "colder-than-normal" transfer case, which increased all generation in the SERC region that was online with available capacity and scaled the loads up in one subregion at a time, evaluating transmission adequacy given higher subregional demands that were 10 percent or higher above 50/50 forecasted levels. Overall, the above three studies did not show any transmission adequacy issues in the SERC subregions for the 2022-2023 winter season, and showed that potential thermal overloads identified in the studies could be mitigated with available operating guides or other mitigation strategies.

PJM. PJM performed a Winter 2022/2023 seasonal assessment assuming a 50/50 load forecast. PJM used power flow cases that simulated the expected system conditions for the 2022/2023 winter peak load period. For the PJM non-coincident load case, each transmission zone is set to its individual respective winter 50/50 peak load forecast value, without a reduction for load diversity and without considering any demand response resources that may be available. PJM also performed several sensitivity studies using the 50/50 non-coincident load case. Finally, PJM calculated projected reactive interface transfer limits[112] for various interfaces.

As shown in Figure 15,[113] based on its winter assessment, PJM believed that it could meet its projected 50/50 winter peak demand of 136,867 MW with available generation (based on normal weather conditions). PJM's extreme winter forecast was 143,782 MW, slightly higher than its previous all-time winter peak demand record of 143,225 MW, which was set on February 20, 2015. To meet that extreme peak demand, PJM projected resource capacity of 157,314 MW, once 16.5 GW of generator outages, 4.2 GW of exports, 6.2 GW for the loss of its largest contingency (gas/electric single point of failure) and 6.1 GW for a no wind/no solar scenario were deducted from available resources. This resulted in estimated reserves of 16,233 MW assuming the 50/50 load forecast and 9,318 MW for the 90/10 extreme load scenario. However, PJM projected approximately 7.6 GW of load management available to respond to additional unplanned resource outages.

2. GENERATOR OWNERS'/OPERATORS' AND NATURAL GAS FACILITIES' WINTER SEASON PREPAREDNESS

a. Generation Resources' Seasonal Preparations

GOs/GOPs indicated that over 90 percent of generators that experienced an outage, derate, or failure to start had a cold weather preparedness plan in effect during the Event, and the same percentage used a pre-winter generating unit maintenance checklist in the fall. See section III for additional information on GOs/GOPs' cold weather preparation.

b. Natural Gas Infrastructure/Facilities' Seasonal Preparations

Natural gas infrastructure facilities took a variety of actions to prepare for winter.[114] Production facilities inspected and made repairs as necessary to insure functionality of heat trace and other heating systems, if applicable. They ordered and stocked essential winter supplies such as cinders for roads (used to access wellheads during icy road conditions), and portable generators. Some buried flowlines[115] to protect them from freezing, and/or added burners to increase temperatures on gas processing units. Natural gas processing entities purchased supplies such as tarps, batteries, spare parts, and mobile heaters, and performed maintenance such as repairing insulation on pipes and checking mobile heaters to ensure they were in good working order.

Pipeline operators implemented their winter operations programs which included performing preventive maintenance on compressor stations and at receipt and delivery points, testing all emergency equipment, servicing backup power supply sources, and performing any necessary equipment overhauls, among other tasks.

112 nterface transfer l m ts are the MW flow l m tat on across a transm ss on nterface to protect the system from large voltage drops or collapse caused by any v able cont ngency.

113 Reproduced w th perm ss on of PJM and © PJM.

114 The Team nstructed all natural gas ent t es that t asked for data to prov de data for the follow ng states, f appl cable: New York, Delaware, Kentucky, Maryland, New Jersey, North Carol na, South Carol na, Oh o, Pennsylvan a, Tennessee, V rg n a, West V rg n a, D str ct of Columb a, Georg a, Alabama, M ss ss pp , Lou s ana, Arkansas, M ssour , owa, ll no s, M nnesota, W scons n, M ch gan, nd ana.

115 Flowl ne s the flow connect on from the wellhead to the separat on fac l ty, p pel ne or storage un t. *See* P p ng and p pel ne systems PetroW k (spe.org).

III. CHRONOLOGY OF EVENTS

A.Preparations in Advance of the Winter Storm

1. WEATHER FORECASTS PREDICTED SEVERE COLD FOR DECEMBER 23-24 AS EARLY AS DECEMBER 14

Similar to Winter Storm Uri, and past major winter storms, the storm that came to be called Winter Storm Elliott[116] was forecast many days in advance. On Wednesday, December 14, at 3 p.m., the National Weather Service issued its "US Hazards Outlook" covering the period that included December 22 to 25 and published its "8-14 Day Temperature Outlook" graphic, as shown in Figure 16, below, showing that large portions of the eastern U.S. were highly likely to experience below normal temperatures.[117]

In its outlook, the NWS predicted that "[a] negative Arctic Oscillation (AO) pattern forecast over North America later in December is expected to promote below normal temperatures" with "[h]igh risk of much below normal temperatures for much of the [contiguous U.S.] east of the Rockies excluding the Northeast, Thu[rsday through Sunday], Dec[ember] 22-25."[118]

SPP and MISO RCs. On the following day, December 15, SPP and MISO first identified the risk that the forecast extreme weather posed to their respective systems, with projected impacts beginning December 21-22.

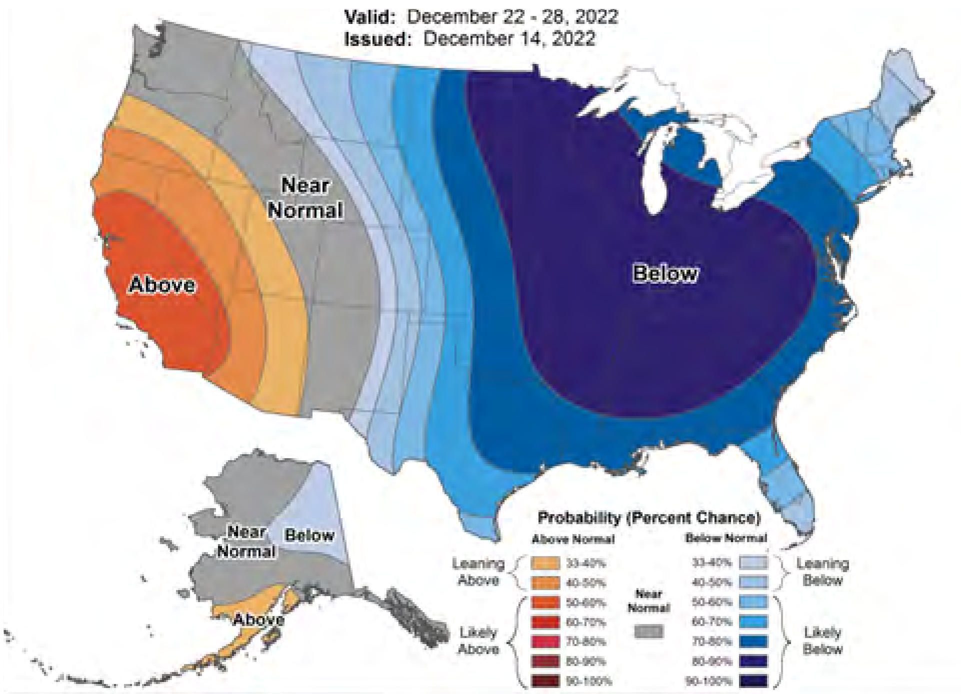
TVA, Southern, and VACAR-South RCs. On December 14, TVA recognized that a major arctic outbreak was likely for Christmas weekend (December 23 to 25), and on December 19, communicated that across its organization. On December 16, Southeastern RC recognized the threat posed by the forecast and discussed on Southeastern RC's daily RC calls from that day until December 25. It also began sharing forecast system conditions via Southeastern RC emails on December 16. Duke updated internal stakeholders on December 19 regarding its concern with the forecast winter conditions, which it expected to be a powerful cold front arriving on December 23, bringing falling temperatures and precipitation (mostly rain).

116 The Nat onal Weather Serv ce of the Nat onal Ocean c and Atmospher c Adm n strat on does not name w nter storms because, accord ng to ts then Deputy D rector of Publ c Affa rs, " w] nter storms are d verse w th cond t ons that evolve throughout the storm's l fe. That s why our (NWS) forecasts, watches and warn ngs focus on spec fic mpacts such as w nd cond t ons, snowfall, ce, temperature, v s b l ty, and other mpacts. W nter storm cond t ons can vary w dely and over a very large area, from commun ty to commun ty. t's cr t cal that people understand how a storm w ll mpact them, n the r area or where they are go ng." A pr vate company, The Weather Channel, began nam ng severe w nter storms n 2012 and those names have been recogn zed by some, but not all, med a sources. KSAT, for example, sa d that t would cont nue to follow the NWS and not recogn ze names for w nter storms. Sarah Sp vey, *Let's chat: Do winter storms really have names? The unofficial naming system has gained some popularity, but experts caution against the naming of winter storms*.,KSAT NEWS (Oct. 19, 2002) https://www.ksat.com/weather/2022/10/19/lets chat do w nter storms really have names/. n 2021 the Team d d not recogn ze the nam ng of W nter Storm Ur , but g ven the w despread use of the w nter storm names by med a d scuss ng both the 2021 and 2022 events, the Team used the names n the Report.

117 *See*, Mel ssa Ou, *National Weather Service Climate Prediction Center "U.S. Hazards Outlook"*,cpc.ncep.noaa.gov/products/arch ves/hazards/data/2022/KWNCPMDTHR.20221214, and "8 14 Day Temperature Outlook" graph c at 814temp.20221214.fcst.g f (3300×2550) (noaa.gov). *See* also examples of coverage n popular med a: Anna Sk nner, *Artic Blast to Bring Dangerous Below Zero Temperatures to These States*, Newsweek (Dec. 20, 2022), https://www.newsweek.com/arct c blast dangerous below zero temperatures these states 1768512; and Pandora Dewan, *Bomb Cyclone Photos: What to Expect From Freezing Weather Forecast*, Newsweek (Dec. 20, 2022), https://www.newsweek.com/bomb cyclone photos freez ng weather forecast 1768515#:~:text Ell ott%20 s%20expected%20to%20arr ve%20 n%20the%20Pac fic,the%20M dwest%20and%20parts%20of%20the%20East%20Coast.

118 Cont guous U.S. ncludes the 48 states south of Canada, nclud ng the D str ct of Columb a.

Figure 16: National Weather Service 8-14 Day Temperature Outlook – December 14, 2022



PJM. The storm was expected to move into PJM's footprint on December 23, bringing snowfall and high wind gusts combining to create blizzard conditions, and freezing rain in the central Appalachians with ice accumulation of 0.10 to 0.25 inches. On December19, PJM weather forecasting alerted PJM Dispatch via email of upcoming blizzard conditions and extreme cold.

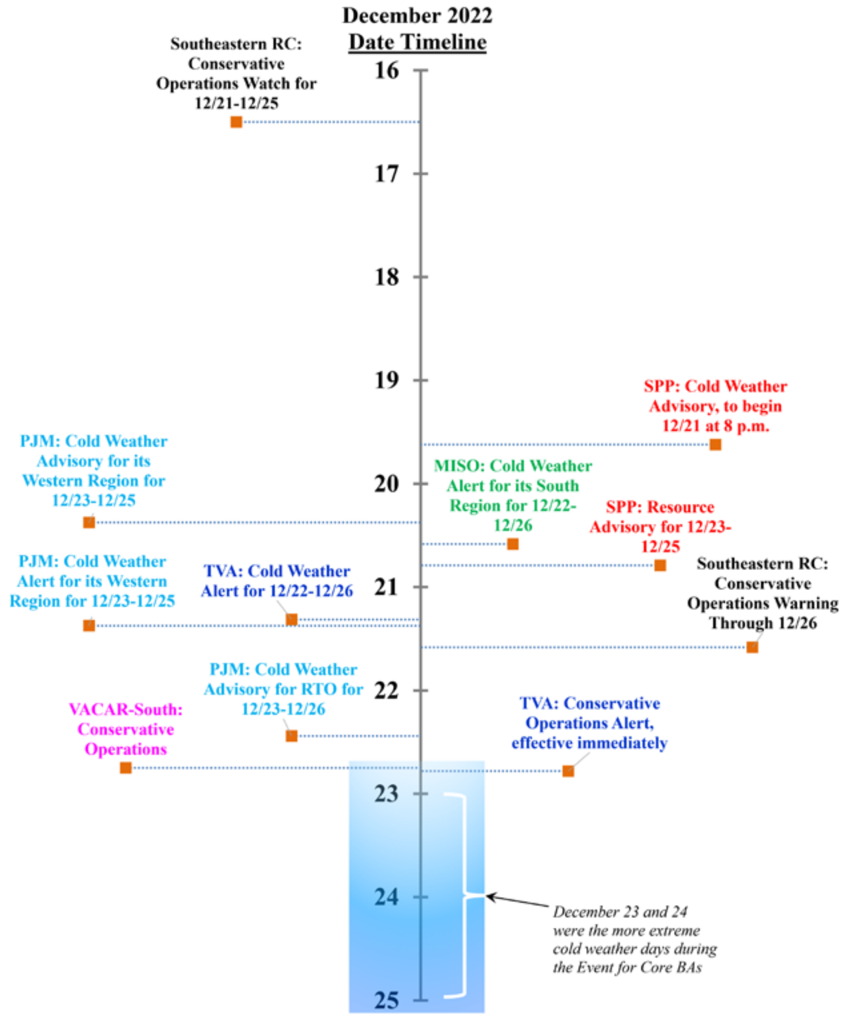
2. ALERTS ISSUED BY GRID ENTITIES AND EXPECTED PREPARATIONS FROM DECEMBER 16 THROUGH 22

All BAs and RCs have established emergency operating procedures (emergency procedures) as required by the Reliability Standards, particularly EOP-011-2, Emergency Preparedness and Operations.[119] Additionally, entities may have their own specific operating procedures that coordinate with or supplement the BA/RC emergency procedures. As part of their responsibilities under the emergency procedures, BAs and RCs issue cold weather advisories, alerts, and conservative operations notices, as necessary.[120] Each entity's emergency operating procedures document the actions that are required by the relevant TOs/TOPs and GOs/GOPs.

119 RSCompleteSet.pdf (nerc.com)

120 For purposes of th s d scuss on, the Report uses the terms "adv sor es," "alerts," and "conservat ve operat ons not ces" to encompass the range of not ces that BAs and RCs ssue as part of the r respect ve emergency operat ng procedures, https://www.nerc.com/pa/Stand/Rel ab l ty Standards Complete Set/RSCompleteSet.pdf. Each BA and RC uses spec fic defined terms for the r not ces. *See, e.g.,* PJM Manual 13: Emergency Operat ons (Aug. 24, 2023), https://www.p m.com/ /med a/documents/manuals/m13.ashx (nclud ng PJM's defined terms for ts alerts and not ces).

Figure 17: RC Watches, Advisories, Alerts and Warnings Issued From Friday, December 16 Through Thursday, December 22, 2022



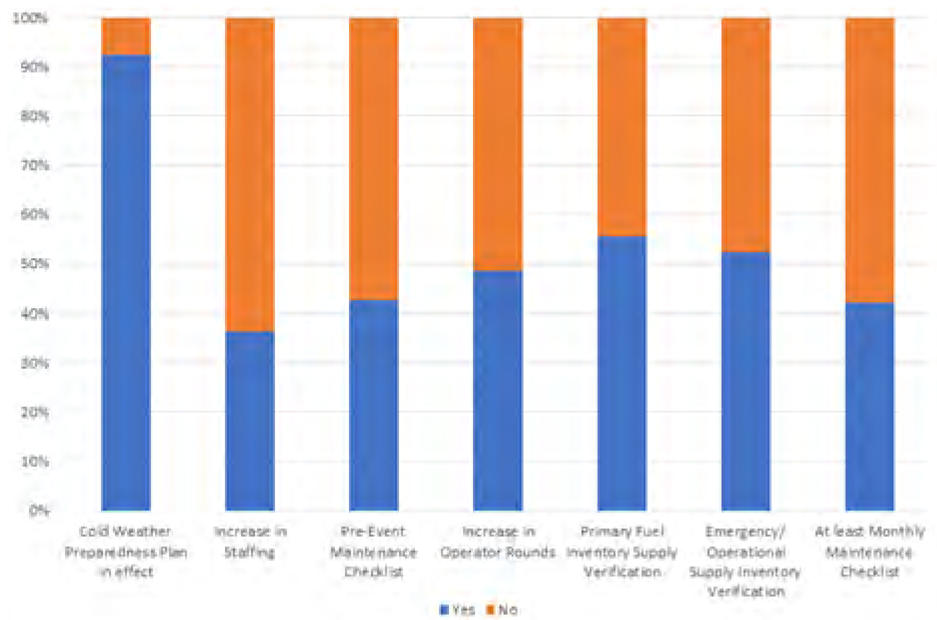
Before and during the Event, affected RCs issued cold weather advisories[121] and alerts,[122] as well as conservative operation declarations. Figure 17, above, summarizes the notices issued in advance of the more extreme cold weather days during the Event (including conservative operations declarations) from December 16 through December 22.

BAs issue the in-advance cold weather alerts and advisories to their stakeholders, including those BES

121 By way of example, PJM's cold weather adv sor es adv sed PJM members to prepare to (1) take freeze protect on measures; (2) rev ew weather forecasts, determ ne any forecast operat onal changes, and not fy PJM of any changes; and (3) update PJM w th operat on l m tat ons assoc ated w th cold weather preparedness (e.g., generator capab l ty and ava lab l ty, fuel supply and nventory concerns, fuel sw tch ng capab l t es, env ronmental constra nts, and generat ng un t m n mum temperatures).

122 Aga n, as an example, PJM's cold weather alerts stated that generat on d spatchers should: (1) rev ew fuel supply/del very schedules n ant c pat on of greater than normal operat on of un ts; (2) mon tor and report projected fuel l m tat ons to PJM d spatcher and update the un t Max Run field n PJM's Markets Gateway f less than 24 hours of run t me s rema n ng; and (3) contact PJM D spatch f t s ant c pated that spot market gas s unava lable, result ng n unava lab l ty of b d n generat on.

Figure 18: Cold Weather Event Preparation by GOs/GOPs with Outages/Derates/Failures to Start



GOs/GOPS within their footprints.[123] The GOs/GOPs are not required to respond to the alerts or verify that they completed their winter readiness steps (i.e., no confirmation to the BA that the generating unit is prepared for the forecast cold weather).

3. NEAR-TERM PREPARATIONS BY GENERATION OWNERS/OPERATORS

Under the currently effective Reliability Standards, GOs/GOPs are required to have cold weather preparedness plans that include inspection and maintenance of the generating unit's freeze protection measures.[124] A common method for implementing inspection and maintenance of freeze protection measures is the use of inspection and maintenance checklists. Over 40 percent of the GOs/GOPs that experienced an outage, derate or failure to start during the Event performed monthly inspections using their checklists, with a subset of those inspecting weekly.Approximately 40 percent of those that have a pre-winter checklist (used to prepare for the season) implement a "pre-event" checklist (which can be used to confirm that nothing has degraded, and that no new maintenance issues have arisen, since the pre-winter checklist was completed).[125] Sixty percent do not perform pre-event inspection or maintenance checklists, which suggests room for improvement. Figure 18, above, illustrates the responses provided by GOs/GOPs that had at least one generating unit that incurred an outage, derate, or failure to start during the Event, when asked whether they performed various near-term preparations. Other areas of cold weather preparedness that could benefit from improved effort include the actions that had 50 percent or less adoption rates in Figure 18, such as providing additional staffing (during an event), increasing operator rounds, verifying inventory of primary fuel and emergency supplies, and using a monthly maintenance checklist.

123 The Report d scusses not ces ssued after December 22 dur ng the Event n Sect on .B.3., below.

124 Rel ab l ty Standard EOP 011 2, Requ rement R7.2. RSCompleteSet.pdf (nerc.com).

125 For example, outages have resulted from nsulat on be ng moved away from p pes to perform work and not be ng properly replaced before the onset of freez ng temperatures.

4. NEAR-TERM PREPARATIONS BY NATURAL GAS INFRASTRUCTURE ENTITIES

As the storm approached, natural gas infrastructure facilities supplemented their seasonal prparations. Some entities took steps to determine that readiness had not declined since the pre-winter preparations, along with implementing short-term measures to be taken shortly before a major storm.

Production. Producers stationed additional field personnel and supplied them with resources to prevent and manage freeze offs by ensuring functionality of heat trace and other heating systems, by injecting methanol, and by increasing flow rates.[126] They pre-arranged for removal of snow and ice from roads to ensure safe access to sites and facilities, along with prepping the roads with cinders in advance of cold weather conditions. Producers also pre-staged materials such as water tanks and portable backup generation where they would most likely be needed. Some producers used tarps and deployed shelters (which could hold heaters, if necessary) to protect equipment prone to freezing. They lowered levels in or emptied water, condensate, and oil tank levels at facilities to which access was expected to become difficult. Most conservatively, two producers anticipated production declines and proactively reduced the amount of natural gas that they marketed in the short term.

Processing. Processing companies increased personnel on duty to respond to plant issues and equipment failures, ensured adequate supplies of methanol, stocked critical spare parts (tarps, batteries, etc.), performed any last-minute maintenance (e.g., repair insulation), and coordinated with producer customers and purchasers of the residue gas produced by the plant. Finally, to the extent that they relied upon some form of an alternative power source (e.g. on-site backup generators), they serviced the power source to ensure operation during the Event.

Pipelines. Pipelines in the path of Winter Storm Elliott began to monitor the weather forecast as the storm began to form, while also implementing cold weather plans and holding internal meetings.[127] These meetings focused on estimated load forecasts, storage strategies, maintenance activities, and line pack management strategies. Due to anticipated operational challenges, some pipelines staffed key compressor stations that ordinarily are not staffed but are essential during peak demand for system reliability. Some tested emergency equipment in advance of the Event.

All pipelines proactively managed and monitored line pack and system integrity. Some pipelines issued critical notices in advance of the storm, ranging from weather advisories to OFOs. Each pipeline increased line pack in anticipation of high demand, supply loss, and potential equipment problems. Most also prepared storage facilities to allow them to withdraw natural gas – including liquid natural gas – to meet customer requests and respond to anticipated increased demand.

5. SHORT-TERM LOAD FORECASTS BY GRID ENTITIES

Accurate short-term load forecasts (that is, the load forecasts BAs performed just days in advance or during the Event, with knowledge of the forecast extreme cold weather) assist with committing and scheduling resources. Many of the BAs normally aim to keep their load forecast error near or below three percent. For example, PJM's daily peak forecast error only exceeded its target load forecast error of up to three percent on a single day between December 1 and December 23, 2022.

126 The Gas Technology nst tute completed a report as part of the nqu ry nto the 2011 Southwest cold weather event, wh ch deta led techn ques for prevent ng freez ng of natural gas product on. L. Brun H lbert et al., *Natural Gas Production in Extreme Weather*, P pel ne & Gas Journal, (June 2021), https://www.pg onl ne.com/magaz ne/2021/ une 2021 vol 248 no 6/guest commentary/natural gas product on n extreme weather. Other methods ncluded water removal us ng glycol dehydrat on and heat ng methods such as catalyt c heaters, fuel l ne heaters and steam systems.

127 One p pel ne held a November 2022 meet ng w th ts customers regard ng cold weather preparedness. Although th s act on was an outl er, t was an effect ve pract ce and the Team encourages all p pel nes to cons der hold ng s m lar meet ngs n the future.

Although BAs projected higher electricity demands for the impending winter storm, most core BA significantly underestimated the peak loads in advance of December 23 and 24, the most extreme cold weather days of the Event. Figures 19 and 20 below, show the Core BAs' four-, three-, two- and day-ahead forecasts versus actual peak loads for December 23 and 24, respectively. Figure 21, below, shows their Mean Absolute Percentage Error (MAPE) across the four-, three-, two-, and day-ahead peak load forecasts for December 23 and 24.

Figure 19: BAs' Four-, Three-, Two-, and Day-Ahead Peak Load Forecasts vs. Actual[128] Peak Loads (Percent Difference) For December 23, 2022

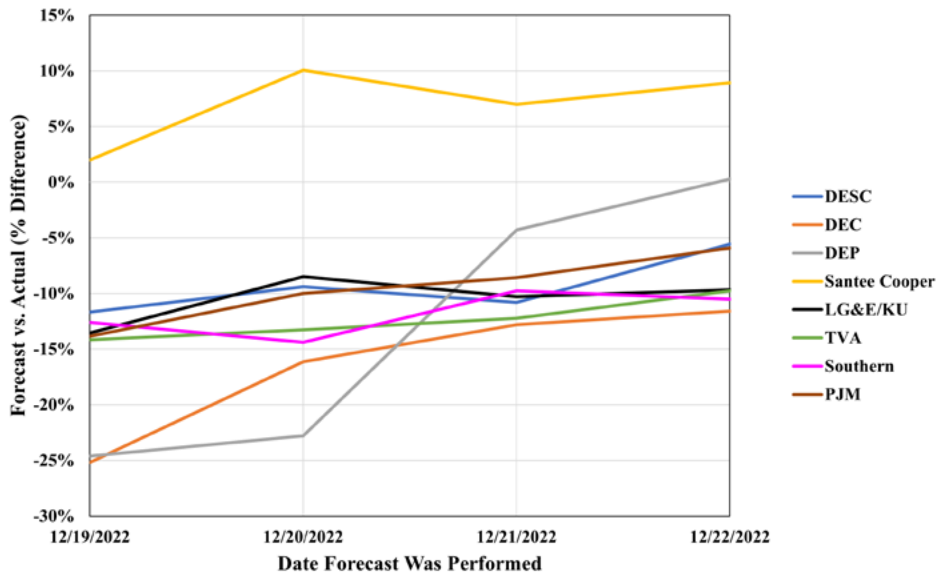
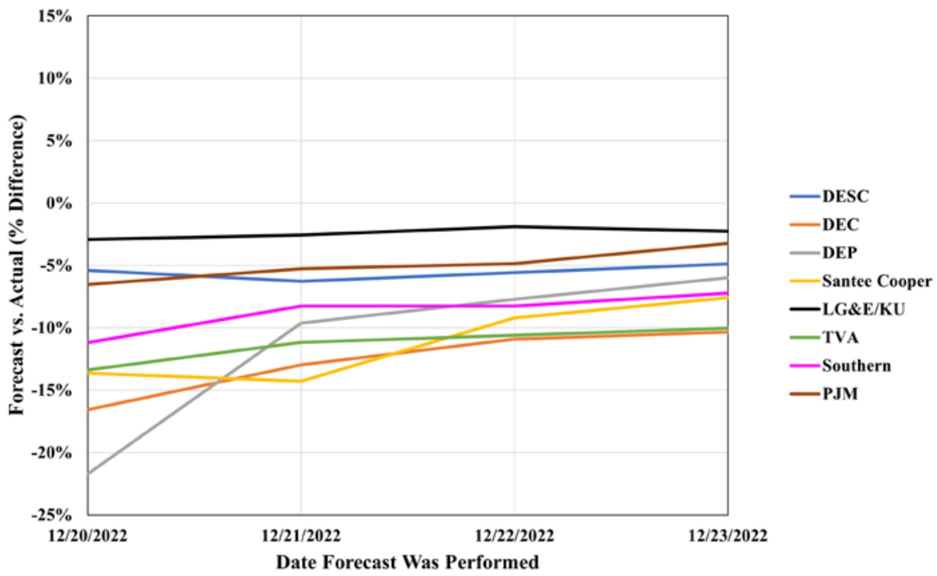
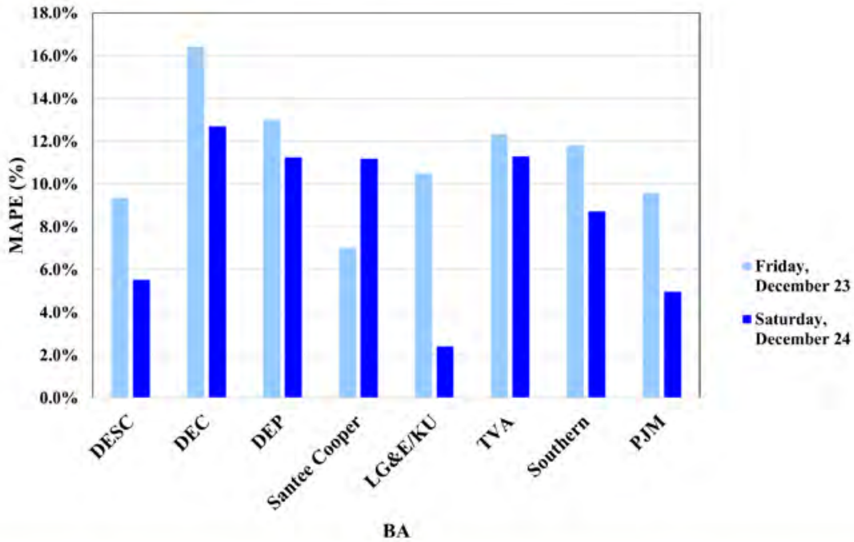


Figure 20: BAs' Four-, Three-, Two-, and Day-Ahead Peak Load Forecasts vs. Actual Peak Loads (Percent Difference) For December 24, 2022



128 For F gures 19, 20, and 21, for BAs that mplemented load management measures dur ng the r respect ve peak load t meframes, actual peak loads used for calculat ons are based on BAs' est mated peak loads w thout load management.

Figure 21: Mean Absolute Percentage Error (MAPE) For BAs' Four-, Three-, Two-, and Day-Ahead Peak Load Forecasts for December 23 and 24, 2022



All of the BAs use weather data as inputs into their short-term forecasts. Most use only three years of data to train their models, which can be problematic if the conditions experienced have no similar day within the past three years. Some BAs have their own meteorologists, while others use only external vendors for weather forecasts. Two BAs automatically add buffers (MW or percentage of load forecast) to account for potential load forecast error. Some have a single system-wide forecast, while others split their forecast to reflect differences in the makeup of their load (e.g., mountains vs. beaches).

Figure 22, below, summarizes how each BA approaches these short-term load forecasts.

Figure 22: Summary of BAs' Short-Term Load Forecast Processes

	Weather Forecast Data	Short-Term Load Forecast Model
DEC, DEP	nternal meteorology team produces forecast.	Uses models developed by three external vendors and projects load based on evaluat on of the r outcomes. Usually p cks h ghest for extreme cold weather day, or looks for h stor cal day to match. DEP prepares east and west (Ashev lle only) forecasts.
DESC	Obta ns weather data from th rd party vendors.	Based on weather forecast model and load model nputs, uses comb nat on of external vendors and one nternal model for develop ng load forecast. ncorporates solar nputs, and any manual adjustments deemed necessary to account for lack of s m lar days to produce a seven day hourly load forecast.
LG&E/KU	External weather nformat on prov ders, vendors.	Short term load forecast s an aggregate of the load forecasts prov ded by the LSEs n the LG&E/KU BA area. n week ahead/next day stud es use a five percent buffer.
PJM	Three external weather nformat on vendors, uses we ghted average based on recent performance.	nternal team manages su te of neural network and pattern match ng models w th final short term load forecast based on staff evaluat on. Benchmarks day ahead forecast aga nst actual for track ng of forecast error.

	Weather Forecast Data	Short-Term Load Forecast Model
Santee Cooper	External weather nformat on prov ders, vendors	Pr mary short term load forecast s prov ded by an external vendor and evaluated aga nst alternat ve forecast prov ded by another vendor. Uses 100 MW (approx mately 1.8 percent of w nter season peak) adder for load forecast error.
Southern	External weather nformat on prov ders, vendors	Next 10 days' hourly weather forecasts are prov ded by external vendors, w th mult ple c t es' peak load we ghted for nput to load forecast ng models, wh ch are neural network based. Southern has large number of models produc ng load forecasts, nclud ng a vendor suppl ed forecast that uses d str but on level metered load data as nputs, wh ch has proven to be the most accurate of the r vendors' forecasts over the past two years for the 1 5 day ahead load forecasts.
TVA	Two external weather nformat on vendors feed nto ts load forecast software.	nternal blend of three load forecast models from vendors, based on three year h story, nformed by weather data and weather forecast. f no s m lar event n the three year h story, look for s m lar events n more d stant past to adjust/extrapolate the load forecast.

6. GRID ENTITIES' OPERATIONAL PLANNING ACTIONS TO PREPARE FOR EVENT

Given the higher electricity demands forecast for the upcoming Winter Storm Elliott, BAs arranged for resources to meet those demands, including attempting to return resources to service that were offline before the storm (e.g., for periodic maintenance). Planned generator outages are typically scheduled months or even years in advance, to perform necessary maintenance, or in the case of nuclear power plants, refueling. BAs in organized markets can ask GOs/GOPs to reschedule their planned generation outages for system reliability, but they cannot require the GOs/GOPs to do so.

a. Generation Returned to Service Prior to Most Severe Event Conditions

Forced outages and derates for the Event Area remained relatively constant (41,607 MW on December 21 versus 42,856 MW on December 23) before the worst part of Winter Storm Elliott began to impact the Event Area.[129] Figure 23 shows the planned and unplanned generation outages and derates within the Event Area from the start of December 21 to the start of December 23.[130] Overall, some BAs had more success than others in returning to service generation that was on outage before the worst period of the Event. For example, Santee Cooper's system operations coordinated with a gas generator in the week preceding the storm to return the unit to service following an unplanned outage due to a pump failure. The pump was repaired on December 21, restoring 28 MW of generating capacity. LG&E/KU was able to return to service nearly all of its generation that was on planned outages before the Event. A total of 8,501 MW of planned outages were returned to service within the BA footprints listed in Figure 23 before the worst part of Winter Storm Elliott began to impact the Event Area. Beyond December 23, GOs continued efforts to return prior-outaged generation to service where feasible, which offset the total unavailable generation during the Event.

129 Forced outages often occur due to equ pment fa lure or freez ng and when and f a un t can be t mely returned to serv ce s unpred ctable.

130 The start of December 23 (w th the except on of the SPP, wh ch was mpacted w th ncreased unplanned generat on outages dur ng the Event beg nn ng December 22) was pr or to the most severe drops n temperature. Accord ngly, SPP s not ncluded n F gure 23 to prov de a more un form compar son.

Figure 23: Planned and Unplanned Generation Outages in BA Footprints, at the Start of December 21, and December 23, 2022 (Prior to the Most Severe Drops in Temperature)

BA	Planned at the start of :		Unplanned at the start of:		Total Unava lable, at the start of:		21st 23rd Decrease n Generat on Out of Serv ce
	Dec. 21 (MW)	Dec. 23 (MW)	Dec 21 (MW)	Dec. 23 (MW)	Dec. 21 (MW)	Dec. 23 (MW)	(MW)
DEC	391	391	1,662	1,820	2,053	2,211	158
DEP	983	1,811	507	841	1,490	2,652	1,152
DESC	7	7	350	133	357	140	217
LG&E/KU	704	10	138	631	842	641	201
MISO	12,610	11,178	20,824	20,004	33,434	31,182	2,252
NYISO	3,161	2,085	2,414	3,119	5,575	5,204	371
PJM	9,586	6,253	12,582	12,787	22,168	19,040	3,128
Santee Cooper	570	570	400	110	1,540	1,250	290
Southern	3,022	2,486	758	913	3,780	3,399	381
TVA	3,153	895	1,972	2,498	5,125	3,393	1,732
TOTAL	34,187	25,686	41,607	42,856	75,794	68,542	7,252

b.Generation Committed Early for Reliability

In general, all BAs within the Core Event Area thought in advance of the Event that they individually had sufficient resources to meet their respective forecast electricity demands expected during Winter Storm Elliott. The BAs did not discount the possibility of some level of unplanned generation outages as a result of the storm, but those with smaller reserve margins thought they could purchase (i.e., import) power from external sources, or rely on bringing online quick-start/short-lead-time generating units to meet their peak electricity demands. TVA committed all available generation seven days prior to the Event and told the GOP when they would need the generation to be online. Santee Cooper planned to staff two generating units for quick start-up that would otherwise have longer lead times. SPP made multiple long-lead-time generating unit commitments: (1) on December 21, for the next two days, (2) on December 22, for Christmas Eve, and (3) on December 23, for Christmas Day, to improve the likelihood of having the additional online capacity for those days, as well as committing short-lead-time natural gas-fired units so that they could procure sufficient natural gas before the holiday weekend.

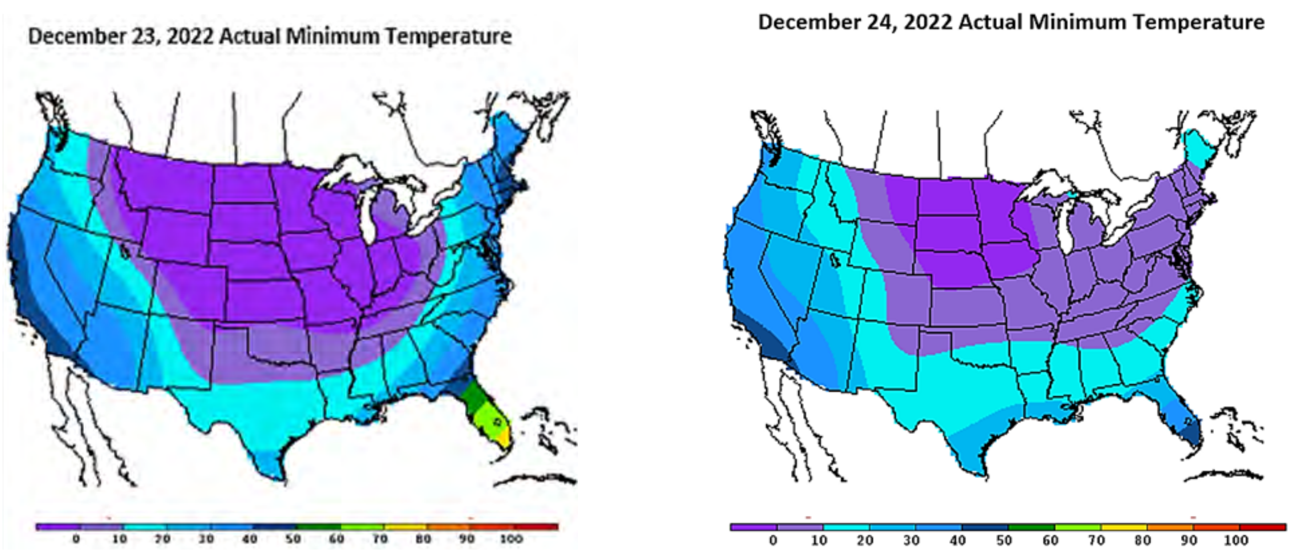
c. Transmission Facilities Returned to Service Before the Event

Some TOPs provided details on actions they took to return transmission facilities to service that had been on outage prior to the Event. TVA returned several transmission facilities to service before the Event, including one transmission line and two circuit breakers. Southern restored a transmission line that improved its ability to transfer power to and from Florida utilities, and additionally restored to service two other transmission lines, a circuit breaker, and two power transformers. PJM increased its transfer capability through coordination with its TOs which resulted in the return to service of two major transmission lines early on December 23. DEP and DEC indicated that they had no significant transmission outage plans or outages before or during the Event.

B. December 22 - 24: Extreme Cold Weather Conditions Lead to Widespread Generation Outages and Natural Gas Infrastructure Issues, Forcing Grid and Pipeline Operators to Make Difficult Decisions, Such as Shedding Firm Electric Load or Curtailing Firm Pipeline Customers

On December 22, the storm hit the Midwest, bringing snow, low temperatures and strong winds (with gusts up to 60 miles hour) and wind chill temperatures as low as -42 degrees. Although accumulation was minimal, the combination of snow and gusting winds caused blizzard conditions in some areas. The storm moved eastward and by December 23, Chattanooga, Tennessee had dropped from 49 degrees to 7 degrees. Similarly, Charleston, West Virginia dropped 42 degrees on December 23 (with wind gusts over 50 mph). The actual lows for December 23 for the Midwest and South Central U.S. were largely 20 degrees or below. From December 23 into 24 the extreme cold finally reached the east coast, and the actual lows for December 24, as shown on Figure 24, below, reflect that except for part of Florida, the lows were below 20 degrees. These temperatures were 15 to 30 degrees lower than normal low temperatures, with some elevated areas greater than 30 degrees lower (than normal low temperatures), as seen in Figure 25, further below.

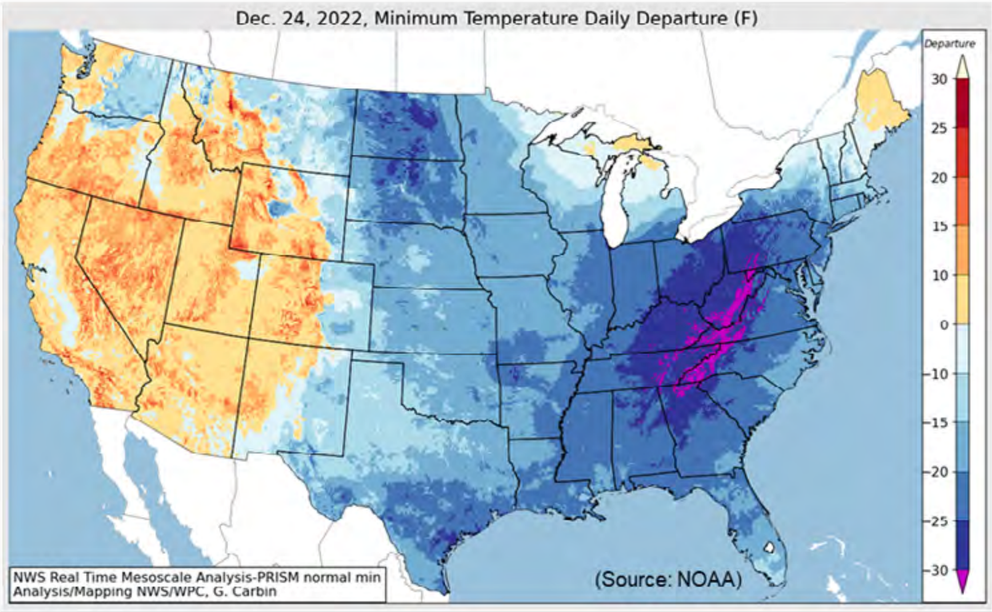
Figure 24: December 23 and 24, 2022 Actual Minimum Temperatures – Lower 48



1. UNPLANNED GENERATING UNIT OUTAGES RAPIDLY ESCALATE

All of the BAs went into the Event with some measure of generation unavailable, but during the afternoon and evening of December 22 unplanned generation outages began to rapidly escalate. In fact, of the more than 371,000 MW of generation that was lost due to forced outages, derates and failures to start during the entire Event—a period stretching from December 21 to December 26—more than 20 percent (74,000) of all generation losses would occur in the 12 hours between 6:00 a.m. and 6:00 p.m. on December 23.

Figure 25: Departures from Normal Minimum Low Temperatures, December 24, 2022



SPP (outages began afternoon of 12/22). SPP experienced "key generation losses in the eastern part of SPP's footprint"[131] beginning December 22 at around 3:40 p.m.[132] and continuing into the evening and early morning hours. By December 23 at 10 a.m., unplanned generation outages and derates in the SPP footprint escalated by 8,900 MW.

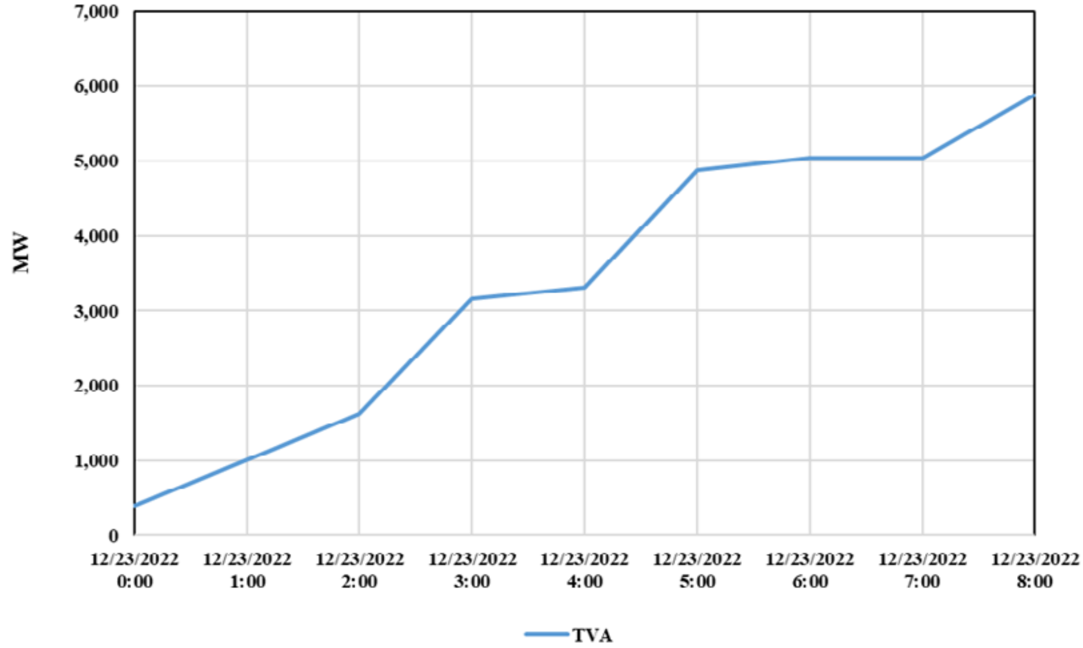
MISO (outages began early 12/23). In MISO, unplanned generation outages and derates began to escalate on December 23 and MISO BA operators were faced with over 6,000 MW of incremental unplanned generation outages; by 9:15 a.m., 2,000 MW of unit trips and failures to start in MISO South contributed to MISO BA operators implementing emergency measures.

TVA (outages began early 12/23). TVA unplanned generation outages began shortly before 1:00 a.m. on December 23. Outages and failures to start escalated sharply to a total of nearly 6,000 MW by 8 a.m. as shown in Figure 26, equivalent to nearly 20 percent of its peak load.

131 *See Review of SPP's Response to the Dec. 2022 Winter Storm* (Apr l 2023), at 10.

132 All t mes stated w th n the Report, unless otherw se spec fied, are n Eastern Standard T me, even f the ent ty s n the Central T me Zone (EST).

Figure 26: Incremental Unplanned Generation Outages in the TVA BA Footprint During Event, December 23, 12 a.m. to 8 a.m.

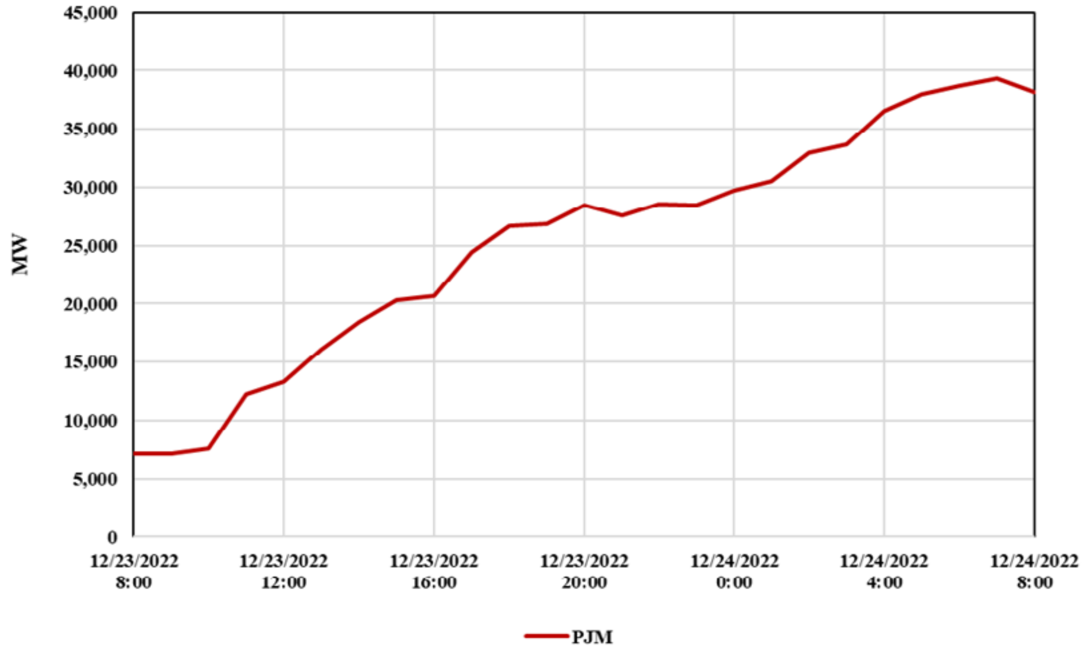


LG&E/KU (outages began early 12/23). Beginning at 1:28 a.m. on December 23, then throughout the morning and afternoon, generators experienced derates and outages due to cold weather and mechanical issues; at 1:08 p.m., significant power plant derates due to fuel issues (discussed further in subsection (a) below) led to an approximately 900 MW reduction, including one unit trip and six units that were derated to operate at minimum output for approximately 50 hours (until December 25, 4:00 p.m.); then from 3:39 p.m. to 6:44 p.m., an additional 500 MW of unplanned generation outages occurred.

PJM (outages began about 4 a.m. on 12/23). Unplanned outages and derates began to escalate shortly after 4 a.m. on December 23, then from about 8:00 a.m. to 5:00 p.m., rapidly escalated at a rate of over 2,200 MW per hour (for a total of approximately 20,000 MW); outages continued to escalate until December 24 at 8:00 a.m.[133] Over the 24-hour period, PJM sustained nearly 33,000 MW of unplanned generation outages and derates, as illustrated in Figure 27.

133 Th s outage data, l ke all other generat on outage data unless found on a graph c cred ted to an ent ty other than the Team, s based on the data the Team obta ned d rectly from the GOs/GOPs.

Figure 27: Incremental Unplanned Generation Outages in the PJM BA Footprint During Event, December 23, 8 a.m. to December 24, 8 a.m.



DEC and DEP (outages began late evening 12/23). In the DEC and DEP footprints, unplanned generation outages and derates began at about 11:30 p.m. on December 23, and by December 24 at 8 a.m., DEC and DEP had lost about 2,000 MW; outages continued into the early afternoon of December 24.

Southern (outages began midnight 12/23). From December 24, 12:00 a.m. to December 24, 2:00 a.m., Southern had approximately 500 MW of gas/oil generating unit capacity forced offline; then from 2:00 a.m. to 6:00 a.m., it had an additional 890 MW of gas/combined cycle generating capacity forced offline (1,390 MW total incremental unplanned outages from midnight to December 24, 6:00 a.m.).

DESC (outages began early 12/24). Six generating units, over 1,000 MW of generation total, sustained unplanned outages from December 24, 12:30 a.m. until about 9:10 a.m.

Santee Cooper (outages began early 12/24). Santee Cooper experienced over 500 MW of unplanned generation outages and derates beginning December 24 at 2:35 a.m. to 7:00 a.m. In addition, a boiler tube leak forced a 300 MW unit offline late December 23; it was unrelated to the weather but increased Santee Cooper's total unplanned generation outages to over 800 MW.

GOs reported to several BAs, including TVA and LG&E/KU, that many of the generating unit outages were due to Freezing Issues.

a. Rapid Emergence of Fuel Issues

Fuel Issues were a significant driver of the unplanned generation outages and derates early on December 23. Notably, within PJM, outages caused by Fuel Issues grew eight-fold between 6:00 a.m. and noon on December 23—and fifteen-fold between 6:00 a.m. and 6:00 p.m. that same day, outpacing the increase in outages due to Mechanical/Electrical Issues. By midnight on December 23, the total unplanned generation shortfall due to Fuel Issues exceeded the shortfall due to Freezing Issues, as seen in Figure 28, below.

Figure 28 Growth in Unplanned Generation Outages, Derates, and Failures to Start for Three Most Common Causes of Generation Outages in PJM, December 22 to 24

PJM	12/22/2022	12/23/2022				12/24/2022	
	Midnight	6:00am	Noon	6:00pm	Midnight	6:00am	Noon
Mechanical/Electrical Issues	5,746	6,448	7,497	10,927	12,458	16,909	16,130
Fuel Issues	576	597	5,062	9,014	11,133	13,283	12,709
Freezing Issues	1,966	2,625	5,436	10,770	10,379	12,979	12,928

Although the growth in Fuel-Issues-related generation loss was most acutely seen in PJM, virtually all of the BAs/RCs saw generation lost or derated due to Natural Gas Fuel Issues[134] on December 23 and 24. SPP, TVA, LG&E/KU, and VACAR-South RC all reported gaining awareness on December 23 or 24 that generating units were struggling to find adequate natural gas supply or that pipelines were struggling or unable to maintain adequate pressure at certain locations.

SPP. SPP began receiving system overrun limitation alerts for gas pipelines during the week of December 19. This was an early indication of potential fuel supply problems and SPP considered the alerts when evaluating forecasts of resource unavailability. Between December 22 and 25, SPP received communications from plant operators about fuel procurement issues through operator-to-operator communication and via plant operator outage entries made in SPP's generator outage management system.

MISO. Gas supply availability contributed to increased unplanned outages, particularly on the afternoon of December 23, that pushed MISO into emergency procedures. Generation in the MISO Region is connected to nearly three dozen interstate and intrastate pipelines, and the top five pipelines serve over 36 GW of gas generation in MISO. MISO became aware of gas availability issues when gas generators began communicating outages to MISO's generator outage management system, indicating an unavailable commitment status in their real-time offers, and/or phoning to inform the MISO Generation and Interchange operator of their expected outage submission due to gas unavailability. By the end of the day on December 23, MISO had experienced 23 GW of gas generation forced outages. Nearly 50 percent of gas generators reported outages to MISO that were due to Fuel Transportation/Supply Issues. Most of these were forced/emergency outages with little or no prior notice to MISO Operations. Such a significant volume of unplanned outages eroded MISO's reserve margin and contributed to MISO's declaration of emergency procedures on December 23. Increased fuel risk and associated uncertainty regarding gas generator availability on December 24 contributed to MISO operators committing additional generation.

TVA. GOs reported to TVA BA operators that some generating units were experiencing outages due to low natural gas fuel pressure. For example, on December 24, at 8:00 a.m., a 900 MW combustion turbine (CT) / combined cycle (CC) site was derated by 243 MW due to low natural gas delivery pressure issues. Further, on December 25, at 4:20 a.m., a 1,075 MW multi-CT/CC site was reduced by 978

134 As descr bed earl er n the Report, Natural Gas Fuel ssues nclude the comb ned effects of decreased natural gas product on; cold weather mpacts and mechan cal problems at product on, gather ng, process ng and p pel ne fac l t es result ng n gas qual ty ssues and low p pel ne pressure; supply and transportat on nterrupt ons; curta lments and fa lure to comply w th contractual obl gat ons. Add t onally, t ncludes sh ppers' nab l ty to procure natural gas due to t ght supply, proh b t ve, scarc ty nduced market pr ces, or m smatches between the t m ng of the natural gas and energy markets.

MW to minimum output (97 MW total), because of low gas delivery pressure issues.

LG&E/KU. On December 23, at 1:09 a.m., pipeline pressures for two natural gas-fired generating stations began to drop below the contract limits; and at 1:08 p.m., LG&E/KU experienced approximately 900 MW in generation losses (unit trip and six units derated) arising from low delivery pressures on a pipeline supplying these generating units.

DEC. On December 24, Transco pipeline notified DEC BA operators of low pressure issues and the potential timeline to recover pressure. The low pressure affected two natural gas-fired units, totaling 178 MW in unplanned generation derates.[135]

PJM. PJM had 186 generating units that failed to start. One-third of those were natural gas-fired CTs and CC units that reported to PJM that they did not have fuel or were fuel-limited.

135 Derates occurred after the DEC BA morn ng peak demand ended and d d not mpact DEC's ab l ty to meet ongo ng system demand, wh ch rema ned at lower levels throughout the rema nder of the hol day weekend.

Fuel Switching

As the 2021 Report noted, "[u]nits capable of fuel switching have both economic and reliability benefits: allowing operators to purchase the cheaper of two fuels and have an alternate source of fuel if one source is interrupted or curtailed." In the Event, about 259 generating units, representing 34,518 MW, were capable of a secondary fuel option. About 53 of those generating units, representing 15,405 MW, attempted to switch from their primary fuel to their secondary fuel. The majority, 88 percent, representing 12,567 MW, were initially successful in switching fuel types. Approximately twelve percent of the fuel-switching-capable units, representing 2,749 MW, either failed to switch or experienced outages related to their use of alternate fuels after switching, due to various mechanical problems. Causes for switching failures included low gas supply pressure, gas\fuel oil leak, fuel pump issues, fuel oil divider failure, feedwater pump breaker failure, isolator failure, combustor purge line failure, high exhaust spread temperature, and solenoid freezing.

Figure 29: Location of Fuel-Switching-Capable Units in the Event Area

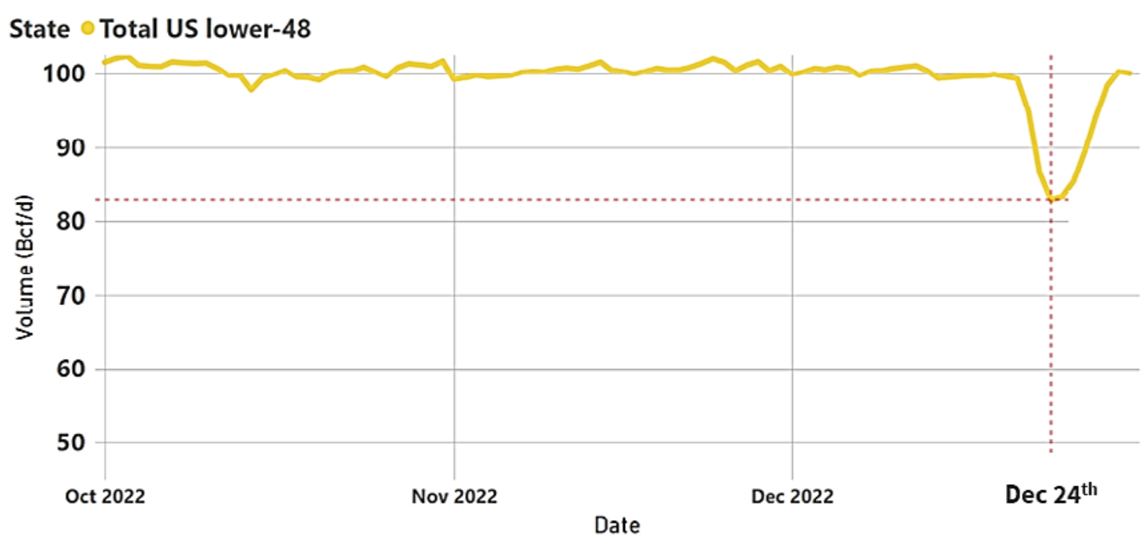
Of the generating units that successfully switched fuels, 73 percent, representing 11,767 MW, used gas as their primary fuel and oil\distillate oil as an alternate fuel. About 27 percent, representing 672 MW, used oil or distillate oil as their primary fuel and gas as an alternate fuel, and two units, representing 520 MW, used gas as their primary fuel and coal as an alternate fuel.

2. NATURAL GAS INFRASTRUCTURE OPERATING ISSUES RAPIDLY MOVE FROM PRODUCTION FACILITIES TO PIPELINES

a. Production declines begin

As Winter Storm Elliott moved across North America and temperatures decreased, dry natural gas[136] production in the lower 48 states declined. Production volumes on December 22 fell by 4,411 MMcf/day from the previous day and reached their largest daily decline between December 22 and December 23 – a difference of 8,368 MMcf/day. Dry natural gas production declined by 18 percent, falling to a low of 82.9 Bcf/day on December 24, 2022, as shown in Figure 30, below. Winter Storm Elliott primarily affected production in the Marcellus and Utica Shale formations. Together the Marcellus and Utica Shale formations create the Appalachian basin, which produced more gas in 2022 than any other area of the U.S., accounting for 29 percent of U.S. gross natural gas withdrawals (or 34.6 Bcf/d), according to EIA (see Figure 31, below). As shown in Figure 32 below, Marcellus Shale production volumes reached a low of 21,856 MMcf/d on December 24 (a 23 percent decrease compared to maximum production on December 19). Utica Shale production volumes reached a low of 3,017 MMcf/d on December 26 (a 54 percent decrease compared to maximum production on December 19).

Figure 30: Daily Dry Natural Gas Production (October - December 2022)[137]



136 “Dry natura gas” s produced by natura gas process ng fac t es that remove other hydrocarbons to produce what s known as “p pe ne qua ty” dry natura gas that meets the heat ng content and other restr ct ons necessary for the safe operat on of p pe ne and d str but on company fac t es.

137 S&P Global Commod ty ns ghts, ©2023 by S&P Global nc.

Figure 31: Monthly U.S. natural gas gross withdrawals by region (January 2012 - December 2022)

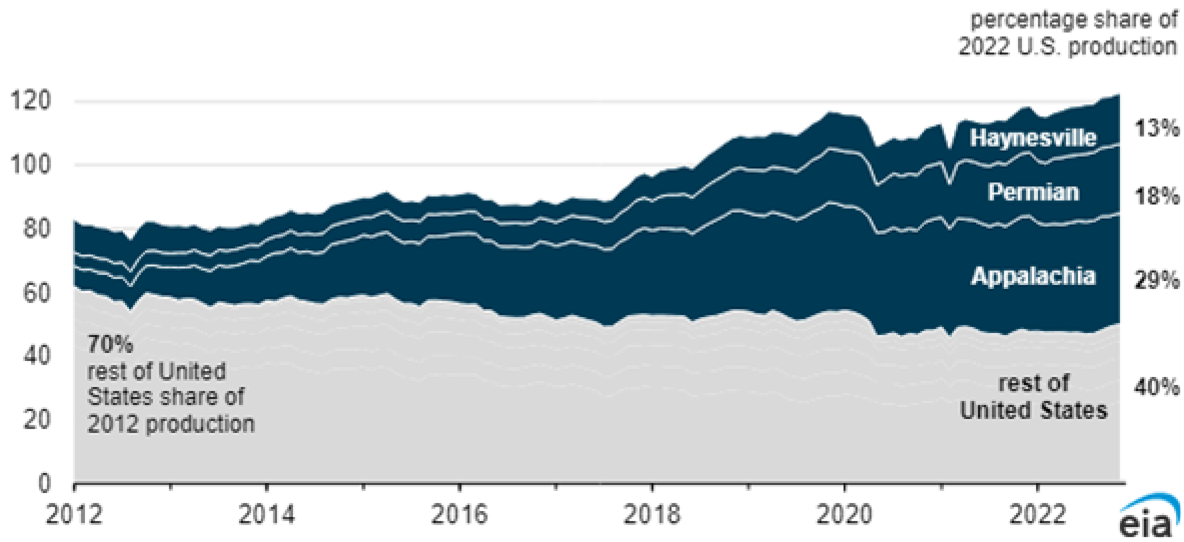
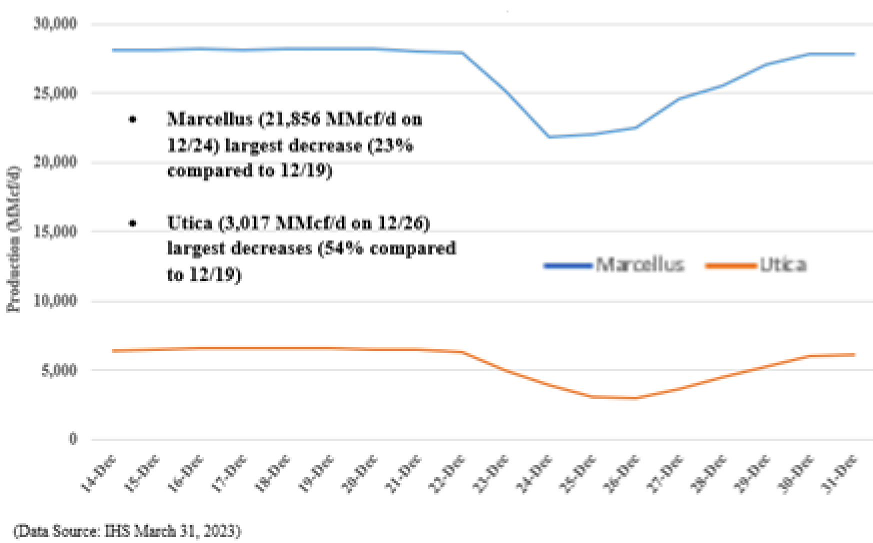


Figure 32: Natural Gas Production - Marcellus and Utica Shale Basins, December 14 – 31, 2022



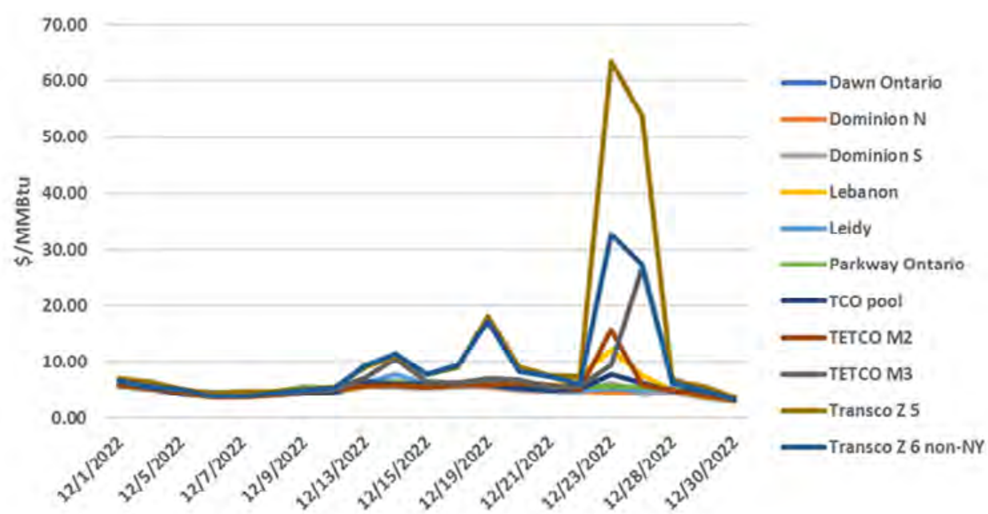
All but one natural gas producer identified freeze-offs as the primary cause of production declines, including frozen production equipment as well as wellhead freeze offs. Seven of the ten reporting producers identified downstream issues[138] as a significant driver of production declines. Downstream issues included outages in gathering systems, compressors, and processing plants, as well as one pipeline that could

138 Some producers also own and operate gather ng l nes/fac l t es, others del ver the r product on to gather ng systems owned by others. Thus the categor zat on of "downstream" may not be cons stent or l m ted to gather ng systems.

not take gas from certain producers,[139] which caused idling of producer equipment. The idling of producer equipment then exacerbated freezing of production equipment and caused further reductions in natural gas production. Poor road conditions, which prevented personnel and, in some cases, water hauling trucks, from reaching remote production sites were also identified as an issue, although not as commonly as during Winter Storm Uri.[140]

These natural gas losses from critical natural gas production areas, in conjunction with increased demand, caused prices to increase dramatically in natural gas markets. For example, natural gas prices for Transco Zone 5, which extends from the Georgia-South Carolina border to the Virginia-Maryland border, increased more than eight-fold for trading on December 23 as compared to December 21. See Figure 33, below. Higher price levels can have a cascading effect in the marketplace, as natural gas pipelines may calculate their OFO penalties by pricing the penalty as a multiple of the natural gas market price. As a result, a shipper that is out of balance on a pipeline may choose to pay higher market prices for natural gas to avoid paying penalties; this in turn produces higher penalties and adds to the incentive to buy ever more expensive natural gas.[141]

Figure 33: S&P Global Market Intelligence Day-Ahead Natural Gas Prices for Northeast Region – Non-NY/NE for December 2022[142]



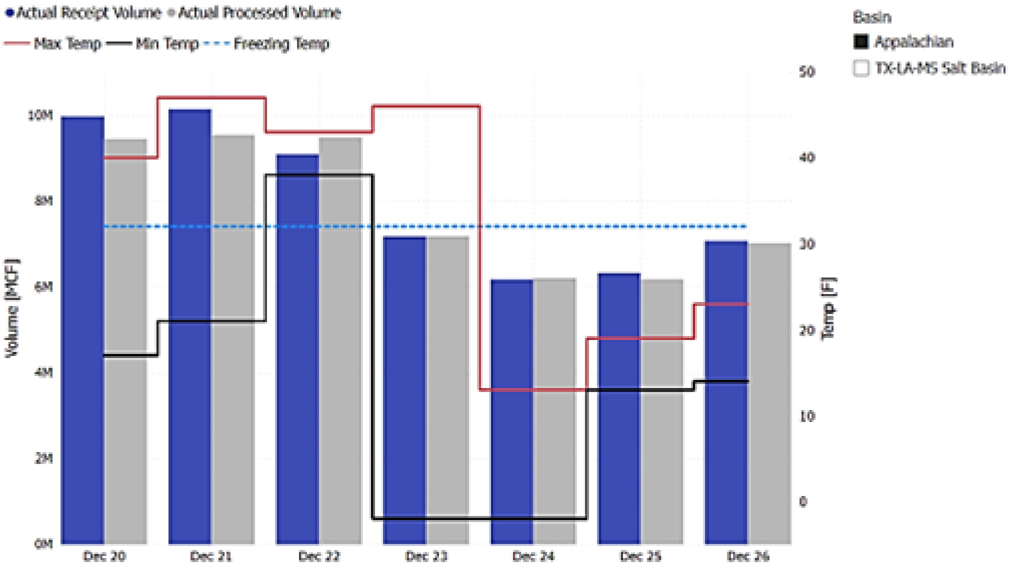
139 One p pel ne stated that lead ng up to and on the even ng of December 23, t started to pack ts l nes n preparat on for h gh demand on December 24. The h gh pressure temporar ly prevented producers from be ng able to move the r gas onto the p pel ne. The same p pel ne also had a lag n demand load the morn ng of December 24, caus ng pressures to rema n h gh, wh ch exposed producers further to freez ng vulnerab l t es as they could not move the r supply onto the p pel ne system at that t me.

140 *See* Analys s, sect on V.C.2., for more exam nat on of the causes of product on losses.

141 Natural gas traders have expla ned the exacerbat ng effect of potent al penalt es dur ng scarc ty events dur ng prev ous extreme cold weather events. The Team d d not nterv ew traders n the Event about th s ssue, although the same preex st ng cond t ons of scarc ty and cr t cal not ficat ons w th potent al for penalt es ex sted dur ng the Event as ex sted dur ng prev ous events.

142 Source: S&P Global Market ntell gence Cap tal Q Pro. © 2023 S&P Global Market ntell gence (and ts aff l ates, as appl cable) (nd v dually and collect vely, "S&P"). Reproduct on of any nformat on, data or mater al, nclud ng rat ngs ("Content") n any form s proh b ted except w th the pr or wr tten perm ss on of S&P. S&P does not guarantee the accuracy, adequacy, completeness, t mel ness or ava lab l ty of any Content and s not respons ble for any errors or om ss ons (negl gent or otherw se), regardless of the cause, or for the results obta ned from the use of such Content. n no event shall S&P be l able for any damages, costs, expenses, legal fees, or losses (nclud ng lost ncome or lost profit and opportun ty costs) n connect on w th any use of the Content.

Figure 34: Natural Gas Processing Facilities - Receipt Volume (December 20 – 26, 2022)



b. Processing and Pipeline Operating Issues

The extreme low temperatures beginning December 22-23 caused natural gas demand to increase at the same time that the volume of gas received by processing facilities declined, as illustrated in Figure 34.

Some processing companies said that they did not receive the full contracted amount of gas supply from producers, though they reported that they generally processed the gas they received.

On December 23 and 24, the strained operating conditions due to gas supply shortages experienced across the pipeline network were further exacerbated by equipment issues faced on certain pipelines. Natural gas pipeline facilities experienced 19 equipment issues which directly affected shippers, such as GOs/GOPs and local gas distribution companies. The largest reported cause of pipeline equipment issues was weather/freezing issues, followed by mechanical issues. The cold temperatures caused valves and compressor units at varying locations along the pipeline system to freeze, reducing or preventing the flow of gas through these facilities (see Figure 35, below). These issues caused instances of reduced natural gas pressure and 14 declarations of force majeure on certain pipelines which directly affected shippers (see Figure 36, below). Pipeline operators issued force majeures (which curtailed firm and interruptible gas transportation) to inform shippers that an event outside of their ability to reasonably foresee would affect all or a portion of the gas scheduled to flow through a segment of the pipeline system. Two pipelines issued a total of seven force majeures which affected a total of 156 firm shippers due to freezing issues, mechanical issues and reduced supply at seven compressor stations.

Eight of the fifteen interstate pipelines surveyed by the Team reported a total of 53 instances of commercial power loss at their facilities, totaling 466.5 hours during the Event. The outages averaged approximately nine hours in duration, although some lasted longer than three days.[143]

143 *See* sect on V.C.4 for add t onal analys s.

Figure 35: Number of Pipeline-Reported Equipment Issues with Some Associated Flow Reduction

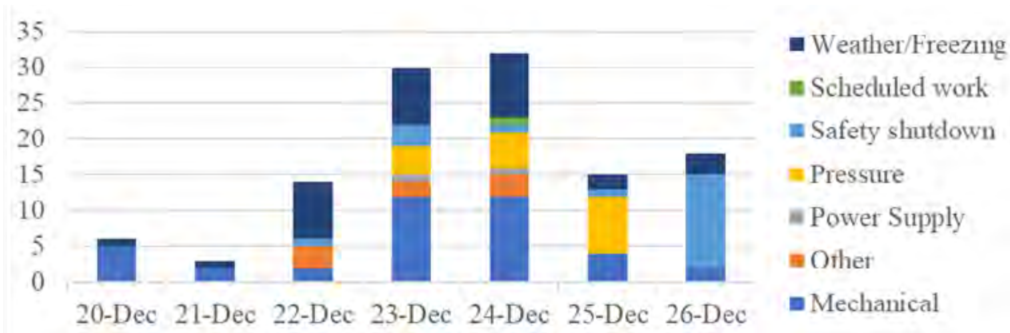
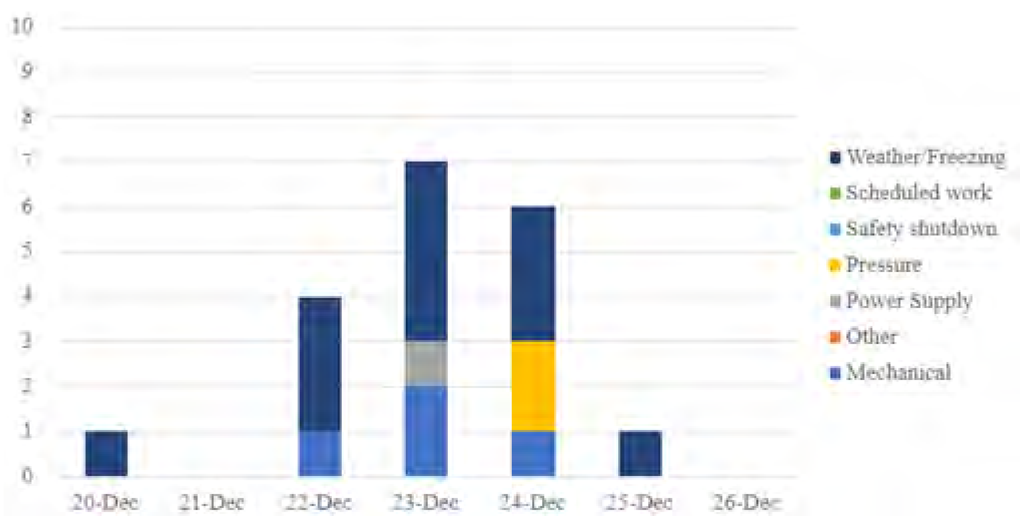


Figure 36: Number of Pipeline-Reported Equipment Issues Directly Affecting Shippers



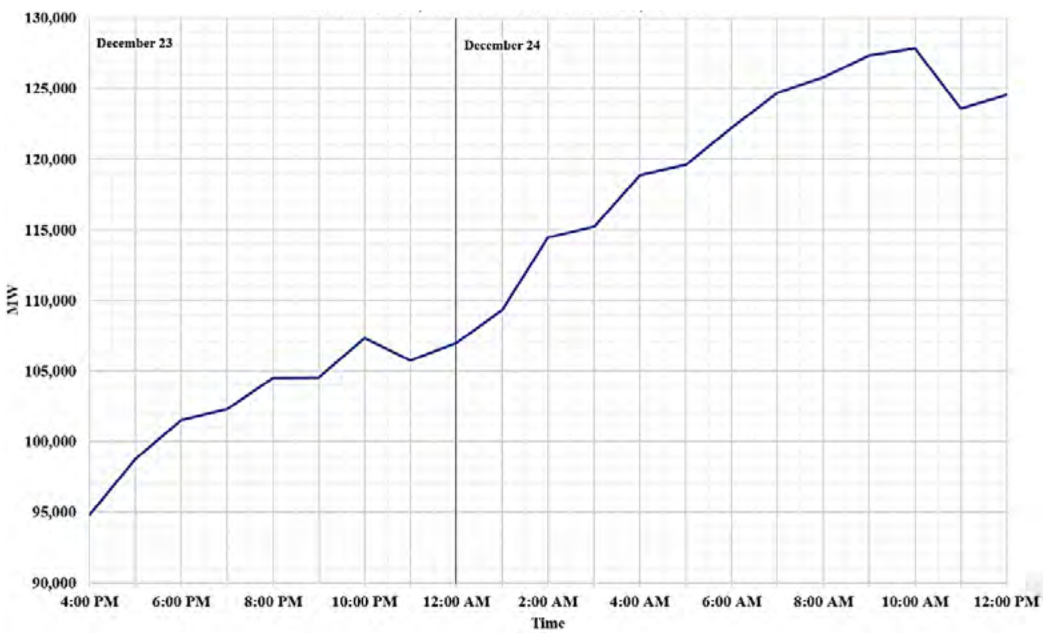
3. GRID OPERATORS' REAL-TIME ACTIONS AND COORDINATION DUE TO UNPLANNED GENERATION OUTAGES AND HIGH ELECTRICITY DEMANDS TO MAINTAIN BES RELIABILITY ACROSS A WIDE AREA

The breadth and scope of generation loss resulting from Winter Storm Elliott created unique and challenging conditions for grid operators. Figure 37, below, shows the total generation outages and derates impacting the Event Area during the most difficult period for the grid, the evening of December 23 and the morning of December 24. The graph includes both planned and unplanned generating unit outages; those existing at the beginning of the Event and those that occurred during the Event. Including generation that was already out of service,[144] a total of over 127,000 MW of generation was unavailable at the worst time, approximately 10 a.m. on December 24, which represented **18 percent** of the U.S. portion of the winter 2022-2023 anticipated resources in the Eastern Interconnection.[145]

144 Those un ts that were already out of serv ce ncluded generat ng un ts undergo ng planned ma ntenance outages and those un ts that ncurred forced outages before the Event, that had not yet returned to serv ce dur ng the worst po nt of the Event.

145 Based on data from NERC 2022 2023 W nter Rel ab l ty Assessment. *See* note 12. W thout the generat on that was already out of serv ce, the outages represented 13 percent of the U.S. port on of the w nter 2022 2023 ant c pated resources n the Eastern nterconnect on.

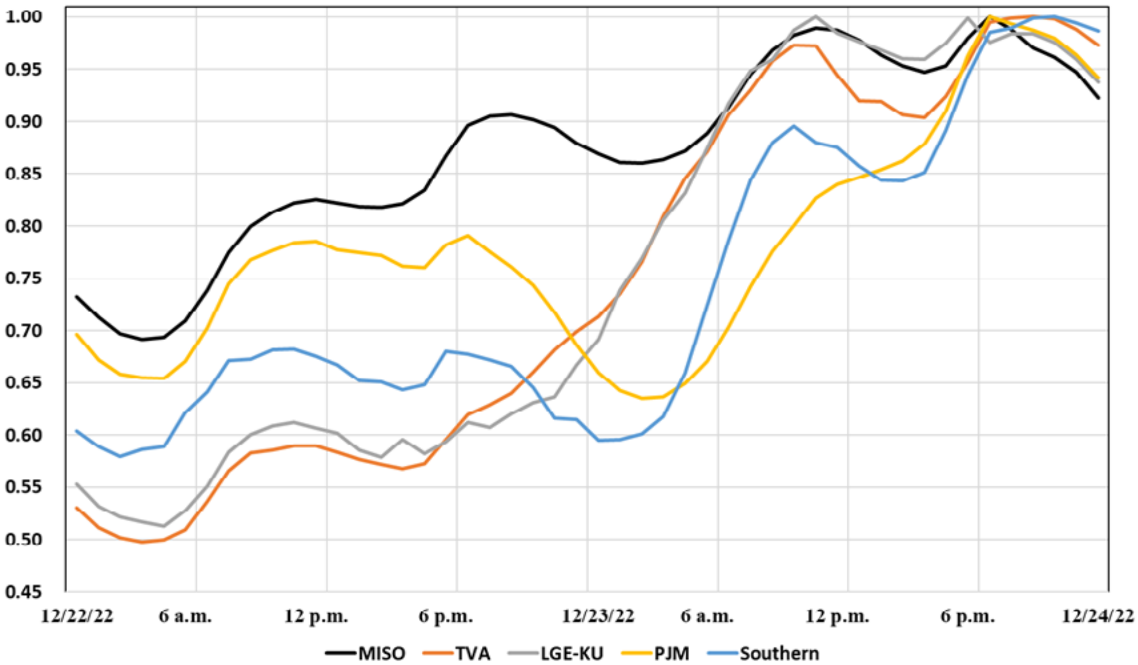
Figure 37: Total Estimated Unavailable Generation in U.S. Portion of Eastern Interconnection[146] – December 23, 4:00 p.m. to December 24, 12:00 p.m.



Due to the breadth and scope of generation loss during the Event, several BAs encountered the same set of circumstances during the day and into the evening on Friday, December 23: rapidly-increasing electricity demands due to the extreme cold weather and high levels of unplanned generation outages and derates. Figure 38, below, shows how dramatically BA electricity demands increased from Thursday morning, December 22, to Friday evening, December 23, and explains why BAs had little energy to share with other BAs experiencing EEAs. Other than Southern BA, which experienced its winter peak load the morning of December 24, the BAs shown *all* experienced their peak demands on the evening of December 23.

146 Total generat on shortfall s est mated, s nce t does not nclude potent al planned and unplanned generat on outages that may have ex sted for the Flor da pen nsula dur ng the t meframe, s nce analys s of that reg on was not ncluded n the targeted scope of the nqu ry.

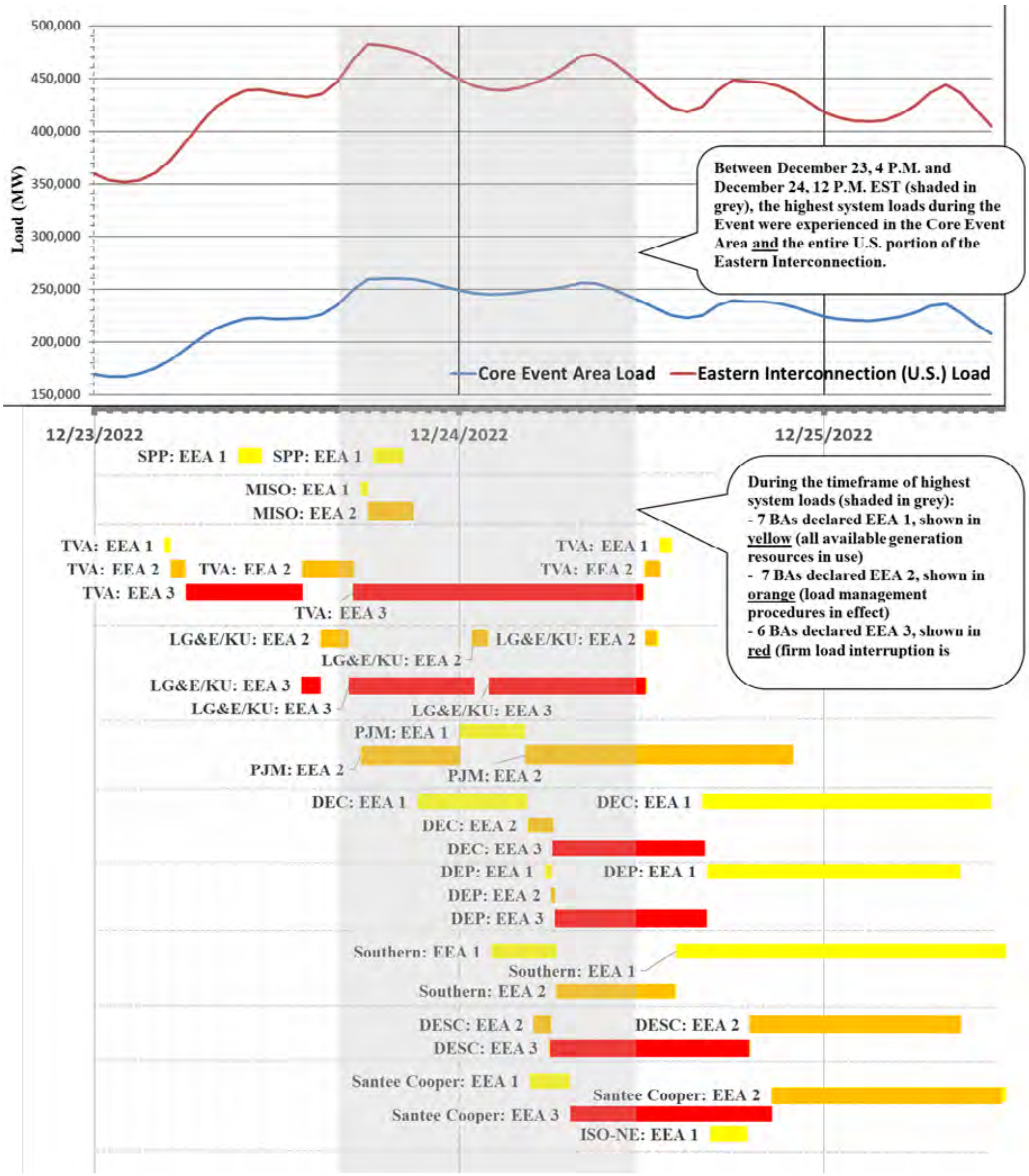
Figure 38: BA Normalized Hourly System Load Patterns for December 22-23, 2022 (Normalized to December 23 Peak Loads Experienced)[147]



As demand grew and supply shrank over December 23 and 24, electric grid entities took proactive measures to protect their footprints by declaring conservative operations actions. By the end of December 24, almost all the BAs impacted by Winter Storm Elliott were forced to implement EEA procedures. See Figure 39, below. The gray shaded area represents the timeframe of highest system loads in the Core BAs.

147 DEC, DEP, DESC and Santee Cooper BAs (not shown n the figure), wh ch are located further east, l kew se exper enced the r system peak loads on Saturday, December 24, and exper enced a s m lar pattern of ncreas ng load.

Figure 39: Core Event Area and Eastern Interconnection (U.S.) System Loads and Event Area Energy Emergencies Timeline – December 23 12:00 a.m. to December 25, 12:00 p.m.



The widespread and simultaneous energy emergency conditions greatly reduced the BAs' ability to obtain power from neighboring entities.

Note regarding "N-1"

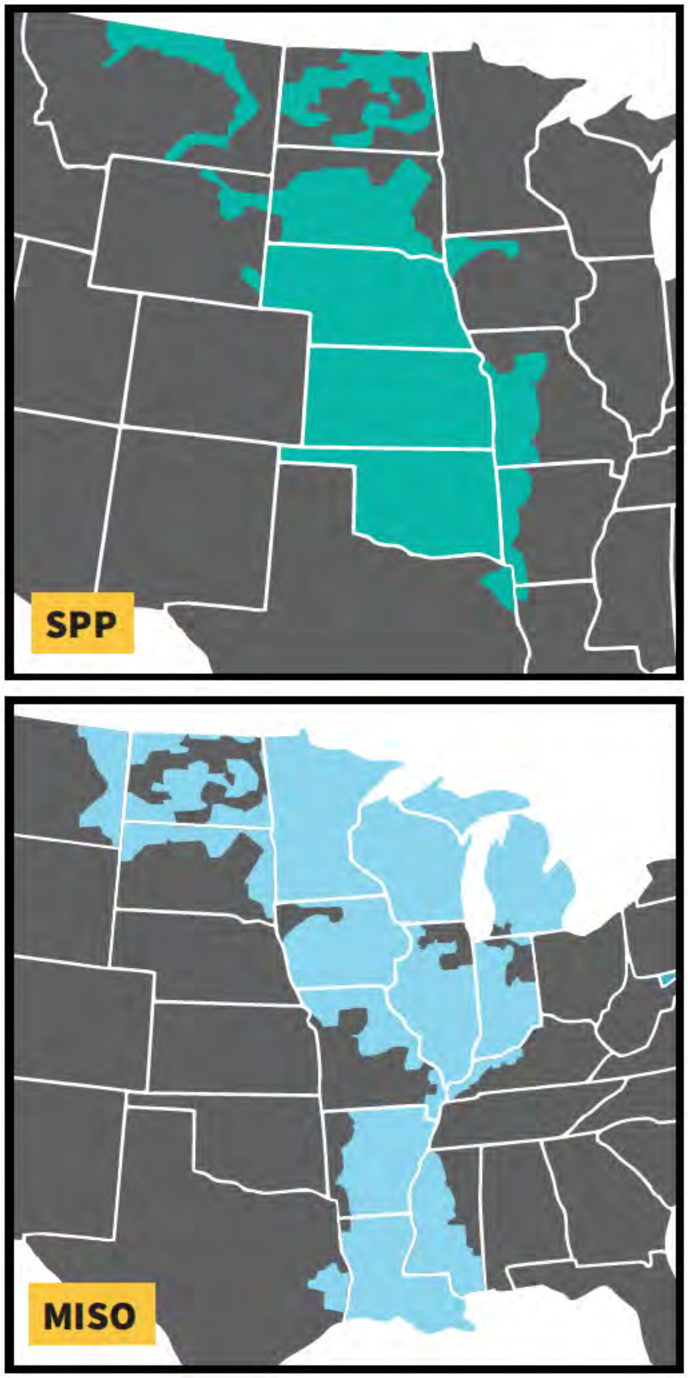
As described above in Section III, there were numerous coincident unplanned generator outages and derates. This meant the grid operators were operating a grid that was far from the N-1 planning c iteria (e.g., loss/outage of one generator) used to plan the transmission grid.[148] Instead they were experiencing an **N-"numerous"** condition[149] at any given time during the Event. The AC transmission system that comprises the BES relies heavily on online generation for reliable operation. Having sufficient online generators enables more effective congestion management, by facilitating AC power transfers while allowing transmission constraints to remain within system operating limits, as well as enabling system stability and the maintenance of normal thermal and voltage limits.

a. Thursday, December 22: Elliott begins to impact U.S. portion of Eastern Interconnection

- Winter Storm Elliott begins to impact westernmost part of U.S. Eastern Interconnection
- SPP and its TOPs first face operating challenges

SPP was the first BA in the U.S. portion of the Eastern Interconnection to experience Elliott's extreme cold and high winds, although its footprint did not incur more severe emergency conditions as others did in Elliott, or as SPP had experienced in Winter Storm Uri. SPP noted that the storm front moved more quickly than in 2021 and swept from northwest to southeast.[150]

Figure 40: SPP and MISO Footprints



148 For more nformat on on transm ss on system plann ng performance, *see* NERC Rel ab l ty Standards, Transm ss on Plann ng (TPL), TPL 001 5.1 Transm ss on System Plann ng Performance Requ rements. RSCompleteSet.pdf (nerc.com).

149 1,702 nd v dual generat ng un ts exper enced outages, derates, or fa lures to start for the ent re Event Area from December 21 to 26, 2022.

150 *See* SPP Report at 21.

SPP reported that it did not experience an increase in unplanned transmission outages. SPP largely escaped the heavy snow and freezing precipitation that most threatens transmission elements. However, its system operators were challenged with escalating unplanned generation outages and electricity demands on December 22, before grid operators to the east like PJM experienced the same conditions. In addition, a localized area on its transmission grid created operational challenges.

Between 1:00 and 7:00 p.m. on December 22, SPP experienced multiple unplanned generating unit outages totaling 1,400 MW in the eastern portion of SPP's footprint in a very short time frame between 1:00 p.m. and 7:00 p.m. As these unplanned generation outages were occurring, SPP was on its way to setting a record for winter seasonal electricity demand of 47,157 MW, which occurred at 6:27 p.m.[151] In addition, SPP's eastern area grid conditions were further strained by a planned transmission line outage near the 1,400 MW of generating unit losses. The transmission outage, which began in September 2022, was scheduled for completion in January 2023 (a planned upgrade to increase the transfer of energy from the central portions of the SPP system eastward into the area most impacted during the Event).[152] The combination of events contributed to increased transmission congestion and low voltages on the 345 kV and 161 kV networks in southwest Missouri. Local transmission operators in the SPP footprint implemented 29 MW of load shed at 10:00 p.m. on December 22 in the Branson, MO area to alleviate the low transmission voltages.[153] After hydroelectric generation in the area was restored to provide voltage support and voltages recovered, transmission operators were able to restore the load by 12:00 a.m. on December 23.

b. Morning of Friday, December 23: BES reliability conditions worsen overnight

- Extreme cold weather moves eastward
- MISO and TVA operators faced with rising unplanned generation outages coupled with high electricity demands
- Grid operator coordination to manage transmission constraints
- SPP's ability to maintain reserves challenged during early morning
- SPP and TVA declare energy emergencies
- TVA declares EEA 3, sheds firm load[154]

MISO. As the extreme cold weather moved eastward, throughout the early morning hours of December 23, and as unplanned generation outages and failures to start began in the MISO South region, MISO found that its real-time MISO South system load exceeded its forecast. Pursuant to its security constrained economic dispatch, MISO's north-to-south power transfer, known as its Regional Directional Transfer (RDT),[155] increased to supply more power to meet its southern load (see Figures 41 and 42, below).

151 All t mes stated w th n the Report, unless otherw se spec fied, are n Eastern Standard T me (EST). f the ent ty s located n the Central T me Zone, the t mes were converted to EST.

152 SPP Report at 28.

153 SPP performed a post event analys s and found that f dur ng Ell ott the planned transm ss on l ne outage (the l ne descr bed earl er that was outaged from September 2022 to January 2023) had been back n serv ce, along w th an add t onal newly constructed transm ss on l ne and a then unava lable capac tor bank, t would have reduced low voltage l m t exceedances to less than ten t mes as many (from 292 low voltage l m t nstances to only 25 low voltage l m t nstances).

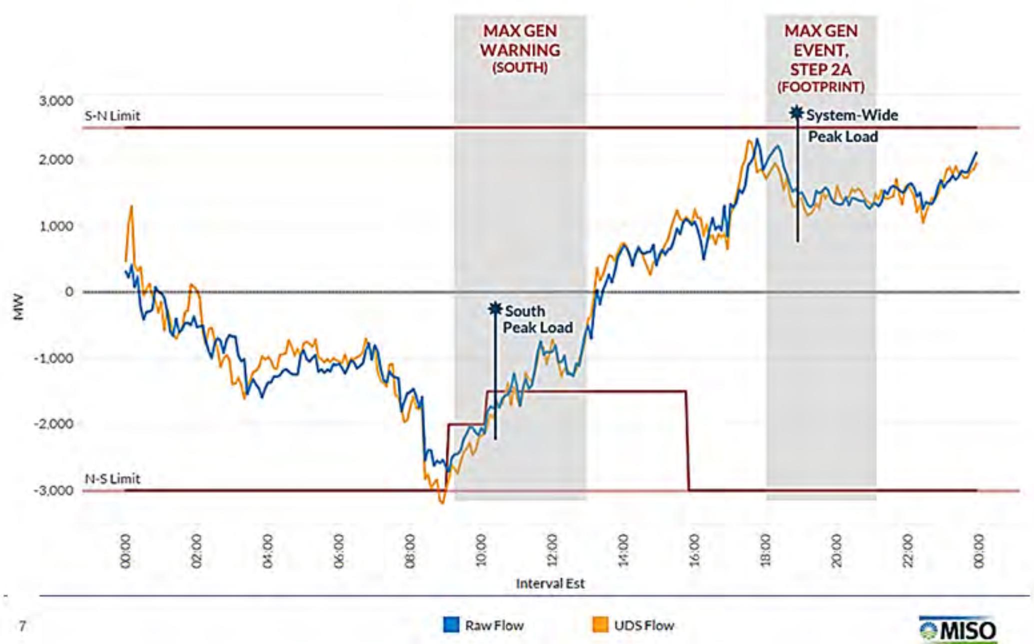
154 Red text references EEAs exper enced by BAs.

155 M SO l m ts the amount of power t transfers ntra market v a ts RDT, referred to as ts Reg onal D rect onal Transfer L m t (RDTL), under a jo nt coord nat on agreement w th SPP, AEC (Assoc ated Electr c Cooperat ve, nc.), TVA, LG&E/KU, Southern and PowerSouth, to 3,000 MW from north to south (1,000 MW firm and 2,000 MW non firm, as ava lable) and 2,500 MW from south to north (1,000 MW firm and 1,500 MW non firm, as ava lable). Wh le the total AC t e l ne capac ty, calculated by add ng the total capac ty of all t e l nes between the BAs at ssue, may nd cate a large transfer capac ty, the actual ab l ty to transfer power w ll be dependent on system cond t ons at the t me of transfer, nclud ng amb ent temperatures, generat on outages and d spatch, transm ss on outages and derates, all of wh ch dr ve actual power flows on transm ss on l nes and can l m t ava lable transfer capab l ty.

Figure 41: Illustration of MISO's Regional Directional Transfer

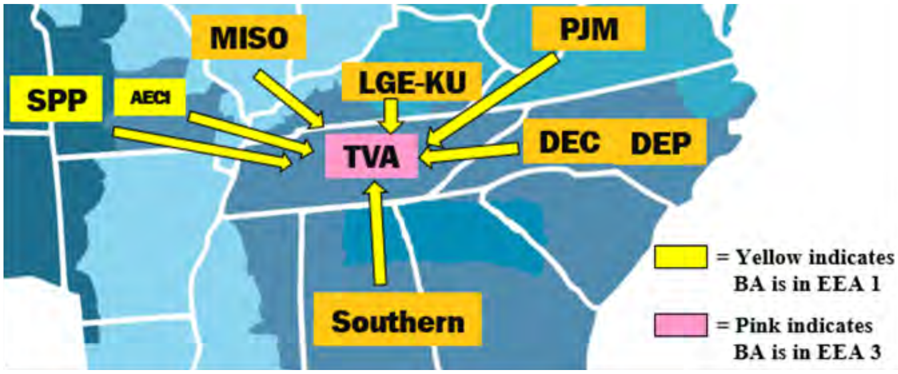
At 9:00 a.m., based on SPP's observed system conditions, SPP asked MISO to reduce its RDT limit (north-to-south power transfer) to 2,000 MW, and approximately an hour later, asked MISO to further reduce it to 1,500 MW. MISO complied with both requests, reducing the RDT, as shown in Figure 42, below. MISO and SPP coordinated to release the RDT reduction later that afternoon.

Figure 42: MISO Regional Directional Transfer (RDT) Flow,[156] December 23, 2022



156 Pos t ve flow s M SO South to North flow; negat ve flow s M SO North to South flow. mage used by perm ss on of M SO.

Figure 43: Status of TVA's Neighboring BAs for Potential of Scheduling Import Power, Morning of December 23



Throughout the morning of December 23, MISO's electricity demand continued to increase along with unplanned generation outages within its own footprint. At 9:15 a.m., MISO implemented a "Maximum Generation Warning" in MISO South.[157] MISO's entire BA footprint electricity demand also escalated throughout the morning of December 23, with morning and evening hour-average peak loads close in magnitude to one another. For the hour-ending 11:00 a.m., MISO's hourly load was 104,804 MW, 99 percent of what its evening peak hourly load would soon be. The combination of high system loads and higher-than-expected forced generation outages throughout the day eventually led MISO to declare an energy emergency at 5:30 p.m., as described further below.

SPP. SPP RC faced local transmission issues the morning of December 23. A combination of unplanned generating unit outages and transmission outages in the eastern SPP footprint contributed to depressed local voltage conditions in southwestern Missouri/northeastern Oklahoma.[158] In addition to these challenges, SPP BA faced operating reserve shortages to meet its early morning peak system load, which by hour-ending 10:00 a.m., had reached 96 percent of its previous-evening record-breaking winter peak load. From 9:27 a.m. to 11:00 a.m. on December 23, SPP declared EEA 1, and curtailed approximately 600 MW of non-firm exports due to its own operating reserve shortfalls, preventing SPP from being a source of power for neighboring BAs during that time. At 11:33 a.m., SPP declared a transmission operating emergency in response to abnormally large numbers of post-contingency system constraints that were breached due to system conditions. According to SPP, the purpose of its transmission operating emergency declaration was to ensure internal and neighboring entities were aware of the abnormal system conditions in its footprint. At 4:09 p.m., SPP terminated the transmission operating emergency. SPP did not need to implement pre-contingent load shed, but rather relied on post-contingent plans put in place by the TOPs within its footprint. At no time during the transmission operating emergency did SPP have an interconnection reliability operating limit (IROL) exceedance.

TVA. When TVA's available generation resources rapidly decreased the morning of December 23, TVA declared EEA 1 and 2 by 5:38 a.m., followed by EEA 3 at 6:12 a.m.

157 M SO's Max mum Generat on Warn ng declarat on, n add t on to call ng for all generat on resources to be comm tted to meet load, called for ts members to schedule n (to the M SO footpr nt) external resources, and to curta l non firm exports.

158 AEC , a transm ss on operator and BA located n M ssour and northeastern Oklahoma, contacted TVA (ts Rel ab l ty Coord nator) and other ne ghbor ng ent t es at approx mately 8:30 a.m. to request voltage support for ts southwestern M ssour /northeastern Oklahoma serv ce area, wh ch was affected by SPP's unplanned outages n the area. AEC declared a Transm ss on Emergency at 9:05 a.m., and prepared to shed load, but d d not need to shed load due to mproved cond t ons.

In addition to taking the emergency actions, TVA sought emergency energy from its neighboring BAs.

Initially, TVA received emergency energy imports from MISO, DEC, Southern, and PJM (depicted in Figure 43, above). These imports were sufficient to avert the need for TVA to order firm load shed for a time. By 9:38 a.m., PJM needed to curtail half (250 MW) of its emergency power delivery to TVA due to an SOL condition – a portion of PJM's emergency energy interchange schedule actual power flow caused a transmission facility within the PJM footprint to reach its emergency flow limit in real time.[159] Despite tightening conditions on the MISO system as the morning progressed, MISO maintained steadily increasing exports to TVA throughout the day. At 10:15 a.m., TVA was able to obtain 243 MW from its Reserve Sharing Group (from LG&E/KU), which offset a portion of the PJM reduction in emergency energy.[160] By 10:31 a.m., TVA operators ordered firm load shed of approximately five percent of its peak system load (estimated to provide over 1,500 MW in load reduction) in response to escalating unplanned generation outages (now at 6,500 MW, an increase of 2,000 MW since 5:00 a.m.) and rising electricity demand. At the same time, TVA's available emergency purchase power had decreased, and other neighboring BAs were unable to provide emergency energy.[161]

This was the first time in TVA's history that TVA ordered firm load shed. TVA would need to shed firm load a second time due to even worse conditions across the entire Event Area by early morning December 24. A little over two hours later, at 12:43 p.m., TVA was able to order restoration of firm load due to an increase in TVA's own available generation resources beginning early afternoon, and a limited increase in import power. These conditions enabled TVA to temporarily improve to EEA 2 for approximately three hours; it later returned to EEA 3 as the evening peak approached with energy supply conditions worsening.

c. Friday Evening, December 23: BES conditions continue to worsen

- Extreme cold weather now expands across LG&E/KU and PJM footprints
- Friday evening peak loads are highest for several BAs in Event Area
- Energy emergencies declared by SPP, TVA, MISO, LG&E/KU, and PJM
- MISO declares two local transmission emergencies, no load shed needed
- SPP returns back to EEA 1, challenges maintaining reserves
- TVA returns to EEA 3, continues load management measures and customer appeals for voluntary load reduction
- PJM and MISO declare EEA 2, implement load management measures
- LG&E/KU declares EEA 3, sheds firm load

During the day and into the evening hours on Friday, December 23, several BA footprints experienced the same challenging combination: rapidly increasing electricity demands due to the extreme cold weather (as illustrated in Figure 38, above), plus high levels of unplanned generation outages. For some BAs, the unplanned generation outages continued to increase at a rapid rate as illustrated earlier in Section III.

LG&E/KU. With LG&E/KU's system load already at 96 percent of its new all-time record winter peak load which occurred December 23, coupled with significant unplanned generation derates, by 1:36 p.m. on December 23, LG&E/KU declared EEA 3, but recovered to an EEA 2 by 2:52 p.m. At 4:29 p.m., PJM BA curtailed

159 H gh level of transm ss on fac l ty load ng or flow was further exacerbated by s gn ficant levels of unplanned generat on outages (an N "numerous" cond t on) comb ned w th ncreas ng electr c ty demands, n the reg on. PJM took appropr ate act ons to ma nta n the fac l ty load ng w th n ts l m t, ma nta n ng BES rel ab l ty.

160 Aga n at 11:50 a.m., LG&/KU cont nued ts ass stance to TVA by extend ng prov s on of 243 MW Reserve Shar ng to TVA.

161 As of 9:42 a.m., AEC BA was also at EEA 1. SPP, though not a ne ghbor ng BA to TVA but a potent al source of power v a wheel ng through AEC or M SO, was also n an EEA 1 dur ng th s per od.

the 400 MW import power due to experiencing rapidly increasing levels of unplanned generation outages coincident with increasing system load in its own footprint. With import power curtailment, at 4:29 p.m., LG&E/KU requested emergency energy from its contingency reserve sharing group. TVA, although in EEA 2 at the time, supplied LG&E/KU with 400 MW of emergency energy. At 4:45 p.m., LG&E/KU re-entered EEA 3. However, following TVA's return at 5:18 p.m. to an EEA 3 condition, at 6 p.m. it could no longer spare the 400 MW of emergency power to LG&E/KU. With the loss of its import power schedules to offset the generation derates, and its increasing system load conditions, LG&E/KU began over 300 MW firm load shed at 5:58 p.m. Over the next several hours, LG&E/KU was able to incrementally restore firm load that was shed as system loads decreased after its evening peak, and by 10:11 p.m., restored all firm load.

PJM. As the severe cold weather moved into the PJM area, loss of generation resources and load increases both exceeded their forecast amounts. As these factors increased throughout the Event, PJM needed to take emergency actions to mitigate the impact to its system. Earlier in the Event, before Winter Storm Elliott reached its footprint, PJM exported energy to neighboring BAs to its west that were short on capacity. However, as the storm moved in and the generation losses and loading increased on the PJM system, by 5:30 p.m. on December 23, PJM itself needed to declare EEA 2, invoking load management measures (e.g., demand response). PJM also reduced its energy exports, no longer able to be a source of power for BAs in need due to its own operating reserve shortfalls. According to PJM operators, PJM had barely avoided load shedding on December 23.[162]

Figures 44 and 45,[163] below, show how PJM's reserves declined throughout the day on December 23, driven heavily by unplanned generation forced outages in its footprint.

162 Aff dav t of Paul McGlynn n Essent al Power OPP, LLC et al. v. PJM nterconnect on, LLC, Docket No. EL23 53 000, 23 54 000, 23 55 000 (hereafter "McGlynn Aff dav t"), at ¶¶ 10, 34, 36 40, 48 51, 59.

163 These mages are reproduced w th the perm ss on of PJM ©PJM.

Figure 44: PJM Unplanned Generation Outages and Reserves, December 21-26, 2022

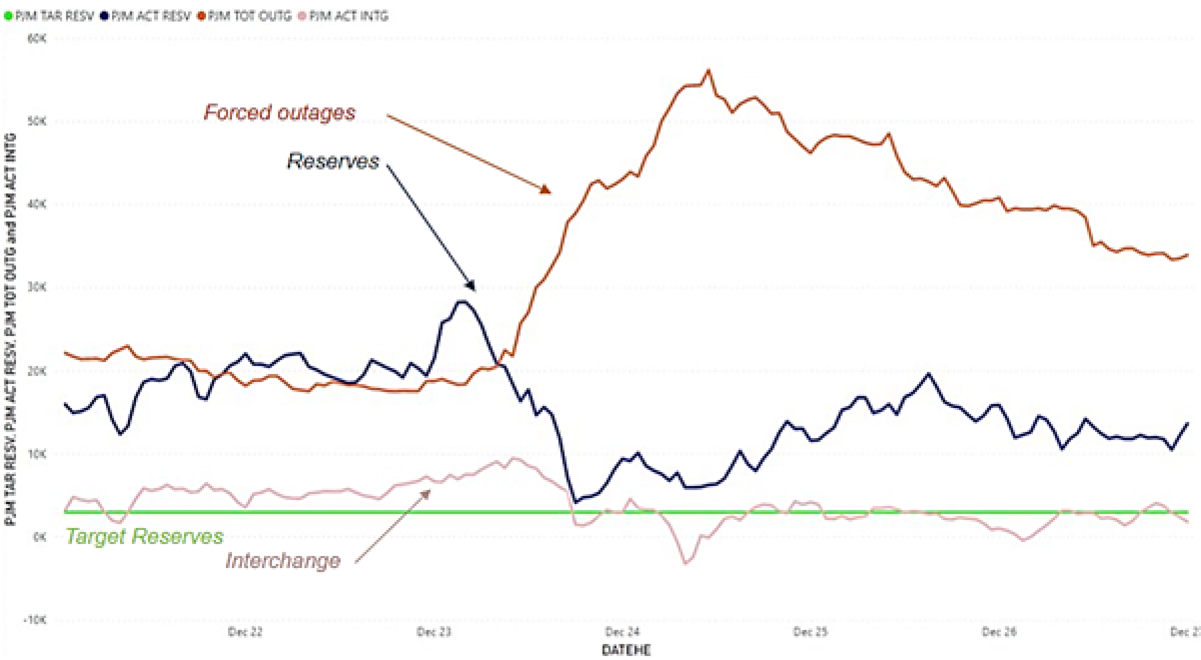


Figure 45: PJM BA Synchronized Reserves, December 23, 2:00 p.m. – December 24, 12:00 a.m.

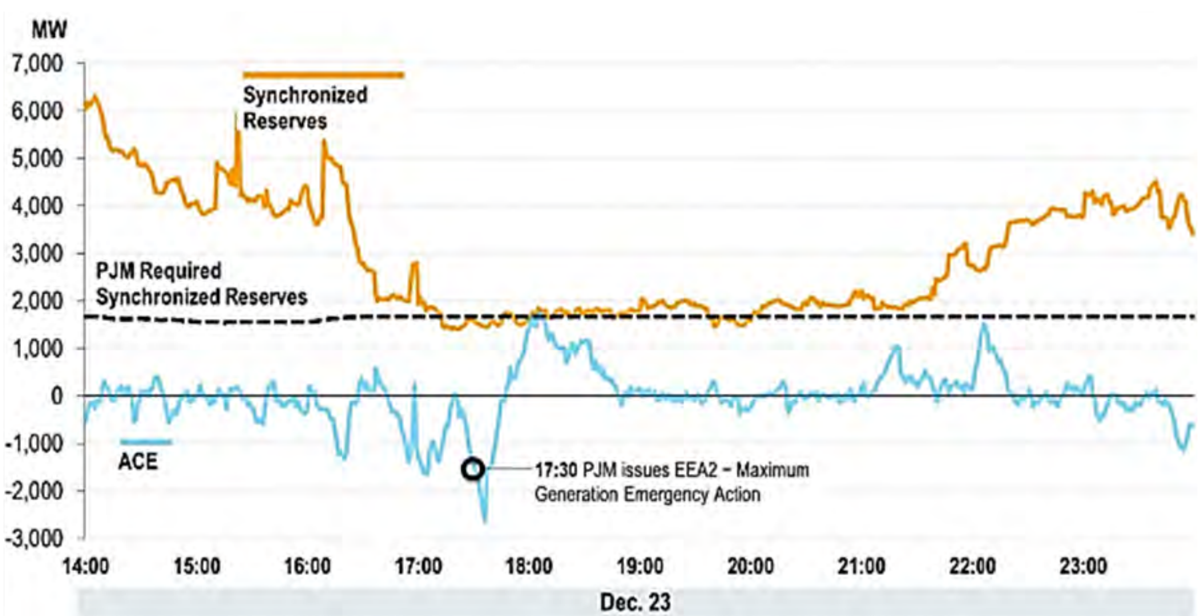
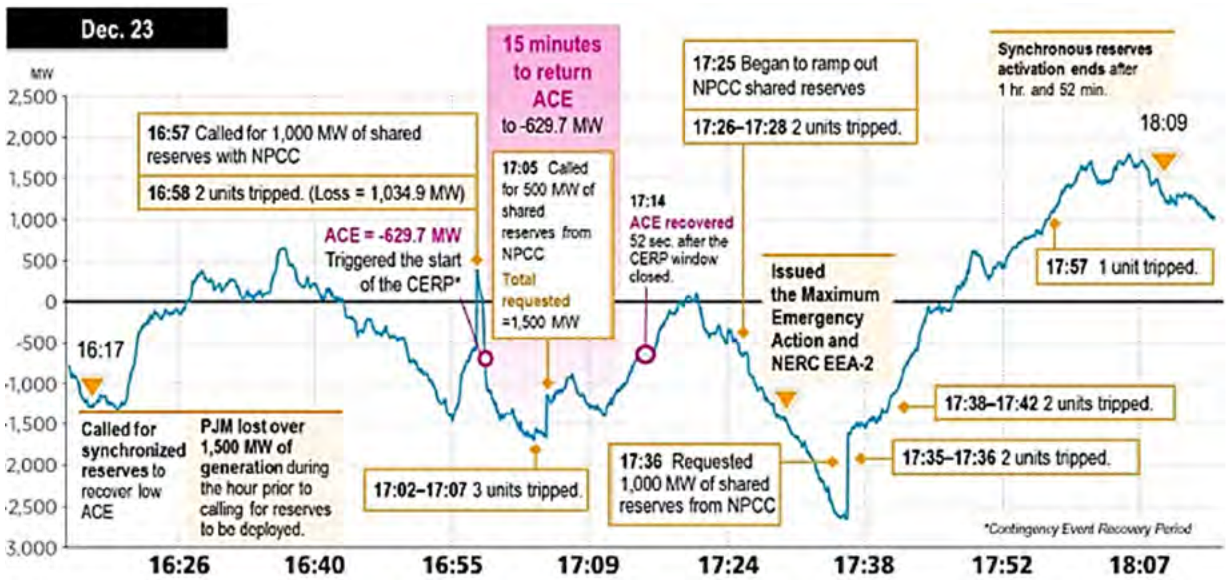


Figure 46: PJM BA Area Control Error (ACE) and Actions Timeline, December 23, 4:15 p.m. – December 24, 6:15 p.m.



As shown in Figure 46[164] above, PJM was able to benefit from a Simultaneous Activation of Ten-Minute Reserve (SAR) agreement with the Northeast Power Coordinating Council (NPCC). The SAR Agreement allowed PJM to call on reserves of up to 1,500 MW during the Event. PJM requested SAR assistance five times between December 23 and 24, all of which were due to stressed system conditions. PJM remained in EEA 2 until midnight December 23, narrowly avoiding the need that evening to declare EEA 3 and shed firm load. By midnight, conditions improved enough for PJM to downgrade to EEA 1, but that was short-lived, as described further below.

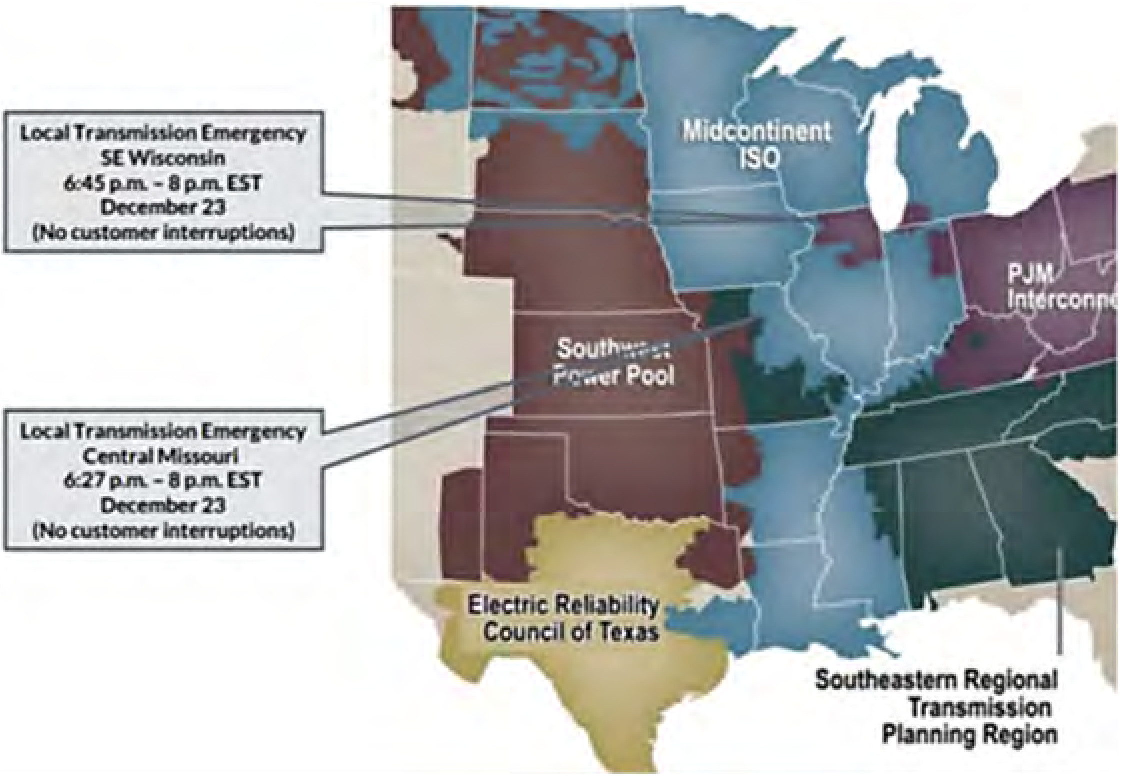
MISO. System electricity demand levels remained elevated throughout the day on December 23. This was not only true for its south region, which, as described above, contributed to MISO invoking a maximum generation warning, but also for its entire footprint. Following MISO's morning peak load on December 23, demand levels remained at or above 95 percent of the Winter Storm Elliott peak demand that MISO would experience that evening. Those high loads, coupled with unplanned generation outages increasing throughout the afternoon, led MISO to declare EEA 1 at 5:30 p.m. and EEA 2 at 6:00 p.m., when load and generation losses did not improve. Similar to PJM, when MISO declared EEA 2, it implemented its demand response, which reduced the electricity demand in its footprint. MISO remained in EEA 2 until 9:00 p.m., when its electricity demand lessened.

During the evening of December 23, MISO RC operators declared two local transmission emergencies to help manage congestion on its system. As shown in Figure 47, below, on December 23, in southeastern Wisconsin, MISO established a post-contingent mitigation plan to avoid significant redispatch of generation within that local area. Also on December 23, in eastern Missouri, MISO declared a local transmission emergency, which provided access to additional hydroelectric generation that was only available during emergency conditions.

164 Th s mage s reproduced w th the perm ss on of PJM © PJM.

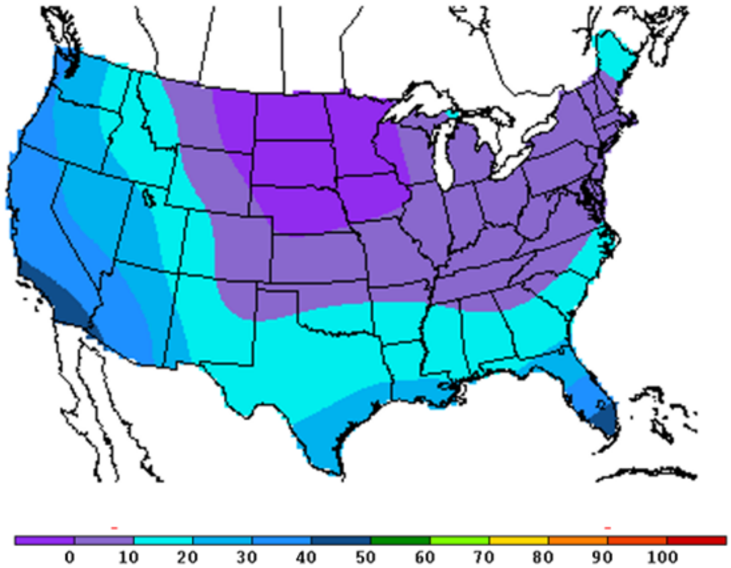
Finally, MISO declared a Transmission Loading Relief (TLR) 5[165] to manage transfers for a post-contingent constraint in southeastern Michigan, which was in effect from December 24 at 2:00 a.m. until 12:00 p.m. on December 26.

Figure 47: MISO Local Transmission Emergencies, Evening of December 23, 2022



165 Transm ss on Load ng Re ef (TLR) 5 s the h ghest eve of Transm ss on Load ng Re ef that can be dec ared by a Transm ss on Prov der. f system cond t ons warrant, a TLR 5 can enab e the Transm ss on Prov der to curta a firm transm ss on reservat on(s) to decrease the mpact on an over oaded transm ss on fac ty. f a Transm ss on Prov der curta s a F rm Transm ss on Reservat on, t must curta ts own firm oad on an equa bas s.

Figure 48: December 24, 2022 Actual Minimum Temperatures – Lower 48



SPP. Just as in the morning, SPP BA was still facing operating reserve shortages to meet its December 23 evening peak system load, which by hour-ending 7:00 p.m., was already over 90 percent of December 22's evening record peak load and rising. The evening of December 23, SPP declared its second EEA 1 from 6:20 p.m. to 9:20 p.m. and curtailed approximately 1,100 MW of non-firm exports, which prevented SPP from being a source of power for BAs in need due to its own reserve shortfalls.

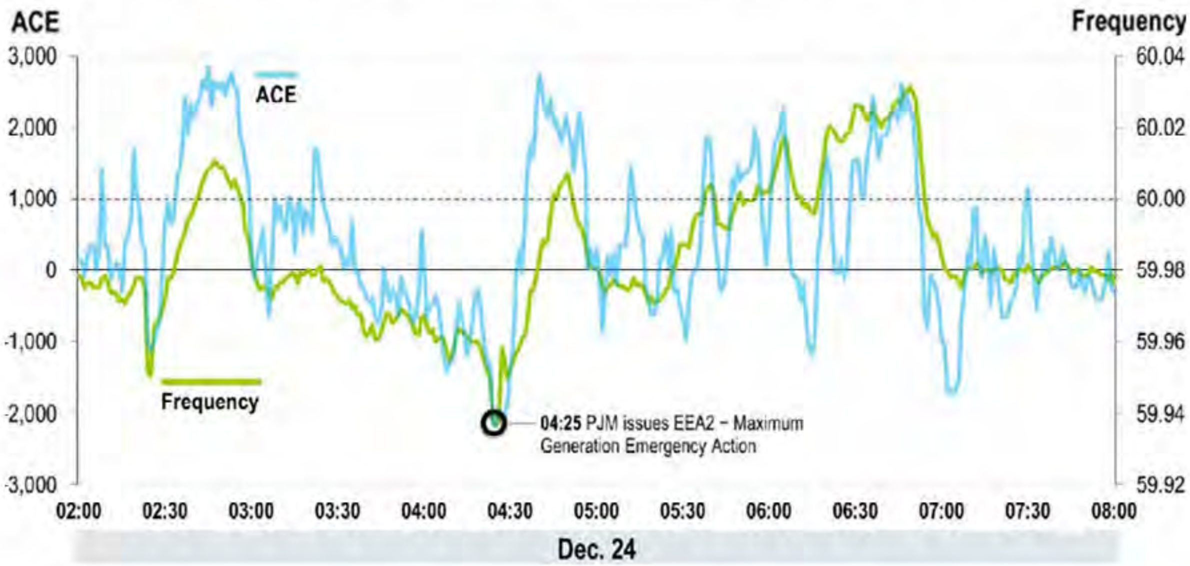
TVA. At 5:18 p.m., TVA returned to EEA 3 because neighboring entities such as Southern were dealing with their own energy emergencies by reducing their energy exports to TVA, and TVA's electricity demand was trending toward what would become its all-time record winter peak load later that evening. TVA, now at risk of shedding firm load, recalled the 400 MW contingency reserves that it was providing LG&E/KU at 6:00 p.m. This action, combined with later receiving emergency energy imports through their evening peak hours from DEC and Southern enabled TVA to avoid shedding firm load that evening. TVA would not be able to avoid load shed by the next morning. Figure 39, above, includes a timeline illustrating the Energy Emergencies declared by BAs on December 23.

d. Saturday Morning, December 24: Many simultaneous BES Energy Emergency conditions

- Extreme cold weather expands across southeastern U.S.
- Responsive reserves decline across the Core Event Area
- Simultaneous energy emergencies exist in TVA, LG&E/KU, PJM, DEC, DEP, DESC, Southern, and Santee Cooper
- PJM returns back to EEA 2, implements load management measures, and makes customer appeals for voluntary load reduction
- TVA, DEC, DEP, DESC, Santee Cooper BAs declare EEA 3, shed firm load
- Southern declares EEA 2, obtains emergency energy from Florida, implements load management measures to lower system load, did not need to shed firm load
- NYISO and ISO-NE impacts

Extreme cold weather continues – generation reserves continue to diminish. In the overnight hours heading into the morning of December 24, the extreme cold weather conditions accompanying Winter Storm Elliott eventually blanketed the southeastern U.S. all the way to the Atlantic Ocean, Figure 48, above).

Figure 49: PJM BA Frequency Plot and ACE Conditions, December 24, 2:00 a.m. – 8:00 a.m.



The pattern of unplanned generation outages and high electricity demands seen in the BA footprints described above continued overnight and into the morning of December 24 for BA footprints located in the easternmost region of the U.S. Forced outages and derates of generating units continued to diminish BA reserves during the early morning hours of December 24.

PJM. PJM began December 24 in EEA 1. As the PJM BA continued to experience significant unplanned generation outages and derates through the early morning hours as referenced in Figure 27, above, at 4:00 a.m. on December 24, PJM issued a call for voluntary conservation to last until 10:00 a.m. on December 25. PJM estimated that responses to its call for conservation helped to reduce load beginning at about 7:15 a.m.

At 4:20 a.m., PJM BA needed to return to EEA 2. At 4:23 a.m., PJM BA had a low ACE event,[166] and called for over 1,000 MW of synchronized (responsive) reserves from its reserve-assigned generation. Only 169 MW of synchronized generation reserves responded (a 16.8 percent response rate).[167]

As shown in Figure 49,[168] above, at 4:25 a.m., PJM BA issued EEA 2, and called for Maximum Generation Emergency Action. PJM also used load management measures during its EEA 2, to take effect at 6:00 a.m. At 6:17 a.m., PJM BA asked Market Participants to submit bids to sell emergency energy in case PJM needed to purchase or import emergency energy, but other actions that PJM took averted the need for the PJM BA to purchase emergency energy. At 6:30 a.m., PJM BA received reports that generators were having to limit their output due to federal government environmental restrictions. PJM petitioned the Department of Energy (DOE), and DOE later granted permission,[169] to lift emissions-related restrictions until noon, Monday December 26.

166 A low ACE event s the Low Balanc ng Author ty ACE L m t (MW), calculated based on the Low Frequency Tr gger L m t of approx mately 59.95 Hz for the Eastern nterconnect on. *See* F gure 49, above, and NERC Rel ab l ty Standard BAL 001 2 Real Power Balanc ng Control Performance, Attachment 2. RSCompleteSet.pdf (nerc.com).

167 PJM has normally seen performance over the past three years n the 50 70 percent response range when call ng for synchron zed reserves.

168 Reproduced w th perm ss on of PJM and copyr ghted by PJM.

169 PJM secured the order from the DOE under sect on 202(c) of the Federal Power Act (16 U.S.C. § 824a(c)). PJM rece ved the DOE order at 5:45 p.m. on December 24 and mmed ately mplemented t.

At 7:15 a.m., PJM BA issued a Voltage Reduction Warning and Reduction of Non-Critical Plant Load, indicating that a voltage reduction[170] may be required during a future critical period. At 7:30 a.m., PJM BA conducted an SOS Transmission conference call on which PJM BA advised TOs to prepare for a Voltage Reduction Action (i.e., order to perform voltage reduction) and to be sure to have their load shed plans in place. By 8:00 a.m., over 24 percent of the PJM generation fleet (approximately 46,000 MW) was experiencing a forced outage, which was higher than the 22 percent forced outage level that PJM experienced during the Polar Vortex in 2014.[171] In total, PJM BA faced approximately 57,000 MW of generator unavailability for the morning peak on December 24 (including planned outages and forced outages that began before the Event). The other load management measures improved system conditions enough over the next few hours that PJM did not need to order voltage reduction or firm load shed on the morning of December 24.[172] At first PJM estimated that its load management efforts reduced load by 7,400 MW, but it later realized that it only received approximately 3,500 MW.[173] Still, PJM was able to restore exports to support its neighbors by 10 a.m. At 10:00 p.m., PJM BA terminated its EEA.

TVA. As shown in Figure 39, above, TVA remained at EEA 3 since the evening of December 23. At 5:51 a.m. on December 24, with its system load still near where it had peaked the evening before, unplanned generation outages still occurring, and its import power curtailed, the TVA BA area again ordered firm load shed of approximately five percent of its peak system load/1,500 MW. At 6:12 a.m., TVA suffered an additional curtailment of import power and ordered an additional five percent firm load shed (10 percent total, estimated by TVA to be a 3,200 MW reduction).[174] TVA later incurred an additional unit trip of nearly 300 MW and was unable to reduce back to five percent of its peak system load until 10:27 a.m. Finally, at 11:30 a.m. TVA BA released its order for the remaining five percent load shed. As system load began to decrease and some generating capacity returned to service, TVA lowered from EEA 3 to EEA 2 at 12:08 p.m., dropping to EEA 1 at 1:07 p.m. and terminating its EEA at 1:45 p.m.

DEC. Already in EEA 1 at the start of December 24, as unplanned generation outages increased and PJM BA curtailed export schedules to DEC, DEC declared EEA 2 at 4:30 a.m., and EEA 3 at 6:10 a.m. By 6:27 a.m., DEC ordered 400 MW of firm load shed, later increasing it to 1,000 MW at 7:10 a.m. Later that morning, as system load dropped and a generation plant returned to service, DEC ordered the restoration of firm load at 10:00 a.m. DEC manually restored the last load shed circuits at 3:45 p.m.

DEP. Experiencing conditions similar to DEC, DEP declared EEA 1 December 24 at 5:37 a.m. DEP escalated to EEA 2 at 6:06 a.m. when its purchased power was curtailed, and to EEA 3 at 6:18 a.m. after an additional generation outage. With system load increasing, DEP ordered 600 MW of firm load shed at 6:25 a.m., but increased it to 800 MW at 7:10 a.m., up to a maximum of 961 MW by 7:56 a.m. By 8:14 a.m. DEP began restoring a portion of its firm load,

---

170 Based on transm ss on equ pment wh ch ex sts n certa n locat ons of the BES, electr c gr d operators can control the transm ss on equ pment to reduce voltage levels to lower the BA system load (wh le ma nta n ng BES rel ab l ty) as an emergency load management measure, n advance of and to reduce the need for firm load shed. *See* PJM Manual 13: Emergency Operat ons.

171 McGlynn Aff dav t, at ¶ 13.

172 At 6:15 p.m. on December 24, PJM ended the Voltage Reduct on Warn ng and Reduct on of Non Cr t cal Plant Load, and the Voltage Reduct on Alert at 6:34 p.m.

173 PJM Report at 42 (for December 23 (1,100) and 24 (2,400).

174 n add t on to PJM, other BAs ne ghbor ng TVA had concerns of meet ng the r own load/reserve requ rements the morn ng of December 24 based on h gh electr c ty demands and unplanned generat on outages, derates, and fa lures to start exper enced thus far dur ng W nter Storm Ell ott. For example, w th the SPP BA exper enc ng challenges to ma nta n ng adequate operat ng reserves tw ce on December 23 dur ng morn ng and even ng peak t meframes, to l m t further ncrease of the export of the SPP BA, the SPP transm ss on serv ce prov der (TSP) reduced the r total power] transfer capab l ty (TTC) of the SPP export nterface from December 23, 10:00 p.m., through December 25, 1:00 p.m. SPP BA commun cated th s act on w th M SO, TVA and Southern and not fied them to contact SPP f they needed ass stance and SPP would evaluate ts ab l ty to help. These calls were on the morn ng of the 24th. (*See* SPP Report at 9).

restoring all by 8:43 a.m. DEP improved to EEA 1 at 4:20 p.m.

DESC. With increasing generation outage levels, on December 24, at 4:56 a.m., DESC declared EEA 2 and initiated load management procedures, followed by voltage reductions to reduce system load. By 5:53 a.m., DESC declared EEA 3. At 8:00 a.m., DESC ordered approximately 95 MW firm load shed. DESC was able to purchase 100 MW of import power from Southern, and by 8:09 a.m., restored its firm load. DESC continued to implement load management, customer appeals for conservation, and voltage reduction to lower its system load, and at 7:10 p.m., dropped to EEA 2. DESC remained at this level overnight until 9:00 a.m. on December 25 when it exited its energy emergency.

Santee Cooper. Santee Cooper began experiencing unplanned generation outages related to Winter Storm Elliott during the early morning hours of December 24. At 5:34 a.m., Santee Cooper declared EEA 1, and by 7:18 a.m. was at EEA 3 and ordered 86 MW firm load shed. At 7:33 a.m., Santee Cooper ordered all firm load shed restored.

Southern, NYISO, and ISO-NE. On December 24, due to the unplanned generation outages and increasing loads, Southern BA declared an EEA 1 at 2:00 a.m. The Southern BA requested implementation of voltage reduction programs to help reduce load on its system. Faced with additional unplanned generation outages, at 6:25 a.m., the Southern BA declared an EEA 2 due to declining operating reserves and expected load increase, and requested emergency energy from its neighbors. At 7:00 a.m., Florida Power and Light provided 1,000 MW of emergency energy to the Southern BA Area. As it began to receive emergency energy from Florida Power, the Southern BA was able to provide 100 MW of emergency energy assistance to DESC. By midday, Southern BA load began to decrease, and Southern BA was able to increase this assistance to DESC to 400 MW at 1:00 pm, and by 2:15 p.m., downgraded to an EEA 1. As the need for emergency energy decreased due to improved system conditions in the DESC BA area, Southern BA decreased its emergency energy to 200 MW and finally to 0 MW at 10:00 p.m.

With the winter storm making its way to New York and New England, the governor of New York on Thursday December 22, declared a state of emergency for the entirety of New York, and on the same day, the National Weather Service Buffalo upgraded the winter storm watch to a blizzard warning, and warned of possible blizzard conditions in Buffalo to begin Friday afternoon December 23, and to last approximately 30 hours, with peak wind speeds that could reach approximately 70 mph, with one to three feet of snow.[175] Although there were over 100,000 power outages in the NYISO footprint, as well as tens of thousands of customers without power in the ISO-NE footprint across Maine, Vermont, and New Hampshire, they were mostly due to the winter storm's impact on the electric distribution systems. While there were unplanned BES generation outages in the NYISO footprint during the Event, NYISO did not need to enter into an energy emergency and was able to assist neighboring BAs during the Event, such as PJM, with reserves as described earlier in Section III.

ISO-NE needed to invoke EEA 1 the evening of December 24. ISO-NE incurred over 2,000 MW of unplanned generation outages and derates in its footprint on December 24, and also experienced over 1,000 MW reduction of import power from Hydro Quebec due to the winter storm's impact on Hydro Quebec's system. Those conditions, coupled with high electricity demands, led ISO-NE to declare EEA 1 from 4:30 p.m. to 7:00 p.m., which was then cancelled as conditions improved in its BA.

e. Operating Conditions Improve - Evening of December 24 –December 25

- Core Event Area operating conditions improve
- Energy Emergencies end

175 NEW YORK STATE PREPAREDNESS AND RESPONSE EFFORTS Bl zzard of 2022 After Act on Rev ew (August 2023) at 15, https://www.dhses.ny.gov/system/files/documents/2023/08/nys aar on buffalo bl zzard response.pdf.

As Christmas Eve and Christmas Day unfolded, Event Area electricity demands decreased (as seen on the graph in Figure 39, above). Also, on December 25, extreme cold weather ushered in by Elliott began to subside in some of the BA footprints. Some generating units also returned to service and increased BA reserve levels. However, also as shown in the Figure 39 timeline, above, multiple BAs were experiencing Energy Emergencies which extended into midday, December 25, although none needed to shed firm load on Christmas Day:

- DEC BA, returned to EEA 1, December 24, at 4:00 p.m., EEA 1 cancelled on December 25, at 11:00 a.m.
- DEP BA, EEA 1 cancelled on December 25, at 9:00 a.m.
- DESC BA, cancelled EEA 2 on December 25, at 9:00 am.
- Santee Cooper BA, EEA 2 until December 25, 5:04 a.m., EEA 1 cancelled December 25, at 9:00 a.m.
- Southern BA, EEA 1 cancelled December 25, 12:00 noon.
- PJM BA, EEA 1 cancelled December 24, at 10:00 p.m.

4. NATURAL GAS PIPELINE OPERATORS' REAL-TIME ACTIONS

a. Pipeline Operator Actions Due to Natural Gas Supply Shortfalls and Equipment/Facility Outages

1. Gas Pipeline Scheduling

The natural gas scheduling system is based on the Gas Day which is standard nationwide, beginning at 9:00 a.m. CCT[176] and ending at 9:00 a.m. CCT the following day. All nominations for transportation service are for a daily quantity to be transported over that 24-hour period. The rate at which a shipper may use its contracted quantity, also known as a flow rate, on a given pipeline is determined by the individual pipeline's tariff and the flexibility of that pipeline to permit non-ratable flows (that is, delivery in a single hour of more than 1/24 of the daily nominated quantity). Except for special services, pipeline services are generally based on the assumption of uniform hourly flows over the Gas Day.

At a designated time each day, a shipper "nominates" a quantity of natural gas that it wishes to have transported by the pipeline under a transportation contract between receipt and delivery locations on the pipeline. The nomination goes through a confirmation and scheduling process to ensure that the nomination matches the amount of gas that the pipeline will receive from or deliver to the designated locations, and that there is enough available capacity for the nomination to flow. Before a pipeline schedules a shipper's nominated quantity of natural gas for transportation, the pipeline confirms the shipper's nomination with upstream and downstream parties to make sure the shipper has contracted for sufficient gas with an upstream supplier to fulfill its nomination, and to ensure the downstream entity, such as an LDC, has sufficient capacity to accept the gas. If demand for service along a specific path exceeds the pipeline's capacity (i.e., if a pipeline has capacity constraint), priority rules are used to schedule higher priority nominations while lower priority nominations are reduced or rejected. After all gas has been scheduled, nominations are confirmed back to the shippers and the pipeline is obligated to deliver the confirmed nominated quantity of gas.

2. Gas Pipeline Operations Under Normal Conditions

Natural gas pipelines (and LDCs) have operations centers or control rooms that are staffed 24 hours a day, every day of the year. Pipeline personnel known as controllers monitor the pipeline systems for, among other things, operational status, natural gas flow rates, and readings of the natural gas pressure within the pipeline and temperatures. Controllers are the first to notice and respond to abnormalities such as pressure changes or compressor failures and notify and to communicate with field personnel who respond to these conditions.

Each pipeline must maintain a minimum pressure for gas to flow and must stay below the maximum allowable

176 Central Clock T me, wh ch s Central Standard T me except dur ng Dayl ght Sav ngs T me, when t s one hour n advance of Central Standard T me.

operating pressure at which it can safely operate (MAOP). Like electric grid operators, pipeline operators use Supervisory Control and Data Acquisition (SCADA);[177] pipelines use it primarily to monitor the flow of gas on the system.

Line pack is the volume of gas maintained or held within a pipeline system. The more gas that is “packed” into the pipeline, the higher the pressure. System operators continually manage the amount of gas in their pipelines to ensure that customer demands can be met while staying within safe and reliable pressure ranges, which vary from pipeline to pipeline. Pipelines rely on line pack to match the time-varying demands of their customers (shippers) and the supply of natural gas that generally is injected into the pipeline at a consistent rate through the day (production gas). Under normal operating conditions, line pack on a pipeline goes through a 24-hour cycle. During the morning peak, when some shippers, such as electric generating units, withdraw gas at a non-ratable flow rate, the line pack decreases. Later in the day, when shippers either pause or decrease the rate of gas withdrawal, pipelines pack the lines to replenish the gas taken off the system. As long as a customer’s gas usage does not threaten the pipeline system’s integrity, pipeline operators may provide customers with the flexibility of non-ratable flows or deviation from their scheduled quantity. Additionally, pipelines generally offer balancing services and bill their shippers monthly to allow for daily fluctuations. This allows shippers up to 30 days to balance the amount of gas that shippers delivered into the pipeline with the quantity of gas that was taken off the pipeline. Lastly, during normal operating conditions, if the pipeline is not constrained and is able to meet all of its firm contractual nominations, any excess capacity can be used for interruptible transportation service.

Ahead of weather events or at other times that stress the system, a pipeline system operator will store gas in its transmission system during the hours of low demand (packing) leading up to the event, and then use that gas during the hours of high demand, reducing the amount of gas in the system (drafting). During periods of high demand, natural gas supplies flowing ratably[178] into a pipeline over the 24-hour gas-day period may not be sufficient to satisfy the increased demand from shippers in the same overlapping period leading to the draft condition. A draft condition occurs when supply is less than demand. This may occur on an hourly or daily basis. A draft condition leads to lower line pressure and/or reduced line pack, to which operators respond with a variety of approaches, such as reduced system tolerances and the use of natural gas imbalance management techniques designed to maintain system integrity and provide reliable service to all shippers.

During constraint periods, a pipeline may more strictly enforce ratable flows and reduce system imbalances by requiring shippers to match their supply of gas delivered into the pipeline with the amount taken out. If a shipper’s supply of natural gas into the pipeline is less than its nominated amount, a pipeline may reduce the shipper’s confirmed nomination to match the amount of natural gas actually delivered into the pipeline system.[179] Pipelines may also use the types of notices described below in the sidebar on pipeline communications to keep the system balanced and within operating pressure range.[180] By using notices to reduce the amount of gas customers may take off the pipeline or the rate at which the gas is being taken off, pipelines can keep pressure up. During the Event, one pipeline restored its line pack by reversing flow in a segment of its system, but not all pipelines have that ability. Pipelines may also reduce or curtail certain

177 A Superv sory Control and Data Acqu s t on (SCADA) system operates v a coded s gnals sent over commun cat on channels to remote stat ons to mon tor and prov de control of remote equ pment.

178 Mean ng at a constant rate; rece pt operators flow on a steady rate bas s as ment oned above. Steady state flow refers to the cond t on where the flu d propert es at a po nt n the system do not change over t me.

179 Changes n gas del ver es do not occur nstantly. Operat onal Balanc ng Agreements (OBA) contractually spec fy how gas mbalances between flows and scheduled amounts are to be managed. nterstate p pel nes are obl gated by FERC regulat ons to have OBAs at nterconnects w th other nterstate p pel nes and w th ntrastate p pel nes. These agreements enable counterpart es to make operat onal changes and rev se nom nat ons.

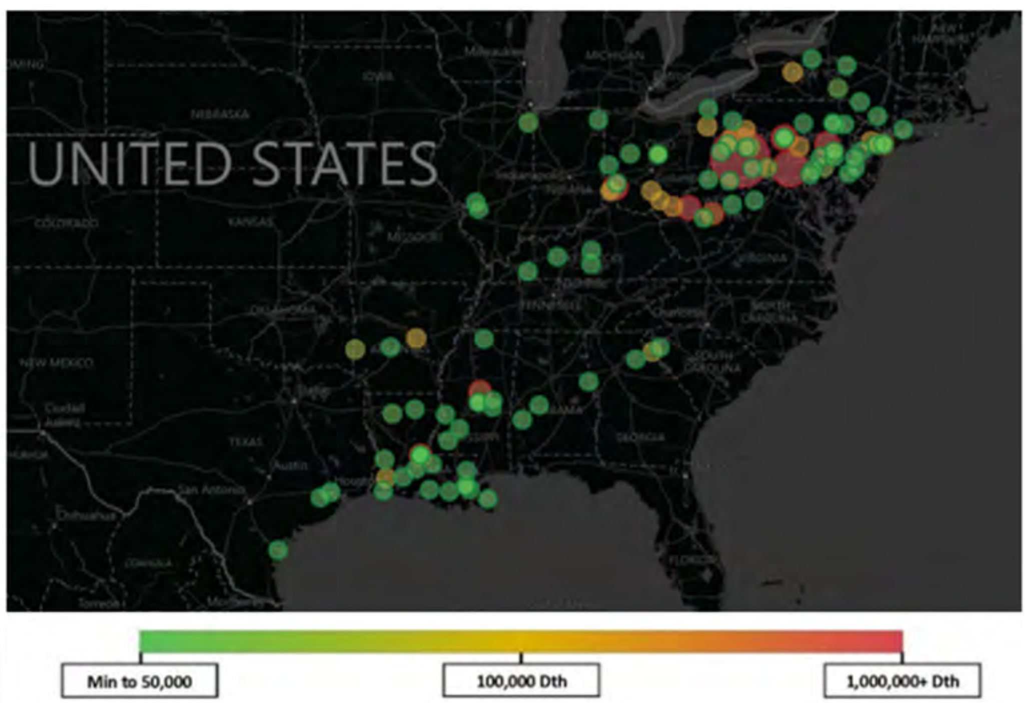
180 *See* s debar on p pel ne commun cat ons at 76, below.

transportation services based on their priority level (e.g., interruptible transportation) if their capacity cannot meet all of the demand.

Pipelines can turn some facilities on and off, whether by remote operation via SCADA or manually using field personnel, to alleviate pressure concerns that could affect the reliability of their system. However, this option is rarely exercised. In 2011, New Mexico Gas Company curtailed pipelines to several rural communities when it received reports of no gas or low gas pressure in the Albuquerque area, indicating that its system was near collapse.[181] These curtailments allowed pressure to recover in the remainder of its system. The option to turn off facilities feeding shippers at designated delivery points that are supplying less gas than they are withdrawing is rarely, if ever, exercised. If enough customers take more gas than they are entitled to, this can negatively affect pipeline pressures for customers located farther down the pipeline.

Interstate pipelines use storage to support system operations (e.g., to provide system balancing or support no-notice transportation services), to provide contract storage services, or a combination of both. Interstate pipeline companies, intrastate pipeline companies, LDCs and independent storage service providers may own and operate underground or above-ground storage facilities. However, the owners/operators of storage are not necessarily the owners of the natural gas held in storage.

Figure 50: Magnitude of Supply Shortages by Receipt Point Locations for Gas Days December 20-26, 2022



Most of the working gas held in storage belongs to shippers, LDCs, or end users who own the gas. Some interstate pipelines reserve varying amounts (from three percent to 22 percent) of their natural gas storage capacity to support their system operations. During extreme cold weather events withdrawals from customers with rights to storage such as LDCs (for natural gas-fired home heating, among other uses) increases. In Winter Storm Uri, the South Central Region (including Texas) saw record storage withdrawals of 156 Bcf for the week ending February 19,

181 2011 Report at 127 130.

2021, which were instrumental in preventing more adverse outcomes on both the natural gas infrastructure system and the grid.

Each of these tools is important in maintaining the reliability of the pipeline system, allowing operators to ensure the proper amount of gas flows through the system. Force majeure can be issued when emergency conditions, such as freezing of equipment, threaten operations. OFOs are important because they notify shippers to stay within their nominated and confirmed quantities of gas or risk penalties.

3. Gas Pipeline Real-Time Operations During Winter Storm Elliott

Once Winter Storm Elliott struck, many pipelines began to experience decreased natural gas supply at numerous receipt points, which are the points where pipelines receive gas into their system. Figure 50, shows the magnitude of supply shortages during the relevant period by receipt point locations. Ten out of the 15 surveyed pipelines reported supply loss or underperformance, defined as the actual physical receipts being less than the shipper's confirmed nomination. The magnitude of supply loss is represented on Figure 50 by the green to red color gradient, with red indicating a higher volume of supply loss. Figure 50 clearly shows significant supply reductions at receipt points located in the Marcellus and Utica Shale formations. Pipelines also indicated that although they can track the volume of supply underperforming at receipt points on their respective systems, they were not always privy to the upstream issues causing the supply loss.

Pipeline Communications

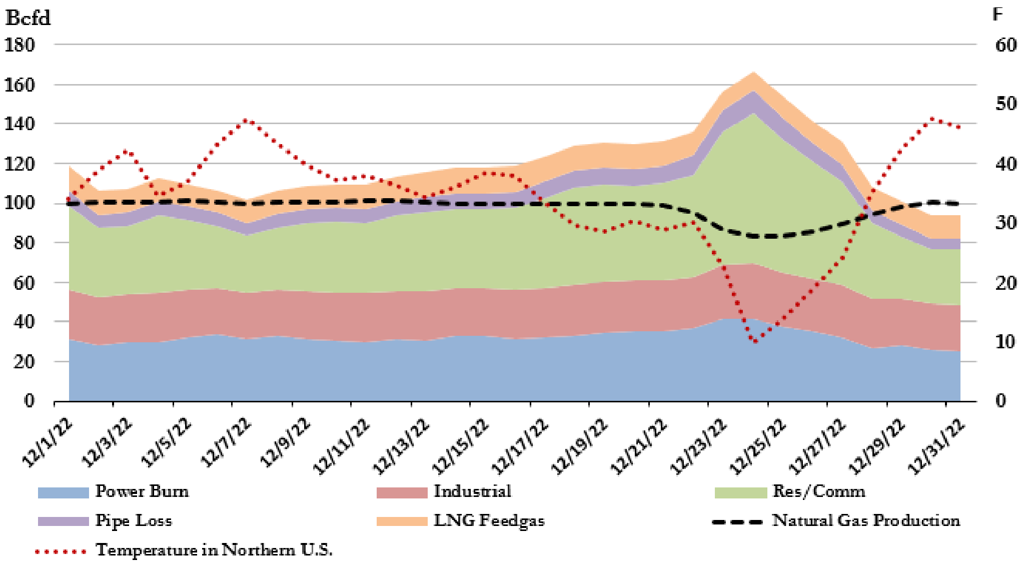
Interstate pipelines issue a variety of communications and directives to shippers and, pursuant to FERC regulations (18 CFR §284.12 (2022)), post critical notices to describe strained operating conditions, to issue operational flow orders and, when applicable, to make force majeure announcements. Most intrastate pipelines provide similar information and instructions to shippers, either by posting or direct communications.

Critical notices describe situations when the integrity of the pipeline system is threatened. A critical notice will specify the reasons for and conditions making issuance necessary, and also state any actions required of shippers. Operational integrity may be determined by use of criteria such as the weather forecast for the market area and field area; system conditions consisting of line pack, overall projected pressures at monitored locations, and storage field conditions; facility status (defined as horsepower utilization) and availability; and projected throughput versus availability, for capacity and supply.

Operational flow orders (OFO) are used to control operating conditions that threaten the integrity of a pipeline system. (Individual pipeline companies may have other names for operational flow orders such as alert days, performance cut notices or an emergency strained operating condition). OFOs request that shippers balance their supply with their usage on a daily basis within a specified tolerance band. An OFO can be system-wide or apply to selected points. Failure by a shipper to comply with an OFO may lead to penalties. Pipelines may also limit services such as parking and lending of natural gas, no-notice (the provision of natural gas service without prior notice to the pipeline), interruptible storage and excess storage withdrawals and injections.

Force majeure, if authorized by the pipeline's tariff, is a declaration of the suspension of obligations because of unplanned or unanticipated events or circumstances not within the control of the party claiming suspension, and which the party could not have avoided through the exercise of reasonable diligence.

Figure 51: Natural Gas Supply and Demand, December 1 – 31, 2022[182]



Starting the morning of December 23, pipeline operators were faced with increasing demand for natural gas after seeing supply shortfalls throughout the night of December 23 (see supply and demand pattern in Figure 51, above). Supply shortfalls peaked on December 24 at 7.1 Bcf. The mismatch between supply and demand challenged pipeline operators' ability to provide consistent, dependable natural gas operations needed by generating units. Line pack was one strategy pipelines used to handle these hourly fluctuations in supply and demand, partially to assist generators' operations.

Figure 52 below, shows that the ongoing imbalance between the gas entering and leaving the pipeline systems caused the interstate pipelines' line pack to continuously drop throughout December 24. Pipelines actively monitored their line pack and pressures and responded promptly; issuing underperformance notices to shippers to inform them that they were not supplying all of the gas they were obligated to supply. To meet confirmed nominations of customers, pipelines used line pack and/or gas from storage to try to cover shortfalls as much as possible. These efforts were successful at the onset of the storm, allowing pipelines to deliver confirmed nominations of gas to meet customers' demand. However, as the storm progressed, supply shortfalls continued and customers' demand increased to a level where some customers began taking more gas than what they supplied and/or confirmed through nominations, which contributed to low pipeline pressures. On December 24, due to the mismatch of shippers' receipt and delivery volume, multiple shippers' confirmed nominations were reduced to match their supply of gas into the pipeline.

Figures 53 and 54, below, show the notices issued by the pipelines in advance of the Event on December 20 as well as during the Event from December 21 to 26. Force majeure and OFO issuances peaked on December 23, while critical notices peaked on December 24. One pipeline had compressor station outages that led to three force majeure issuances, affecting 93 firm shippers; another issued five force majeures from December 23 to 25 due to freezing-related compressor station outages, affecting 63 firm shippers.

182 Source: S&P Global Commod ty ns ghts, ©2023 by S&P Global nc.

Figure 52: Average of Normalized Line Pack Pressures For the 15 Interstate Pipelines Surveyed, December 20 – 26, 2022

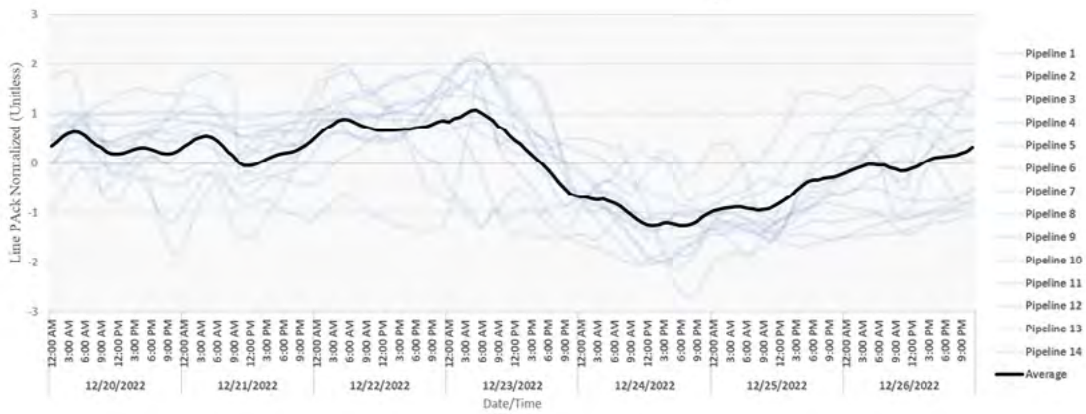


Figure 53: Interstate Natural Gas Pipeline Notices Issued, December 20 – 26, 2022

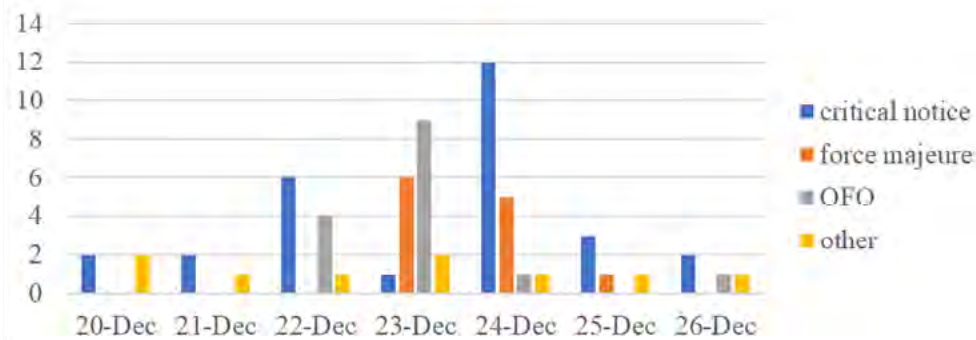
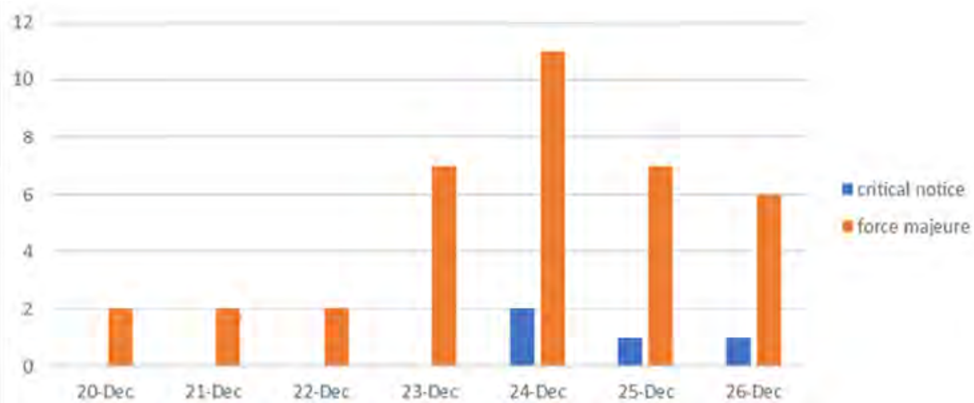


Figure 54: Ongoing Notices with Associated Flow Reductions, December 20 – 26, 2022



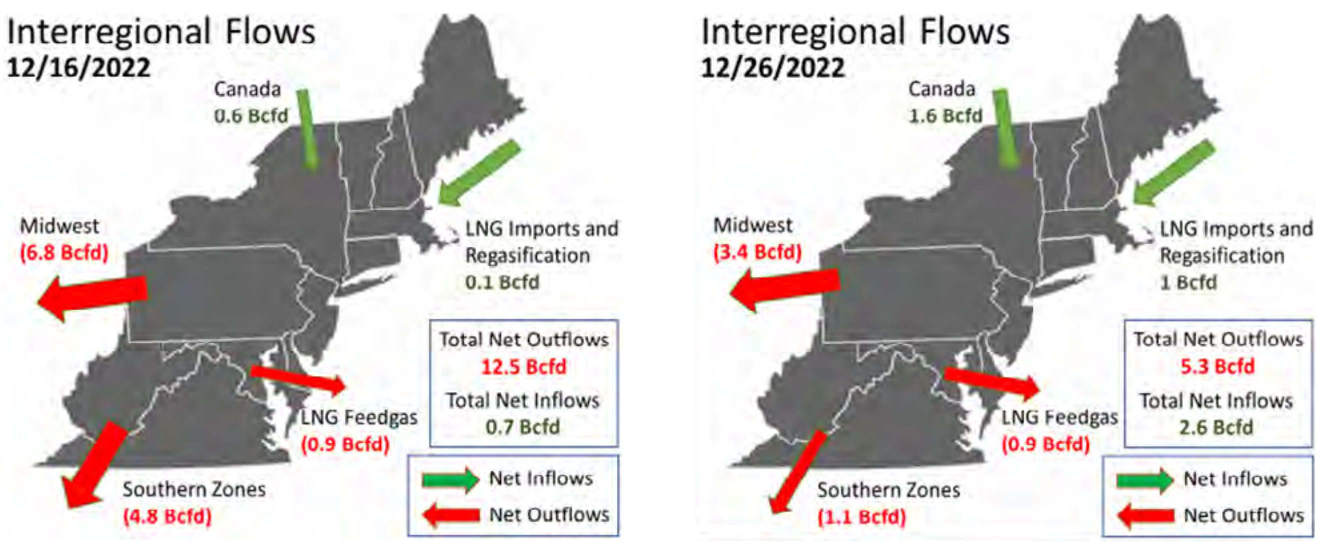
Low pipeline pressures caused by reduced gas supply entering pipelines combined with increased demand also resulted in issues at interstate pipeline interconnections with other pipelines, where shippers' gas supply quantities were inconsistent with shippers' confirmed nominations on the receiving pipeline; resulting in confirmed nominations that failed to align with the quantity of gas flowing. These issues caused imbalances between supply and demand at pipeline interconnection points, requiring some pipelines to implement scheduling restrictions and forcibly reduce previously confirmed nominations. The scheduling restrictions and forcible reduction of confirmed nominations may not have been necessary if non-performing shippers had acted to address their lack of performance. The pipelines had to contact those shippers repeatedly to find out how they planned to balance their gas flows and in some instances were unable to do so before it became necessary to implement scheduling restrictions and reduce nominations.

Several of the pipelines communicated with PJM or NYISO during the Event. These discussions allowed the pipelines to obtain useful information, for example, about PJM's load forecast or burn profiles for gas generators, and to share the performance of their systems and available capacity with the BAs. One pipeline provided PJM with a list of receipt points that were underperforming according to their nominated levels.[183]

2. INTERREGIONAL NATURAL GAS FLOW PATTERN CHANGES

As weather affected natural gas supply, demand, and pipeline operations, the movement of natural gas between regions in the eastern half of the United States changed. The Northeast region reduced outflows to neighboring regions and increased imports from Canada, while the Southeast region simultaneously increased outflows to the Midwest, decreased outflows through LNG exports, and had less access to Northeast supply.

Figure 55: Natural gas flows into and out of the U.S. Northeast region[184]



Since the dramatic growth of shale natural gas production in the Northeast began over a decade ago, the region has produced substantially more natural gas than it consumed, allowing for net outflows of

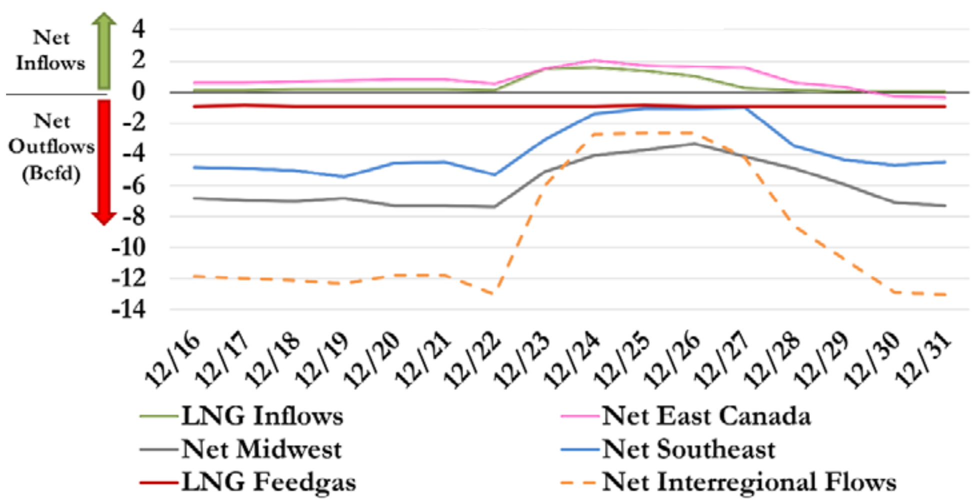
183 W nter Storm Ell ott h t on a hol day weekend. Th s created pressure on p pel nes' commun cat ons teams because of an ncrease n sh pper nqu r es due to the large volume of confirm ng party reduct ons they ssued. Th s requ red some of the p pel nes to call n vacat on ng staff.

184 Flow s ze arrows are approx mate. Reg on borders are general zed and may not reflect modeled p pel ne zones. Source: S&P Global Commod ty ns ghts, ©2023 by S&P Global nc.

natural gas to the south and west most of the time.[185] As seen in Figure 55 above, however, by the end of the Event, net scheduled outflows declined to just 5.3 Bcfd, compared to typical outflows of about 12.5 Bcfd (as measured a week earlier). The Northeast also typically sees substantial imports from Canada over the winter, and during the Event the Northeast increased its imports from Canada, with most of the LNG imports received coming from the Saint John LNG facility in New Brunswick, Canada. Net flows toward the southeast fell 4.8 Bcfd on December 16 to just over 1 Bcfd on December 26, which was the biggest portion of the reduction in total net outflows from the Northeast.

The change in flow patterns was not enough to change the Northeast into a net importer of natural gas, but, as seen in Figure 56 below, overall net outflows from the region reached a low of just under three Bcfd over the Christmas weekend. Flows did not return to their pre-storm levels of about 12 Bcfd, until December 30, 2022. Net outflows from the Northeast to the Midwest reduced by half during the Event as shippers in the Northeast kept more gas in-region and drops in production meant less gas was available after meeting Northeast regional demand. Cove Point LNG in Maryland consistently received flows for export throughout the Event, but also appears to have delivered significant volumes of natural gas back onto the pipeline system from its on-site storage at the same time.

Figure 56: Net Interregional Flows From the Northeast Over the Second Half of December 2023[186]



For the last decade, the Southeast region typically has received substantial net inflows, reversing the historic northwards flow direction on many of the major interstate pipelines. The Midwest market has in the recent past been supported by Northeast outflows, but during the Event Northeast outflows to the Midwest declined, creating room for flows from the Southeast. As a result, flows from the Northeast declined substantially while the Southeast increased net outflows to the Midwest. LNG feed gas demand declined, possibly due to higher supply costs for exporters that rely on spot purchases or difficulty in obtaining transportation capacity for exporters that use interruptible transmission. As seen in Figures 57 and 58 below, some

185 The data presented n th s sect on s based on scheduled ntraday Cycle 3 nom nat ons, wh ch may not reflect actual p pel ne flows due to rregular rece pts by sh ppers.

186 Source: S&P Global Commod ty ns ghts, ©2023 by S&P Global nc.

amount of LNG regasification occurred in the Southeast during the Event, likely at LDC storage facilities and possibly at some LNG export facilities.

Figure 57: Natural Gas Flows Into and Out of the U.S. Southeast Region[187]

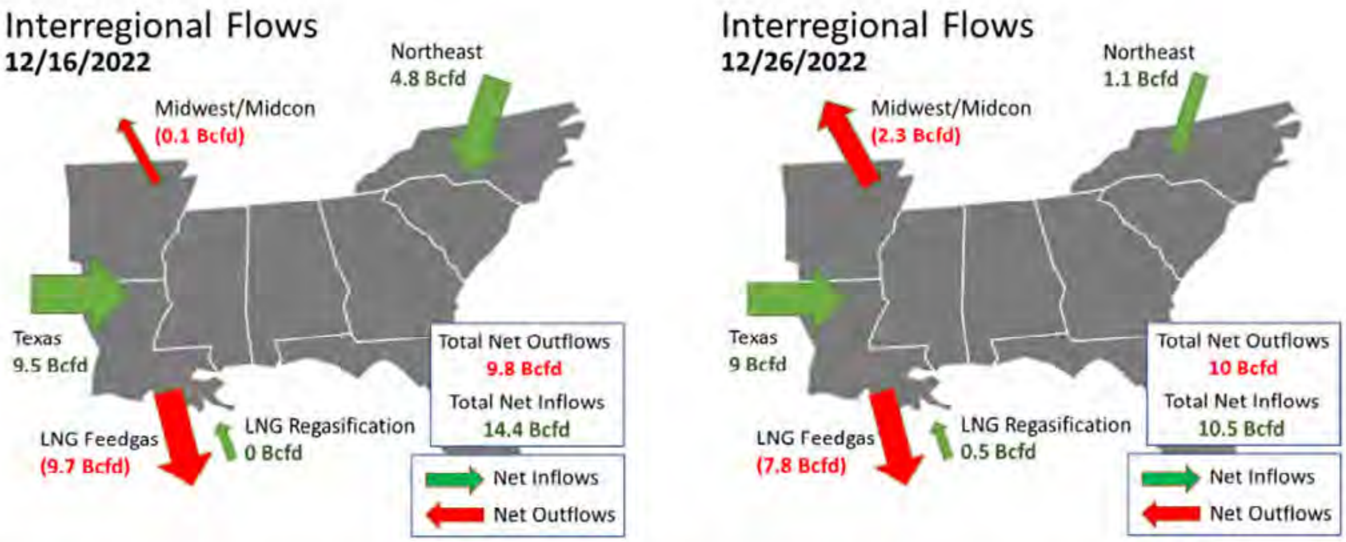
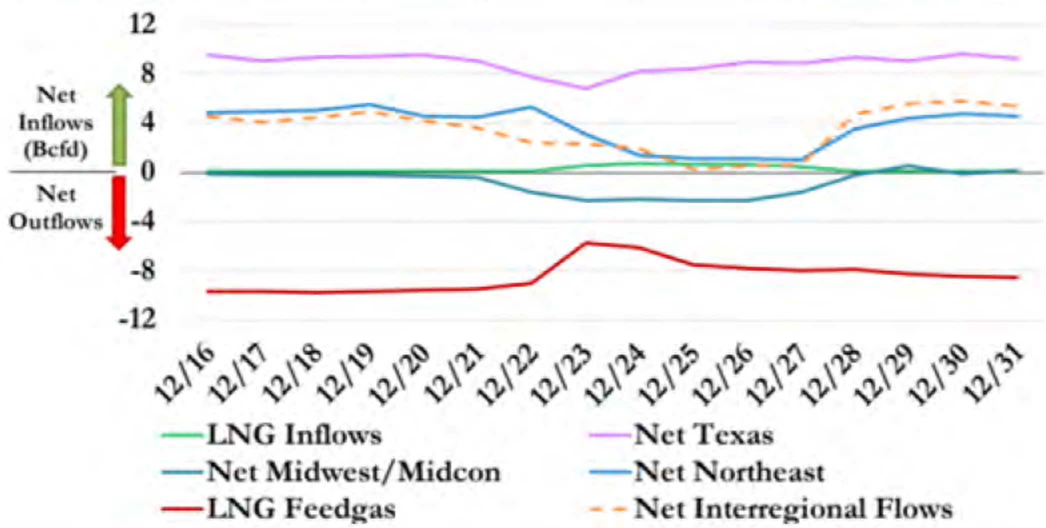


Figure 58: Interregional Flows from the Southeast over the second half of December 2023[188]



a. Storage Operations

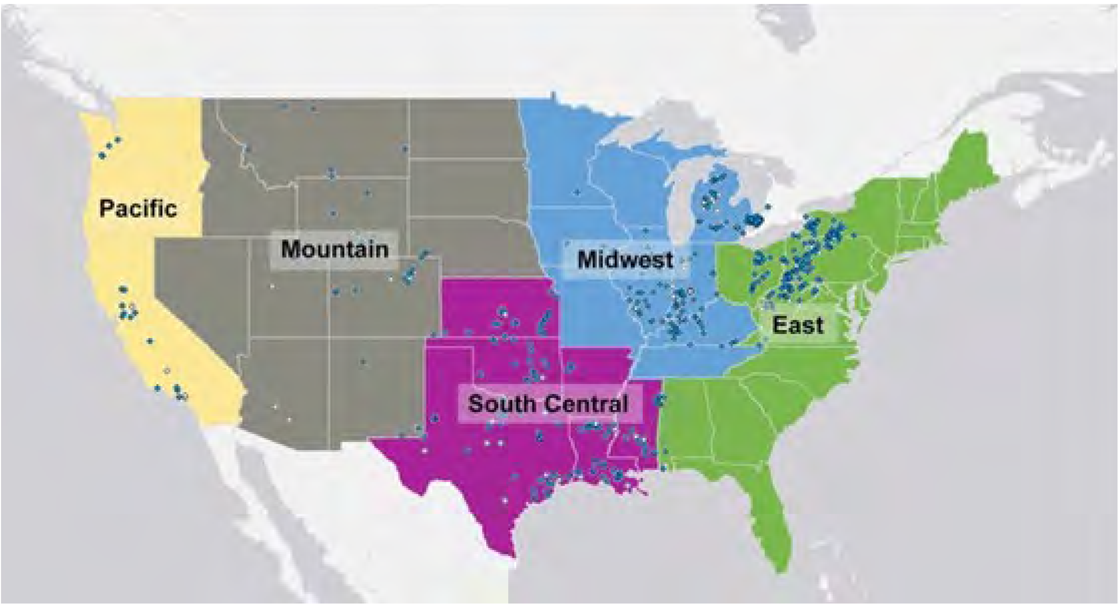
The U.S. Energy Information Administration (EIA) collects and provides weekly estimates of working gas volumes held in underground storage facilities in the lower 48 states and at five regional levels. EIA breaks down regions

187 Flow s ze arrows are approx mate. Reg on borders are general zed and may not reflect modeled p pel ne zones. Source: S&P Global Commod ty ns ghts, ©2023 by S&P Global nc.

188 Source: S&P Global Commod ty ns ghts, ©2023 by S&P Global nc.

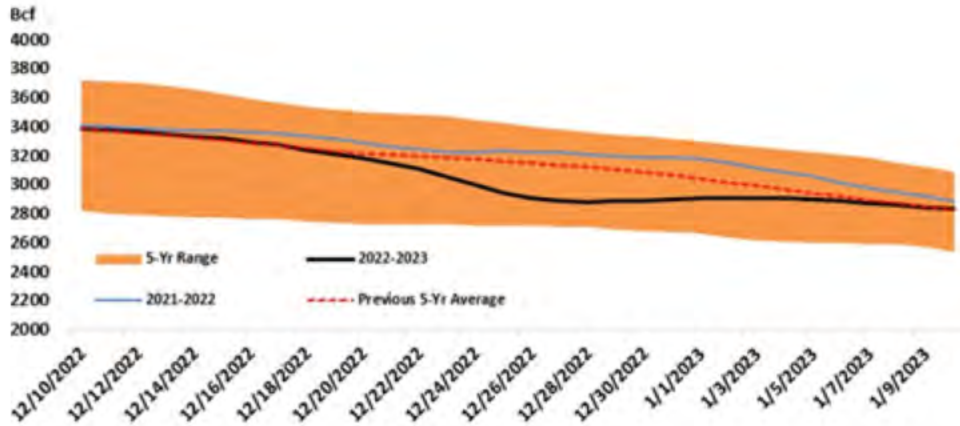
for natural gas storage into the Pacific, Mountain, Midwest, South Central, and East. These are geographically-defined regions and the storage fields are concentrated in the South Central, East, and Midwest regions (see Figure 59, below). Changes in these gas inventories on a weekly basis primarily reflect net withdrawals or injections.

Figure 59: Natural Gas Storage Field Regions of the U.S.



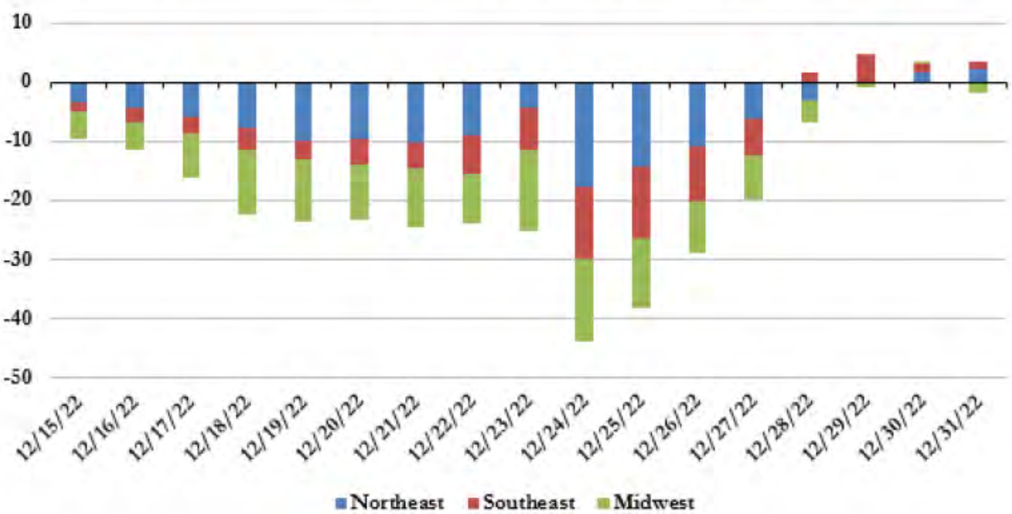
According to S&P Global Insights data there was a notable decline in inventory of stored natural gas during the Event, which reflected reliance on stored natural gas as natural gas production fell and demand increased. Although the natural gas storage levels did not dip below the lowest level reflected in the five-year range, they did dip below both the five-year average and levels seen the year before (see Figure 60, below). S&P uses different regions from EIA, which vary slightly in the Event Area (e.g., Ohio and Kentucky are in the Northeast, not the East, and there is no South Central, only Southeast, Texas and Midcon Producing (Oklahoma, Arkansas, and Kansas).

Figure 60: Natural Gas Storage Levels: November 18, 2022 – February 3, 2023, and Five-Year Average for Same Period[189]



The majority of withdrawals during the Event were in the South Central, Midwest, and East Regions (see Figures 61 and 62, below). Once the storm passed and temperatures rose, gas returned to storage and the South Central region experienced net positive injections. During the Event, 235 Bcf of natural gas was withdrawn from storage nationwide to meet the heightened natural gas demand, a 55.5 percent increase in withdrawals from storage as compared to the five days prior (December 16-21). Regionally, the three most affected regions of the Northeast, Southeast, and Midwest withdrew 160.0 Bcf of natural gas from storage, nearly 70 percent of all withdrawals from storage in the U.S.

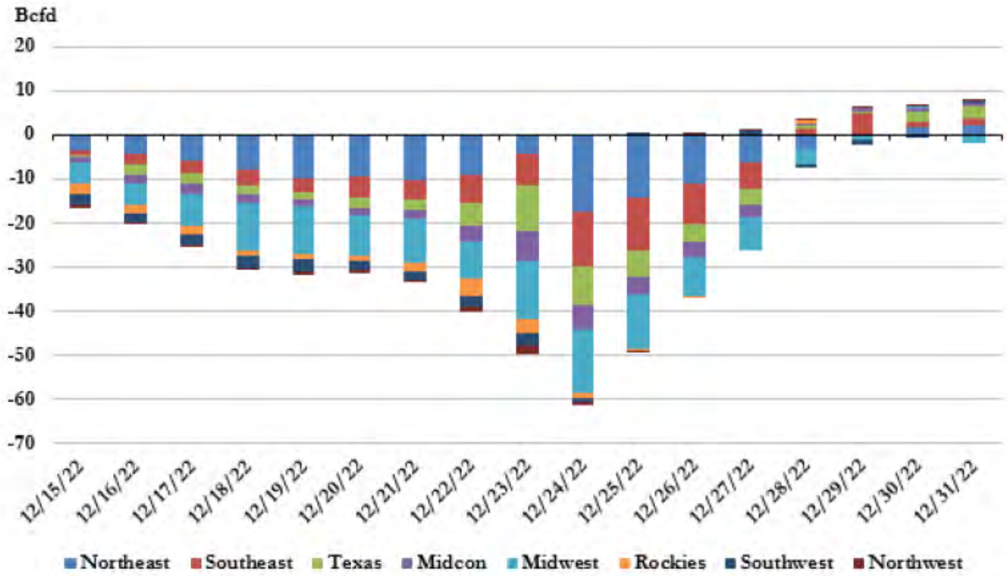
Figure 61: Natural Gas Storage Net Withdrawals From the Relevant Regions: December 15 – December 31, 2022[190]



189 Source: S&P Global Commod ty ns ghts, ©2023 by S&P Global nc.

190 F gures 61 and 62: source: S&P Global Commod ty ns ghts, ©2023 by S&P Global nc.

Figure 62: Natural Gas Storage Net Withdrawals in the U.S.: December 15 – December 31, 2022



c. Natural Gas-Fired Generating Units Faced with Loss of Interruptible Transportation, Inability to Find Sufficient Supply, and Force Majeure Cutoffs of Firm Transportation

The mismatch between the availability of gas and the demand from natural gas-fired generating units on December 23 and 24 had an immediate and substantial impact on generation. Natural gas-fired generating units that responded to inquiry data requests relayed their experiences in this period:

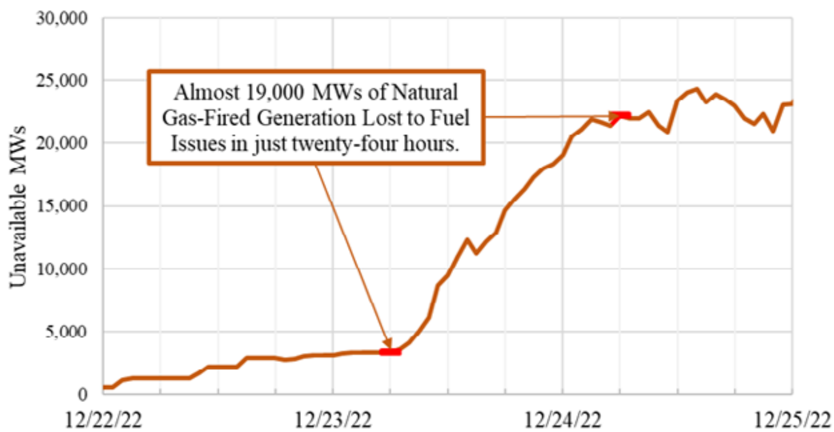
- A 300 MW+ fossil steam unit in SPP cut its generation in half early on December 23 because the gas supplier under its interruptible pipeline delivery arrangement was experiencing a supply limitation.
- An 800 MW+ combined cycle unit in PJM with a firm supply contract reported, on the morning of December 23, that it was forced to cease generating entirely because "gas fuel [was] unavailable."
- Four affiliated gas turbines in PJM, whose collective capacity was in excess of 800 MW, reported on December 23 that fuel unavailability due to market conditions had caused them to stop generating.
- Six centrally-located affiliated gas turbine units owned by a vertically-integrated utility, each with a capacity of nearly 200 MW, reduced their generation by more than 50 percent on the afternoon of December 23 because their pipeline was unable to provide the minimum delivery pressure to the units.
- In the late afternoon of December 23, a gas turbine located in PJM with nearly 200 MW capacity ceased generation because its gas supplier was unable to meet its needs under its firm pipeline delivery arrangement.

These individual narratives—just a handful of examples from many—illustrate the larger collective experience of natural gas-fired generating units during this critical period. On December 23 and 24, more than 41,700 MW of natural gas-fired generation reported outages, derates, or failures to start due to Fuel Issues. Figure 63, below lists the major sub-causes of Fuel Issues experienced by natural gas-fired generating units.

Figure 63: Gross Unavailable MW, Natural Gas Units Experiencing Fuel Issues, Top Sub-Causes, December 23-24, 2022

Fuel Issue - Sub-Cause[191]	December 23	December 24
nterrupt ble P pel ne Del very nterrupt on	6,268	5,485
Market ssues	5,173	9,913
F rm P pel ne Del very Curta lment	4,533	700
Gas Del very Pressure ssues	1,532	2,557
Market Pr ce Restr ct on	1,040	0
Fa lure to Fulfill F rm Supply Obl gat ons	972	2,852
Transportat on Schedul ng Constra nts	716	0
TOTAL	**20,234**	**21,507**

Figure 64: Incremental Unplanned Unavailable Generation in the Event Area, Natural Gas Units, Fuel Issues, December 22 - 25, 2022



There is a clear relationship between these outages and the system-wide struggle to obtain gas and maintain pressures described above. As illustrated in the below chart, there is a sharp upwards trend in net incremental natural gas-fired generation lost to Fuel Issues beginning the morning of December 23, just as pipelines began to experience supply shortfalls. As illustrated in Figure 64 above, starting that morning, and over the next 24 hours, nearly 19,000 MW of net incremental generation from natural gas-fired generating units were lost due to Fuel Issues.

d. Reliability-Threatening Delivery Pressure Decreases at Major Natural Gas LDC Citygate

Winter Storm Elliott greatly impacted the operations of Consolidated Edison Company of New York, Inc. (Con

191 The follow ng are descr pt ons of above sub causes: nterrupt ble P pel ne del very nterrupt on nterrupt ble p pel ne transportat on unava lable due to contractual or tar ff prov s on; Market ssues Market ssues other than h gh market pr ces, such as unable to purchase gas n short term market (could not find a gas suppl er n the market); F rm P pel ne Del very Curta lment F rm p pel ne gas transportat on curta led (reduct on of gas del ver es; Force majeure, P pel ne enforces ratable takes prov s on to tar ff levels); Gas Del very Pressure ssues Del vered gas pressure below Generator's m n mum operat ng pressure (e.g., pressure too low for generator to operate); Market Pr ce Restr ct on H gh market pr ces (chose not to purchase gas due to h gh market pr ces); Fa lure to Fulfill of Contractual Obl gat ons Fa lure of fuel suppl er to fulfill firm contractual obl gat ons (Sell ng counterparty fa ls to del ver firm gas to pr mary p pel ne rece pt po nt, force majeure on the supply); Transportat on Schedul ng Constra nts Transportat on schedul ng constra nts due to Hol day schedule (less gas scheduled than needed).

Edison),[192] the natural gas LDC for Manhattan, The Bronx, and portions of Queens and Westchester County, NY. On Christmas Eve morning, the five interstate natural gas pipelines serving Con Edison began experiencing drops in pressure at Con Edison's citygate due to production losses and operational issues. The pressures declined precipitously and at noon, the pipelines informed Con Edison that they had exhausted their line pack and storage withdrawals, and pressures would not improve until demand decreased. Con Edison managed to supply its customers with gas and maintain necessary pressure, by declaring an internal Gas System Emergency and implementing its specification for "Limiting Gas Use and Load Shedding During a Supply Curtailment or Emergency." As part of the Gas System Emergency, Con Edison activated its LNG regasification plant.

Had Con Edison's citygate pressures not recovered, it was in danger of losing pressure on, or needing to cut service to, all or large portions of its system. Even losing service to 130,000 customers would be considered a major outage and could have taken five to seven weeks to restore, depending on the availability of mutual aid. Had it lost the majority of its system, over a million customers in New York City and nearby areas would have been unable to heat their apartments and houses while the outside temperature was in the single digits, for months. Moreover, a system-wide outage would likely have caused extensive property damage due to damaged water pipes within homes and buildings. Critically, these dire circumstances occurred despite Winter Storm Elliott not qualifying as a "design day" event. LDCs designate certain parameters for "design day" events to plan gas capacity requirements, and a "design day" reflects the highest gas demand that the LDCs expect to be obligated to serve on an extremely cold winter day. The actual average temperatures on December 23 and 24 in the Con Edison service territory were 17 and 15 degrees, respectively. By contrast, Con Edison's design day is based on a zero-degree temperature variable.[193]

On December 16, Con Edison began to prepare for Winter Storm Elliott, including communicating with relevant stakeholders to coordinate in preparation for the storm. In addition to standard daily communications, weather event coordination efforts began on December 19 between Con Edison, National Grid, and Pipeline Control from Enbridge, Inc. (Texas Eastern Transmission, LP ("Texas Eastern") and Algonquin Gas Transmission, LLC ("Algonquin")) (collectively, "Enbridge"), Williams Companies Inc. (Transcontinental Gas Pipe Line Company, LLC) ("Williams"), and Iroquois Gas Transmission System, L.P. ("Iroquois") to discuss upcoming weather patterns and event preparation plans specific to the New York City market area.

On December 21, Con Edison notified its interruptible customers that they were being curtailed and issued OFOs. Additionally, due to colder trending forecasts and overlapping restrictions with Kinder Morgan Inc. (Tennessee Gas Pipeline Company, LLC), Con Edison activated its compressed natural gas (CNG) station and scheduled it to capacity. As the storm worsened, Con Edison issued additional curtailment notices to customers with dual-fuel interruptible and off-peak firm sales and transportation covering December 23 through 27. Also on December 23, Con Edison placed its liquid natural gas facility on stand-by. On December 24 Con Edison

192 Con Ed son and ts aff l ated compan es ma nta n a portfol o of contracts w th vary ng lengths of exp rat on and flex b l ty. The compan es have entered nto supply agreements that are des gned to prov de rel able serv ce to firm natural gas customers under des gn day w nter cond t ons n the serv ce areas. These contracts nclude firm gas supply (100 percent domest c or LNG), firm p pel ne transportat on, product on area and market area storage, firm peak ng serv ces, LNG, and c tygate baseload suppl es. Con Ed son had contracted for more nterstate p pel ne capac ty and natural gas commod ty than requ red to meet customer demand on December 24.

193 Con Ed son uses a weather concept called "Temperature Var able" (TV) as a reference po nt n the weather adjustment process. The TV s used n calculat ng and forecast ng future system peak demands, cons der ng extreme w nter weather cond t ons (susta ned low temperatures over two Gas Day per ods). The gas day average (GDA) temperature s a 24 hour ar thmet c average start ng at 10 a.m. us ng the Central Park Nat onal Weather Stat on dry bulb temperature. The formula for calculat ng the system TV on a da ly bas s ncorporates two days' worth of GDA's. The current day's GDA s we ghted at 70 percent and the prev ous day's GDA at 30 percent.)

issued OFOs that restricted short positions to two percent of gas scheduled through the Event and began hourly transportation restrictions to 1/24th of schedule. At this time, all of Con Edison's upstream interstate pipelines had imbalance OFOs in place restricting the availability of unscheduled gas. Con Edison's upstream pipelines also began reporting various issues including operating constraints, receipt points underperforming, upstream low pressures, compressor station issues, force majeure, and maxed out line pack.

The Con Edison system performance continued to be within expected operating ranges through December 23. Despite interstate pipeline pressures beginning to fall at Con Edison's metering and regulating stations (which measure and control the pressure of gas and interconnect with interstate pipelines), the impacts on supply to Con Edison were within normal expectations through the morning of December 24. However, for the Intraday 1 (ID1) nomination cycle on December 24, interstate pipelines began to restrict underperforming meters. At that time, Con Edison was not notified of the specific reason for pipeline restrictions or reductions by marketers or producers. Due to the reduced supply and continuing high demand, the average meter station inlet pressure (reflecting the interstate pipelines' low pressure issues) for Con Edison declined rapidly and reached its lowest levels between the nomination deadline and scheduling for the December 24 ID1 cycle from 11:00 a.m. to 2:00 p.m. ET. The average pressure fell from 806 pounds per square inch gauge (psig) at 12:00 a.m. on December 23 to 441 psig at 2:00 pm on December 24. Con Edison Gas Control began implementing emergency measures after the interstate pipelines notified Con Edison that they had depleted their line pack, had no more ability to withdraw from storage, and would continue to have low interstate pipeline pressures until demand decreased. A likely contributing factor exacerbating pipelines' integrity issues was that some generators may have flowed in excess amounts over their confirmed nominations. The pipelines used line pack and gas from storage to meet the incremental demand, but as the Event progressed, the supplementary demand volumes in conjunction with continuing supply shortfalls led to low pressures and the reduction of confirmed nominations. Con Edison, given its downstream location near the end of the interstate pipelines, was disproportionately impacted by the deteriorating pipeline conditions, through no fault of its own.

e. LDC Gas System Emergency, Orders for Fuel Curtailments to Natural Gas-Fired Generation, and Public Appeals to Reduce Gas Demand

On December 24 at 1:26 p.m., Con Edison management declared an internal Gas System Emergency and dispatched its LNG facility, which ramped up to maximum dispatch, because the interstate pipelines serving Con Edison's citygate said that their pressures were not recovering. Later that day, at 2:14 p.m., Con Edison Gas Control declared Gas System Condition Red, which meant that "gas supply through gate station(s) . . . [was] . . . severely limited or completely interrupted resulting in imminent risk to more than 500 services." This Condition Red remained in place until December 26 at 10 a.m. In accordance with its "Guidelines for Major Contingencies on the Gas System" specification, Con Ed "order[ed] electric and steam generation stations to . . . completely curtail gas use." Con Edison had already dispatched its LNG Plant at 2 p.m., another step allowed under Gas System Condition Red. At 6:30 p.m. that evening, Con Edison issued a public appeal to reduce demand. Under the specification for Limiting Gas Use and Load Shedding During a Supply Curtailment or Emergency, Con Edison had 11 steps to mitigate a supply shortage or to limit gas during an emergency, which progresses from taking steps to increase the supply of natural gas to firm customer load shedding. Con Edison implemented actions through at least step 7, public appeals to reduce demand, before the Gas System Emergency abated. Figure 65 shows the average meter station inlet pressure on December 21-27, relative to the declaration of the Gas System Emergency and Gas System Condition Red. Figure 66, below, shows how the meter station inlet pressures for the five interstate pipelines serving Con Edison's citygate declined precipitously on Christmas Eve, before recovering on Christmas through December 27.

Figure 65: Con Edison Average Meter Station Inlet Pressure (PSIG), December 21 - 27, 2022

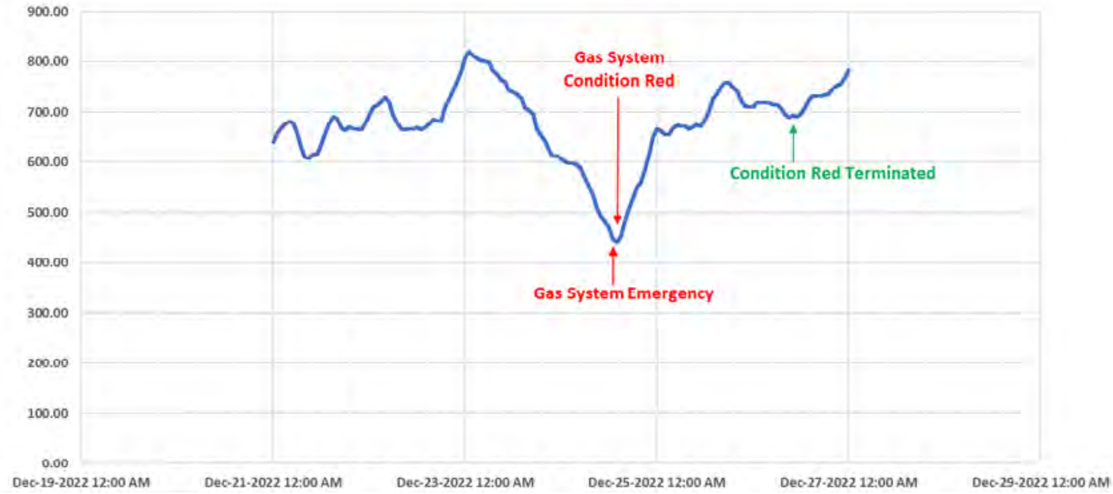
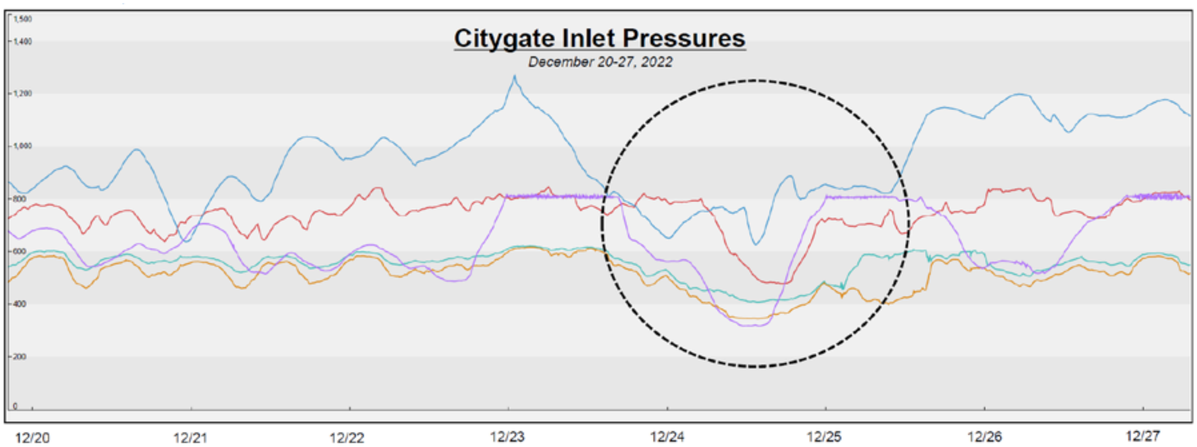


Figure 66: Con Edison Citygate Inlet Pressures, December 20 - 27, 2022



Efforts to address the situation continued on Christmas Day. Con Edison ramped down its LNG facility due to increasing pipeline pressures at its citygate and to preserve asset inventory, placing the LNG facility back on standby status at 8:13 a.m. Pressures at the citygate were recovering but the pipelines reported in a 7 a.m. call that line pack was still depleted. On December 26, Con Edison finally terminated its Gas System Condition Red.

C.Post-Event Actions by Affected Entities, Government Agencies and State Governments

1. ACTIONS BY AFFECTED ENTITIES

Several of the affected entities later conducted comprehensive reviews of the performance of their systems during Winter Storm Elliott. TVA created an "After Action Report" which included several recommendations to improve energy supply, real-time load forecasting and operations, emergency protocols, and customer and stakeholder engagement.[194] TVA has committed to adding 10,000 to 14,000 MW of new generation by 2030 to help meet demand. It is currently in the process of building 3,800 MW of new generation, including solar energy, energy storage, combustion turbines, and combined-cycle natural gas. It is also investing in infrastructure, enhancing its transmission systems, and building a new Systems Operations Center.[195]

PJM prepared an "Event Analysis and Recommendation Report," outlining the lessons learned from Winter Storm Elliott and improvements it plans to make.[196] These included improving generator performance, enhancing forecasting and modeling, and tackling long-standing gaps in gas-electric coordination. PJM is working on developing improvements through its Critical Issue Fast Path stakeholder process. PJM recently submitted proposed enhancements to the capacity market rules that address certain recommendations from its report, including, but not limited to, enhanced risk modeling, refined resource accreditation, updates to the balancing ratio, and changes to bonus eligibility for Demand Resources and Energy Efficiency Resources.[197]

LG&E/KU prepared two event summary reports, one for its Generation, Transmission and Distribution operations, and one for its Gas operations. It is looking at potential process improvements, such as public messaging and projects at plants to minimize valve freezing and other cold weather impacts.[198] Santee Cooper developed a historical average forced outage rate for units during extreme events to estimate how much additional reserves should be considered during this type of event.

2. ACTIONS BY GOVERNMENT AGENCIES AND STATE GOVERNMENTS

On August 25, 2023, the South Carolina Office of Regulatory Staff filed a report titled "Inspection and Examination Report of Duke Energy Carolinas, LLC and Duke Energy Progress, LLC: December 2022 Winter Storm Outages and Blackouts."[199] The report identified five key causes for the rolling outages (firm load shed), which impacted over 500,000[200] customers across North and South Carolina, ranging from three to ten hours each: (1) Duke[201] significantly underestimated demand, failed to update its forecast estimates, and did not make

194 Tennessee Valley Author ty After Act on Report, at 20 21, https://blox mages.newyork1.v p.townnews.com/local3news.com/content/tncms/assets/v3/ed tor al/4/3e/43e4b436 eb67 11ed a87a 530b1c4c2bd9/645537f5cd9d7.pdf.pdf).

195 *Id.* at 22.

196 PJM, W nter Storm Ell ott Event Analys s and Recommendat on Report ("PJM Report"), pages 2 3, https://www.p m.com/ /med a/l brary/reports not ces/spec al reports/2023/20230717 w nter storm ell ott event analys s and recommendat on report.ashx .

197 *See PJM Interconnection, L.L.C.,* Docket No. ER24 98 000 (Oct. 13, 2023); *PJM Interconnection, L.L.C.,* Docket No. ER24 99 000 (Oct. 13, 2023). PJM has stated that t w ll cont nue to engage w th stakeholders on recommendat ons from the PJM Report.

198 *Talking Points*,https://lge ku.com/employee resources/ce/talk ng po nts/2023/01/w nter storm ell ott (last v s ted Oct. 26, 2023).

199 nspect on and Exam nat on Report of Duke Energy Carol nas, LLC and Duke Energy Progress, LLC December 2022 W nter Storm Outages and Blackouts, Docket No. ND 2023 1 E (Aug. 25, 2023), ec372380 8639 406e 816e fc9fe0d45cfd (sc.gov)

200 https://news.duke energy.com/releases/duke energy updates north carol na ut l t es comm ss on on w nter storm ell ott emergency outage event#:~:text CHARLOTTE%2C%20N.C.%20%E2%80%93%20Leaders%20from%20Duke,from%20occurr ng%20that%20way%20aga n

201 DEC and DEP.

supply planning adjustments; (2) Duke experienced multiple failures at various plants, some due to planned maintenance and others due to operational issues that forced them to shut down, such as cracks in the insulations and frozen instruments; (3) power purchases from neighboring utility companies were curtailed; (4) power generation contracted by other utilities failed; and (5) the automated software tool to manage the rotating outages failed, causing significant delays as Duke had to manually restore power. The report also discussed Duke's delay in communicating with customers. The outages began between 6:15 and 6:25 a.m. on December 24. The report found Duke began notifying customers one hour later. The investigation also found Duke told customers the timeframe for power restoration would be 30 to 60 minutes, when in fact it took several hours.

Ultimately, the report found that there is "room for improvement" in Duke's cold weather preparedness plans for its generation facilities. The investigation made several recommendations, including ensuring that doors and louvers that could expose equipment to the elements are left closed, and installing heaters. The investigation also recommended Duke enhance staffing and the frequency of operators making rounds during severe winter weather events. On August 29, 2023, Duke submitted a letter[202] to the Public Service Commission responding to the report, which took issue with several of its findings, including with the report's statement that Duke failed to respond to supply adequacy risk, asserting that Duke did respond and made purchases to increase operating reserves where they were forecasted to be below target. Duke also said that the models used by the industry to forecast power demand "look backwards in time" for similar circumstances, and that a similar day in December did not exist. However, the letter stated that Duke has created a corrective action plan, and that it has completed 76 of the 101 action items in the plan, with the action items in progress.

The Kentucky Public Service Commission has been using a preexisting docket regarding approval of a demand side management plan and approval of fossil fuel-fired generating unit retirements to obtain data from LG&E/KU regarding the Event, but has not issued any findings.[203] On February 17, 2023, the Kentucky Attorney General sent LG&E/KU an initial request for information.[204] The inquiry asked the companies to "[p]rovide a detailed, thorough and comprehensive explanation regarding the causes of the rolling blackouts [firm load shed] the Companies instituted during Winter Storm Elliott[…]." On March 10, 2023, LG&E/KU provided their responses to the initial data requests.[205] This included a summary of events prepared by LG&E/KU.[206] In this summary, the companies stated that the rolling blackouts were caused by interstate gas pipeline pressure limitations, mechanical issues, and other cold weather issues. The companies explained that the projected net peak load was far lower than the actual peak load on December 23. Three of the companies' units were offline during this time and not expected to be needed. The supplier for two of the plants also failed to meet its contractual obligations, and there were interruptions in energy deliveries. LG&E/KU explained that as the conditions across the regional grid began to deteriorate, they executed their Capacity and Energy Emergency Operating Plan in order to restore system balance.

202 36b057d1 aba3 47d5 9bbe 4a9f2d4fbb0f (sc.gov)

203 The record was closed as of September 15, 2023, and the Comm ss on stated that t w ll ssue a dec s on after October 5, 2023. The docket d d not show a dec s on as of the morn ng of October 30. *Winter Storm Elliott Events in the LG&E and KU Balancing Authority Area (BAA)*(Dec. 24 25, 2022), https://psc.ky.gov/pscecf/2022 00402/r ck.lovekamp%40lge ku.com/03102023103319/03 AG DR1 LGE KU Attach to Q13%28l%29 Att 1 W nter Storm Ell ott LKE Event Summary.pdf.

204 *Kentucky Coal Association First Data Request (filed Feb. 17, 2023)* https://psc.ky.gov/pscecf/2022 00402/mmalone%40hdmfirm.com/02172023095137/F rst Data Requests to Compan es.final.pdf; *Attorney General Data Requests* (Feb.17, 2023), https://psc.ky.gov/pscecf/2022 00402/rate ntervent on%40ky.gov/02172023023845/23..02.17 AG DR 1 2022 00402 F NAL.pdf.

205 *Kentucky Utilities Co. & Louisville Gas and Electric Co. Response* (Mar. 10, 2023),https://psc.ky.gov/pscecf/2022 00402/r ck.lovekamp%40lge ku.com/03102023103319/02 AG DR1 LGE KU Responses.pdf.

206 *Winter Storm Elliott Events in the LG&E and KU Balancing Authority Area* (BAA) (Dec. 23 24, 2022), https://psc.ky.gov/pscecf/2022 00402/r ck. ovekamp%40 ge ku.com/03102023103319/03 AG DR1 LGE KU Attach to Q13%28 %29 Att 1 W nter Storm E ott LKE Event Summary.pdf.

IV. ANALYSIS AND FINDINGS

A. Overview of Event Causes

Three causes accounted for 96 percent of the generating unit outages, derates or failures to start, based on number of MW: Mechanical/Electrical, Freezing, and Fuel Issues, as shown in Figure 67. Natural Gas Fuel Issues, (the larger portion with small dots in the orange pie segment) were 20 percent of all causes (and 83 percent of outages caused by Fuel Issues).[207] Figure 68, below, illustrates the generating unit outages by fuel type over the course of the Event. Natural gas-fired units represented 47 or 63 percent of the incremental unplanned generation loss, based on number of outages or MW, respectively.[208] Unplanned outages of natural gas- and coal-fired generating units began to rise on December 22 and rose steadily into December 23. Early on December 23, the rate of outages of natural gas-fired generating units rose sharply, and this trend continued throughout December 23. This is consistent with what Balancing Authorities told the Team, especially in PJM and MISO: that multiple natural gas-fired generating units reported their inability to perform during that period, in many cases, only when called to find out why they had not come online.[209] Natural gas-fired generating unit outages peaked at nearly 60,000 MW for the Event Area by midday on December 24. Natural gas-fired generating units played such a large role in the Event due to the large percentage of natural gas-fired generation in the Event Area (nearly 42 percent, see Figure 11), and the multiple outage causes which affected this fuel type (Fuel Issues, Freezing Issues and Mechanical/Electrical Issues not directly caused by freezing). According to the NAESB Report, "trends in electrification coupled with the growth in renewable resources and the retirement of coal-fired generation, likely mean there will be a greater reliance upon electricity produced by natural gas as a balancing resource."[210]

Freezing Issues caused 31 percent of all generating unit outages, and over 75 percent of Freezing Issues occurred at ambient temperatures that were above the GOs' documented operating temperatures.[211] Both open-frame generating units, common throughout the south, and natural gas production infrastructure, with its associated water, are known to be vulnerable to freezing. In addition, wind turbines are known to be vulnerable to blade icing because of freezing precipitation. Coal-fired units can be vulnerable to frozen coal piles or difficulty processing wet coal, especially if the coal piles remain undisturbed during periods of freezing precipitation.[212] The extent to which generating units of all types still experienced outages, derates and failures to start to Freezing Issues continues to be a major concern. Freezing Issues and Fuel Issues combined to cause 55 percent of all unplanned generating unit outages, derates and failures to start during the Event, as shown in Figure 67 below (as measured by MW). Mechanical/Electrical Issues, responsible for an additional 41 percent of outages, derates and failures to

---

207 Natural Gas Fuel ssues nclude the comb ned effects of decreased natural gas product on; cold weather mpacts and mechan cal problems at product on, gather ng, process ng and p pel ne fac l t es result ng n gas qual ty ssues and low p pel ne pressure; supply and transportat on nterrupt ons; curta lments and fa lure to comply w th contractual obl gat ons. Add t onally, t ncludes sh ppers' nab l ty to procure natural gas due to t ght supply, proh b t ve, scarc ty nduced market pr ces, or m smatches between the t m ng of the natural gas and energy markets.

208 Unless otherw se nd cated, w th n th s sect on values expressed as percentages correspond to the total amount of ncremental generat on lost   *i.e.* unava lable MW   as reflected n data prov ded by generat ng un t owners and/or operators. *See* Append x C.2 for a breakdown of outages, derates and fa lures to start by fuel type, among other analyses.

209 *See* Sect on   .B.1.a) regard ng M SO and PJM exper ences regard ng generator reported fuel ssues on December 23.

210 NAESB Report at 67.

211 *See* note 61 for an explanat on of the var ous methods GOs can choose to document an operat ng temperature and how the Team calculated th s stat st c.

212 Th s can be m t gated by cont nuous movement of the coal p le (us ng bulldozers or s m lar equ pment) dur ng freez ng prec p tat on/extreme cold weather cond t ons.

start, also increased as temperatures fell and decreased as temperatures rose, but unlike Freezing Issues, the method by which the cold affected the generating unit was less obvious.

Figure 67: Total MW Loss of Incremental Generation Outages, Derates, and Failures to Start (Outaged MW) by Cause, December 21-26, Total Event Area

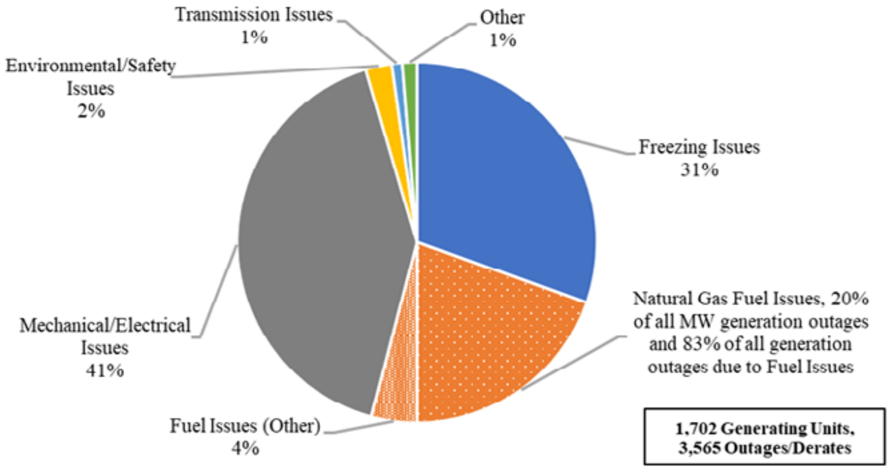


Figure 68: Generation Outages, Derates, and Failures to Start (MW) by Fuel Type, December 21-26, Total Event Area

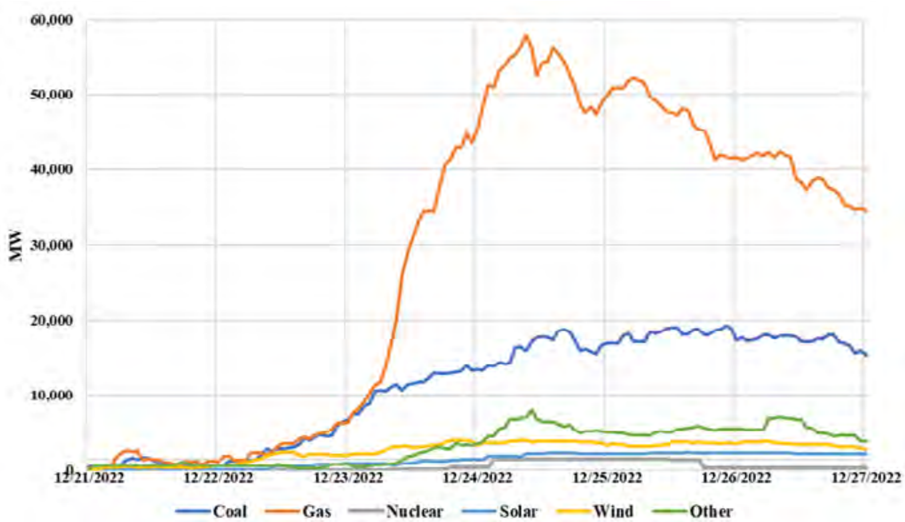
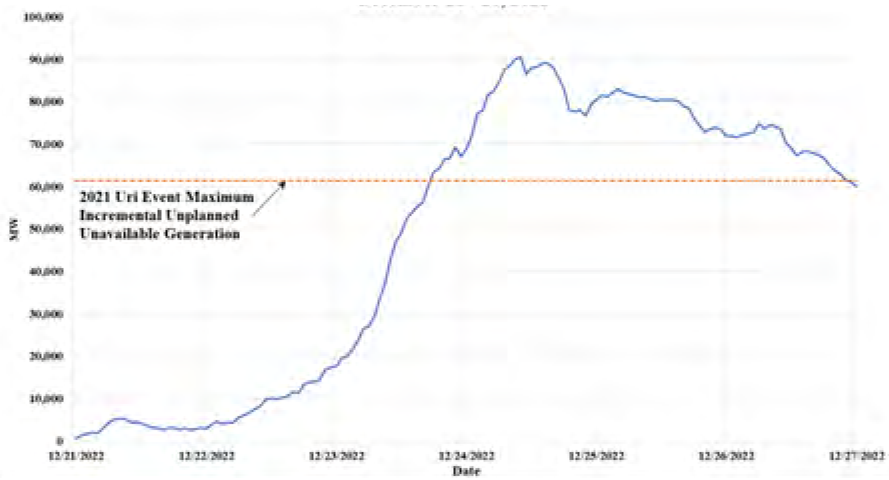


Figure 69: Incremental Unplanned Coincident Unavailable Generation in the Event Area, December 21-26, Total Event Area



At its worst point, the U.S. portion of the Eastern Interconnection had over 127,000 MW of generating outages, including outages that began before the Event, equivalent to **18 percent** of the U.S. portion of the anticipated resources in the Eastern Interconnection.[213] The peak coincident incremental unplanned unavailable generation in the Event (90,500 MW), as shown in Figure 69, above, was roughly 50 percent larger than the peak magnitude of coincident incremental unavailable generation during Winter Storm Uri (represented by the red dotted line in Figure 69), although the Uri event lasted more than twice as long (13 days versus six days).

213 Accord ng to the NERC 2022 2023 W nter Rel ab l ty Assessment. *See* note 12.

B. Causes of Generating Unit Outages During the Extreme Cold Weather

1. SUMMARY

An analysis of the data collected in connection with Winter Storm Elliott reiterates the relationship between the onset of freezing temperatures and the rise of generation loss caused by Freezing Issues, by Mechanical/Electrical Issues strongly correlated to declining temperatures, or by Fuel Issues whose root cause can be traced to the onset of extreme cold weather, as shown in Figure 70, below.

Winter Storm Elliott, and its impact on generation, is notable for two material reasons.

First, the scale of generation lost during Winter Storm Elliott is unprecedented, with a peak incremental unplanned generation loss totaling 90,500 MW. This reflects generation loss at 1,702 individual generating units spread over 3,565 discrete unplanned outages or derates. This incremental unplanned generation loss during Winter Storm Elliott, after the catastrophic effects of Winter Storm Uri just one year earlier, raises a concerning alarm about the ability of the grid to handle extreme cold weather events.

Second, Mechanical/Electrical Issues related to extreme cold weather events (as distinguished from Freezing Issues) rose as temperatures fell, a pattern seen in every extreme cold weather inquiry event since 2018. The 2021 Report noted that as temperatures fell, generation losses attributed to Mechanical/Electrical Issues increased[214] and that "[i]n the 2018 event, a similar pattern was evident—the total generating unit outages were correlated with temperatures—again, as temperatures fell, the incidence of unplanned outages and derates increased."[215] As reported in the 2021 Report, these outages may be caused by the impact of extreme cold weather on mechanical and thermal stress, thermal cycling fatigue and other effects of cold weather such as embrittlement and gelling of fuels and lubricants.[216]

2. MECHANICAL AND ELECTRICAL ISSUES

a. Summary Analysis

Overall, generating units reported 1,418 unplanned outages, derates or failures to start for various reasons linked to Mechanical/Electrical Issues – accounting for 40 percent of all generation losses reported during the Event and peaking at more than 31,000 MW of incremental unplanned generation loss during the Event. Most manifested as forced outages (48 percent) or forced derates (43 percent).

Within the Mechanical/Electrical Issues category, the most significant individual sub-cause of outages was Equipment Failures/Issues by a wide margin (72 percent). Other than Equipment Failures/Issues, the only other sub-cause within the Mechanical/Electrical Issue category that had a material presence (approximately 10 percent) was Control System Issues. No other single sub-cause identified by GOs/GOPs materially contributed to lost generation attributable to Mechanical/Electrical Issues.

b. Relationship Between Freezing Conditions and Mechanical/Electrical Issues

As indicated in Figure 71, below, over 80 percent of the incremental unplanned MW lost to Mechanical/Electrical Issues occurred when generating units began to experience below-freezing temperatures.

214 *See* Recommendat on 11 and F gure 105 n 2021 Report.

215 *See* 2021 Report at 217.

216 *See* 2021 Report at 215 217.

Figure 70: Incremental Unplanned Unavailable Generation in the Event Area, Primary Event Causes, December 21 - 26, 2022

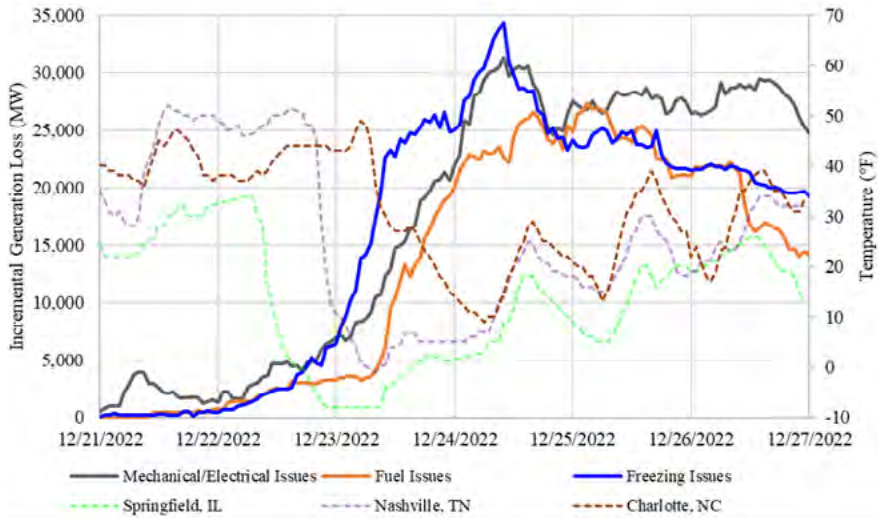
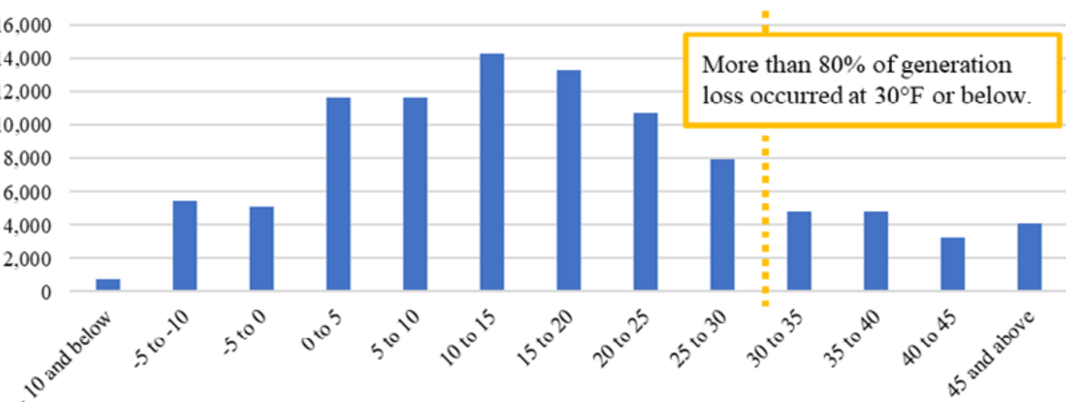
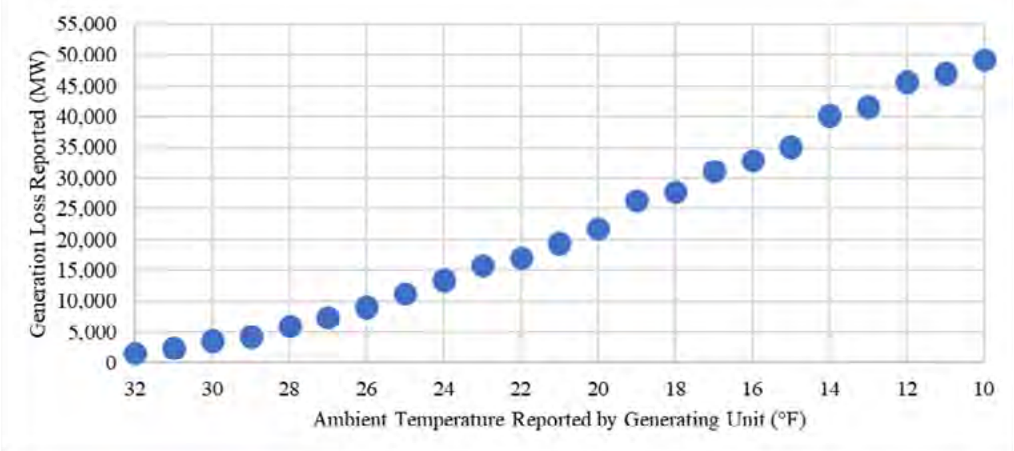


Figure 71: Generation Loss, Mechanical/Electrical Issues by Temperature (°F) Reported at Time of Outage, December 21-26 2022



As illustrated below, generating units steadily lost generation due to Mechanical/Electrical Issues as temperatures declined. In aggregate, generating units reported more than 49,000 MW of lost generation due to Mechanical/Electrical Issues in temperatures between 32 degrees and 10 degrees, as seen in Figure 72, below.

Figure 72: Cumulative Gross Generation Loss, Mechanical/Electrical Issues by Temperature (°F) Reported by Generating Unit, December 21-26, 2022

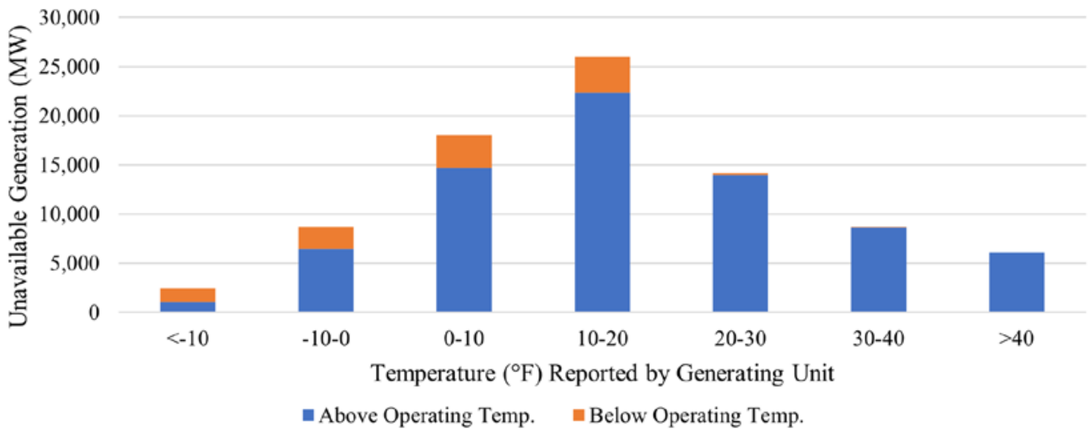


Not every generating unit that experienced a Mechanical/Electrical Issue in below-freezing conditions during Winter Storm Elliott did so *because of* extreme cold weather conditions. The Team believes it is reasonable to conclude that a material portion of Mechanical/Electrical Issues are causally connected to these extreme cold weather conditions. This relationship is supported by reasonable inferences drawn from the numerical data provided by generating units, as well as by narrative responses provided by units explaining their Mechanical/Electrical Issues. Some units that reported Mechanical/Electrical Issues in below-freezing conditions explicitly linked those Mechanical/Electrical Issues to the impacts of cold weather. For example, one generating unit reported that generation was lost because "[g]enerator gas temperature became too low due to ambient temperature." Another claimed that the generating unit "would not start due to oil temperature too low." However, even without considering these explicit claims, many units reported a range of issues that Team members believe, based on their review of the data provided, were likely or probably caused by cold weather conditions. For example:

- Increased oil viscosity with colder ambient temperature (or colder cooling water) was a common issue in the Event:
  - Losses in fuel oil pressure can be caused by cold-induced high viscosity, leading to inability to operate a unit on fuel oil.
  - Wind turbine generators may also suffer from high oil viscosity (lubricant or hydraulic controls), creating pitch problems seen in the Event.
- Many generating units reported material dimensional changes (*i.e.,* shrinkage) during the Event, which may add stress in mechanical systems.

The data also suggest that the ***extreme*** nature of these cold weather events—that is to say, unusually quick drops in temperature, high winds and/or atypical combinations of conditions—may play a role in generation loss due to Mechanical/Electrical Issues.

Figure 73: Generation Loss, Mechanical/Electrical Issues, December 21-26, 2022



As shown in Figure 73, above, comparing generating units' documented operating temperature to the ambient temperature conditions that they reported while experiencing Mechanical/Electrical Issues revealed a clear and disturbing outcome. A substantial majority of generation losses due to Mechanical/Electrical Issues (87 percent) occurred at an ambient temperature above the generating units' documented operating temperature.[217]

Using only the units' ambient design temperature, for those units that provided that temperature, nearly 39,000 MW of generation was lost due to Mechanical/Electrical Issues where units (a) reported freezing or below-freezing ambient temperatures in connection with the generation loss, (b) provided an ambientdesign temperature, and (c) where the ambient design temperature was 10 degrees or more below the temperature at which the Mechanical/ Electrical Issue occurred.

The data available suggests that some portion of the Mechanical/Electrical Issues outages may have been more appropriately categorized as Freezing Issues, and that the remainder illustrate a relationship between mechanical/electrical component malfunction and temperature that, to date, has not been fully explored or understood. Given the large percentage (40 to 41 percent, by number of units and MW, respectively) and MW losses (150,569 MW) caused by Mechanical/Electric Issues, better understanding the relationship between mechanical/electrical component malfunctions and temperatures is critical to improving future extreme cold weather performance by generating units. The Team believes an improved understanding can and should be evaluated on both a unit-by-unit basis—which the Team hopes can be obtained, in part, through the practices advanced in Recommendation 1—and on a systematic basis—through the study advanced in Recommendation 2.

3. FREEZING ISSUES

a. Summary Analysis

Data collected from generating units related to Freezing Issues during Winter Storm Elliott demonstrated similar trends to the data analyzed in the 2021 Report. Overall, units reported 1,030 distinct Freezing Issue-related

217 Th s figure s based only on un ts that prov ded amb ent temperature cond t ons for the r un ts exper enc ng outages not all un ts reported amb ent temperatures as requested. t s also based on the h ghest of the (up to three) temperatures that the ent ty could have prov ded: amb ent des gn temperature, h stor cal operat ng temperature, or current cold weather performance temperature determ ned by an eng neer ng analys s. *See* also, note 61. Other mater als related to the Report, nclud ng the presentat on g ven by Team members on September 21, 2023, stated that nearly 80 percent of Mechan cal/Electr cal ssues occurred above a generat ng un ts' m n mum operat ng temperature. That figure was based on a conservat ve earl er analys s of the data collected.

unplanned outages, derates, or start-up failures, which, combined, caused 110,962 MW of generation loss at various times during the Event,[218] and as illustrated in Figure 67, above, were 31 percent of the total MW of generation outages, derates, and failures to start during the Event. Variations by approximate U.S. geographic region basis in the Event Area for all unplanned generation MW outages due to **Freezing Issues** (as compared to other outage causes, e.g., Mechanical/Electrical Issues or Fuel Issues) are shown in Figure 74, below.

Figure 74: Variation by Approximate U.S. Geographic Region in the Event Area for Unplanned Unavailable Generation (MW) due to Freezing Issues

Approximate U.S. Geographic Region	Unplanned Unavailable Generation Due to Freezing Issues(Percent of MW)
New York	5%
M dAtlant c/M dwest	27%
Central/South Central	33%
Southeast	43%
Total Event Area	**31%**

Most BA footprints located in the southeast portion of the Event Area experienced higher percentages of unplanned generation outages due to Freezing Issues as compared to other geographic regions––especially compared to the northern portions of the Event Area.[219]

The specific types of Freezing Issues were similar to those seen during Winter Storm Uri. A substantial number of outages were linked to frozen transmitters, frozen sensing lines, or other frozen instrumentation – approximately 42 percent of all generation lost to Freezing Issues (Figure 75, below). As in the 2021 event, Freezing Issues caused a large percentage of unplanned wind generation outages and derates — 53 percent (by MW) or 40 percent (by number of outages). Freezing Issues caused 75 percent (by MW) and 43 percent (by number of outages) of unplanned outages and derates of nuclear units. Historically, Freezing Issues have been rare in nuclear units, due in part to their enclosed design.[220]

b. Existing and Pending Reliability Standards

Two sets of mandatory NERC Reliability Standards applicable to GOs—NERC Standard EOP-011-2, and the forthcoming EOP-012-1—are of particular relevance here.

In August 2021, the Commission approved the adoption of EOP-011-2, effective April 1, 2023, as part of a package of cold weather Reliability Standards.[221] As part of these updates, EOP-011-2 was revised to make clear that the GO is the "entity responsible for compliance" with the extreme cold weather Reliability Standards. This

218 Th s value s d st nct from the 90,500 MW of ncremental co nc dent unplanned outages dur ng the Event, wh ch s was the level of unplanned generat on outages, derates, and fa lures to start for all causes the gr d operators n the Core Event Area were faced w th at approx mately 10:00 a.m. on December 24, 2022. The 111,000 MW represents the MW of generat on capac ty outages, derates, and fa lures to start that were due to Freez ng ssues at var ous t mes dur ng the ent re Event, from December 21 26, 2022.

219 Open frame generat on fac l t es, wh ch are common throughout warmer cl mates n the U.S., are des gned and constructed w thout enclosed bu ld ng structures to avo d excess ve heat bu ld up n the summer but are more vulnerable to freez ng. *See* 2011 Report, Append x: Power Plant Des gn for Amb ent Weather Cond t ons, and 2021 Report at 162.

220 *See* Append x C.2., Add t onal Charts and F gures for Unplanned Generat on Outages Dur ng Event, Unplanned Generat on Outages by Fuel Type.

221 *See N.* Am. Elec. Rel ab l ty Corp., 176 FERC ¶ 61,119 at P 1 (2021).

required GOs to “develop, implement, and train on their extreme cold weather preparedness plans.”[222]

Figure 75: Unavailable MW by Balancing Authority, Freezing Issues, December 21 - 26, 2022[223]

Equipment Category	Components and Systems Impacted	Event Count	MWs Outaged or Derated	
Turbine Blades	Icing on blades	127	6,281	5.7%
Instrumentation	Frozen transmitter	49	17,776	16.0%
	Frozen sensing lines	27	9,757	8.8%
	Frozen instrumentation	58	18,824	17.0%
Other Equipment Freezing Problems	Frozen equipment	27	4,388	4.0%
	Frozen valve	39	11,860	10.7%
	Frozen water lines	19	6,547	5.9%
	Frozen pipes	24	5,702	5.1%
	Equipment failure	57	8,026	7.2%
	Other freeze-related issue	173	21,668	19.6%

Requirement R7 requires each GO to “implement and maintain one or more extreme cold weather preparedness plan(s) for its generating units” linked to each unit’s “design temperature, . . . historical operating temperature, or . . . current cold weather performance temperature determined by an engineering analysis.”[224]

More recently, in February 2023, the Commission approved new Reliability Standard EOP-012-1 – Extreme Cold Weather Preparedness and Operations. The new standard builds on EOP-011-2, “enhance[] the reliable operation of the [grid] by requiring generator owners to implement freeze protection measures, develop enhanced extreme cold weather preparedness plans, implement annual trainings, draft and implement corrective action plans to address freezing issues, and provide certain extreme cold weather operating parameters to Reliability Coordinators, Transmission Operators, and Balancing Authorities for use in their analyses and planning.”[225]

The crux of these standards is that generating units are expected to have an extreme cold weather preparedness plan tethered to one or more of the minimum operating temperatures associated with the unit – ambient design, historical operating minimums, or an extreme cold weather performance temperature determined by an engineering analysis. This minimum operating temperature is conveyed to that generating unit’s Balancing Authority so that it may rely on the temperature information in connection with planning and dispatch decisions.

c. Operating Parameters Provided by Generating Units

The vast majority of generating units that provided data for this report had obtained an ambient design temperature, minimum historical operating temperature, or extreme cold weather performance temperature determined by an engineering analysis. Of generating units that responded to the data request,[226] 67 percent

222 *Id.* at PP 4, 6.

223 “Other freeze related ssue” ncludes freeze related sub causes external to the generat ng un t such as frozen coal or ce on transm ss on l nes.

224 *See* EOP 011 2 R7.3.2. RSCompleteSet.pdf (nerc.com).

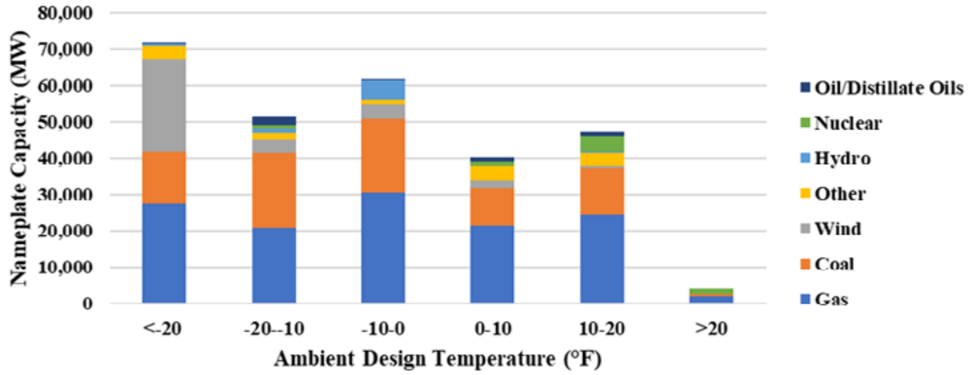
225 N. Am. Elec. Rel ab l ty Corp., 182 FERC ¶ 61,094 at P 36 (2023). The effect ve date for Rel ab l ty Standard EOP 012 1 s October 1, 2024.

226 Unless otherw se noted, percentages n th s sect on are based on the nameplate capac ty of the generat ng un ts that prov ded the necessary data.

reported a minimum design temperature. A slightly higher percentage, 74 percent, reported a historical minimum operating temperature, and very few units, only eight percent, reported an extreme cold weather performance temperature determined by engineering analysis.

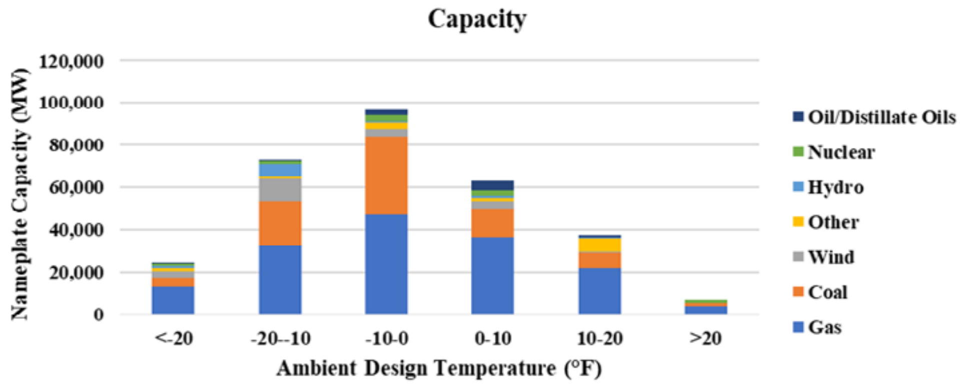
As illustrated in Figures 76 and 77, below, approximately two-thirds of the generating unit capacity (measured by nameplate MW) that responded with an ambient design temperature or a historical minimum operating temperature indicated a design temperature or a historical minimum operating temperature below zero degrees. More than 80 percent of units responded with an ambient design temperature below 10 degrees. Ambient design temperatures of coal units were spread across temperatures ranging from less than -20 up to 20 degrees. Similarly, ambient design temperatures of natural gas units were spread mostly across those ranges, except for a few units that had temperatures over 20 degrees. Over 80 percent of wind and one hundred percent of the solar units reported ambient design temperatures below zero degrees.

Figure 76: Ambient Design Temperature by Fuel Type and Total Capacity



The primary takeaway from this data is that of the units that reported outages, derates, or failures to start during the Event, nearly 84 percent of the total unit capacity reported a "documented operating temperature"—that is to say, the highest of their stated design temperature, historical minimum operating temperature, or an extreme cold weather performance temperature determined by an engineering analysis, of 10 degrees or lower. Although these data suggest that the generating units impacted by Winter Storm Elliott were, at a minimum, designed to operate or had successfully operated in extreme cold, over 63,000 MW (over 75 percent) of generation had outages, derates or failed to start due to Freezing Issues at temperatures above their documented operating temperature during the Event, as discussed below.

Figure 77: Historical Minimum Operating Temperature by Fuel Type and Total Capacity

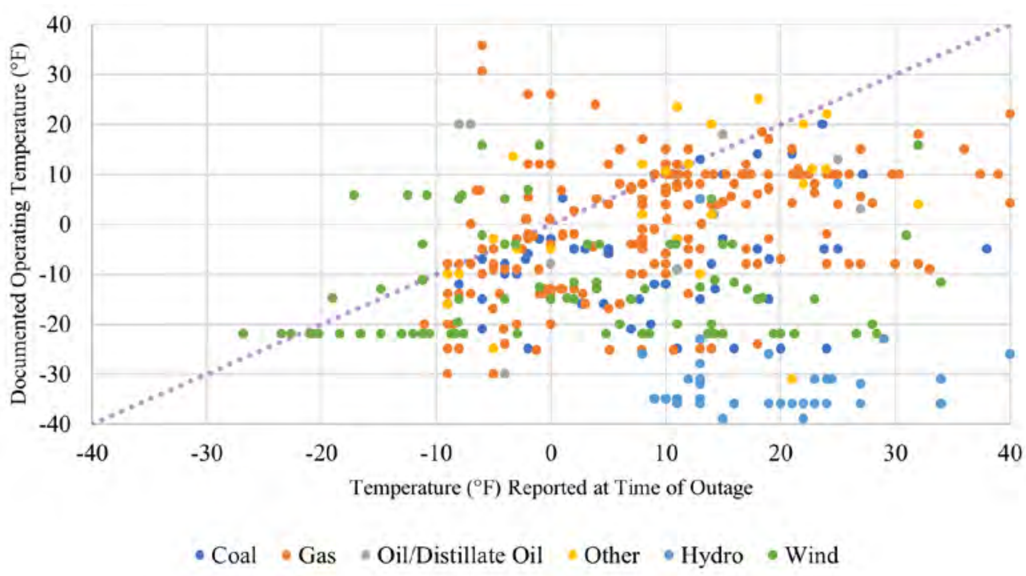


d. Freezing Above Documented Operating Temperature

A substantial majority of generation loss by units that reported Freezing Issues occurred at temperatures that were above the documented operating temperature thresholds incorporated into EOP-011-2, Requirement R7. Generating units of all primary fuel types—with the exception of a small number of generating units whose primary fuel type was oil—reported Freezing Issues well above their documented operating temperature.

In sum, generators did not perform according to their documented operating temperature. The scatter plot (Figure 78, below) compares the ambient temperatures reported by generating units with Freezing Issues to the documented operating temperature of that unit. The diagonal line represents the points at which the ambient temperature and documented operating temperature are equal. A substantial majority all of the generating unit outages plotted fall below (or the right of) the line, meaning that their outage occurred at temperatures above their documented operating temperature.

Figure 78: Temperature Reported at Time of Outage versus Documented Operating Temperature for Generators with Freezing Issues



e. Impact of Wind and Precipitation on Freezing Issues

The Team reviewed data to evaluate the impact of other weather conditions—wind and precipitation—on generating units reporting Freezing Issues. Wind can have a cooling effect that may cause unexpected Freezing Issues below ambient design temperatures. Precipitation coupled with freezing temperatures can also greatly impact generating unit operations during extreme cold weather events. This review did not reveal significant or clear trends—in part because the low number of units experiencing Freezing Issues below their minimum operating temperature frustrates a comparative analysis on those grounds.

On average, the wind speeds reported for units that had Freezing Issues above their document operating temperature averaged 16 mph, while wind speeds reported for units that had Freezing Issues below their minimum operating temperature averaged 20 mph. These two data points suggest that the cooling effect of wind did not substantially affect whether a given generating unit would experience a Freezing Issue above or below its minimum operating temperature. See Figure 79, below.

Precipitation affected whether a unit would fail above its documented operating temperature for some fuel types, such as oil and wind, but not for others fuel types such as natural gas and coal. Figure 80 below, breaks down performance by fuel type.

Protecting generator cold weather critical components from extreme cold weather is not complicated. Freeze protection measures -- such as heat trace, insulation, wind breaks, or targeted roofing to protect insulation from getting wet—have been used for years to prevent failure. What makes the difference between successful operation for the duration of an extreme cold weather event and unplanned outages due to freezing? Observations over multiple extreme cold weather events suggest that improved outcomes are associated with attention to detail, consistency in implementing the plan for protecting generator cold weather critical components, and preventing complacency when preparing for winter. Several entities involved in the Event shared stories about generating units lost because seemingly insignificant areas were insufficiently protected. For example, one entity had a false floor in its unit, and did not realize that a pipe was not insulated beneath the floor. The small section of pipe under the floor froze and caused the unit to trip.

Figure 79: Average of Wind Speed Reported for Units with Freezing Issues Comparing Above/Below Documented Operating Temperature

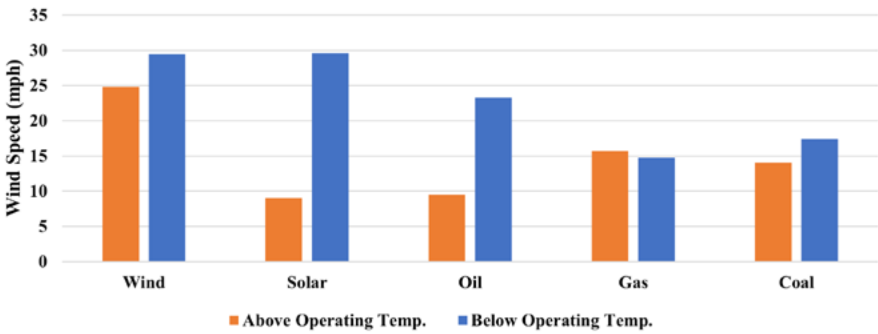
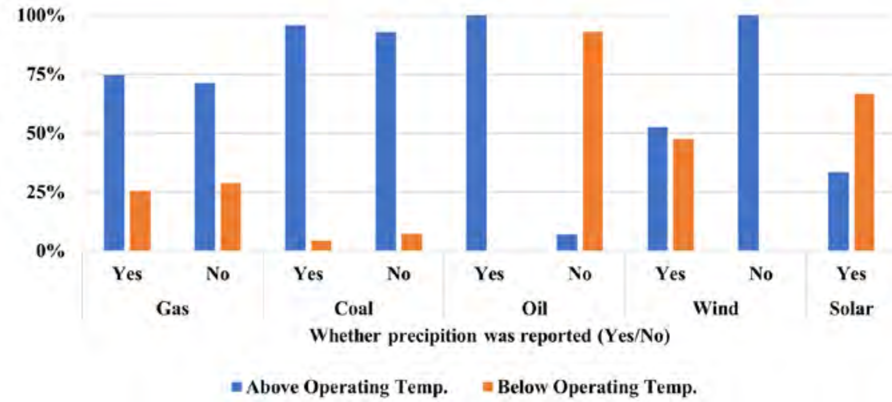


Figure 80: Precipitation Reported for Units with Freezing Issues Comparing Above/Below Documented Operating Temperature



The Lesson of Consecutive Cold Weather Events: Consistency, Attention to Detail, and a Sense of Urgency are Critical to Effective Cold Weather Preparation

As described more fully below, there have twice been extreme cold weather events that resulted in no load loss shortly after a similar event during which firm load was shed.

The first set of events occurred in February, 2011. In early February 2011, ERCOT, Salt River Project, and El Paso Electric Company needed to shed firm customer electric load, over 4,000 MW total, due in part to generating unit outages caused by freezing. On February 10, 2011, cold temperatures returned to Texas. "Actual temperatures in the ERCOT region averaged a low of 19 degrees with a 12-degree wind chill."[227] Yet ERCOT did not shed either firm or interruptible load despite setting a new winter peak of 57,915 MW.[228]

The 2011 Report found that "ERCOT avoided service interruptions on February 10 largely because there were far fewer forced outages."[229] While weather differences also played a role,[230] **the 2011 report found that "repairs made and protective measures taken during the event of February 2 remain[ing] in place" were a significant factor.**[231] GOs/GOPs had addressed vulnerabilities including "re-routing piping or moving vulnerable equipment, correcting transformer oil levels at wind farms, and adding freeze-resistant chemicals.

227 2011 Report at 99.

228 2011 Report at 99.

229 2011 Report at 99.

230 The February 10 ow of 19 degrees was the same as the February 2 ow, however the w nd ch was ower on February 2 and ow temperatures dur ng the ear er event were more pers stent, rema n ng n the ow twent es for four days w th w nd ch s between 10 and 14 degrees. 2011 Report at 99.

231 Generator owners had " nstalled w nd breaks, nclud ng tarps or enclosures, added portable heaters or heat lamps, repa red or added nsulat on, and repa red or added heat trace. One generator changed ts procedures for mon tor ng the rel ab l ty of ts heat trace. Some generators also cont nued the r ncreased level of staff ng to address freeze protect on ssues, and others changed elements of the r control log c to prevent un ts from automat cally tr pp ng." 2011 Report at 100.

At least five generators kept units running, started units earlier or took other measures to keep from having a cold start. After so many static sensor and other lines froze the week before, some units left water lines draining, or took other measures to keep water flowing."[232]

The second set of events occurred in January 2014 and February 2015. On January 6 and 7, 2014, parts of the Eastern Interconnection experienced a "polar vortex," with "temperatures 20 to 30 [degrees] below average, and some areas [35 or more degrees] below their average temperatures."[233] As NERC noted in its "Polar Vortex Review," "these lower temperatures had a drastic impact on load, with many of the RCs/BAs [e.g., MISO, PJM, TVA, VACAR-South RC (including Duke), and Southern/Southeastern-RC] reporting record or near-record winter peak demands. PJM exceeded its historic winter peak on both January 7 and January 8, 2014, and MISO reported that they exceeded their historic winter peak for three straight days (January 6–8, 2014)."[234] Due to the high loads and unplanned generating unit outages, including an estimated 19,500 MW of generation outages due to "cold weather conditions," and "a significant reduction of generating capacity due to curtailments and interruptions of natural gas delivery," affected entities needed to use "load reduction procedures such as voltage reduction, interruptible loads, and demand-side management," and in one case, to shed 300 MW of firm load, to maintain system reliability.[235]

A little more than a year later, severe cold temperatures hit the Eastern Interconnection again. "Numerous cities [in the Eastern Interconnection] hit their daily low-temperature records during February 2015. Due to the low temperatures and associated high electricity demand for heating needs, PJM set a new wintertime peak demand record of 143,086 megawatts the morning of February 20, 2015 . . . The new peak record surpassed the previous all-time winter peak . . . set [during the Polar Vortex]. Although the new record winter peak was set during this time frame, no emergency demand response or any other capacity emergency actions were required. Many other areas also set all-time record winter peaks in 2015."[236] PJM and DEP set winter peak load records in 2015 that remained unbroken during the Event, and DEC broke its 2015 record by less than 150 MW.[237] Yet "[g]enerator performance in . . . February of 2015 showed improvement over 2014 with improved overall forced outage rates." or example, PJM's forced outage rate dropped from 22 percent to 13.4 percent.[238] NERC attributed this improvement to "steps generation owners . . . initiated after the winter of 2014."[239] NERC used GADS[240] data to compare winter 2015 equivalent forced outage rates (EFOR) to those during the polar vortex in 2014 and to previous years' rates.[241]

232 2011 Report at 100.

233 Polar Vortex Rev ew at .

234 Polar Vortex Rev ew at v .

235 Polar Vortex Rev ew at 2,4.

236 NERC 2015 W nter Rev ew, December 2015, at v. https://www.nerc.com/pa/rrm/ea/ColdWeatherTra n ngMater als/2015 W nter Rev ew December 2015 F NAL.pdf

237 *See* Table 2, n 2015 NERC report. Southern Company and TVA st ll d d not break the r 2014 w nter peak load records.

238 NERC 2015 W nter Rev ew, December 2015, at v.

239 NERC 2015 W nter Rev ew, at v.

240 *See* note 44.

241 NERC 2015 W nter Rev ew, at 1.

NERC provided examples of preparations taken by the generating unit owners, including:

- Owners started units earlier than expected, due to anticipated colder temperatures, helping to mitigate the risk of taking more time to start.
  - Keeping stations in service overnight with a reduced output level was beneficial to ensuring that the unit would stay warm and online when needed for the peak.
- Proactive staffing of typically unmanned stations enabled more rapid response.
- Many generating units in the PJM footprint participated in prewinter operational testing, and those that did, had a lower rate of forced outages than those that did not.

But seven years later, faced with peak loads that were generally lower than in 2014 or 2015, many of the same BAs experienced high rates of forced outages. PJM, for example, found that despite many measures undertaken in the wake of the Polar Vortex, its Capacity Resource forced outage rate was worse in the Event than in the Polar Vortex (24 percent versus 22 percent).

4. BLACKSTART UNITS

Of significant concern is that blackstart-designated generating units totaling 19,000 MW experienced forced outages, derates or failures to start during the Event. Blackstart-designated units are those that claim the ability to be started without the aid of external power sources. Given this unique functionality, blackstart units serve a critical grid reliability function—restarting the grid in the event of its failure. It is, therefore, disconcerting that generation loss due to the unavailability of blackstart-designated units coincided with the arrival of extreme cold weather conditions and the corresponding acceleration of generation loss throughout the bulk electric system.

Figure 81: Unavailable Generation - Blackstart-Capable Generating Units, December 22 - 24, 2022

242 NERC 2015 W nter Rev ew at 6.

Figure 82: Unavailable Generation in the Event Area, Blackstart-Capable Generating Units, By Primary Cause

Blackstart Units – Reported Event Cause	Event Count	Unavailable MW
Mechan cal/Electr cal ssues	89	7,737
Fuel ssues	86	6,717
Freez ng ssues	61	3,565
Env ronmental/ Safety ssues	6	810
Transm ss on System ssues	6	261

Figure 83: Unavailable Generation in the Event Area, Blackstart-Capable Generating Units, By Primary Cause and Dual Fuel Capability

Blackstart Units Type	Freezing Issues (MW)	Fuel Issues (MW)	Mechanical/Electrical Issues (MW)	Other (MW)
Gas Only	1,266	5,060	1,200	0
Gas/O l	1,678	920	3,607	561
Other	621	737	2,910	510
Total	3,565	6,717	7,737	1,071

Altogether, 155 blackstart-designated generating units (119 of which were natural gas-fired) reported more than 248 discrete outages, derates or failures to start. Of these, 29 percent reported *multiple* outages, and 23 percent were start-up failures—*i.e.* units that failed to perform the essential function of blackstart units.

Blackstart generation loss unit types included natural gas-fired, dual-fuel capable, and other primary fuel types.

5. HIGH WIND SHUTOFFS

Most conventional wind turbines are designed to operate at wind speeds of no more than 55 mph and must shut down when wind speed exceeds those levels.[243] Excluded from the foregoing analysis of Freezing Issues and Mechanical/Electrical Issues were wind turbine units that reported generation loss due to high winds—High Wind Shutdown—as the cause of their forced outage. Some generating units reported unique outages lasting only a handful of minutes on a turbine-by-turbine basis, resulting in hundreds of spreadsheet lines—but ultimately these shutoffs did not constitute a significant source of generation loss during Winter Storm Elliott. In aggregate, Generation Owners attributed fewer than 1,000 MW of generation loss to High Wind Shutdowns.

6. FUEL ISSUES

Fuel Issues accounted for 24 percent of all generation lost during the Event—a cumulative total of more than 86,000 MW—and were the third largest cause of unplanned

243 *See*, Off ce of Energy Eff c ency & Renewable Energy, *How Do Wind Turbines Survive Severe Storms?* (June 20, 2017), https://www.energy.gov/eere/art cles/how do w nd turb nes surv ve severe storms ("When the anemometer reg sters w nd speeds h gher than 55 mph (cut out speed var es by turb ne), t tr ggers the w nd turb ne to automat cally shut off.").

outages, derates and failures to start. In total, 452 generating units reported 730 distinct forced outages, derates or failures to start during the Event due to Fuel Issues. Natural gas-fired generating units experienced the overwhelming majority of Fuel Issues: 71,423 MW of natural gas-fired generating unit outages and derates were 83 percent of all Fuel Issue-caused generation outages and derates during the Event, as shown in Figure 84, below.[244] For natural gas-fired generation alone, comparing the outages during the Event caused by Natural Gas Fuel Issues to Freezing Issues and Mechanical/Electrical Issues, Natural Gas Fuel Issues caused nearly one-third (31 percent, by MW) of natural gas-fired generating units' unplanned outages and derates.[245]

Figure 84: Unplanned Unavailable Generation in the Event Area Caused by Fuel Issues, December 21-26, 2022

Generating Unit Primary Fuel Type	Unplanned Outages During Event (MW)	Percent of Unplanned MW Outages Due to Fuel Issues
Gas	71,423	83%
Coal	13,439	16%
Other	1,602	2%

Fuel-Issue-caused natural gas-fired generation outages (referred to as the sub-cause "Natural Gas Fuel Issues" described earlier in the Report) include the combined effects of decreased natural gas production; cold weather impacts and mechanical problems at production, gathering, processing and pipeline facilities resulting in gas quality issues and low pipeline pressure; supply and transportation interruptions; curtailments and failure to comply with contractual obligations. Additionally, it includes shippers' inability to procure natural gas due to tight supply, prohibitive, scarcity-induced market prices, or mismatches between the timing of the natural gas and energy markets.

See Figure 85, below, for information on the contractual arrangements held by some of the GOs/GOPs involved in the Event.

Each subset of the 71,423 MW of natural gas-fired generating unit outages and derates due to Natural Gas Fuel Issues total tells a distinct story:

- Nearly 7,500 MW of generation outages were linked to gas delivery pressure issues, reflecting the difficulty natural gas pipelines and other distribution points faced in responding to production losses. Another 2,000 MW was linked to transportation constraints.
- Market Issues and Market Price Restrictions accounted for approximately 24,000 MW of generation loss—reinforcing how surging demand and production losses impacted generating units. Somewhat paradoxically, GOs/GOPs of natural gas-fired generating units attributed more generation loss to the failure of gas suppliers to satisfy firm supply commitment and/or pipeline firm curtailments (16,500 MW of cumulative generation loss) than to interruptible pipeline interruptions

244 Th s s n part because natural gas fired generat ng un ts were the most common (over 41 percent of the generat on capac ty n the Event Area, as seen n F gure 11). Natural gas fired un ts were also the most common n pr or extreme cold weather events (2011: ERCOT 52 percent; 2021: ERCOT 52 percent, M SO South 60.6 percent, SPP 38.5 percent). The only other un ts that exper enced mater al generat on loss due to Fuel ssues dur ng W nter Storm Ell ott were coal un ts. Fuel ssues for all fuels other than gas and coal, comb ned, accounted for two percent of all unplanned outages, derates and fa lures to start.

245 *See* Append x C.3. Causes of Unplanned Generat on Outages, by Fuel Type of Generat on.

(14,000 MW of cumulative generation loss). This finding was supported by the Team's cross-check of the causes claimed against data provided by the GOs/GOPs of those generating units about their contractual arrangements.

Figure 85: Generating Unit Natural Gas Commodity and Transportation Contracts

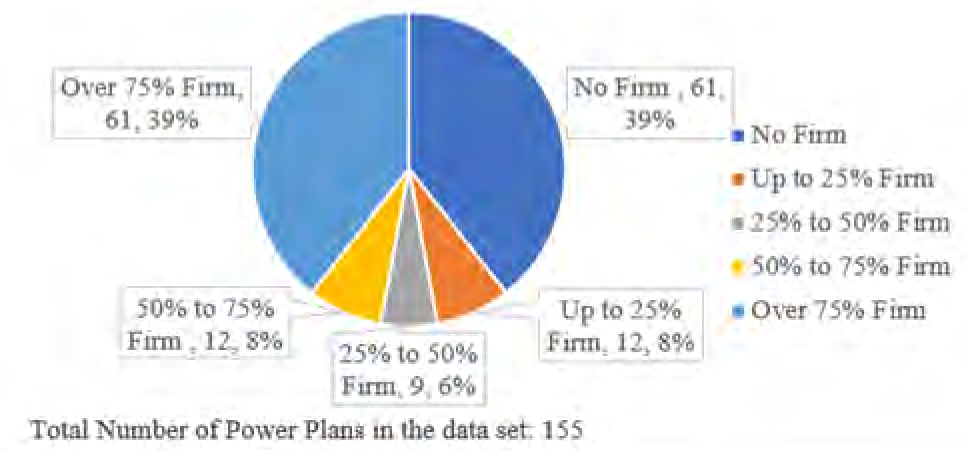
Generating Unit Natural Gas Commodity and Transportation Contracts										
Type of Gas Commodity and Transportation Contract:	MISO		PJM		Southern		SPP		Other BAs	
	Generators	Percent	Generators	Percent	Generators	Percent	Generators	Percent	Generators	Percent
Firm Commodity/Firm Transportation	53	38%	61	37%	0	0%	0	0%	28	26%
Firm Commodity/Mixed Transportation	0	0%	1	1%	0	0%	0	0%	0	0%
Firm Commodity/Non-Firm Transportation	8	6%	26	16%	0	0%	0	0%	0	0%
Non-Firm Commodity/Non-Firm Transportation	28	20%	18	11%	2	5%	27	34%	9	8%
Non-Firm Commodity/Mixed Transportation	3	2%	0	0%	0	0%	15	19%	2	2%
Non-Firm Commodity/Firm Transportation	20	14%	11	7%	0	0%	17	21%	0	0%
Mixed Commodity/Mixed Transportation	11	8%	21	13%	0	0%	16	20%	20	19%
Mixed Commodity/Firm Transportation	7	5%	3	2%	14	38%	0	0%	14	13%
Mixed Commodity/Non-Firm Transportation	8	6%	17	10%	21	57%	3	4%	28	26%
Did not provide information re: commodity contract type	1	1%	2	1%	0	0%	2	3%	0	0%
No contract or did not provide information about transportation contract type	2	1%	7	4%	0	0%	0	0%	5	5%
Total	141	100%	167	100%	37	100%	80	100%	106	100%

During the Event, unplanned natural production outages due to freeze-related issues, road conditions, loss of power and unplanned outages of gathering and processing facilities decreased the natural gas available for supply and transportation to many natural gas-fired generating units in the Eastern Interconnection. Out of the **61** power plants[246] that reported having at least 75 percent of their fuel requirement under firm transportation, only **25** reported also having at least 75 percent of the fuel needed for their winter

246 The Team had a sample s ze of sl ghtly over 200 generat ng plants that prov ded most of the requested nformat on about fuel contract ng pract ces. Generator owners prov ded fuel contract data on a plant bas s, wh ch often ncluded mult ple generat ng un ts. The Team removed plants that d d not answer the requests for the r total or da ly gas natural gas requ rements, result ng n a l st of 155 plants.

peak operation under firm supply contracts. The Team focused on GOs/GOPs that provided their fuel requirements. As shown in the figure, the plants were nearly evenly split between those that had no firm transportation at all, and those that had over 75 percent of their natural gas fuel requirements supported by firm transportation.

Figure 86: Number of Power Plants by the Level of Firm Transportation Service Contracts Covering Their Natural Gas Fuel Requirements



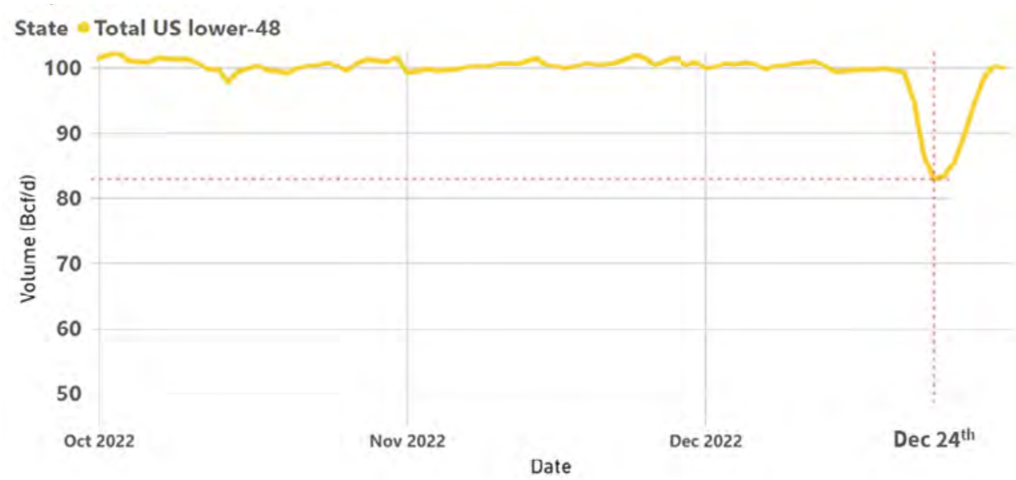
C. Causes of Natural Gas Supply and Delivery Facility Outages[247]

1. SUMMARY

As Winter Storm Elliott moved across North America and temperatures dropped, natural gas production in the lower 48 states declined, with volumes on December 22 decreasing 4,411 MMcf/day from the previous day.

The largest daily decline in natural gas production – 8,368 MMcf/day – occurred between December 22 and December 23. Dry natural gas production for the lower 48 U.S. saw an 18 percent decline, falling to a low of 82.9 Bcf/day on December 24, 2023, as shown in Figure 87, below.

Figure 87: Daily Dry Natural Gas Production (November - December 2022)[248]



Winter Storm Elliott primarily affected the Marcellus and Utica Shale formations. Marcellus Shale production volumes reached a low of 21,856 MMcf/d on December 24 (23 percent decrease compared to maximum production on December 19). Utica Shale production volumes reached a low of 3,017 MMcf/d on December 26 (54 percent decrease compared to maximum production on December 19). Focusing on states, the largest natural gas production decreases in the Event Area occurred in Pennsylvania, Ohio, and West Virginia, whereas Louisiana production was relatively unaffected. Ohio saw the largest relative decline compared to maximum production volumes for December, reaching a low of 3,018 MMcf/d on December 26 (54 percent decline compared to production on December 17). Pennsylvania and West Virginia both reached their lowest production volumes of 16,226 MMcf/d (22 percent decline compared to production on December 20) and 5,630 MMcf/d (26 percent decline compared to production on December 18), respectively, two days prior on December 24. Figures 88 and 89[249] show the declines by state over time, and the geographic locations of the volumetric outages, respectively.

247 Unless otherw se stated, the source of data for th s sect on s the sample of producers, gatherers, processors, and p pel nes that responded to the Team's data requests.

248 Source: S&P Global Commod ty ns ghts, ©2023 by S&P Global nc.

249 Source for both figures: S&P Global Commod ty ns ghts, ©2023 by S&P Global nc.

Figure 88: Sum of Natural Gas Production Volume, by Date and State (October - December 2022)

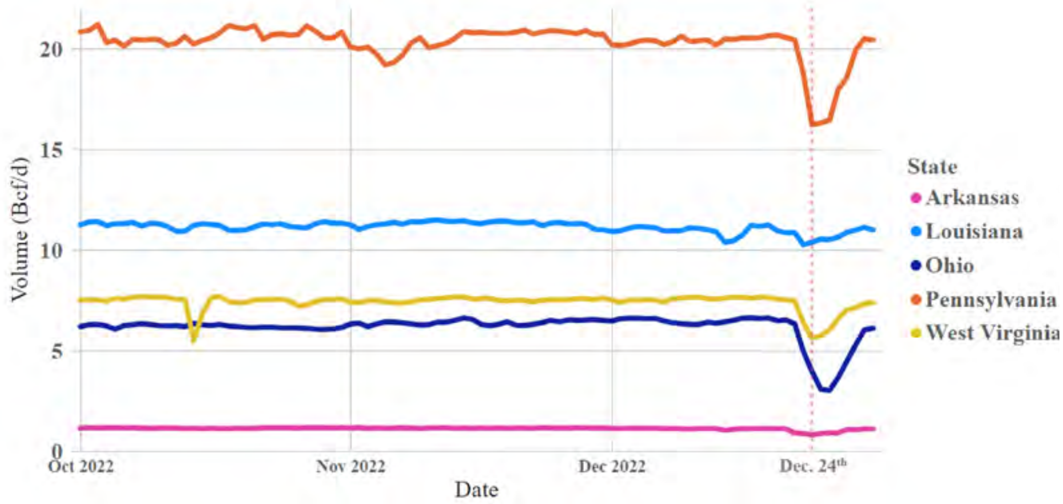
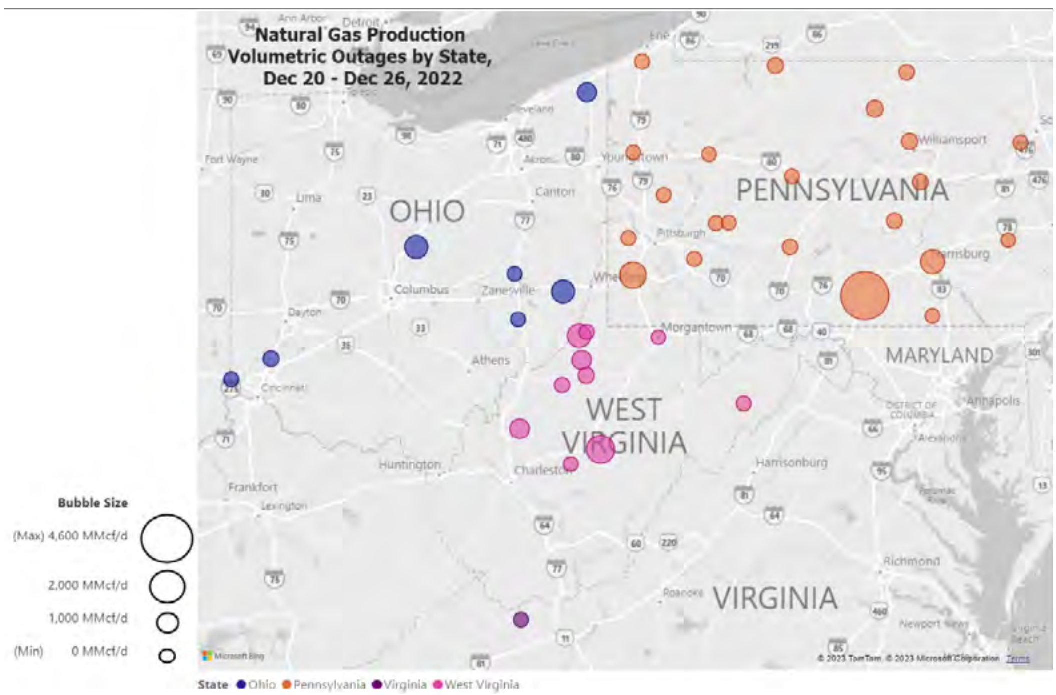


Figure 89: Natural Gas Production Volumetric Outages by State, December 20 – 26, 2022



Certain pipeline injection points were especially affected. Westmoreland, Pennsylvania, declined by over 6.8 Bcf over the Gas Days of December 21-26, compared to expected production, and Greene, Pennsylvania, declined by over 3 Bcf. Other points experiencing declines over one Bcf included Calhoun and St. Clair Pennsylvania, Monroe, Ohio and Marshall, West Virginia.[250]

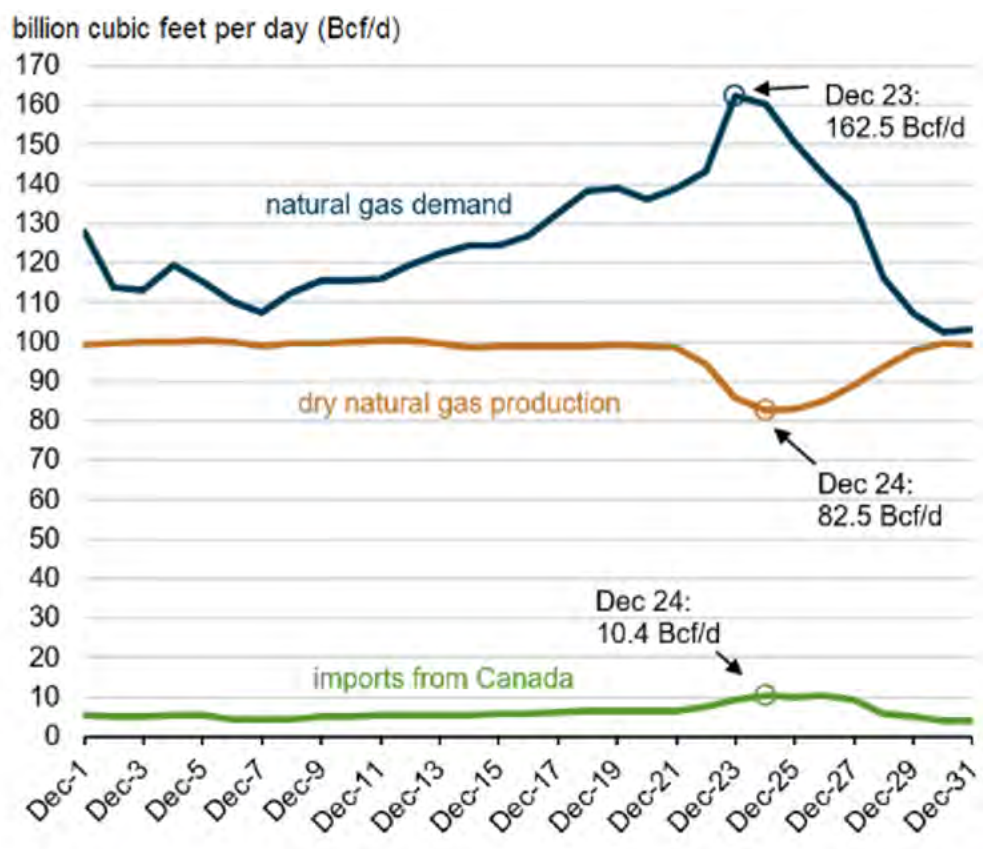
The last time U.S. natural gas production rapidly declined to this degree was during Winter Storm Uri.

250 *See* F gure 50 for a map of rece pt po nts exper enc ng supply shortages.

Record natural gas demand during Winter Storm Elliott was met by increasing withdrawals from storage and pipeline imports from Canada. Natural gas pipeline imports from Canada supplied 10.4 Bcf of natural gas to the United States on December 24, the highest daily natural gas imports from Canada since February 2007.[251]

Figure 90 below shows record peak demand for natural gas on December 23 and the production nadir on December 24.

Figure 90: Daily Natural Gas Supply and Demand in the Lower 48 States, December 1 – 31, 2022[252]



It is important to note that natural gas demand, as that term is used by the U. S. Energy Information Administration, is the sum of actual gas consumption, natural gas and LNG exports, pipeline losses and fuel gas. EIA's natural gas demand does not include the gas that would have been burned by dispatched natural gas-fired generating units rendered unavailable due to Natural Gas Fuel Issues, Freezing Issues, or other causes. Put another way, although EIA reported record demand for December 23, that figure under-represented the potential natural gas demand because it excluded natural gas that generators would have consumed had they not experienced an outage, derate, or failure to start.

The December 23 demand for gas of 162.5 Bcf included estimated total consumption of natural gas in the lower 48 states of 141 Bcf – a record daily high (exceeding the previous record daily high of 137.4 Bcf set on January

251 Natural Gas Weekly Update, January 19, 2023 U.S. Energy nformat on Adm n strat on, (last v s ted November 3, 2023).

252 Source: S&P Global Commod ty ns ghts, ©2023 by S&P Global nc.

1, 2018) and 21.5 Bcf of exported gas, pipeline losses, and fuel gas. Figure 91, below, shows the relative shares of natural gas consumption for natural gas fired-generating units ("PowerBurn"), industrial production, residential and commercial use ("ResComm"), and LNG feedgas for the Event Area. Power burn and residential and commercial use consumed similar shares until the onset of the extreme cold weather, when residential and consumer usage spiked. LNG feedgas decreased by nearly 20 percent, mostly in the Southeast as shown in Figure 92, below. Figure 92 shows the overall and relative increase (or decrease) in the various sectors' natural gas consumption for the Northeast, Midwest and Southeast regions, combined. Residential and commercial use had the largest percentage increase by far, at nearly 50 percent, with pipe losses coming in second, increasing by a third.

Figure 91: Northeast/Midwest/Southeast Natural Gas Consumption[253]

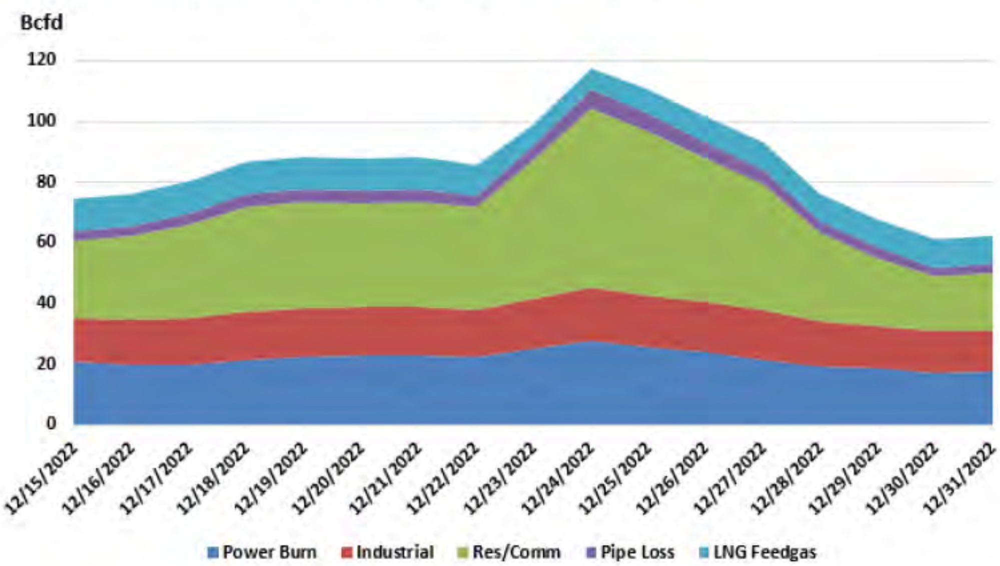


Figure 92: Overall and Relative Increase in Natural Gas Consumption for the Northeast, Midwest and Southeast Regions[254]

Bcfd	December 15-20 Average	December 21-26 Average	Percent Change
Northeast/M dwest/Southeast Natural Gas Demand	82.3	100.5	22.1%
Power Burn	21.2	24.6	15.8%
Res/Comm	31.4	46.0	46.5%
ndustr al	15.3	16.5	7.9%
LNG Feedgas	10.6	8.5	19.8%
P pe Loss	3.9	5.0	29.2%

253 Source: S&P Global Commod ty ns ghts, ©2023 by S&P Global nc.

254 Source: S&P Global Commod ty ns ghts, ©2023 by S&P Global nc.

2. NATURAL GAS PRODUCTION DECLINES

The Team sought to gather information from the largest producers in the area that experienced the greatest decreases in natural gas production. Based on the Team's analysis of publicly-available information and data from S&P Global Community Insights, the Team focused its data collection efforts on a sample of 12 large producers in Pennsylvania, Ohio and West Virginia. Eight producers with operations in Pennsylvania, Ohio, West Virginia, and Virginia – representing over 15,000 natural gas wells – provided responses to questions about estimated marketed production declines during Winter Storm Elliott.[255] Producers were asked to identify production volume declines by date and county, and to identify an associated cause for the declines. Only 38 to 53 percent of the production entities provided the requested data for December 23 to 26,[256] the days with the most substantial production losses, as shown in Figure 93, below. One producer did not provide any information after several attempts by the Team.[257] The Team grouped them into the following categories: Freeze-offs; Downstream Issues; Access to roads cut-off; Proactive Reduction in Sales.[258]

Figure 93: Natural Gas Marketed Production Volume Declines, December 20 – 26, 2022

Date	Marketed Production Volume Decline MMcf/d with Causes	Total Marketed Production Volume Decline (MMcf/d)	% of Data
12/20/2022	541.24	718.82	75%
12/21/2022	569.87	838.19	68%
12/22/2022	532.48	854.27	62%
12/23/2022	2,044.46	3,869.75	53%
12/24/2022	1,579.86	4,209.68	38%
12/25/2022	1,878.98	4,416.39	43%
12/26/2022	1,743.17	3,832.59	45%

All but one producer identified freeze-offs as a primary cause of production reductions, including frozen production equipment as well as wellhead freeze offs. Seven of the 10 producers identified downstream issues

255 n total, 10 producers responded to the data request, but only e ght prov ded the data on the est mated marketed product on decl nes. *See* footnote 100 wh ch descr bes the relevant reg ons the ent t es were asked to prov de product on data.

256 Th s s an example of an ssue the Team faced when gather ng nformat on from non jur sd ct onal ent t es.

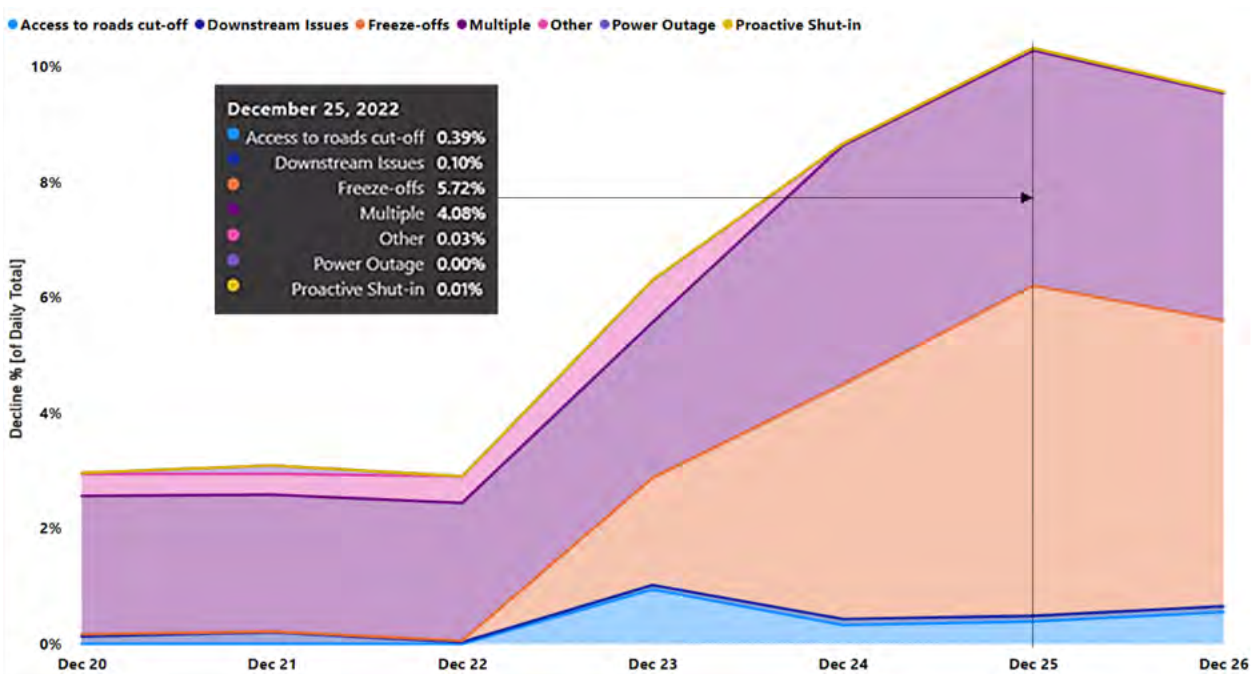
257 Deta s regard ng the way n wh ch th s producer responded ustrate the benefits that w obta n f an agency or ent ty s g ven jur sd ct on over the re ab ty of the natura gas system. The Team n t a y tr ed to contact the producer v a wr tten data requests. When the producer d d not respond, the Team assumed that the data requests had not been rece ved or had reached the wrong person ssues that had ar sen w th other producers and that cou d be reso ved v a a phone ca . The Team contacted the producer and was referred to a spec fic nd v dua . He, however, d d not return ca s. The Team fina y managed to reach h m n h s off ce, and he sa d that t was h s understand ng that cooperat on w th the Team was "vo untary." A though the Team exp a ned the mportance of cooperat on n he p ng to te the ent re story of what happened dur ng W nter Storm E ott, he sa d on y that he wou d d scuss t w th others at the producer and wou d ca back n a week or two. The Team never heard from h m aga n.

258 The Team had to group the causes prov ded nto overarch ng categor es s nce there was a s gn ficant var at on n the causes used/prov ded n the responses. Th s s also another reason why an agency or ent ty w th jur sd ct on over the rel ab l ty of the natural gas system could prove benefic al by creat ng some level of standard zat on or un form ty n outage/operat onal mpacts cause des gnat ons that could support mean ngful analys s (compare, e.g., GADS data spec ficat ons for BES GOs/GOPs to prov de data about generat ng un t outages Generat ng Ava lab l ty Data System (GADS) (nerc.com)).

as a significant driver of production declines; these issues included outages in gathering systems, compressors, and processing plants, as well as pipelines that could not take the gas from the producers,[259] which caused idling of producer equipment, which itself exacerbated production equipment freezing and caused further reductions in natural gas production. Five out of 10 identified poor road conditions, which prevented personnel and, in some cases, water hauling trucks, from reaching remote sites, although this was not as common as during Winter Storm Uri. Finally, two producers proactively reduced the volume of contractual sales during the Event because they expected production declines.

Figure 94, below, illustrates the decline by category calculated against the daily estimated production as reported by producers. Figure 95 breaks down the causes of production losses on December 23 to 26. Freeze-offs peaked as the leading cause of production declines on December 24 and 25, while downstream issues peaked on December 23.

Figure 94: Natural Gas Daily Production Decline by Cause, December 20 – 26, 2022



259 One p pel ne stated that lead ng up to and on the even ng of December 23, they started to pack the r l nes n preparat on for h gh demand on December 24. The h gh pressure temporar ly prevented producers from be ng able to move the r gas onto the p pel ne. The same p pel ne also had a lag n demand load on the morn ng of December 24, caus ng pressures to rema n h gh, wh ch exposed producers to further freez ng vulnerab l t es as they could not move the r supply onto the p pel ne system at that t me.

Figure 95: Total Percentages of Natural Gas Daily Production Decline by Cause, December 23 – 26, 2022

	Production Event Causes on December 23rd	
	Natural Gas Infrastructure Condition	Facility Event Causes
Freeze-offs	Equipment freezing at well/gathering facilities.	16.6%
Downstream Issues	Third party/downstream issues (e.g., processing plant down)	44.5%
Access to roads cut-off	Road/access to well/gathering facilities	8.4%
Multiple	Multiple Issues (combination of two or more of above issues)	24.0%
Other Issues, Unrelated Issues	Proactive shut-in	0.0%
	Other Issues	6.5%
Total		100.0%

	Production Event Causes on December 24th	
	Natural Gas Infrastructure Condition	Facility Event Causes
Freeze-offs	Equipment freezing at well/gathering facilities.	46.9%
Downstream Issues	Third party/downstream issues (e.g., processing plant down)	1.2%
Access to roads cut-off	Road/access to well/gathering facilities	3.8%
Multiple	Multiple Issues (combination of two or more of above issues)	47.8%
Other Issues, Unrelated Issues	Proactive shut-in	0.0%
	Other Issues	0.3%
Total		100.0%

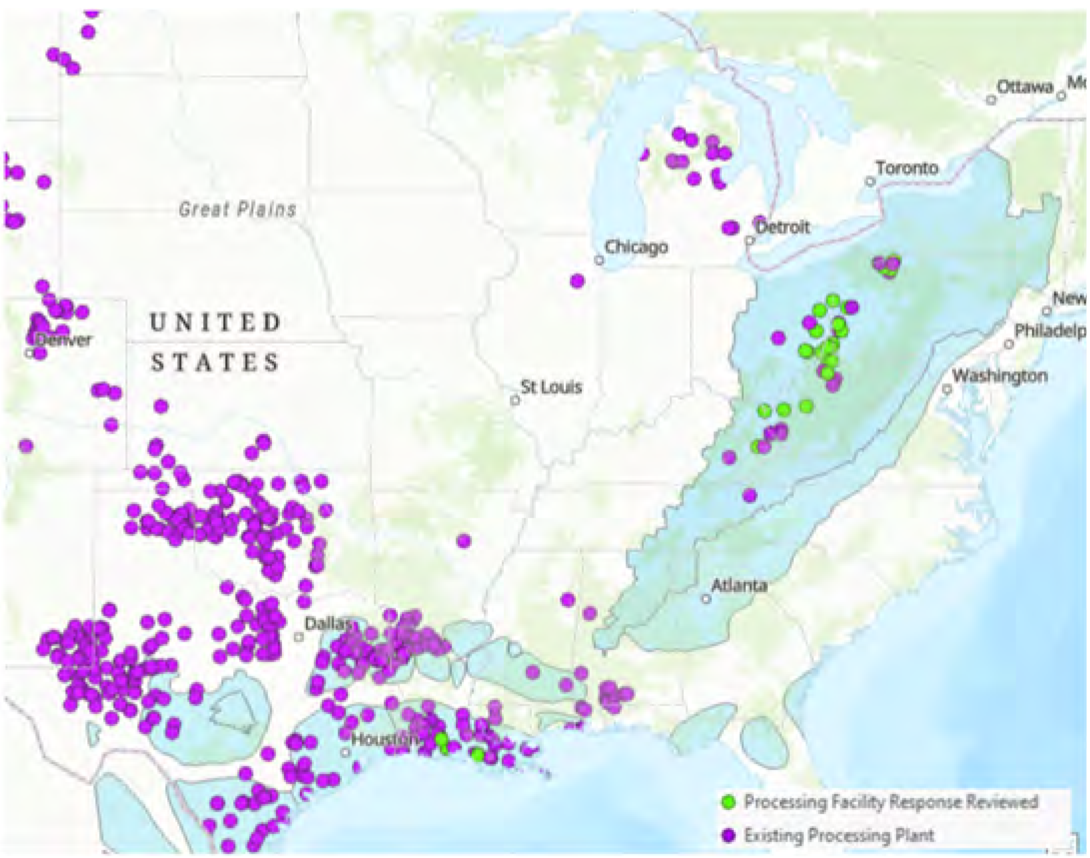
	Production Event Causes on December 25th	
	Natural Gas Infrastructure Condition	Facility Event Causes
Freeze-offs	Equipment freezing at well/gathering facilities.	55.4%
Downstream Issues	Third party/downstream issues (e.g., processing plant down)	1.0%
Access to roads cut-off	Road/access to well/gathering facilities	3.7%
Multiple	Multiple Issues (combination of two or more of above issues)	39.5%
Other Issues, Unrelated Issues	Proactive shut-in	0.1%
	Other Issues	0.3%
Total		100.0%

	Production Event Causes on December 26th	
	Natural Gas Infrastructure Condition	Facility Event Causes
Freeze-offs	Equipment freezing at well/gathering facilities.	51.8%
Downstream Issues	Third party/downstream issues (e.g., processing plant down)	1.0%
Access to roads cut-off	Road/access to well/gathering facilities	5.7%
Multiple	Multiple issues (combination of two or more of above issues)	41.1%
Other Issues, Unrelated Issues	Proactive shut-in	0.1%
	Other Issues	0.3%
Total		100.0%

3. NATURAL GAS PROCESSING

The Team obtained data from a total sample size of 26 natural gas processing plants located in the Texas-Louisiana-Mississippi Salt Basin (8) and Appalachian Basin (18). However, the Report focuses on the Appalachian Basin because it experienced the largest decrease in natural gas supply during the Event. Data regarding the Texas-Louisiana-Mississippi Salt Basin is in Appendix D. See Figure 96, below for depiction of geographic locations of the processing facilities.

Figure 96: Natural Gas Processing Facilities in Event Area



As shown in Figure 97 below, temperatures declined drastically on December 23. Weather stations in Morgantown, West Virginia, which is located within the Appalachian Basin, captured temperatures ranging from 46 degrees to -2 degrees on December 23. This decline continued December 24, over the course of which the average temperature in Morgantown was 29 degrees below the historical normal.[260]

Figure 97: Morgantown, WV Actual Daily Temperatures

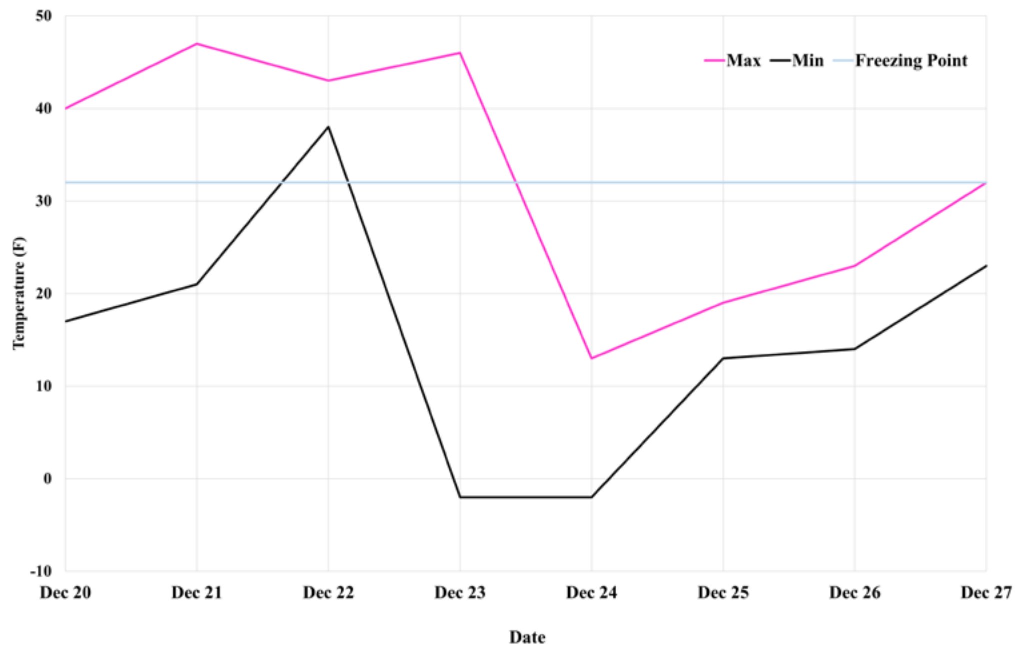
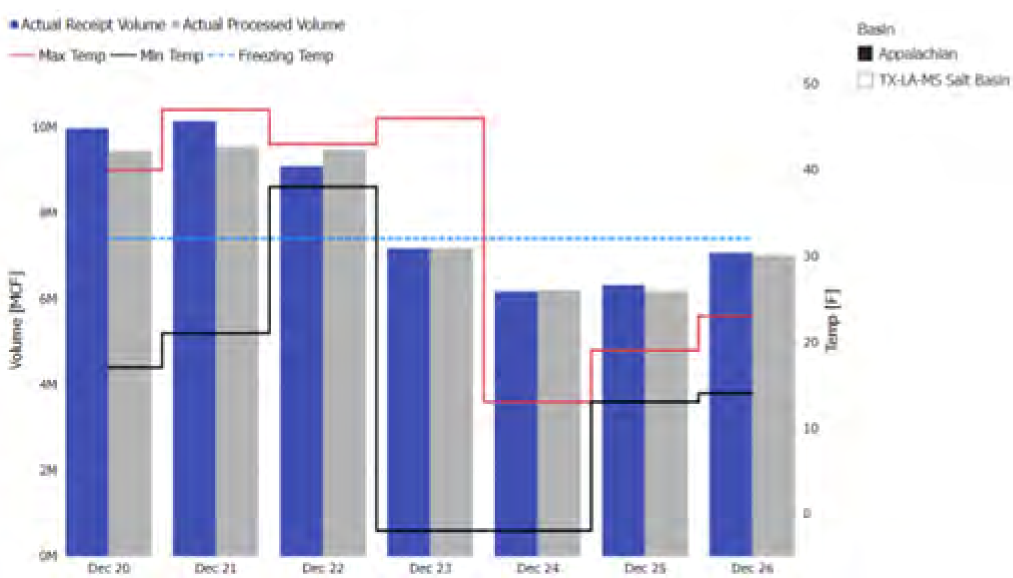


Figure 98: Appalachian Basin Processing Facility Receipt Volume and Processed Volume, December 20 – 26, 2022



260 *See* F gure 25 for departures from normal lows for December 25.

As temperatures plunged, natural gas demand increased, while at the same time, the volume of gas received by processing facilities declined, as seen in Figure 98, above.

Some processing facilities that participated in the inquiry reported they did not receive the full contracted amount of gas supply from producers. Despite not receiving all the gas they expected, processing facilities reported that they processed all the gas they received on the days that receipt volume was most decreased.

Processing losses, analyzed by the day of maximum losses in each basin, were largely caused by reduced gas supply, which in turn was caused by producers' equipment freezing or pressure issues in their gathering pipeline systems. However, as shown in Figure 99 below, as it became colder, some processing facilities also experienced mechanical outages/failures, power outages, and plant equipment Freezing Issues. Overall, the top causes in both basins are, in order, reduction in receipt volumes, producer freeze/pressure issues (these would also cause a reduction in receipt volumes but some producers expressly identified these causes), power outages, and processing facility mechanical outages. As shown in Figure 100, on the December 23 (the second) table, reduced natural gas receipts were by far the largest cause of lost processing facility volume, accounting for 71 to 84 percent of those losses. Processing facility Freezing Issues caused 10 to 16 percent of the lost processing volume, and curtailment or loss of power supply, which had been a substantial cause in the 2021 Event, maxed out at 5.6 percent. Only 25 percent of the 26 processing plants were protected from power outages by local power provider critical load designation agreements.

Figure 99: Appalachian Basin Event Processing Facility Event Causes—Dec. 22 – 29, 2022

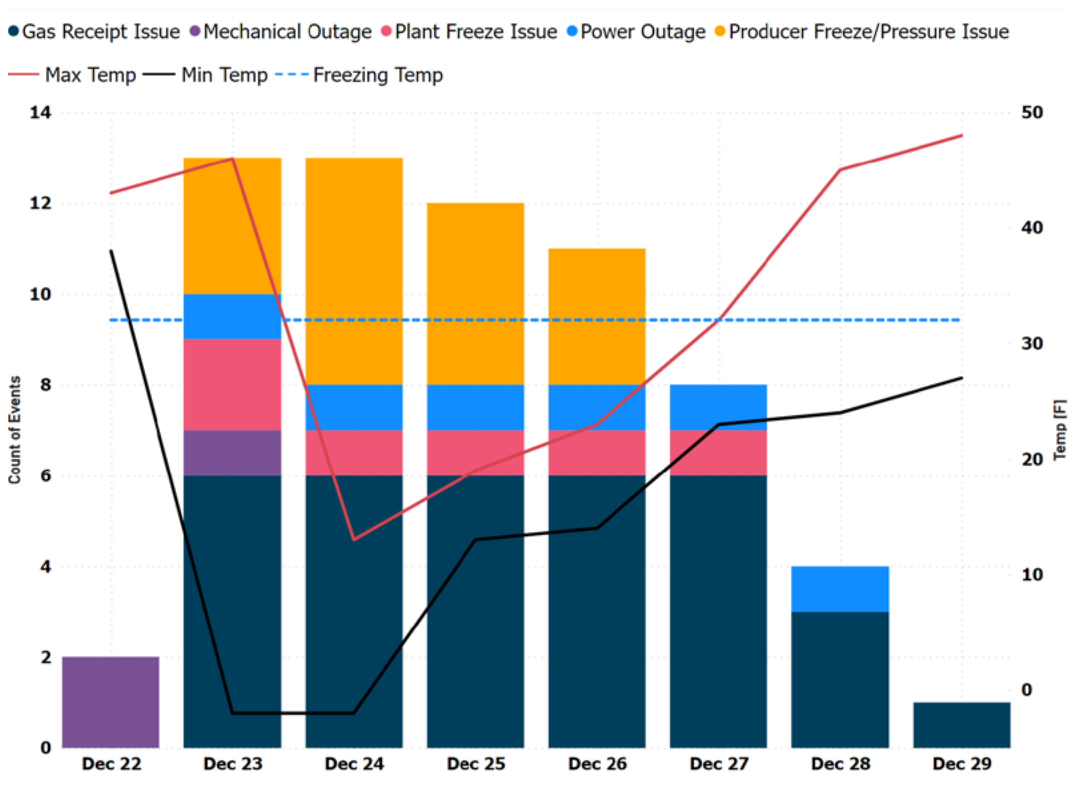


Figure 100: Processing Facilities Event Causes, December 22 – 26, 2022

Processing Facility Disruption Event Causes on December 22		
Cause	**Natural Gas Infrastructure Conditon**	**Facility Event Causes**
Freezing Temperature and Weather Conditions	Reduced Natural Gas Receipt from Production/Gathering/Facilities	71.4%
	Freezing Issues at Processing Facilities	0%
Loss of Power	Processing Facilties- Loss of Power Supply or curtailmennt	0%
Other issues	Mechanical Outage - Non weather Related	28.6%
Total		100%
* There were a total of 7 causes of processing plant events occuring on December 22		

Processing Facility Disruption Event Causes on December 23		
Cause	**Natural Gas Infrastructure Conditon**	**Facility Event Causes**
Freezing Temperature and Weather Conditions	Reduced Natural Gas Receipt from Production/Gathering/Facilities	72.2%
	Freezing Issues at Processing Facilities	16.6%
Loss of Power	Processing Facilties- Loss of Power Supply or curtailmennt	5.6%
Other issues	Mechanical Outage - Non weather Related	5.6%
Total		100%
* There were a total of 18 causes of processing plant events occuring on December 23		

Processing Facility Disruption Event Causes on December 24		
Cause	**Natural Gas Infrastructure Conditon**	**Facility Event Causes**
Freezing Temperature and Weather Conditions	Reduced Natural Gas Receipt from Production/Gathering/Facilities	81.82%
	Freezing Issues at Processing Facilities	13.60%
Loss of Power	Processing Facilties- Loss of Power Supply or curtailmennt	4.500%
Other issues	Mechanical Outage - Non weather Related	0%
Total		100%
* There were a total of 22 causes of processing plant events occuring on December 24		

Processing Facility Disruption Event Causes on December 25		
Cause	**Natural Gas Infrastructure Conditon**	**Facility Event Causes**
Freezing Temperature and Weather Conditions	Reduced Natural Gas Receipt from Production/Gathering/Facilities	84.2%
	Freezing Issues at Processing Facilities	10.5%
Loss of Power	Processing Facilties- Loss of Power Supply or curtailmennt	5.3%
Other issues	Mechanical Outage - Non weather Related	0%
Total		100%
* There were a total of 19 causes of processing plant events occuring on December 25		

Processing Facility Disruption Event Causes on December 26		
Cause	**Natural Gas Infrastructure Conditon**	**Facility Event Causes**
Freezing Temperature and Weather Conditions	Reduced Natural Gas Receipt from Production/Gathering/Facilities	83.3%
	Freezing Issues at Processing Facilities	11.1%
Loss of Power	Processing Facilties- Loss of Power Supply or curtailmennt	5.6%
Other issues	Mechanical Outage - Non weather Related	0%
Total		100%
* There were a total of 18 causes of processing plant events occuring on December 26		

4. NATURAL GAS DELIVERY

The interstate natural gas pipeline facilities experienced 19 equipment issues which directly affected shippers, including Generation Owners and LDCs. The largest reported cause of equipment issues was weather/freezing issues, followed by mechanical issues (see Figure 101, below). The cold temperatures caused valves and compressor units at varying locations along the pipeline system to freeze, reducing or preventing the flow of gas through the facilities (see Figure 102, below). Eight force majeures, five of which were due to freezing, affected a total of 156 firm customers.[261] Yet a sampling of the force majeure provisions of interstate natural gas pipeline tariffs indicates that they either expressly included language that used "freezing of pipelines [or pipes or lines]" as examples of force majeure, even though pipeline owners can take measures to avoid

261 *See* Sect on .B.4(a)(3).

freezing of pipeline equipment; or they included broad language about "unscheduled repairs" or "mechanical or physical failure that affects the ability to transport gas," which could be interpreted to include freezing-related issues."[262] Similarly, the force majeure clause in the NAESB "Base Contract for Sale and Purchase of Natural Gas" expressly includes "weather related events affecting an entire geographic region, such as low temperatures which cause freezing or failure of wells or lines of pipe." Using express inclusions or broad language in force majeure clauses disincentivizes natural gas infrastructure entities from taking steps to ensure that natural gas will be available when it is most needed, during an extreme cold weather event.

Figure 101: Pipeline-Reported Equipment Issues Directly Affecting Shippers – Cause Breakdown

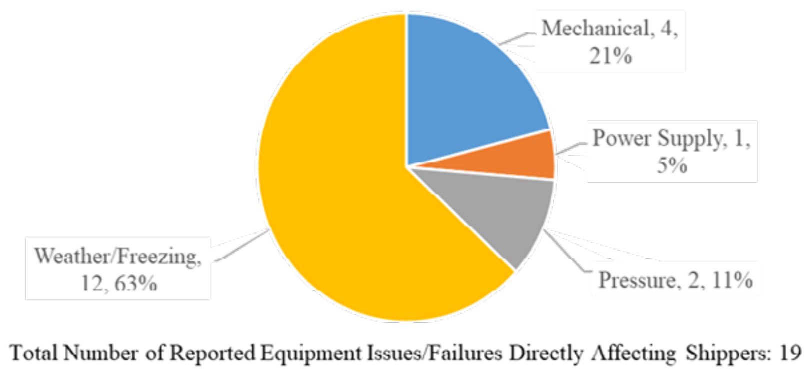
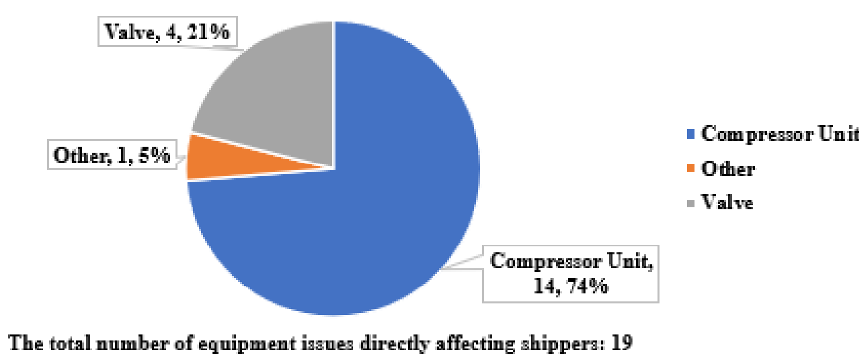
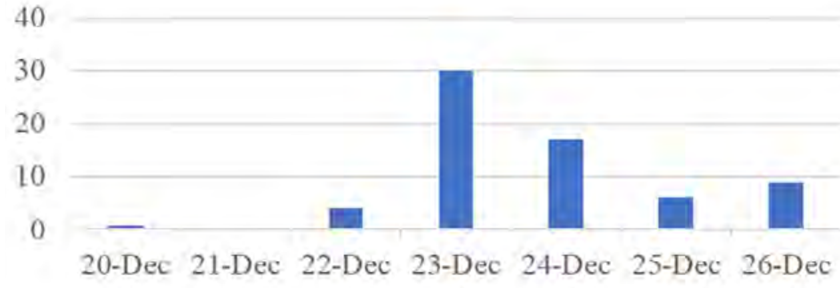


Figure 102: Pipeline-Reported Equipment Issues Directly Affecting Shippers by Equipment Type



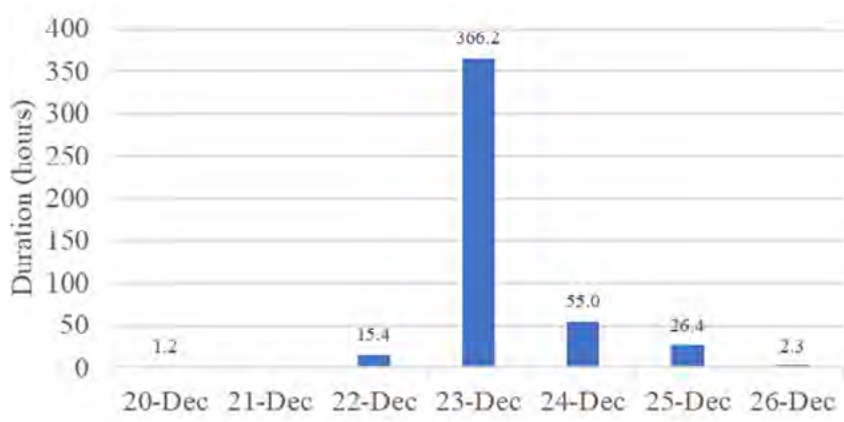
262 Rock es Express P pel ne, LLC, Tar ffs, § 21.2 Force Majeure (3.0.0), Columb a Gas Transm ss on. LLC, Basel ne Tar ffs, Gen. Terms & Cond t ons, § 15.1 Force Majeure (0.0.0), Northern Natural Gas Co, Gas Tar ffs, Sheet No. 217, G T and C § 10 Force Majeure (1.0.0), Transcont nental Gas P pe L ne Co. F fth Rev sed Volume No. 1, Prov s on and Contract Ent tlements, § 11 Force Ma eure (5.0.0).

Figure 103: Pipelines - Total Power Outages Reported



Eight of the 15 pipelines reported a total of 53 instances of commercial power loss at their facilities from December 20-26 (shown in Figure 103 above), averaging approximately nine hours in duration, although some lasted longer than three days (see Figure 104, below). Only one power outage impacted shippers because the compressor stations used redundant compressor units powered by gas-fueled backup or portable generation. Of the 15 pipelines that provided data, only four have facilities designated as critical with their electricity provider. Some pipelines stated that they did not see the need to designate critical facilities, while others stated that they prefer to communicate with electric providers during any load shedding events. One pipeline stated that it performed a study following the Event and did not identify any critical site within the service territory of its power provider.

Figure 104: Total Duration of Pipeline Power Outages



D.Grid Entities' Preparedness and Emergency Operations

1. SHORT-TERM LOAD FORECASTING ANALYSIS

A significant majority of the short-term forecasts (4-, 3-, 2-, and next-day peak load forecasts for actual peak loads) for all eight BAs underestimated the actual peak demand. There were only eight instances of the 64 short-term forecasts that overestimated the actual peak demand. The Mean Average Percent Error (MAPE) for all the short-term forecasts for the peak load of December 23 was approximately 11.25 percent and the MAPE for all the short-term forecasts for the peak load of December 24 was approximately 8.51 percent; with an average MAPE of 9.88 percent for both days for all eight BAs. The short-term forecasts generally improved as the day for the forecast peak demand approached, as shown in Figures 19 and 20, in Section III.

The Team identified some of the possible reasons for the underestimation of the actual peak demand: inaccurate weather forecasts, changes in consumer behavior, especially on peak, and changes to the grid (e.g., addition of non-conforming loads or population growth). The Team also found that many of the entities' models lacked the data history (e.g., similar historical days) for the holiday weekend winter peak extreme cold weather conditions forecast. Some BA operators made manual adjustments to the load forecasts to attempt to make them more realistic. Those that used an "adder" to account for potential load forecast error (LG&E/KU, Santee Cooper) had the lowest MAPE for December 24.

While weather-related factors were important, those that did "backcasts" found that their load forecasts were still off even after being corrected for temperature, so clearly temperature was only one factor, although an important one. Multiple entities noted the difficulty of predicting load for a holiday weekend, when there may be few holiday weekends within the historical data available to the model, and few or none of those may coincide with colder-than-ordinary weather. The combination of a holiday weekend plus extreme cold weather made reliance on prior similar days especially challenging. Most entities expected holidays to lower load, but because of the extreme cold, did not see this pattern emerge. A couple of entities mentioned that they had experienced load growth within their service territory, and the importance of being aware of where this load growth is occurring and its composition (is it residential? Data centers? Commercial? Industrial?)

Another important element to identify in an entity's load is the presence of resistive heating. As explained in the 2021 Report in connection with Recommendation 16,[263] as temperatures drop below zero, homes with heat pumps must rely on electric resistance heating, and the hourly electric demand in kilowatts increases sharply as temperatures decline, to up to four times as much as at 32 degrees, once the temperature reaches minus 10.[264] Multiple entities mentioned the fact that temperatures dropped extremely quickly from relatively temperate temperatures to abnormal lows for their area. When temperatures drop very quickly, but homeowners keep their heat set at the same temperature, heating units must run constantly to try to maintain a steady temperature, rather than cycling as is expected and calculated for "normal" winter load forecasts. Some mentioned the severity of the cold—for one entity, three standard deviations beyond their normal December lows—so that they did not have loads at those temperatures in the historical sample of loads used in the load forecasting models (three years for the majority of the entities).

263 "BAs should have staff w th spec al zed knowledge of how weather mpacts load, nclud ng the effects of heat pump backup heat ng and other supplemental electr c heat ng . . ." 2021 Report at 225

264 2021 Report at 225 and F gure 108.

2. ANALYSIS OF OPERATIONAL PLANNING PROCESSES

As summarized earlier in Section III, the BAs thought prior to the Event that they individually had sufficient resources to meet their respective expected forecast electricity demands. They anticipated the possibility of some level of unplanned generation outages from the winter storm; they were proactive in their preparation efforts. To determine steps the BAs could take to improve their processes, the Team considered the following outcomes from the Event:

- Most of the BAs underforecast their peak electricity demands experienced on December 23-24.
- The BAs did not anticipate the significant level of unplanned generation outages and derates that would occur during the storm, or the rates at which they would occur, which were similar to the outage rates experienced in Texas during Winter Storm Uri in 2021.[265]
- Many natural gas-fired generating units were unavailable because they had not made advance arrangements for natural gas fuel supply for when they ultimately would be committed to operate, and by the time they were notified of their commitment, natural gas supplies were not available.
- The entities thought that they had sufficient reserves to meet their anticipated peak electricity demands, but the severity and widespread nature of the storm, which left multiple neighboring entities in the same position, forced them into a reactionary state of operation, with limited flexibility, options, or time. As a result, several entities needed to shed firm load.

Short-term planning processes typically use deterministic methods and calculations to develop short range resource plans for the next day or several days in advance of the operating day, with plans easily adjusted for the unplanned outage of one or two generation resources through deterministic recalculations. However, the Team found that preparation for another event like Winter Storm Elliott and other extreme cold weather events would benefit from considering a wider range of outcomes representing greater uncertainty, multiple days in advance of the extreme cold weather operating day in risk areas such as:

- Load forecast
- Generation extreme cold weather availability
- Generation fuel availability
- Multiple-neighboring entity impact
- Transmission system constraints

The Team recognizes consideration of this wider range of outcomes may be seen as suggesting use of long-range planning "probabilistic methods" in the control room. However, because these cold weather events have repeatedly revealed significant differences between what was expected and what the operators actually faced, the Team finds that considering a wider range of outcomes representing greater uncertainty should aid in preparation and decision-making multiple days in advance of future extreme cold weather events like Winter Storm Elliott.

3. ANALYSIS OF EMERGENCY OPERATING CONDITIONS AND COORDINATION

a. Coincident high electricity demands, unplanned generation outages and derates, and many Energy Emergency Alerts

Several of the Core BAs' resource assessments and scenarios for the winter 2022-2023 season relied

265 Sect on .B.1. above, descr bes TVA's unplanned generat on outages wh ch ncreased by 6,000 MW from shortly before 1:00 a.m. to 8:00 a.m. on December 23. W th n the PJM footpr nt, unplanned outages and derates began to escalate shortly after 4 a.m. on December 23, and then from about 8:00 a.m. to 5:00 p.m., they rap dly escalated at a rate of over 2,200 MW per hour. The TVA and PJM exper ences were s m lar to the rate of ncrease n generat on outages and derates that was exper enced n the February 2021 event n the ERCOT footpr nt, from February 14, 10:00 p.m. to February 15, 1:00 p.m. (3 hour per od). *See* 2021 Report at 130

on the availability of external generation resources (i.e., purchase power/import power schedules and emergency energy availability) to meet winter season reserve targets. This reliance is dependent on both availability of the power to be imported and on the interregional transfer capability to deliver the power. Some of the BAs' approaches to reliance on external generation resources in planning to serve higher than normal winter peak load levels combined with higher levels of resource outages are as follows:

- One BA identified use of firm transmission (for importing power), combined with economic interruptible energy products for reserves coverage, of 505 MW, 1,519 MW, and 205 MW, for the months of December 2022, January 2023, and February 2023, respectively, to meet its winter reserve above normal load/above normal resource outage scenario margins.
- Another BA assumed 1,000 MW in purchases as part of its 2023 winter season planning and sensitivity analysis.
- One BA calculated a negative reserve margin based on its 90/10 load forecast coupled with expected generation outages, even with use of demand response measures (implying a likely need for purchase power during extreme cold weather conditions).
- Another BA calculated a negative reserve margin based on its 90/10 load forecast without accounting for any generation outages, and with use of demand response measures (again, implying likely need for purchase power during extreme cold weather conditions).

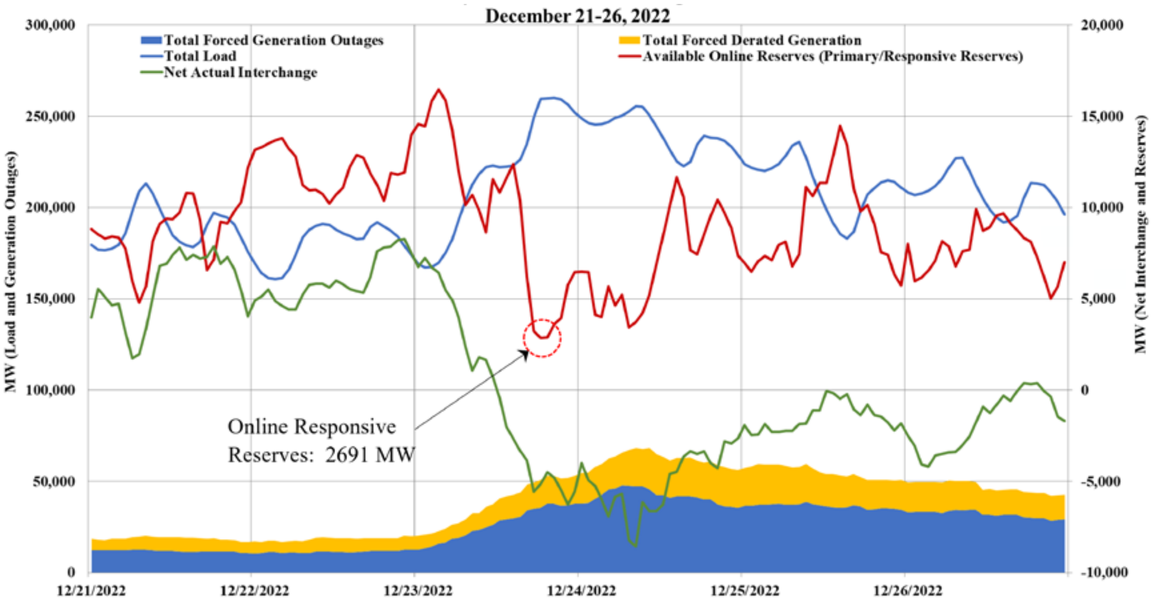
As described above in Section III, during the Event, many BAs in the U.S. Eastern Interconnection had to declare energy emergencies, with some shedding firm load. Most BAs experienced their highest levels of unplanned generation outages and derates and winter peak loads within several hours of one another as Winter Storm Elliott blanketed their footprints simultaneously.[266] A BA's reliance on purchased or import power to meet its system load plus reserves often meant the difference between having to shed load or not. See Figure 39.

System load in the U.S. portion of the Eastern Interconnection increased by 132,000 MW during a 14-hour period coinciding with the arrival of Winter Storm Elliott. By 10 a.m. on December 24, system load levels for several BAs were well above 90 percent of their respective peak loads during Winter Storm Elliott, and most of those BAs had already invoked load management measures (EEA 2) or even firm load interruptions, reducing the percentages which are shown in Figure 39, above. Had the load management and firm load shed measures not been in place, the December 24 peak would have been close to the December 23 evening peak of 482,444 MW (shown in Figure 39, above).

The affected BAs arranged for purchase power imports to cover forecast or actual declining reserves positions that reflected their own unplanned generation outages and derates coupled with rising forecast and actual system loads for December 23 and 24. Those BAs that anticipated potential need and already had prior arrangements for purchase power took steps to schedule those deliveries with the purchase-selling entity (within the source BA) for the coldest days. Because many of the BAs that were in need are directly connected via AC ties as illustrated in Figure 12 (listing the tie lines between BAs), arranging for purchase power imports from a purchase-selling entity within an adjacent BA during less extreme circumstances would normally be fairly straightforward, especially for BAs directly connected to each other like PJM and Duke, or PJM and TVA. But most of the directly-neighboring BAs found themselves simultaneously experiencing Energy Emergencies and did not have energy to share with their neighbors.

266 The five extreme cold weather events n the past 11 years (2011, 2014, 2018, 2021, and 2022) covered large geograph c reg ons. Dur ng the 2018 and 2021 events, generat on reserves ex sted n d stant operat ng footpr nts where the extreme cold weather event was not as ntense or had not yet mpacted those areas, wh ch afforded the opportun ty for power transfers, l m ted by transm ss on constra nts.

Figure 105: Total Reserves, Generation Outages and Derates, and Load for Event Area: December 21 - December 26, 2022



b. Health of the Eastern Interconnection during Winter Storm Elliott peak electricity demand

The Core Event Area and the U.S. portion of the Eastern Interconnection were experiencing the highest winter electricity demands during Winter Storm Elliott, as shown in Figure 39, above. Meanwhile, while system loads were peaking across the Interconnection, total unplanned generation outages and derates were climbing as shown in Figure 69, above. To gain perspective on the overall health of the Interconnection during this most critical period of the Event, the Team estimated the remaining responsive reserves. The Team reviewed:

- the total online/synchronized reserves in the Core Event Area (see Figure 105),
- the system load of the U.S. portion of the Eastern Interconnection (see Figure 39), and
- total unavailable generation in the U.S. portion of the Eastern Interconnection during the Event (see Figure 37).

The Team found that there were periods during the evening of December 23 and the morning of December 24 when the "potential responsive reserves" (which included online and any offline resources) were lowest while system demand was at its highest levels, as illustrated in Figure 105, below. The Team notes that its estimates of how low responsive reserves dropped are conservative, since they may include offline capacity, and do not account for additional offline capacity in other portions of the Eastern Interconnection.[267] During this same period, Eastern Interconnection frequency excursions were common. Figure 106, below, illustrates one-minute-average system frequency, which declined below 59.95 Hz several times on the evening of December 23 and the morning of December 24 during periods of low responsive reserve capacity.

267 The Team conservat vely est mated capac ty; the actual capac ty shortage could have been worse as the Team d d not account for any offl ne capac ty n Canada or the Flor da pen nsula (.e., other port ons of the Eastern nterconnect on), wh ch were not w th n the Event Area.

Figure 106: Eastern Interconnection Frequency: December 23, 4:00 p.m. to December 24, 12:00 p.m.

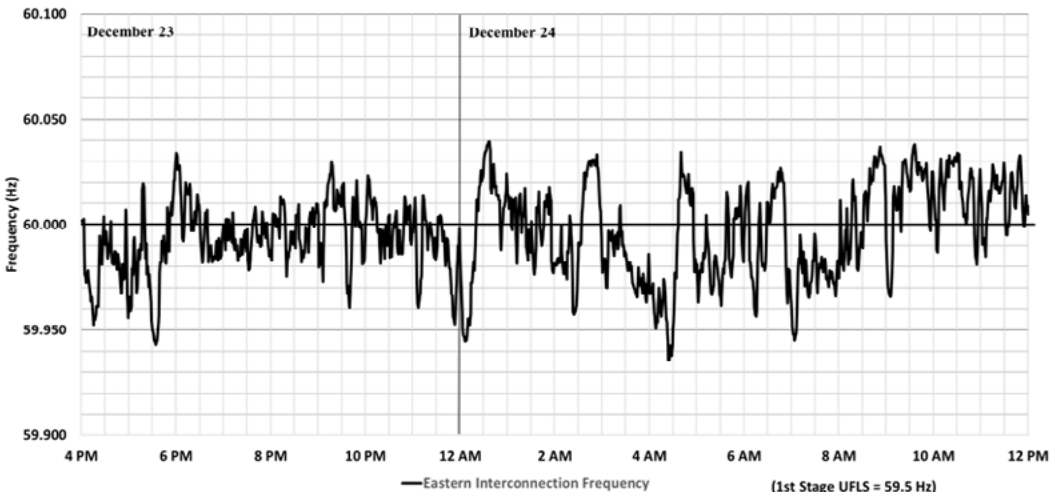
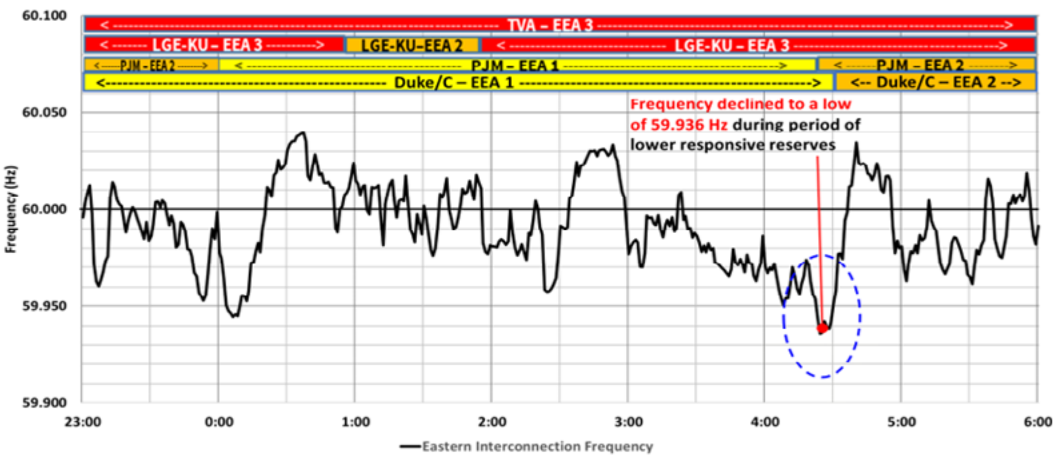


Figure 107: Eastern Interconnection Frequency: December 23, 11:00 p.m. to December 24, 6:00 a.m.



As seen in Figure 107 above, at about 5:40 p.m. on December 23, the Eastern Interconnection frequency decreased to a one-minute average of 59.943 Hz, and dropped to its lowest point during the Event, 59.936 Hz, at about 4:25 a.m. on the morning of December 24. Based on this limited review, the Team is concerned that, accounting for next contingencies (e.g., large generation outage, single point of failure contingency), the Eastern Interconnection appears to have been at risk of potential instability during this timeframe of escalating winter system demands, rapidly escalating unplanned generation outages and derates, and declining responsive reserves.[268]

c. Grid Communications and Coordination

Before and during the Event, RCs remained in contact with each other, as well as with their member BAs, either directly via voice communication or through the NERC-managed Reliability Coordinator Information System (RCIS). RCs were able to communicate EEAs and other emergency measures they took during the Event on the

268 The study should also cons der how close the nterconnect on may have been to an underfrequency load shed event.

RCIS message system. All RCs have read and write access to the RCIS. Although they do not have write access to the RCIS, BAs and TOPs can request read access to the system. Given the valuable information shared by RCs on the RCIS during emergency events, BAs that have not already done so should request access to the RCIS system and monitor those communications during extreme cold weather events, at a minimum. BAs can also ask their RC to communicate on RCIS their ability, or lack thereof, to provide energy to other BAs experiencing energy shortages during emergencies. This practice could reduce the number of entities that a BA short on energy would need to contact in an emergency.

Generally, many of the RCs have a daily operational call, as well as ad hoc calls and other communications as system conditions dictate. Examples of some of the standing calls relevant to the Event include: (1) NPCC has a brief standing daily 9:30 a.m. call (which includes PJM, MISO, and others), which can be initiated by any RC, and any follow up items from these calls are assigned to control room managers;[269] (2) MISO has a standing daily 8:00 a.m. MISO RC coordination conference call, which includes TOPs and BAs within the MISO Reliability Coordination Area, as well as neighboring RCs, including PJM, SPP, and TVA.

Before and during the Event, RCs coordinated on specific issues and concerns affecting their systems, including the following:

- VACAR-South RC coordinated with adjacent RCs on two potential thermal overloads, one involving a tie line between DEP and PJM and the other involving a tie line between Santee Cooper and Southern. In both cases, the potential overloads were mitigated through the use of adjusted ratings.
- SPP RC agreed to allow an additional increase in the RDT on Saturday, December 24, for an emergency energy request that TVA made from MISO.
- TVA RC coordinated with PJM RC to mitigate real-time overloads within the PJM/AEP footprint on the morning of December 23, and PJM and TVA RCs also coordinated to resolve low voltage conditions observed in the East Kentucky Power Cooperative area.

When conditions permitted, entities directly impacted by the storm provided neighboring entities with emergency energy. Examples included:

- PJM, Duke, MISO, and Southern provided emergency energy to TVA,
- TVA provided emergency energy to LG&E/KU,
- Florida Power and Light and MISO provided emergency energy to Southern, and
- Southern provided emergency energy to DESC.

As described earlier, PJM was able to leverage its simultaneous activation of reserves/SAR procedure with NPCC during the Event.[270] During the evening of December 23, for example, PJM asked NPCC for reserves support (up to 1,500 MW) during the period that PJM activated its Synchronous Reserves emergency procedure. The Team found that the entities communicated and cooperated well during the Event, doing as much as possible to assist their neighboring BAs even while under their own systems were experiencing emergency conditions.

269 *See*, Northeast Power Coord nat ng Counc l, nc., NPCC Emergency Preparedness Commun cat ons Procedures (Sept. 2, 2022), https://www.npcc.org/content/docs/publ c/program areas/standards and cr ter a/reg onal cr ter a/procedures/c 01 emergency preparedness procedure.pdf. (outl n ng procedures for NPCC ad hoc call).

270 *See* R22 and Attachment B of the NPCC Reg onal Rel ab l ty Reference D rectory # 5 Reserve https://www.npcc.org/content/docs/publ c/program areas/standards and cr ter a/reg onal cr ter a/d rector es/d rectory 5 reserve 20200426.pdf.

E. Variable Energy Resources' Performance and Uncertainty Analysis

Variable energy resources (VERs) such as wind and solar were part of the energy supply mix during the Event. During the Event, solar and wind comprised 1.94 percent and 1.12 percent of installed capacity, respectively, in the core Event Area, as noted in Figure 11. For PJM, solar and wind comprised 1 percent and 2 percent, respectively, of the net installed generation capacity. Figure 108, below, illustrates the actual generation output by VERs, as a percentage of the total generation production output in the PJM footprint during the Event.

Figure 109, below, shows day-ahead versus actual production profiles of both wind and solar resources in PJM during the Event. Winter Storm Elliott occurred shortly after the winter solstice,[271] resulting in a relatively narrow potential solar production time window each day during the Event.

Figure 108: PJM Percent VER Actual Generation Production Output, December 21 – 26, 2022

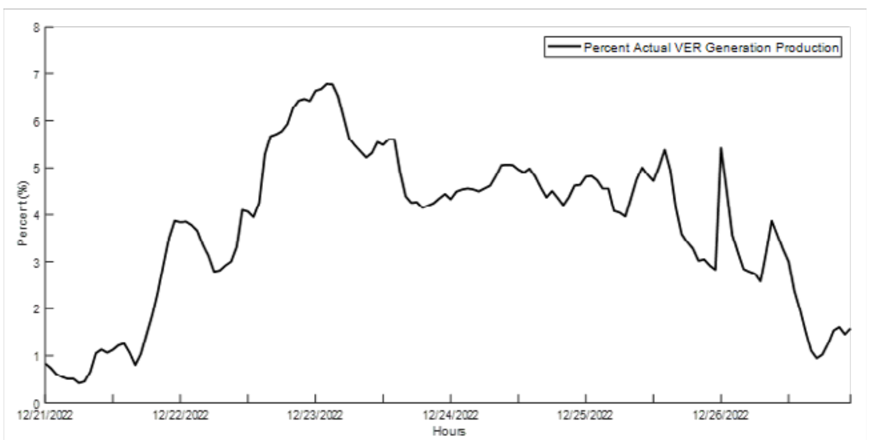
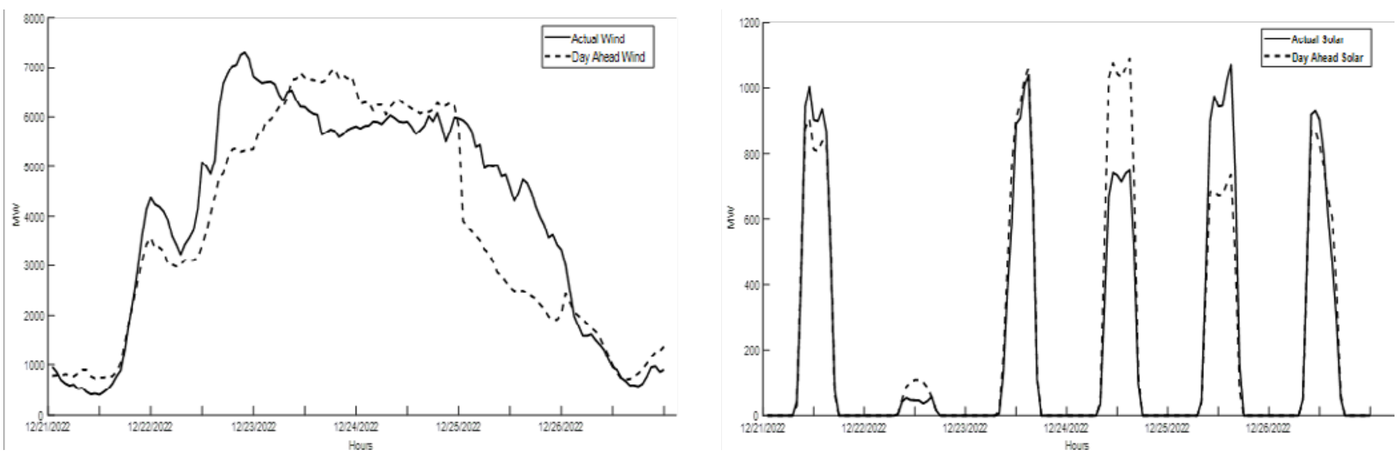
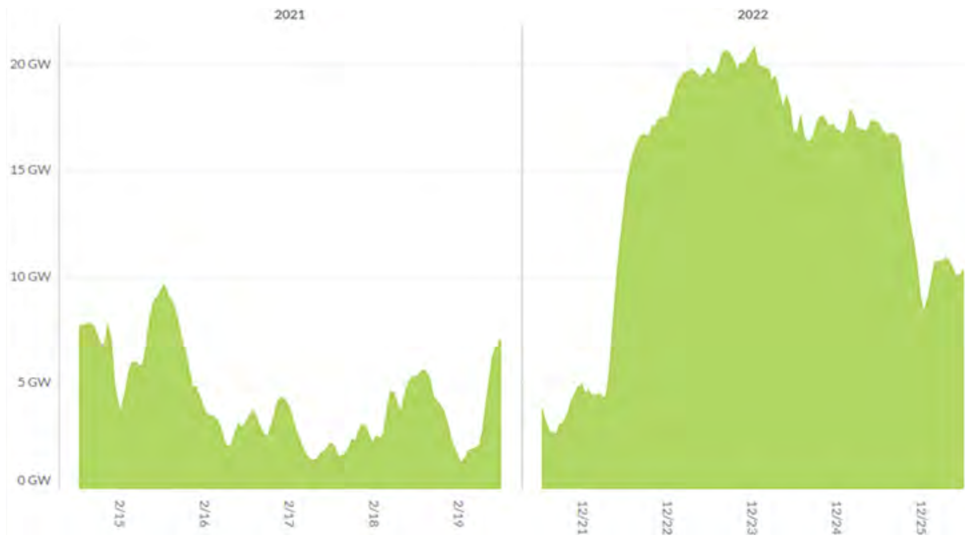


Figure 109: PJM Day-Ahead and Actual Hourly MW Wind and Solar Production, December 21 – 26, 2022



271 W nter So st ce for the Northern Hem sphere was December 21, 2022 4:47 p.m. The w nter so st ce marks the shortest day and ongest n ght of the year.

Figure 110: MISO Actual Wind Generation – Storms Uri (2021) and Elliott (2022)[272]



The limited availability of solar production time during winter, when daylight hours are shorter, highlights the value of storing energy from solar production for when it is needed most during the winter non-daylight peak load timeframes. For example, DESC noted that on the morning of December 24, their solar resources began to produce energy, which, while after the morning peak, contributed to DESC's ability to pump water at its pumped storage facility so that its capacity would be available for the December 24 evening peak and the December 25 pre-dawn morning peak.

Wind energy production in higher-penetration areas west of the core Event Area (SPP, MISO) was high, especially during the onset of the Event on December 22 and 23. Figure 110, above, shows a wind production comparison between Winter Storm Uri and Winter Storm Elliott in MISO.

For SPP, wind resources performed above accredited capacity on December 22 at 17,900 MW, coinciding with high SPP system load. With high system loads expected to continue, SPP had to anticipate uncertainty including whether the forecast for high wind levels would hold, and the extent to which wind farms would be shut down or derated for low ambient temperatures or high wind cutoff. The actual wind generation output level slowly decreased after the December 22 peak load and reached its lowest level of 2,700 MW 20 hours later, on December 24 at 6 p.m.[273] SPP's experience illustrates the challenge of aligning VER production levels with power grid needs. Absent energy storage opportunities, the higher variability of wind and solar production increases the demand for dispatchable generation with high ramping capacity[274] to balance generation with load during times when wind or solar power is low, and the system is near peak demand.

Understanding and modeling uncertainties with VER production in the operations planning horizon can help minimize reliability and resource adequacy risks, especially at times of system stress, such as during extreme cold weather events. Shifting from deterministic to probabilistic methods for resource availability/adequacy analyses can better model the uncertainties surrounding VER production. See Recommendation 8 in section V.

272 Repr nted w th perm ss on of M SO.

273 SPP Report at 6.

274 *See* Department of Energy, *Importance of Flexible Electricity Supply* (May 2011), https://www1.eere.energy.gov/solar/pdfs/50060.pdf.

V. RECOMMENDATIONS[275]

A. Generator Cold Weather Reliability

Each successive analysis of extreme cold weather events has highlighted the need for generating units to proactively prepare for the onset of cold weather events.[276] Each inquiry report has built on previous analyses and findings to explain how generating units can best achieve that end. In August 2021, the Commission approved the adoption of EOP-011-2, effective April 1, 2023, in response to a recommendation from the 2018 Report, and required Generator Owners to have cold weather preparedness plans for their units. The 2021 Report took the next logical step by recommending that generating units be required to "(i) identify cold-weather-critical components and systems and (ii) identify and implement freeze protection measures for those components and systems."[277] The 2021 Report also recommended that generating units that experienced unplanned outages due to freezing should be required to develop Corrective Action Plans to guard against future outages.[278]

More recently, the Commission has approved revisions to the NERC Reliability Standards, in EOP-012-1, that implemented recommendations from the 2021 Report.[279] These changes, the Commission found, "represent[] an improvement to the Reliability Standards and enhance[] the reliable operation of the Bulk-Power System by requiring generator owners to implement freeze protection measures, develop enhanced cold weather preparedness plans, implement annual trainings, draft and implement corrective action plans to address freezing issues, and provide certain cold weather operating parameters to Reliability Coordinators, Transmission Operators, and Balancing authorities for use in their analyses and planning."[280] These modifications have not yet become effective.

Recommendation 1(a): Findings support the need for prompt development and implementation of the remaining recommended revisions to the Reliability Standards from 2021 Report Key Recommendation 1 to strengthen generators' ability to maintain extreme cold weather performance.

Despite the fact that nearly two thirds of all generating units that provided data indicated that they had begun to make improvements to their cold weather preparedness plans in response to the findings of the 2021 Report, and that many units had already begun to implement improvements required under EOP-011-2, R7.3.2, prior to its effective date of April 2023, 111,000 MW of generating units in the Event footprint still experienced unplanned outages, derates or failures to start due to Freezing Issues.[281] The Team considered whether to recommend additional mandatory Reliability Standards, but with many important Standards either approved, but not yet effective, or still in the drafting stage (e.g. identification of generator cold weather critical components, developing Corrective Action Plans

275 Because the recommendat ons are ntended to be shared w dely and may be shared w thout the rema nder of the Report, terms that have been otherw se been abbrev ated elsewhere n the Report, such as GOs/GOPs for Generator Owners/Operators, w ll be spelled out the first t methey are used n each recommendat on.

276 *See* 2021 Report at 185 86.

277 *See* 2021 Report at 185 86, Recommendat ons 1(a) and (b).

278 *See N. Am. Elec. Reliability Corp.,* 176 FERC ¶ 61,119, at P 1 (2021).

279 The first of ts Requ rements become effect ve October 1, 2024.

280 *N. Am. Elec. Reliability Corp.,* 182 FERC ¶ 61,094, at P 36 (2023).

281 An encourag ng find ng was that roughly two th rds of all generat ng un ts sa d they had begun to make mprovements to the r cold weather preparedness plans n response to the find ngs of the 2021 Report.

to operate at Extreme Cold Weather Temperatures), this recommendation focuses instead on fully implementing the recommendations already made in response to the 2021 Report. That over 75 percent of the generating units with unplanned outages due to Freezing Issues failed above their documented minimum operating temperatures suggests that work in this area is not yet complete. For additional background and analysis relevant to Recommendation 1(a) see section IV.B.3., above.

Recommendation 1(b): Findings from the Report support the need for robust monitoring by NERC and the Regional Entities of compliance with the currently-effective and approved generator cold weather Reliability Standards, to determine if reliability gaps exist. NERC should identify the generating units that are at the highest risk during extreme cold weather and work with the Regional Entities (and Balancing Authorities, if applicable) to perform cold weather verifications of those generating units until all of the extreme cold weather Standards proposed by the 2021 Report are approved and effective. (Verify highest risk units by Q4, 2023; implement by Q3, 2024)

As mentioned in 1(a), the Team considered recommending additional Reliability Standards, including for several of the sub-parts of Recommendation 1, but was persuaded to focus on fully implementing the 2021 Report recommendations. Robust compliance monitoring of the currently-effective and approved extreme cold weather Standards can help to discern whether there are patterns which suggest that sub-parts of Recommendation 1 may need to be added to the Standards. For example, if compliance monitoring were to show that large numbers of Generator Owners/Operators were not fully-prepared for winter until mid-December or later, it may suggest that Recommendation 1(g) should be considered for addition to the Standards.

Given that the Extreme Cold Weather Preparedness and Operations Reliability Standards will not be fully effective until May 2028, and that generating units continue to experience high volumes of unplanned outages due to the top three causes of Freezing and Fuel issues as well as Mechanical/Electrical Issues, the Team considered what could be done in the meantime to improve generating unit performance to enhance the reliable operation of the grid. The Team recommends identifying those units at the highest risk of unplanned outages due to Freezing Issues (based on generating units' performance in previous events, their responses to NERC's Level 3 Alert or other criteria) for expedited cold weather verifications. The Team also recommends additional near-term, but slightly less expedited, cold weather verifications as explained in the next recommendation.

Recommendation 1(c): Generator Owners/Operators should assess their own freeze protection measure vulnerability, and NERC or the Regional Entities should perform targeted cold weather verifications pursuant to a risk-based approach.

Generator Owners/Operators should not wait for an extreme cold weather event to occur in their Balancing Authority Area, but should learn from the experiences of others, as well as the many resources available.[282] Based on the guidance provided by the Report, the 2021 Report, and the resources available from NERC and the Regional Entities, GOs/GOPs should assess their own freeze protection measures protecting generator cold weather critical components, and determine whether the generator cold weather critical components continue to be vulnerable to extreme cold, the accelerated cooling effect of wind, and precipitation. To determine whether GOs/GOPs are implementing the currently-effective cold weather Reliability Standards, NERC and the Regional Entities should conduct targeted cold weather verifications, using a risk-based approach. The GOs/GOPs selected would not be those considered at the highest risk of unplanned outages due to Freezing Issues, (i.e., those that are targeted by Recommendation 1(b)), but should be those in the next tier of risk and below. These verifications

282 *See* note 52 for a l st of resources.

should continue until all of the Reliability Standards revisions recommended by Key Recommendation 1 of the 2021 Report have become effective. For additional information in support of Recommendation 1(c) see Key Recommendation 1 in the 2021 Report.

Recommendation 1(d): Generator Owners/Operators of generating units that have experienced outages, derates, or failures to start above their documented operating temperature limits should consider conducting engineering design reviews to: (1) evaluate the accuracy and completeness of existing design information (including as it relates to the documented operating temperature limits) and calculated extreme cold weather operational thresholds: (2) evaluate whether existing freeze protection measures are adequate to protect their identified generator cold weather critical components; (3) evaluate whether design features to address cold weather and freezing conditions are being optimally implemented; (4) evaluate the impact of any modifications or additions to the original design on the documented operating temperature limits; (5) evaluate whether any modifications or additions resulted in new generator cold weather critical components; (6) evaluate the impact a unit's "cold" versus "hot" status has on its design limits, including the identification of a "cold start-up" temperature for each unit, if applicable; and (7) determine whether the generating unit's operating characteristics have been altered in a way that creates a potential "weak link" component.

The Team recommends that Generator Owners/Operators consider taking additional steps to ensure the reliability of their generating units for the substantial number of units that, during Winter Storm Elliott, experienced Freezing Issues at temperatures above their documented operating temperature limits. The failures above the units' documented operating temperature limits suggest that the information relied upon by many generators may be inaccurate or may no longer be valid after modifications made to the generating units. Generator Owners/Operators that have experienced unplanned outages, derates, or failures to start due to freezing during extreme cold weather events should consider reviewing their documented operating temperature limits, with appropriate expert assistance, to determine whether modifications have changed their limits or whether the limits should be changed for some other reason. A generating unit may have a higher "cold" low temperature limit (the temperature at which it can start in extreme cold weather, when it has not already been running, versus the "hot" temperature, at which it can run continuously). Identifying these temperatures and sharing them with the BA is critical. However, the Team cautions against GOs/GOPs simply raising their documented operating temperature limits to temperatures above those at which the units failed during the Event, without analyzing whether the units could perform at lower temperatures with appropriate protection of their cold weather critical components.

Recommendation 1(e): Generator Owners/Operators should consider conducting operational/functional testing of their "active" freeze protection systems.

Generator Owners/Operators should consider conducting operational and functional testing of their "active" freeze protection systems (e.g., heat trace circuitry/controls, partial discharge recirculation systems) on at least an annual basis, and always prior to winter, to ensure their continued functionality during extreme cold weather events. Like other systems, active freeze protection systems are subject to wear and tear over time. For instance, even a small section of inoperable heat trace system or circuit can leave a critical component unprotected, leading to a freezing-related outage. A heat trace system that no longer properly alarms for circuits that are inoperable will not warn the GO/GOP that its critical components are vulnerable to freezing.

Recommendation 1(f): Generator Owners/Operators should communicate their low temperature limits, and changes to those limits, to their Balancing Authority and Reliability Coordinator on a real-time basis.

Discussions with Balancing Authority representatives while preparing the Report underscored the substantial efforts that BA personnel took in real time to activate generation; only for them to learn that that the generation was unavailable. As noted in PJM's analysis of its own response to Winter Storm Elliott, on the afternoon of December 24, 2022, its operational situation was "strained" in part because of a lack of reliable information of this kind:

> *PJM had put generation resources on notice, through Advisories and Alerts, of PJM's need for them to be prepared to run. PJM relied on Generator Owner/operator-submitted data and believed these reserves were available. In many cases, this data did not reflect the actual capability of the generator and PJM would only learn of the generation resource failures at the time PJM was expecting these resources to begin to run.*[283]

Balancing Authorities seeking to address cold weather events should not be expected to learn such information on an ad hoc basis while simultaneously attempting to respond to worsening generation conditions and/or increased load. The onus should be placed on generating units to communicate and update such information, in real time, to BAs. If a GO/GOP knows that there is a meaningful difference between its cold start-up temperature and the temperature at which it can continue to operate when warm, the GO/GOP should inform the BA, so that the BA can consider the generating unit for pre-operational warming in advance of extreme cold weather events. Before an extreme cold weather event, GOs/GOPs should consider whether high winds or precipitation might affect their ability to perform at the documented low temperature limit(s) that they provided to the BA. Generator Owners/Generator Operators should update this data in real time, and BAs should consider amending their tariffs or procedures to require real-time updates if not already required. BAs should use all information provided by GOs/GOPs regarding the operating limits of their generating units to the fullest extent possible in their operations.

Recommendation 1(g): Generator Owners/Operators should complete their preparations for winter, including implementing their winter preparedness plans and inspecting and maintaining their generating units' freeze protection measures, no later than the earliest first freeze date for the generating unit's location, as determined by National Oceanic and Atmospheric Administration data.[284] Generator Owners/Operators should maintain those preparations until after the last freeze date, as provided by the same data. Those preparations are in addition to any preparations, inspection or maintenance done in anticipation of a specific extreme cold weather event.

Although annual inspections and maintenance of generating units' freeze protection measures are required by EOP-011-2 R 7.2, some evidence suggests that Generator Owners/Operators may not have completed freeze protection maintenance on all of their units before Winter Storm Elliott hit, relatively early in the winter. Winter Storm Elliott is not the only proof that the worst weather can happen early in the season—in the 2021 Report, Appendix B examined five extreme cold weather events that impacted Texas and the South Central U.S. Two of those events happened in December, one in January, and two in February. December is too late for GOs/GOPs to be finishing their preparation for winter.

(1(c) to 1(g): Implement as soon as possible, but by no later than Q4, 2025)

Recommendation 2: NERC should initiate a technical review of the individual causes of cold-weather-related unplanned generation outages caused by Mechanical/Electrical Issues during the Event to identify the root causes of these failures with the goal of determining what can be done to reduce the frequency of these outages during extreme cold weather events. The study should also consider whether additional Reliability Standards are appropriate to address the root causes of these issues. The study should be conducted by

283 PJM Report at 28.

284 *National Weather Service Frost and Freeze Information* (Sept. 2022), https://www.weather.gov/ wx/fallfrost nfo.

either an independent subject-matter expert such as the Electric Power Research Institute or an academic institution, with participation by Generation Owners/ Generation Operators on scoping and providing generating-unit-specific technical expertise. (Initiate Technical Review by Q1, 2024)

Successive reports reviewing cold weather events have consistently demonstrated a steady relationship between decreasing temperatures and a rise in Mechanical/ Electrical Issues in generating units. The 2021 Report suggested that further analysis was required by Generation Owners to "understand the impact of extreme cold weather on mechanical/electrical failures, so that GOs can identify possible methods of reducing the incidence of unplanned outages, derates and failures to start due to [Mechanical/Electrical Issues] during similar events."[285] The persistence of these issues, even in the face of increased awareness, suggests further action needs to be taken.

An independent subject matter group with knowledge of electrical generator design and operations, as well as materials science, among other topics, should study the relationship between Mechanical/Electrical Issues and cold weather events. The study should analyze the types of Mechanical/Electrical Issues experienced by generating units during extreme cold weather events; the types of components and systems most vulnerable to these events; methods and best practices to prevent Mechanical/Electrical Issues from affecting those components and systems; and any other information deemed relevant. Further, the study should differentiate between Mechanical/Electrical Issues caused by extreme cold weather events, and those that simply occurred during such events (e.g., boiler tube leaks).

Recommendation 3: A joint NERC-Regional Entity team, collaborating with FERC staff, should study the overall availability and readiness of blackstart units to operate during cold weather conditions. This study should cover all portions of the U.S. not already studied, and should incorporate existing literature, studies, reports, and other analyses as to the availability and readiness of blackstart units. The scope of the study should include:

- **an evaluation of existing blackstart restoration plans, including a review of potential single points of failure related to natural gas system dependence;**
- **an evaluation of the sufficiency of existing blackstart availability, readiness, and testing criteria, including whether unscheduled, unannounced, or criteria-based testing (e.g., those used in ERCOT) would improve reliability during cold weather events;**
- **the need for ensuring that generating units with dual-fuel capability providing blackstart service have appropriate fuel storage (as determined by the Balancing Authority);**
- **the need to require blackstart generators to test their fuel switching capabilities seasonally;**
- **the need to require additional fuel storage due to import constraints;**
- **the need for Transmission Operators to incorporate generating units' cold weather preparations into the qualification process for certifying generators as blackstart units; and,**
- **any other subject areas identified as areas of substantial interest or concern in the report issued as a result of ongoing efforts to study blackstart unit availability and readiness in ERCOT.[286] (Initiate study by Q1, 2024)**

Over 19,000 MW of blackstart designated generating units (155 units) incurred outages, derates, or failures to start during the Event. Of the 155 units, 119 were natural-gas fueled units (accounting for just under 75 percent of all generation lost by blackstart designated units). These failures were not geographically or causally isolated, instead, they covered the entire area impacted by the Event, arose from Freezing Issues, Mechanical/Electrical Issues, and Fuel Issues, and impacted gas, oil and dual-fuel capable units.

285 2021 Report at 218 (Recommendat on 11).

286 *See* 2021 Report Recommendat on 26.

The readiness and availability of blackstart units is paramount to the reliability of the grid during extreme weather scenarios, and the breadth (both in numbers and causes) of the outages and derates to blackstart units during Winter Storm Elliott suggests the need for systematic evaluation of the readiness of these units. For additional background and analysis relevant to Recommendation 3, see Section IV.B.4.

B. Natural Gas Infrastructure Cold Weather Reliability

Recommendation 4: Legislation by Congress and state legislatures (and/or regulation by entities with jurisdiction over natural gas infrastructure reliability) is needed to establish reliability rules for natural gas infrastructure necessary to support the grid and natural gas local distribution companies that address the needs described in 4(a), (b) and (c).

The 2021 Report noted that "the reliability of the BES depends, in large part, on the reliability of the natural gas infrastructure system, but unlike the BES, with its mandatory Reliability Standards enforced by FERC and NERC, the reliability of the natural gas infrastructure system rests largely on voluntary efforts."[287] In February 2011, extreme cold weather in Texas and New Mexico "resulted in widespread wellhead, gathering system, and processing plant freeze-offs in the Permian and San Juan basins," reducing flow by approximately 20 percent, a much greater extent than had occurred up to that point. LDCs interrupted gas service to more than 50,000 customers in New Mexico, Arizona, and Texas, including the cities of El Paso, Texas, Tucson, Arizona and Taos, New Mexico. While some LDCs were able to restore service within hours because they had only cut a few customers, it took one LDC a week to restore 4,300 customers, using a workforce of 700. The 2011 Report recommended that state legislators and regulators, working with "all sectors of the natural gas industry. . . should determine whether production shortages during extreme cold weather events can be effectively and economically mitigated through the adoption of minimum, uniform standards for the winterization of natural gas production and processing facilities."[288] The 2011 event highlighted the increasing interdependency of natural gas infrastructure and the BES.[289]

In Winter Storm Uri, Natural Gas Fuel Issues were "the second-largest cause of generating unit outages that left residents without heat and light and energy in ERCOT for nearly three days, during freezing temperatures,"[290] even though that event did not involve LDCs interrupting service to customers. Texas natural gas production declined during Winter Storm Uri by 70.1 percent, Oklahoma, by 56.8 percent, and Louisiana, by 53.5 percent,[291] while the lower 48 states' production declined by 28 percent.[292] Like the 2011 Report, the 2021 Report recognized that freezing at the wellheads and other natural gas infrastructure facilities, as well as weather-related road conditions, caused the majority of the gas production decline that contributed to the Natural Gas Fuel Issues. To prevent recurrence of these dramatic drops in production in areas on which the entire United States relies for the production of natural gas, the 2021 Report recommended that "Congress, state legislatures, and regulatory agencies with jurisdiction over natural gas infrastructure facilities should require those natural gas infrastructure facilities to implement and maintain cold weather preparedness plans,

287 2021 Report at 197.

288 2011 Report at 126 132, 212, 214.

289 As the 2021 Report recorded, " a]fter the 2011 event, the Comm ss on n t ated a proceed ng (Docket No. AD12 12 000) n early 2012, request ng comments on quest ons about top cs nclud ng market structure and rules, schedul ng, commun cat ons, nfrastructure, and rel ab l ty." The Comm ss on convened five reg onal conferences and ssued two orders wh ch enhanced p pel ne commun cat on w th gr d ent t es and ncreased p pel ne schedul ng flex b l ty. The 2021 Report noted "some aspects of the problem are e ther outs de the Comm ss on's] author ty or requ re cooperat on among jur sd ct ons" (e.g. the natural gas product on shortages). 2021 Report at 201.

290 2021 Report at 197.

291 As compared to January product on. 2021 Report at 174. The Team used January so that t could compare the 2011 event, wh ch happened February 1 5.

292 As compared to February 8 product on. 2021 Report at 174.

including measures to prepare to operate when specific cold weather events are forecast."[293]

Despite the 2011 and 2021 recommendations for protecting natural gas infrastructure, including wellheads, from extreme cold weather, production remained insufficiently protected during the Event, which led to a reliability-threatening Gas Emergency for Con Edison in New York City. Had its entire system been cut off, Con Edison said it would have taken "many months" to restore service to its million-plus customers, even with mutual assistance, leaving natural gas customers without heat in the middle of winter. No regulatory entity is tasked with ensuring the *reliability* of the natural gas fuel supply relied upon by the BES/grid. The Team recommends that Congress exercise its regulatory power over natural gas infrastructure necessary to ensure grid reliability. Congress could consider whether additional or exclusive authority for natural gas infrastructure reliability should be placed within a single federal agency, as it did with bulk power system reliability in 2005, when it added section Federal Power Act section 215.[294]

Recommendation 4(a): Because extreme cold weather events have repeatedly impaired the production, gathering, processing, and transportation of natural gas, the reliability rules suggested in Recommendation 4 should address, among other topics, the need for natural gas infrastructure reliability rules, from wellhead through pipeline, requiring cold weather preparedness plans, freeze protection measures, and operating measures for when extreme cold weather periods are forecast, and during the extreme cold weather periods.

The last two extreme cold weather events resulted in substantial natural gas wellhead production declines in key locations. In 2021, Texas, Oklahoma and Louisiana saw 50-percent-plus declines, with Texas most impacted with a 70.1 percent decline. In the Event, the Marcellus and Utica Shale formations of the Appalachian Basin declined by 23 and 54 percent, respectively. "On its own, the Appalachian Basin would have been the third-largest natural gas producer in the world [for] the first half of 2021, behind Russia and the rest of the United States."[295] The largest percentage of natural gas production declines were freeze-related in the Event, and this was also true in 2021.[296]

Unlike in Winter Storm Uri, the natural gas production areas most affected during the Event were in areas that routinely experience cold weather. All of the gas producing entities that provided data about outages and disruptions to their facilities had implemented some cold weather preparedness activities for winter. The combination of the rapid temperature drops, and strong winds defeated many of the protections that were put in place. The interrelated nature of the natural gas supply chain added to its vulnerability. See generally IV.C. Each

293 Key Recommendat on 5, 2021 Report at 194. Recogn z ng that mandatory natural gas nfrastructure rel ab l ty rules would not l kely be n place for the upcom ng w nter, the 2021 Report also recommended mult ple pract ces that natural gas nfrastructure ent t es could voluntar ly mplement. Some could be qu ckly mplemented, such as obta n ng emergency back up generators, pre dra n ng storage tanks before severe weather, or mann ng key fac l t es around the clock. Key Recommendat on 6, 2021 Report at 194.

294 The NAESB Forum Cha rs recommended "**a natural gas reliability organization akin to the one currently responsible for electric reliability, NERC**," NAESB Report at 3 (emphas s n or g nal). S m larly, the Nat onal Academy of Sc ence, n ts 2021 report on the Future of Electr c Power n the U.S., The Future of Electr c Power n the Un ted States The Nat onal Academ es Press, recommended that the Comm ss on "des gnate a central ent ty to establ sh standards for and otherw se oversee the rel ab l ty of the nat on's natural gas del very system. Congress should also author ze FERC to requ re greater transparency and report ng of cond t ons occurr ng on the natural gas del very system to allow for better s tuat onal awareness as to the operat onal c rcumstances needed to help support electr c system rel ab l ty." Nat onal Academy of Sc ences (nasonl ne.org).

295 Cor nna R cker and Warren W lczewsk , Shale natural gas product on n the Appalach an Bas n sets records n first half of 2021, Today n Energy (Sept.1, 2021) U.S. Energy nformat on Adm n strat on E A ndependent Stat st cs and Analyhttps://www.e a.gov/today nenergy/deta l.php? d 49377s s.

296 F fty e ght percent of product on decl nes n the 2021 event were caused by freez ng or severe cold weather, nclud ng "product on decl nes d rectly caused by freez ng, preempt ve shut ns to protect natural gas fac l t es from freeze related mpacts, and poor road cond t ons (due to prec p tat on) that prevented the removal of flu ds from product on s tes or access to fac l t es to make necessary repa rs." 2021 Report at 175.

part of the natural gas supply chain is dependent upon the reliability of other sections, which increases the importance of requiring all sections of the natural gas supply chain to protect against the effects of extreme winter weather. Regulators should develop winterization guidelines to protect and continue the operations of production, gathering and processing system facilities during extreme weather events.[297] Those guidelines should address issues arising from low temperature and high winds, as well as precipitation (if precipitation meaningfully worsens the effect of cold on the applicable natural gas infrastructure).[298]

Recommendation 4(b): The reliability rules suggested in Recommendation 4 should address, among other topics, the need for regional natural gas communications coordinators, with situational awareness of the natural gas infrastructure similar to the grid's Reliability Coordinators, that can share timely operational communications throughout the natural gas infrastructure chain and communicate potential issues to, and receive grid reliability information from, grid reliability entities.

During the Event, both Balancing Authorities and natural gas infrastructure entities such as Local Distribution Companies had limited situational awareness as to the extent to which natural gas production losses rippled through the interconnected systems. PJM headed into the operating day of December 23 expecting approximately 158,000 MW of available generation to meet a forecast load of 127,000 MW. But PJM did not anticipate the rapidly escalating generation outages that peaked at over 46,000 MW early on December 24, 70 percent of which were natural-gas-fired units.[299] PJM was unaware of the magnitude of the natural gas production losses despite the fact that PJM's Gas Electric Coordination Team conducts daily reviews during the winter months (November through March) of the interstate pipeline bulletin boards to assess pipeline operating conditions, identify potential natural gas supply risks to the natural gas-fired generation fleet, and provide daily gas risk assessment reports to its dispatch personnel. Con Edison also did not anticipate that it would be notified of potential severe operating pressure reductions that would not recover unless demand was reduced. Pipelines necessarily had to have been aware of decreasing receipts at various points as pressures began to drop. While producers may have had flexibility to make up their nominations over the course of a day, shippers were unaware of what was happening in real time and did not know that the gas they had purchased and nominated had not been delivered to the pipeline until notified of sometimes very large cuts in nominations on December 24.

Operating personnel at the wellhead communicate with gatherers and processors to which they deliver their gas, gatherers and processors communicate their operational issues to the pipelines to which they deliver gas, and pipelines communicate operational issues to their shippers. Although natural gas infrastructure entities often communicate marketing information to end-use customers, in accordance with contractual obligations, it is not the norm for them to communicate with grid operators (e.g., BAs and RCs). Instead, news of operational issues is often communicated in piecemeal fashion from the affected operator to the next operator in the gas production and delivery chain. Absent any informal arrangement to share information, grid operators and Generator Owners/Operators typically receive information about pipeline operational issues only in the form of operational flow orders and critical notices, which often are issued many hours after the issues begin to occur upstream. There is no natural gas infrastructure entity that has the system-wide view as

297 Th s recommendat on s also cons stent w th Recommendat on 16 from the NAESB Report, wh ch stated, n part, that "appl cable state author t es should cons der the development of weather zat on gu del nes appropr ate for the r reg on/jur sd ct on . . .." NAESB Report at 58 59.

298 *See* 2021 Report at 194 95 (Recommendat on 6, wh ch ncluded a long l st of measures that natural gas nfrastructure ent t es could use to protect aga nst freez ng and other cold related l m tat ons).

299 *See* PJM Report at 2.

the RC does for the grid. The NAESB Report recognized the "importance of a wide-area view of natural gas system operations to help ensure reliability and the value of being able to access timely data to assist in operational planning, particularly during critical events or anticipated critical events."[300] While interstate pipelines are required to post certain information on their electronic bulletin boards, intrastate pipelines generally have no such requirements.

Multiple entities, including gas and electric trade groups, BAs and RCs, and GOs, described various information gaps existing in the operations of natural gas infrastructure. Many requested that intrastate pipelines be required to post data similar to what interstate pipelines post on their electronic bulletin boards.[301] A generation trade group noted that increased intrastate transparency would assist "particularly in the posting of actual flow data that can assist in validating force majeure claims and posting of available capacity to assist in identifying locations for additional supply/capacity."[302] An Regional Transmission Organization/Independent System Operator complained about the timeliness of information, noting that "last minute force majeure calls" were the only information they received about availability of commodity during the Event.[303] One entity pointed out that "[s]ince most intrastate pipeline operators also own and operate interstate pipelines, they already have the necessary infrastructure and knowledge of how to accomplish this information sharing at minimal cost and effort."[304] Finally, one trade group argued that the intrastate pipelines' lack of transparency combined with their ability to control both capacity and transportation posed a reliability risk:

> The lack of separation between pipeline operational and marketing functions allows intrastate pipelines to operate as regional monopolies and exert market power in the pricing of gas supply services particularly during time of high demand during extreme weather events, such as Winter Storm Uri. Customers are then forced to choose between exorbitant prices or the real prospect of having no access to natural gas supplies. This lack of competitive choice affects both the system reliability as well as the cost to gas and electric end-use customers.[305]

Based on their experience during the Event, shippers indicated that helpful changes would include providing information *linked to specific receipt points, as soon as possible, updated as often as possible, that included information about the volumetric effect at various receipt points if possible.* NAESB Report Recommendation 1 suggested that FERC could improve the timeliness of information available by directing NAESB to revise its business practice standards related to the timely reporting of natural gas pipeline informational website

300 November 8, 2022 GEH Forum Meet ng Staff Notes (NAESB Report at 18 n.68). The NAESB Report found that some nformat on shar ng between natural gas and gr d ent t es was supported by FERC Order No. 787, wh ch perm ts the commun cat on between certa n part es of operat onal nformat on to support rel ab l ty of natural gas and electr c systems, as well as the NAESB WEQ and WGQ Bus ness Pract ce Standards, ncorporated by reference as part of 18 C.F.R § 38.1(a) and 18 C.F.R § 284.12. However, t also noted that some BAs and RCs (a/k/a SOs/RTOs n the r market roles) stated that there are challenges n access ng and analyz ng such nformat on. (NAESB Report at 18 nn. 69, 71).

301 *See*, e.g., comments of Electr c Power Supply Assoc at on, (Page 93, GEH Survey Response Comment Subm ss ons February 27, 2023) https://naesb.org/pdf4/geh030323w5.docx; comments of Texas Compet t ve Power Advocates, Page 144, GEH Survey Response Comment Subm ss ons February 27, 2023) https://naesb.org/pdf4/geh030323w5.docx; comments of Process Gas Consumers Group and Amer can Forest & Paper Assoc at on, Page 144, GEH Survey Response Comment Subm ss ons February 27, 2023) https://naesb.org/pdf4/geh030323w5.docx

302 (Page 144, GEH Survey Response Comment Subm ss ons February 27, 2023) https://naesb.org/pdf4/geh030323w5.docx.

303 Comments of PJM nterconnect on, LLC, comb ned comment record at page 258.
PJM (Page 118, GEH Survey Response Comment Subm ss ons February 27, 2023) https://naesb.org/pdf4/geh030323w5.docx.

304 Comments of Texas Compet t ve Power Advocates, comb ned comment record at page 284.
TCPA (Page 144, GEH Survey Response Comment Subm ss ons February 27, 2023) https://naesb.org/pdf4/geh030323w5.docx.

305 Comments of Texas Compet t ve Power Advocates, comb ned comment record at page 288.
TCPA (Page 148, GEH Survey Response Comment Subm ss ons February 27, 2023) https://naesb.org/pdf4/geh030323w5.docx.

posting data;[306] enabling the data to be accessible to grid operators as soon as it is reported and available. Additionally, to address the fact that BAs and RCs are reliant on 24/7 operations while some natural gas infrastructure and marketing entities are not available around the clock, NAESB Report Recommendation 7 suggests that natural gas infrastructure operations be fully functioning on a 24/7 basis in preparation for and during events in which extreme cold weather is forecast.[307]

RCs and BAs could use improved information provided to better plan their operations during periods of extreme cold weather. BAs could dispatch more or different generation. For example, PJM could have dispatched long-lead-time units had it known the number of natural gas-fired generating units that would likely have failed to perform. Natural gas-fired generators could seek or activate alternate fuel supply or transportation arrangements (e.g., fuel oil (for dual-fuel units), natural gas storage, switch transportation to another pipeline if the facility is served by more than one pipeline). LDCs could act more quickly to preserve their system reliability (both for their commercial and residential customers as well as to maintain deliveries to any behind-the-citygate generation)[308] and reduce their draw on already-challenged pipelines during extreme cold weather conditions. For example, Con Edison used its LNG facility to preserve necessary system pressure at its citygate, but would have started it earlier, had it known how production declines were likely to affect delivery at receipt points.[309] Recommendation 4(b) differs from Recommendation 5 primarily in scope and timing, as well as prerequisites for achieving the outcome. Recommendation 4(b) seeks natural gas infrastructure entities that have the tools and authority to have the wide-area view, like a Reliability Coordinator does for the grid, and will likely rely on legislation and/or regulation; Recommendation 5 seeks near-term improvements in information sharing that do not require legislation or regulation.

Recommendation 4(c): The reliability rules suggested in Recommendation 4 should address, among other topics, the need to require natural gas infrastructure entities to identify those natural gas infrastructure loads that should be designated as critical for priority treatment during load shed and provide criteria for identifying such critical loads.

Recommendations from the 2011 Report[310] and the 2021 Report[311] highlighted the importance of Transmission Owners/Operators and Distribution

306 For example, operat onally ava lable capac ty, total scheduled quant ty, and any other data necessary to ass st reg onal operators n ma nta n ng system rel ab l ty. The NAESB Report noted, "There was substant al support from both electr c and natural gas part c pants to explore ways to streaml ne and add eff c enc es to the report ng, post ng, and data shar ng processes of natural gas p pel nes (NAESB Report 17 n.62).

307 To address these d fferences, NAESB Recommendat on 7 suggested that " s]tate publ c ut l ty comm ss ons and appl cable state author t es n states w th compet t ve energy markets should engage w th producers, marketers and ntrastate p pel nes to ensure that such part es' operat ons are fully funct on ng on a 24/7 bas s n preparat on for and dur ng events n wh ch extreme weather s forecast to cause demand to r se sharply for both electr c ty and natural gas, nclud ng dur ng weekends and hol days. (States could cons der the approaches adopted n FERC regulat ons affect ng the nterstate p pel nes.) n nstances where state author t es lack enabl ng author ty to take such act ons, the FERC should adopt regulat ons to ach eve dent cal outcomes w th n ts author ty."

308 For example, Con Ed son's d str but on system served 19 generat ng un ts.

309 More accurate and t mely nformat on from upstream ent t es could also help LDCs when to use the r demand response and requests for voluntary customer conservat on. Both are mportant tools for manag ng the t ght cond t ons dur ng extreme cold weather events. The NAESB Report recommended that State publ c ut l ty comm ss ons encourage LDCs w th n the r jur sd ct ons to "structure ncent ves for the development of natural gas and electr c demand response programs" and "to prov de voluntary conservat on publ c serv ce announcements for res dent al, commerc al and ndustr al customers" " n preparat on for and dur ng events n wh ch demand s expected to r se sharply for both electr c ty and natural gas." NAESB Report, Recommendat ons 10 and 11, at 44 45. NAESB Recommendat on 10 was supported by 91 percent of the Wholesale Gas Market and 91 percent of the Wholesale Electr c Market, as those terms are defined n the NAESB Report. d. at 44 45. NAESB Recommendat on 11 was supported by 93 percent of the Wholesale Gas Market and 100 percent of the Wholesale Electr c Market, as those terms are defined n the NAESB Report. d. at 45.

310 Recommendat on 25, 2011 Report at 211 12.

311 Key Recommendat on 1 , 2021 Report at 208.

Providers performing critical load reviews of gas production and transmission facilities and prioritizing critical loads during load shed. Few natural gas facilities were impacted by power outages during the Event, as compared to Winter Storm Uri, because the volume of load shed paled in comparison to ERCOT's 20,000 MW during Winter Storm Uri. But the Team was concerned to find that few natural gas infrastructure entities designated *any* of their facilities as critical loads to their local electricity provider.

All 10 of the natural gas producers who provided information in conjunction with the inquiry responded that they do *not* identify *any of their facilities* as protected or as critical loads even though winterization systems including heat trace can be dependent upon utility-provided electric power. Their utility-powered natural gas production facilities also have no, or limited, alternate or backup power. The Team is aware of producers that do rely on the grid for their electricity but have not identified any of their facilities as critical loads.

Of the two gathering system operators from whom data were collected, one indicated that its gathering system compression facilities do not depend on utility/grid power, but it does depend on the utility power to operate air compressors to maintain emergency shut- down valve positions, start the units and operate control equipment within the facility. Gas-fired backup generators are available at the stations in the event of a power outage to the air compressors/system at the majority of their facilities. The second entity indicated that utility power is its primary source of power. Several of its facilities rely heavily on electricity for gas compression and delivery capacity for a significant portion of their operations, and a loss of electrical power would result in the inability to transport and process large quantities of gas. Only 25 percent of the 26 processing plants that provided data were protected from power outages by local power provider critical load designation agreements.

Of the 15 interstate pipelines that provided data to the Team, four stated that they have facilities designated as critical with their power provider, and 11 provided reasons for not designating any facilities.[312] In total, four pipelines designated 60 facilities as critical. The majority of those facilities (42) are owned by a single pipeline. Pennsylvania had the most identified in a single state, with nine.[313]

The Team recommends that legislative and regulatory actions be taken to either establish criteria for natural gas infrastructure facilities to be designated as critical or create or designate an agency or entity to establish such criteria. The critical facilities identified should then be required to register with or otherwise communicate to their electric service necessary information about their critical natural gas infrastructure facilities such as location. Facilities could include producers, gathering/compressing facilities, processing facilities, and both intrastate and interstate pipelines. Legislators or regulators can look to the collaboration between the Public Utility Commission of Texas and the Texas Railroad Commission on rules for designating natural gas facilities and entities as critical, which was required by Texas House Bill 3648, in the wake of Winter Storm Uri's devastating effects on Texas. On November 30, 2021, the Public Utility Commission and Railroad Commission separately adopted rules to codify HB 3648 and establish new regulations for electric utilities and natural gas entities to ensure critical natural gas facilities are appropriately identified.[314]

312 *See* Sect on V.C.4 for a d scuss on of the reasons g ven for not dent fy ng fac l t es as cr t cal.

313 The other states and number of cr t cal fac l t es dent fied were V rg n a (6), New York (5), Kentucky (4), Alabama (3), Tennessee, M ss ss pp , Oh o, Georg a, and New Jersey (all w th two or fewer).

314 https://www.puc.texas.gov/ ndustry/electr c/cng/default.aspx

C. Natural Gas-Electric Coordination for Cold Weather Reliability

Recommendation 5: The North American Energy Standards Board should convene natural gas infrastructure entities, electric grid operators, and LDCs to identify improvements in communication during extreme cold weather events to enhance situational awareness. (Q2, 2024)

This Recommendation differs from Recommendation 4b in that it does not seek legislation or regulation but seeks near-term options for enhancing situational awareness among natural gas infrastructure and electric grid entities. The Team recognizes that producers, processors, interstate and intrastate pipelines, as well as grid operators such as Balancing Authorities and Reliability Coordinators, could improve their real-time coordination and communication to some extent without the need for a Reliability Coordinator-equivalent for natural gas infrastructure.

There is a need for improved communication among the operators of production facilities (producers, gatherers, processors) and the timely dissemination of this coordinated communication from the production facilities to other natural gas infrastructure entities, BAs, shippers, and end-use customers (i.e., Local Distribution Companies). Discussions should include what should be communicated, how it should be communicated, and to whom it should be communicated. In particular, operators of gas production facilities should provide information to the extent that they are aware of situations that may have potential adverse impacts on the BAs, pipelines, LDCs, and/or shipper reliability, whether such information becomes available before or during extreme weather events. Ideally those communications would include aggregated volume data or confirmed scheduled quantities for key upstream receipt points on the pipeline systems. Information about operational issues (e.g., location, estimated duration of outage) should be communicated to BAs, LDCs, and shippers so they can anticipate and plan for potential critical notices, OFOs or force majeures, rather than react after those notices are issued. Communication can occur without endangering sensitive commercial information, as it does on the BES grid side, by, among other methods, separating the operational employees who share information from the marketing employees.

NAESB Report Recommendations 2 and 3 identified a potential tool that can be used to accomplish the desired information sharing—Argonne National Laboratory's *NGInsight* Tool.[315] The tool makes it possible to identify the potential impact of weather or other critical events on overall natural gas supply.[316] Additionally, through machine learning informed by electric wholesale market participant input, *NGInsight* can rank the severity of natural gas pipeline notifications posted on EBBs to further enhance situational awareness.[317] For more information about how information sharing could be used to improve natural gas and grid system reliability, see Recommendation 4(b).

---

315 Accord ng to the Forum Report, NG ns ght "collects EBB data and prov des near real t me ass m lat on of nformat on from approx mately 75 percent of nterstate and offshore natural gas p pel nes, creat ng a nat onal level v ew of natural gas system s tuat onal awareness. Argonne Nat onal Laboratory Presentat on June 29, 2023 (Page 3, Argonne Nat onal Laboratory) (NAESB Report n.101). The data collected and d splayed by the tool nclude nformat on that dent fies unsubscr bed capac ty, total scheduled quant ty as a funct on of state, county, and/or p pel ne as well as cr t cal and non cr t cal not ces, and the tool has the ab l ty to layer other relevant datasets, such as ut l ty serv ce terr tor es and weather alerts. Argonne Nat onal Laboratory Presentat on June 29, 2023 (Pages 3 4, Argonne Nat onal Laboratory) (NAESB Report n.102). NAESB Report Recommendat on 2 noted that the Comm ss on should "take steps to fac l tate the expans on of the Argonne Nat onal Laboratory NG ns ght tool, w th fund ng from a federal governmental agency, such as the Department of Energy," wh le acknowledg ng the mportance of secur ty and market protect ons. NAESB Report at 21. Th s recommendat on rece ved support from 46 percent of the Wholesale Gas Market and 85 percent of the Wholesale Electr c Market, as those terms are defined n the NAESB Report. d. at 19 20.

316 Argonne Nat onal Laboratory Presentat on June 29, 2023 (Pages 3 6, Argonne Nat onal Laboratory) (NAESB Report n. 103).

317 Argonne Nat onal Laboratory Presentat on June 29, 2023 (Page 5, Argonne Nat onal Laboratory) (NAESB Report n. 104).

Recommendation 6: The Commission should consider whether to order Commission-jurisdictional natural gas entities to provide the Commission with one-time reports describing their roles in assessing and responding to natural gas supply and transportation vulnerabilities in extreme cold weather events.

As discussed in Section IV.C.4 above, freezing was a significant cause of pipeline equipment outages that caused some flow reduction, and the primary cause of pipeline equipment outages directly affecting shippers. Recommendation 6 is based in part on the various preparations for Winter Storm Elliott that pipelines shared with the Team. The Team surveyed a total of 15 interstate pipelines within the Event Area. Pipelines shared common practices in the planning and preparation for Winter Storm Elliott, specifically in areas such as proactively monitoring weather forecasts, manning key facilities, issuing critical notices, increasing line pack, and putting storage facilities on stand-by. However, these measures were assigned different priorities by different pipelines and implemented in different ways depending on the location, design, and size of each individual pipeline system. For example, some pipelines issued pre-emptive Operational Flow Orders (OFOs) prior to the start of the Event, whereas others issued generic notices alerting customers of extreme conditions. Internal (gas control, operations, scheduling, storage, commercial personnel) and external (RTOs, customers, utilities) stakeholder meetings also occurred with varying degrees of frequency among the pipelines. These meetings aired concerns about reliability issues, nominations, and scheduling as applicable to each pipeline's system.

If the Commission were to proceed with an order regarding the one-time reports, it could consider asking the FERC-jurisdictional entities to analyze their experiences in Winter Storms Uri and Elliott, and to address the entities' plan(s) for mitigating identified vulnerabilities. The collected data would allow the Commission to determine if it could take additional actions within its jurisdiction to address the risk that extreme cold weather events pose to the natural gas infrastructure system. If a FERC-jurisdictional gas entity were to submit a one-time report, it could seek CEII treatment or other protections available under the Commission's regulations, as appropriate.

Recommendation 7: An independent research group (e.g., selected National Laboratories from the Department of Energy), should perform one or more studies to analyze whether additional natural gas infrastructure, including interstate pipelines and storage, is needed to support the reliability of the electric grid and meet the needs of natural gas Local Distribution Companies. The study should include information about the cost of the infrastructure buildout. (Initiate study Q1, 2024)

In light of the Commission's role in reviewing interstate natural gas projects and other gas infrastructure (e.g., interstate natural gas storage facilities), as well as the need for sophisticated modeling, the Team recommends that an independent entity with robust modeling capabilities undertake the study. It would be ideal if one of the DOE National Laboratories would conduct the study, as they have the technical expertise and have invested in modeling of the U.S. natural gas and electric infrastructure. However, if that is not feasible, the National Academies of Science and Engineering, and the Electric Power Research Institute have also performed sophisticated grid-related studies in the past, as well as studies of natural gas issues.

The purpose of the study would be to identify additional natural gas infrastructure needs, if any, needed to ensure the continued reliability of the electric and natural gas systems, and the preferred locations of such infrastructure, if applicable, including pipeline infrastructure, natural gas storage, and other supporting systems. The study should consider the needs in light of coincident peaks of LDC demand for natural gas as well as demand from natural gas-fired generation during periods of prolonged, abnormally cold weather. The study should analyze needs on a regional basis and consider current as well as forecast future needs, in light of our evolving and interdependent energy system. The study should consider whether there will be adequate natural gas infrastructure to support new gas usage patterns by gas-fired generation to manage the increased penetration of variable, renewable energy resources and thermal resource retirements, including increased ramping requirements and seasonal resource availability, among others. In addition, the study should consider natural gas infrastructure needs during anticipated, extended extreme heat and cold weather periods. It should also consider recent patterns of natural gas production declines during extreme cold weather (e.g., Winter Storm Uri, Winter Storm Elliott).

The study should include information about the cost of the infrastructure buildout. In making this recommendation, the Team notes that two of the North American Energy Standards Board Report recommendations for additional studies concerned the cost of natural gas infrastructure, for storage and for infrastructure to provide additional firm transportation capacity.[318]

318 Recommendat on 18 sought a study about “whether market ncent v zed nvestments n strateg c natural gas storage fac l t es are suff c ent to address natural gas supply shortfalls dur ng extreme cold weather events, and f the level of nvestment s suff c ent to preserve such fac l t es for use dur ng extreme cold weather events. The study should also explore whether publ c sources of fund ng are needed for nvestment to secure suff c ent storage.” Recommendat on 19 asked for a study of “whether add t onal financ al ncent ves for the natural gas nfrastructure system, nclud ng nfrastructure to prov de add t onal firm transportat on capac ty, would help to address natural gas supply shortfalls dur ng such events l ke Ur], and further support the Bulk Electr c System’s performance dur ng extreme cold weather events.” NAESB Report at 63 64.

D. Electric Grid Operations Cold Weather Reliability

Recommendation 8: Balancing Authorities should assess whether new processes or changes to existing ones—such as multi-day risk assessment processes or advance or multi-day reliability commitments—are needed to address anticipated capacity shortages or transmission system-related reliability problems during well-forecast extreme cold weather events. In performing risk assessments or supporting multi-day reliability commitment, BAs should consider the following:

A. how to account for uncertainty in load forecasts, generating unit fuel availability and extreme cold weather availability, and the effects of extreme cold weather across multiple regions; and
B. committing generating units prior to the onset of extreme cold weather, including a means of ensuring units are compensated for their commitment costs (including the costs of obtaining fuel), even if no dispatch occurs. (Q4, 2023)

The five extreme cold weather events have revealed a set of uncertainty risks that have challenged BAs as they plan for and operate during these events. In every extreme cold weather event, BAs have faced unexpectedly high amounts of unplanned generating unit outages.[319] In four of the last five events, short-term load forecasts were lower than actual for some BAs, and in three of the last five events (the only ones that examined the issue) significant reductions in natural gas production occurred. Many natural gas-fired generating units indicated during the Event that they were unavailable because they did not have advance arrangements for natural gas fuel supply for the hours they were committed to operate, and by the time they were notified for commitment, natural gas supplies were unavailable. All of the BAs thought that they had sufficient reserves arranged to meet their forecast peak electricity demands, until they were faced with escalating unplanned outages and increased customer demand that, for most, exceeded their load forecasts. By the time that these trends were apparent, the BAs had limited flexibility, leading many of them to declare Energy Emergencies and some to shed firm customer load.

These scenarios should no longer be unexpected. BAs need to evaluate the uncertainty or risk they face when preparing for extreme cold weather events that have been forecast well in advance (and all the most serious extreme cold weather events have been forecast many days in advance) to reduce their reliability risk during these events. Evaluating risk or uncertainty, which some BAs already combine with a multi-day reliability unit commitment process, in advance of and during extreme cold weather events will best enable BAs to prepare to meet their commitments and maintain system reliability.

SPP's experience during the Event provides one example of how a BA can combine the evaluation of risk or uncertainty with multi-day unit commitment.[320] According to SPP's Winter Storm Elliott Report, "going into [Winter Storm Elliott] SPP had to anticipate uncertainty in the following areas:

- Uncertainty of accurate load forecasting for December 23, December 24, December 25 due to wind chill.
- Uncertainty if the forecast for high wind levels would hold, and to what extent wind farms would be shut down or de-rated for low ambient temperatures.
- Uncertainty if the gas resources SPP committed would be able to purchase gas.
- Uncertainty if resources SPP committed would be timely due to preheat and start-up.[321]
- Uncertainty of how many resources would trip because of freezing of equipment resulting from low temperatures and high wind chill conditions.
- Uncertainty of how much congestion SPP would

319 *See* F gure 5, wh ch reveals s m lar t es among past extreme cold weather events.
320 Th s s one example. Other BAs may have the r own methods of evaluat ng uncerta nty and/or mult day un t comm tment.
321 SPP was concerned about all gas resources comm tted, not just those comm tted n the day ahead.

experience that required re-dispatch of resources that could lock up headroom of resources.

- Uncertainty if the Missouri River would develop ice blocks preventing adequate river flow and potentially limit hydro generation and cooling water availability."[322]

SPP's Elliott experience revealed the importance of remaining flexible when evaluating uncertainty in extreme cold weather events. For example, the Missouri River freezing issue developed during the Event. During the Event, SPP's Uncertainty Response Team, [323] which helps to identify and address upcoming capacity challenges given forecast system conditions, recommended the commitment of long-lead-time generation, which SPP then committed using its Multi-Day Reliability Assessment process.[324] On December 21, SPP committed generation for December 22 and 23, to help with capacity, deliverability concerns and uncertainty; on December 22, it committed generation for Christmas Eve, and on December 23, for Christmas Day.[325]

SPP also "committed several GW of primarily gas generation ahead of time for Dec[ember] 22 through . . . 25, to cover normal long-lead time units as well as help ensure there was a sufficient amount of gas procured to cover the forecast obligations (a portion of short-lead-time gas units),"[326] through its Multi-Day Reliability Assessment process. This advanced commitment process is particularly helpful if the extreme weather event is expected to occur over the weekend, on a Monday, or on a Tuesday following a holiday weekend, given the limited natural gas market liquidity during these periods. SPP also committed natural gas units that were not long-lead units early so that they could obtain natural gas in advance of Winter Storm Uri and believes that it enabled more units to operate during the worst of the Winter Storm Uri event.[327]

The Team notes that the North American Energy Standards Board Report recommended that Independent System Operators/Regional Transmission Organizations "adopt multiday unit commitment processes to better enable the industry to prepare for and provide reliable service during events in which weather is forecast to cause demand to rise sharply for both electricity and natural gas," and it received 90 percent support from both the gas and electric wholesale quadrants.[328] Additionally, the PJM Report recommended that it "[e]valuate the current multi-day commitment process for use during expected critical

322 SPP Report at 6 7.

323 Da ly evaluat ons flag uncerta nty r sks for the next seven days. The URT appl es uncerta nty factors for load forecast, w nd forecast and resource (generat on outage) error. The URT puts h stor cal data nto "b ns" for w nd forecast error, load forecast error, and generat on outage error, analyzes what weather cond t ons are assoc ated w th part cular ranges of error and then appl es uncerta nty error percentages to ava lable offl ne and onl ne capac ty for every hour for the next seven days. Th s refined "scal ng" process results n, for example, nstead of pred ct ng the poss b l ty of 500 MW of error on a part cular day, pred ct ng 100 MW of error for hour 0700, 200 MW of error for hour 1900, and so on. SPP analyzes for co nc dental error the percentage chance of all of the errors happen ng at the same t me. They look at 50/50, 90/10, and 99.5 percent l kely scenar os, all of wh ch are shared w th operators. f operators see nsuff c ency all the way down to the 50/50 scenar o they know t s more l kely that the system w ll exper ence nsuff c ent resources that day. Larger potent al capac ty gaps are found at the lesser percent le, and smaller gaps are more common, more l kely to be found n the 50/50 scenar o (equally l kely to happen or not happen). SPP uses the uncerta nty evaluat ons produced by the URT to help coord nate how much generat on w ll be allowed to be on planned outages, to comm t long lead t me un ts that may otherw se become unava lable (any un t for wh ch the m n mum start up or down t me s such that the un t cannot be comm tted n the day ahead market, or has another start up ava lab l ty l m t ng c rcumstance), and to prepare m t gat on plans for scenar os where analys s shows a r sk of SPP's capac ty be ng nadequate to meet ts obl gat ons.

324 The URT recommends un ts when an uncerta nty forecast mer ts the need for such un ts and such un ts may become unava lable f not acted upon.

325 SPP Report at 7.

326 SPP Report at 7. SPP has filed proposed tar ff rev s ons to clar fy the ab l ty to comm t short lead t me un ts so that they can obta n natural gas, among other proposed rev s ons.

327 n Ur , SPP needed all ava lable un ts onl ne. n Ell ott, SPP ended up need ng much more natural gas fired capac ty than the short lead t me gas un ts they had comm tted early.

328 NAESB Report at 2, 5 (Recommendat on 9).

high demand periods so as to analyze the costs and benefits of providing greater certainty of fuel supply procurement through the critical period, with a focus on weekends when the gas commodity market can be less liquid."[329]

Pre-operational warming is a practice that has been recommended since the 2011 Report to avoid unplanned freezing-related outages.[330] One way to reduce the risk of unplanned outages is for BAs use their evaluation of the uncertainty to manually commit a portion of their generating units to operate the units before the coldest temperatures arrive, even if the units are not needed to serve load at that point. Doing so will help mitigate the extra challenge created by cold-starting a unit in extreme cold conditions. If a unit fails *during* the advanced commitment, the BA will be able to identify and potentially address generation shortfalls before the extreme weather arrives. During extreme cold weather events like Winter Storms Elliott and Uri, it is not uncommon for BAs to rely on generating units that rarely operate. PJM's experience with units that had not run in four weeks or more is consistent with committing some generation before the coldest temperatures arrive, in an effort to make more generation available when it is most needed. PJM noted that 70.5 percent of units that had not run in four weeks or more before the Event experienced an outage, while only 45.5 percent of units that had run within four weeks did so, a 25 percent improvement. Both testing and manually committing generation before the coldest temperatures arrive can increase the likelihood that the unit will be available to run when needed in real time.[331]

Recommendation 9: Balancing Authorities should improve their short-term load forecasts for extreme cold weather periods by implementing the lessons and practices identified below and sharing newly identified effective practices with peer BAs for continuous improvement. (Implement sharing Q4, 2023)

In four of the last five extreme cold weather events, short-term load forecasts, or forecasts of peak electricity demand, were lower than the actual peak electricity demand, for some BAs in the Core Event Area. Accurate short-term load forecasts in advance of extreme cold weather events enable BAs to commit long-lead-time resources, plan for additional imports that may be needed to meet reserves, and notify customers in advance of potential emergency conditions, to achieve greater awareness and participation if voluntary load reduction is needed. Most BAs in the Event under-forecast load in their 5-day, 4-day, 3-day, 2-day and day-ahead load forecasts, and the Team encourages them to implement and share effective practices for improving short-term load forecasts. However, accurate load forecasts alone could not have overcome the massive volume of unplanned generating unit outages experienced by many of the BAs.

Two key practices for improving short range load forecasts are (1) understanding the drivers of the BAs' extreme cold weather load and (2) studying the drivers of BAs' under-forecast load for past events. The Team found that some entities understood the drivers of their cold weather load far better than others, and those entities performed better on their short-term load forecasts. The use of distribution-level smart meter data, combined with Artificial Intelligence (AI)-powered predictive intelligence, is a promising new approach for understanding load drivers.[332] Some entities used third-party load forecast services and participated in the load forecast process in varying degrees. Entities that were more engaged in and better understood the load

329 *See* PJM Report Recommendat on 9, at 4.

330 2011 Report at 60 61. Dur ng W nter Storm Ur , un ts reported pre operat onal warm ng n response to an ERCOT d rect ve. *See* 2021 Report at 53.

331 PJM recommended, but d d not requ re, generat ng un ts to perform a "Generat on Resource Operat onal Exerc se" before the w nter. *See* PJM Report at 10. These un ts are compensated as pr ce takers, l ke any other self scheduled un ts.

332 Th s serv ce prov des ns ghts to the gr d ent ty (e.g. how much of the load n a part cular area s dr ven by heat ng and/or cool ng, whether beh nd the meter assets may be located w th n ts footpr nt and the r hourly demand), wh ch helps to better pred ct volat l ty n demand, both as to t m ng and magn tude. The th rd party prov der used by the ent t es was nnowatts (https://www. nnowatts.com/).

forecast process, instead of treating it as a “black box” service, performed somewhat better.

Balancing Authorities identified multiple factors that played a role in underestimating short-term load as compared to actual load. For example, they noted that load forecasts were affected by a mismatch between the temperature used in the forecast versus the actual temperatures,[333] high winds,[334] blizzard conditions, and struggles to predict the exact timing of when the coldest weather would arrive. Several entities also found that they did not experience a normal load profile with a deep valley during the night—the drop in temperatures/extreme cold temperatures meant that the “valleys” were abnormally high. Another important element was identifying the presence of resistive heating in an entity’s load.

The Team recognizes that some entities and regions already engage in sharing effective practices and encourages them to continue. But based on the wide variety the Team observed in load forecasting practices within the Event Area, the Team believes that sharing of effective practices can be enhanced, with the aim of improving the accuracy of short-term load forecasts. For more information on improving short-term load forecasts, see Section IV.D.1 and Figures 19-21, above.

Recommendation 10: Resource Planners and entities that serve load should sponsor joint-regional reliability assessments of electric grid conditions that could occur during extreme cold weather events. The assessment results can be used in power supply planning to reduce the risk of firm load shed.[335] (Initiate assessments, Q4, 2024)

Recommendation 10 focuses on improvements that entities responsible for planning and/or acquiring capacity and energy resources to serve firm load can make to help address the risk of firm load shed during future extreme cold weather events. As described in Section III.B, several Balancing Authorities in advance of winter 2022-2023 and during the Event relied on the availability of external generation resources (i.e., in the form of purchase power/import power schedules and emergency energy) to serve their firm load. When the Event impacted all of the adjacent BAs, resulting in curtailment of imports, that curtailment contributed to the need for firm load shed within the BAs that had relied upon imports or the possibility of emergency energy.

The types of extreme cold weather events to be studied are those that, like Winter Storms Elliott and Uri, simultaneously impact multiple operating areas and Regional Entity footprints.[336] The assessments should be conducted jointly, involving multiple planning regions, multiple Regional Entities, and/or multiple BA footprints within regions. They should consider the use of probabilistic approaches in accounting for uncertainties in availability of external generation resources, potential for simultaneous winter peak load conditions in multiple footprints, and uncertainties in deliverability of generation resources (e.g., arrangements from

333 Some ent t es performed “backcasts” (calculat ng the r load forecast w th the actual temperatures) to solate the effect of temperature from other factors.

334 “A r movement s an mportant cause of energy loss, part cular ly] n res dent al bu ld ngs, where nfiltrat on acc dental ntroduct on of outs de a r nto a bu ld ng, typ cally through cracks n the bu ld ng] commonly causes between 30 and 75 percent] of the total heat load n w nter.” Edward A. Arens and Ph l p B. W ll ams, The effect of W nd Energy consumpt on n bu ld ngs, (1977), https://www.a vc.org/s tes/default/files/members_area/med as/pdf/A rbase/a rbase_00017.pdf#:~:text_W nd%20flow%20around%20a%20bu ld ng%20causes%20forced%20convect on,layer%20 tself%2C%20the%20w nd flow%20patterns%20around%20the%20bu ld ng%2C185.

335 Forms of sponsorsh p could nclude, but not be l m ted to, prov d ng nput or adv ce on the development of nterreg onal plann ng models, extreme cold weather study cases and scenar os, and/or through support of collaborat ve plann ng act v t es.

336 The February 2021 W nter Storm Ur mpacted the ERCOT nterconnect on, and M SO and SPP footpr nts n the Eastern nterconnect on (TRE, MRO, and SERC Reg onal Ent ty footpr nts); the January 2018 cold weather bulk electr c system event mpacted, M SO, SPP, TVA, and Southern n the Eastern nterconnect on (MRO and SERC Reg onal Ent ty footpr nts); the 2014 Polar Vortex mpacted both the Eastern and ERCOT nterconnect ons (MRO, RF, NPCC, SERC, and TRE Reg onal Ent ty footpr nts), and the February 2011 event mpacted ERCOT and the Western nterconnect on.

generation resources external to a load serving area).[337]

In accounting for generation resource unavailability, winter assessments typically account for generating unit scheduled/planned outages expected to occur during winter peak load timeframes, as well as an estimated amount of unplanned generation outages. The projected available resource capacity is used to calculate projected resource reserves above the 50/50 and 90/10 winter peak load forecast, or whether there will be an expected shortfall. In estimating the impact of unplanned generation outages, resource planners and entities serving firm load should consider the likelihood of higher levels of unplanned generation outages across multiple regions during extreme cold weather. As an example, NERC uses operational risk analysis as part of its seasonal assessment process, which provides an approach for determining reliability impacts from certain scenarios and understanding how various factors affecting resources and demand can combine to impact overall resource adequacy. Adjustments are applied cumulatively to anticipated capacity—such as reductions for typical generation outages/derates and additions that represent the quantified capacity from operational measures, if any, that are available during scarcity conditions (e.g., emergency maximum generation available). The effects from low-probability events are also considered.

In accounting for risks that peak load conditions may have on serving firm load, planners should consider that winter peak electricity demands during the Event in the BA footprints located from the Central Plains to the Atlantic Seaboard all occurred within a 36-hour period. A multi-area concurrent peak load scenario, coupled with many thousands of MW of unplanned generation outage scenario, compounds the risk of unavailable external generation resources or unavailability of purchase power for import, regardless of intraregional or interregional transfer capability. If a BA is experiencing a worsening capacity and energy emergency condition, it may reach a point when it must curtail all exports unless those exports are backed by installed capacity that is not already counted towards installed capacity for the BA's native load. Purchasing-selling entities[338] should understand the answer to the question "How firm is my firm power purchase?" in advance of future extreme cold weather periods.

In accounting for risks in resource deliverability, winter case extreme scenarios can be performed to determine potential constraints or limitations. For example, as part of its winter assessment, SERC performed a powerflow case simulating a MISO to SERC-East 6,000 MW power transfer to study the impact of a west-to-east transfer during peak conditions. There are related initiatives underway which can be leveraged to ultimately assist entities that serve load to evaluate risks to serving firm load during extreme cold weather periods. NERC Standards development project 2022-03 – Energy Assurance with Energy-Constrained Resources, proposes that entities (most likely BAs and RCs) conduct energy reliability assessments, and when predefined criteria are not met (criteria need not be defined in Standard), the responsible entity shall develop Corrective Action Plans, operating plans, or other mitigating actions. In addition, the Commission recently issued Order No. 896, which directs, among other things, the development of extreme cold weather benchmark events that will form the basis for assessing system performance during extreme heat and cold weather events. The base case, representing system conditions under the relevant benchmark event, will be used to study the potential wide-area impacts of anticipated extreme cold weather events.

337 The 2018 Report recommended that Plann ng Coord nators and Transm ss on Planners should jo ntly develop and study more extreme cond t on scenar os w th model ng that ncludes remov ng generat on un ts ent rely to represent actual generat on outages (espec ally outages known to occur dur ng severe weather), versus scal ng of generat ng un t outputs, and model ng system loads so that the study accurately tests the system for the extreme cond t ons be ng stud ed. 2018 Report at 94 95 (Recommendat on 7).

338 The ent ty that purchases or sells, and takes t tle to, energy, capac ty, and nterconnected Operat ons Serv ces. Purchas ng Sell ng Ent t es may be aff l ated or unaff l ated merchants and may or may not own generat ng fac l t es. *See* NERC Glossary of Terms, at https://www.nerc.com/pa/Stand/Glossary%20of%20Terms/Glossary_of_Terms.pdf.

Recommendation 11: A team of subject-matter experts (e.g., the Eastern Interconnection Planning Collaborative) should conduct a study of the state of the Eastern Interconnection during the evening of December 23 and early morning hours of December 24, to examine dynamic stability and system inertia, and determine how close the interconnection may have been to triggering an underfrequency load shed event. (Initiate study, Q1, 2024)

As seen in Winter Storm Uri, when the power grid suffers an extreme loss of generation resources during periods of high system demands, the grid becomes more vulnerable to a complete blackout. In that event, ERCOT operators were forced to shed larger and larger blocks of firm load, within minutes of one another, to restore frequency and avoid a blackout of the ERCOT Interconnection.[339] As discussed in Section III, and demonstrated by Figure 39, on late December 23 and early December 24, the Core Event Area and the Eastern Interconnection were experiencing their highest winter electricity demands. Figure 37 shows that, at the same time, generating unit outages were climbing. As a result, there were times on the evening of December 23 and the morning of December 24 when the potential responsive operating capacity, which included online and any offline capacity, was within 15,000 to 20,000 MW of the combined loads at the worst points. While that may appear to be an adequate level of reserves, spread over the Eastern Interconnection, and at a time when the risk of additional generating outages was high, the Team is concerned that it may not have provided a sufficient safety net.

During the same period, Eastern Interconnection frequency excursions were common, dropping below 59.95 Hz (the lower band limit for maintaining frequency) four times and dropping as low as 59.936 Hz at approximately 4:25 a.m. Based on these findings, the Team is concerned that the Eastern Interconnection could have been at risk of instability during the period of high winter electricity demands and rising generating unit outages.

The Team believes that the Eastern Interconnection Planning Collaborative,[340] in coordination with NERC, Regional Entity and FERC staff, could assess next-contingency/single-point of failure contingency conditions to assess dynamic stability of the Interconnection through modeling and assessing the Bulk Electric System conditions during the Event. Further study(s) of the Eastern Interconnection during the critical period of the evening of December 23 and early morning December 24 can be used to identify actions needed to improve situational awareness and enhance operator tools and analysis capabilities. Real-time evaluation of such system conditions in the future could provide Reliability Coordinators with visibility of dynamic system conditions (e.g., through integration into its real-time contingency analysis processes), and assist in determining what actions may be taken (remedial analysis). Enhanced operator tools for situational awareness could prove especially useful when operators are faced with future resource mix changes that potentially expose the grid to more stability risks (e.g., as “high-inertia” coal units are retired and replaced by smaller intermittent resources with less inertia).

339 *See* 2021 Report, at 133.

340 The Eastern nterconnect on Plann ng Collaborat ve (E PC) s an organ zat on that was formed n 2009 by NERC reg stered Plann ng Coord nators n the Eastern nterconnect on to perform coord nated nterconnect on w de transm ss on analys s.

VI. CONCLUSION

This report provides a detailed assessment of the Event and the impact it had on portions of the Nation's energy infrastructure and service to consumers. The recommendations are designed to address matters identified in this report that call for improvement.

APPENDICES

APPENDIX A: INQUIRY JOINT TEAM MEMBERS

FERC Staff

Office of Electric Reliability

Noha Abdel-Karim
Victor Barry (Generation Sub-team Co-lead)
Robert Clark
Michael Gandolfo
An Jou Hsiung
David Huff (Team Co-lead)
Eric Oben
Raymond Orocco-John (Generation Sub-team Guide)
Sandeep Sadanandan
Lodie White

Office of Enforcement

Sheryl Caro
Serrita Hill
Jordan Hinds
Candace Jamison
Kirsten Johansson
David Marcou (Generation Sub-Team Process Guide)
Heather Polzin (Team Co-lead)
Michael Raibman
Akshay Thyagarajan
Yvonne Yegge

Office of Energy Projects

Noor Ahmad
Nicole Huang
Darya Khanin
Wallace Knobel
Olubukola Pope (Gas Sub-team Co-lead)
Joshua Roth
Andrea Torres Perez

Office of Energy Market Regulation

Seong-Kook Berry
Kent Mottice

Office of Energy Policy & Innovation

Micah Gowen
Kayam Karnawat
Thomas Pinkston

Office of Energy Infrastructure and Security

Sanjay Bhatia
Donald Gerkin
Amelia Lewis

Office of the General Counsel

Michael Haddad

NERC Staff

Clayton Calhoun
Valerie Carter-Ridley (Grid Operations Sub-team Co-lead)
Shamai Elstein
Richard Hackman (Generation Sub-team Co-lead)
Carole Harding
Marisa Hecht (Team Co-lead)
Matthew Lewis (Team Co-lead)
Kiel Lyons (Team Co-lead)
Heather Miller
Mark Olson
Elsa Prince (Gas Sub-team Co-lead)
Darrel Richardson
Craig Struck
Tony Tatum
Robert Tallman

Regional Entity Staff

Midwest Reliability Organization

John Grimm
Mark Tiemeier

Northeast Power Coordinating Council

Ryan McSherry
Andrey Oks

ReliabilityFirst Corporation
Dwayne Fewless
Kellen Phillips

SERC Reliability Corporation
Maria Haney
Stony Martin
Melinda Montgomery
Richard Stachowicz

Texas Regional Entity
Mark Henry
David Penney

Western Electricity Coordinating Council
Curtis Holland

National Oceanic and Atmospheric Administration, National Weather Service
Greg Carbin

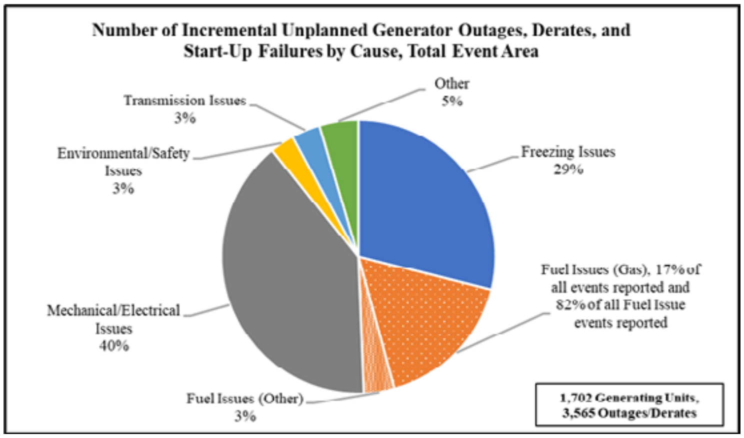
APPENDIX B: ACRONYMS USED IN THE REPORT

AC	Alternat ng Current
BA	Balanc ng Author ty
BES	Bulk Electr c System
CST	Central Standard T me
DC	D rect Current
DSM	Demand S de Management
EEA	Energy Emergency Alert
EHV	Extra H gh Voltage
EMS	Energy Management System
EOP	Emergency Operat ons Procedure
ERCOT	Electr c Rel ab l ty Counc l of Texas
ERO	Electr c Rel ab l ty Organ zat on
FERC	Federal Energy Regulatory Comm ss on
FRAC	Forward Rel ab l ty Assessment Comm tment
GO	Generator Owner
GOP	Generator Operator
HVDC	H gh Voltage D rect Current
ROL	nterconnect on Operat ng Rel ab l ty L m t
SO	ndependent System Operator
kV	K lovolt
LBA	Local Balanc ng Author ty
LMR	Load Mod fy ng Resources
MSSC	Most Severe S ngle Cont ngency
M SO	M dcont nent ndependent System Operator, nc.
MRO	M dwest Rel ab l ty Organ zat on
MVA	Megavolt Ampere
MW	Megawatt
NERC	North Amer can Electr c Rel ab l ty Corporat on
OPA	Operat onal Plann ng Analys s
PC	Plann ng Coord nator
PRC	Phys cal Respons ve Capab l ty
RC	Rel ab l ty Coord nator
RC S	Rel ab l ty Coord nator nformat on System
RDT	Reg onal D rect onal Transfer
RDTL	Reg onal D rect onal Transfer L m t
RF	Rel ab l tyF rst Corporat on
RTCA	Real T me Cont ngency Analys s
RTO	Reg onal Transm ss on Organ zat on
SCED	Secur ty Constra ned Econom c D spatch
SCRD	Secur ty Constra ned Red spatch
SERC	SERC Corporat on
SeRC	Southeastern Rel ab l ty Coord nator
SOL	System Operat ng L m t
SPP	Southwest Power Pool, nc.

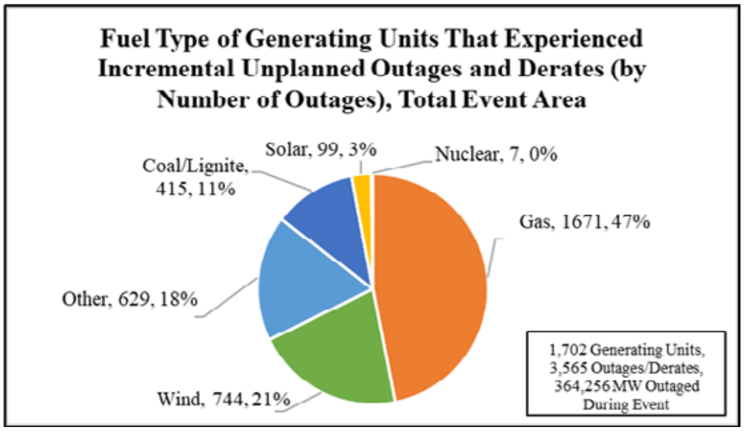
TDU	Transm ss on Dependent Ut l ty
TLR	Transm ss on Load ng Rel ef
TO	Transm ss on Owner
TOP	Transm ss on Operator
TP	Transm ss on Planner
TRE	Texas Reg onal Ent ty
TVA	Tennessee Valley Author ty
UDS	Un t D spatch System
VSA	Voltage Stab l ty Analys s
WECC	Western Electr c ty Coord nat ng Counc l

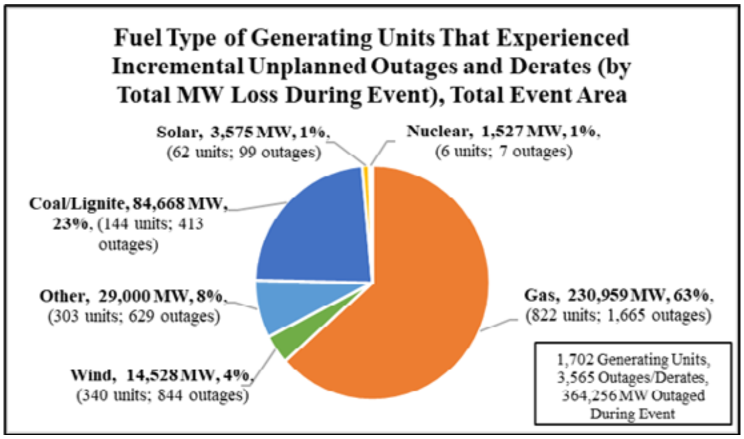
APPENDIX C: ADDITIONAL CHARTS AND FIGURES FOR UNPLANNED GENERATION OUTAGES DURING EVENT

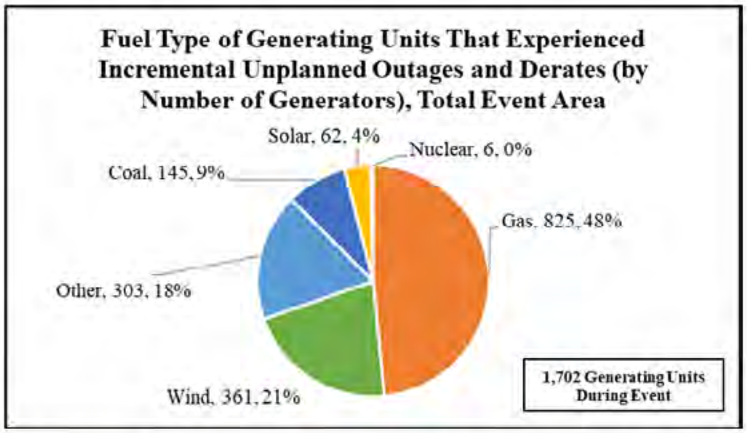
1. Number of Incremental Unplanned Generation Outages, Derates, and Failures to Start BY CAUSE, December 21-26, Total Event Area



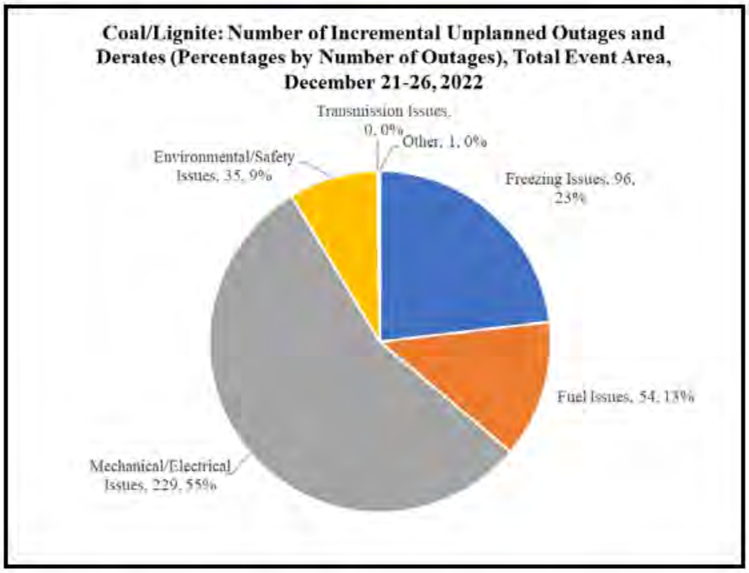
2. Unplanned Generation Outages by Fuel Type

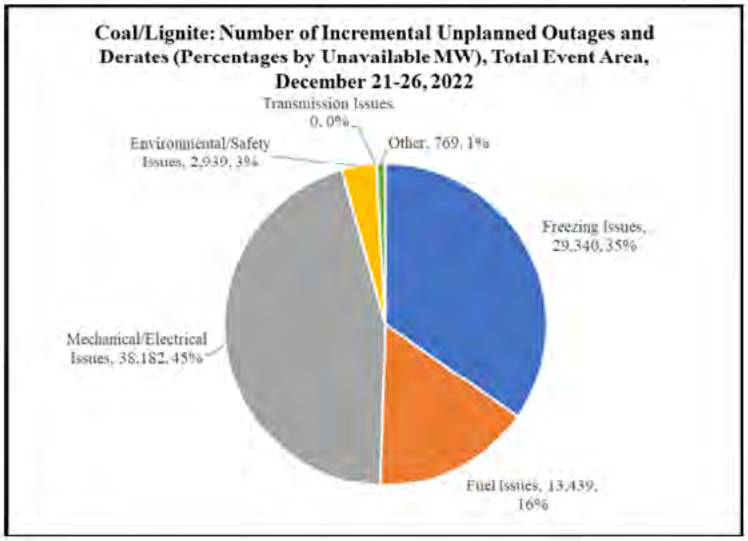




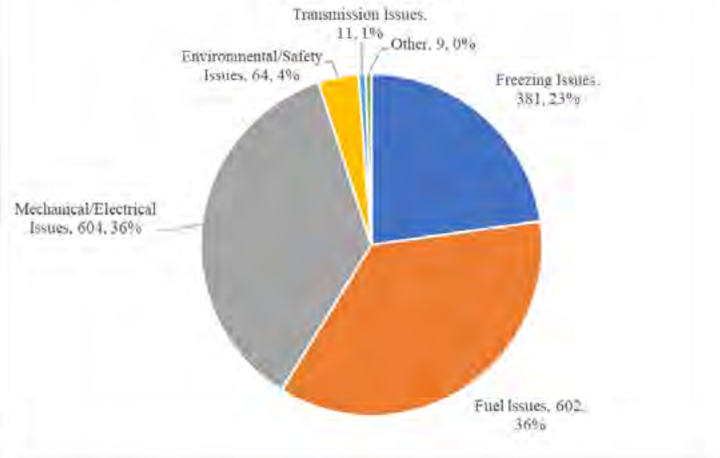


3. Causes of Unplanned Generation Outages, by Fuel Type of Generation

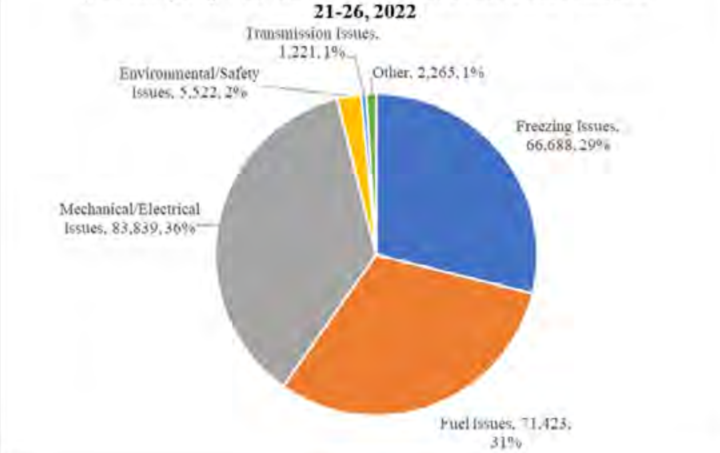


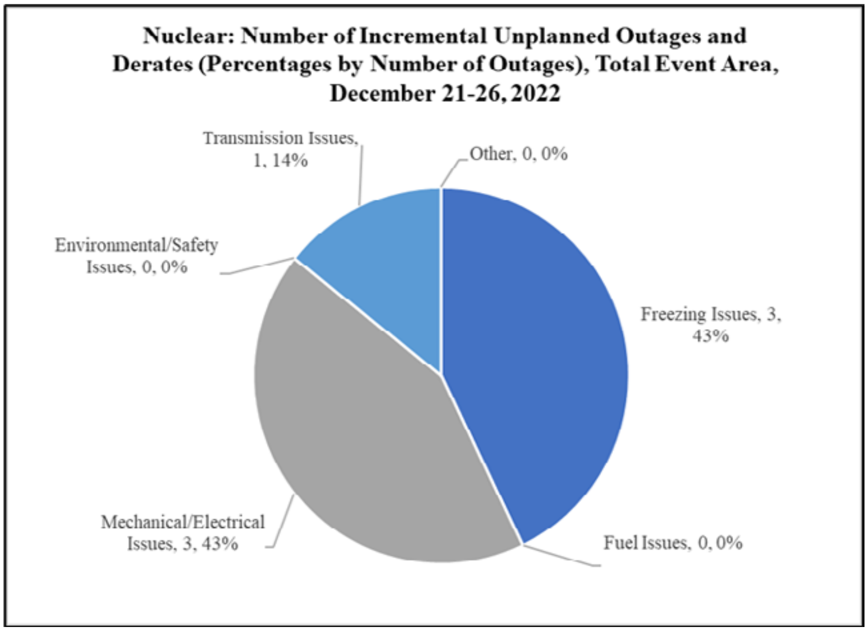


Gas: Number of Incremental Unplanned Outages and Derates (Percentages by Number of Outages), Total Event Area, December 21-26, 2022

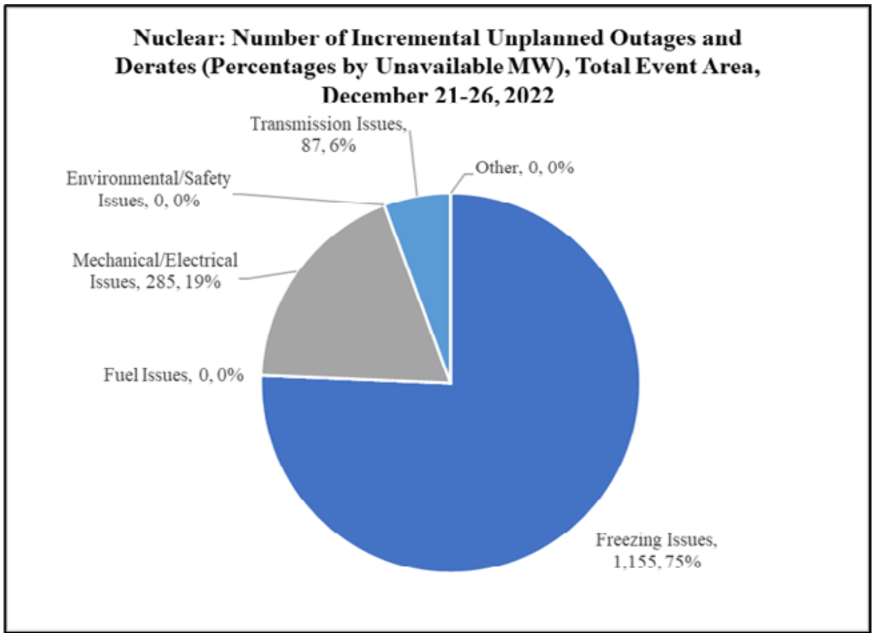


Gas: Number of Incremental Unplanned Outages and Derates (Percentages by Unavailable MW), Total Event Area, December 21-26, 2022

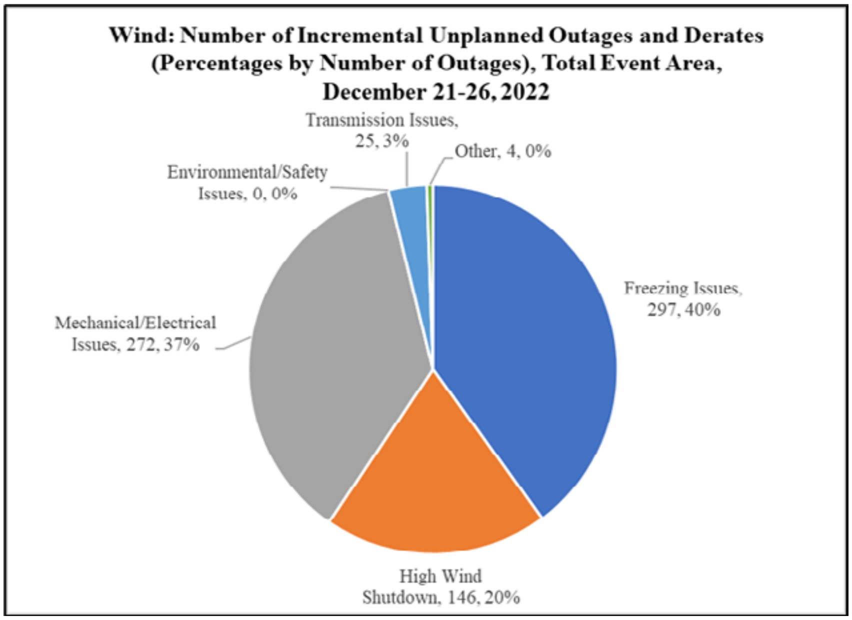


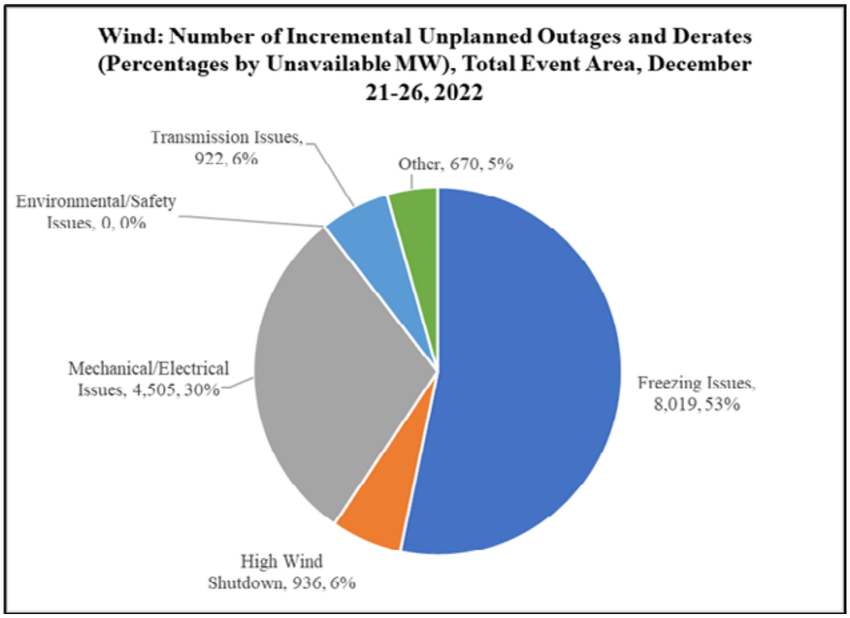


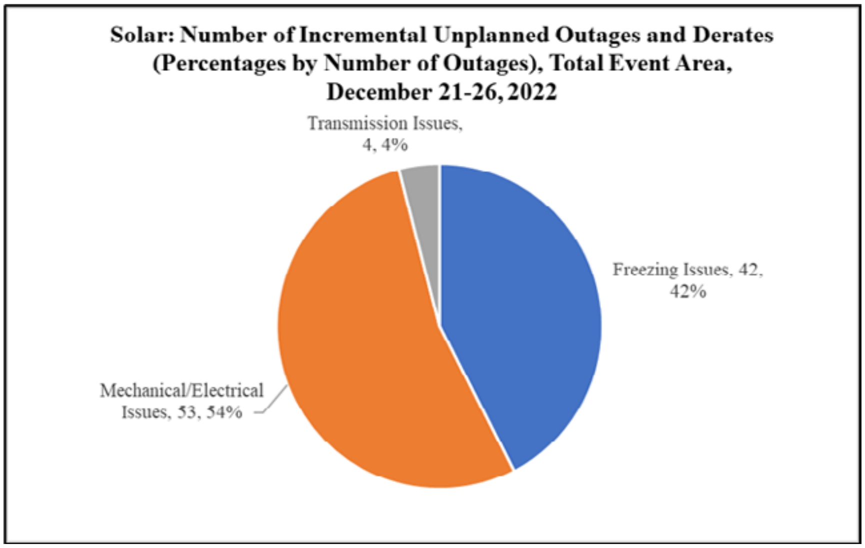
Nuclear: Number of Incremental Unplanned Outages and Derates (Percentages by Number of Outages), Total Event Area, December 21-26, 2022
Transmission Issues, 1, 14%
Other, 0, 0%
Environmental/Safety Issues, 0, 0%
Freezing Issues, 3, 43%
Mechanical/Electrical Issues, 3, 43%
Fuel Issues, 0, 0%

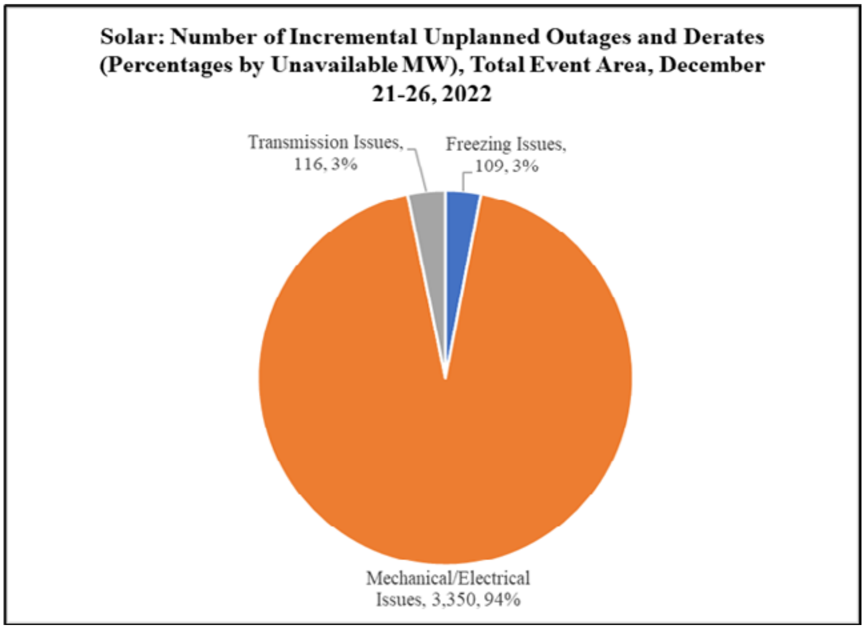


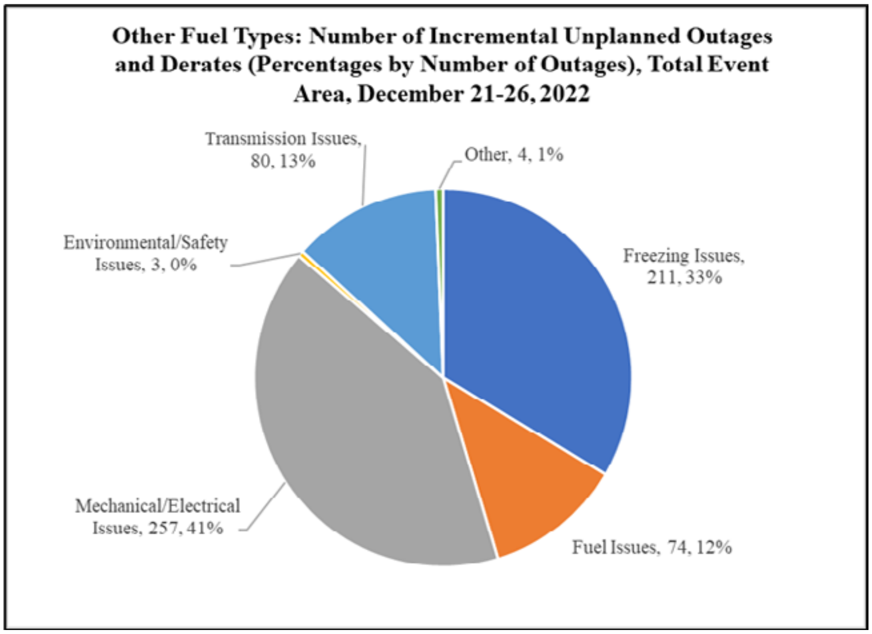
Nuclear: Number of Incremental Unplanned Outages and Derates (Percentages by Unavailable MW), Total Event Area, December 21-26, 2022
Transmission Issues, 87, 6%
Environmental/Safety Issues, 0, 0%
Other, 0, 0%
Mechanical/Electrical Issues, 285, 19%
Fuel Issues, 0, 0%
Freezing Issues, 1,155, 75%

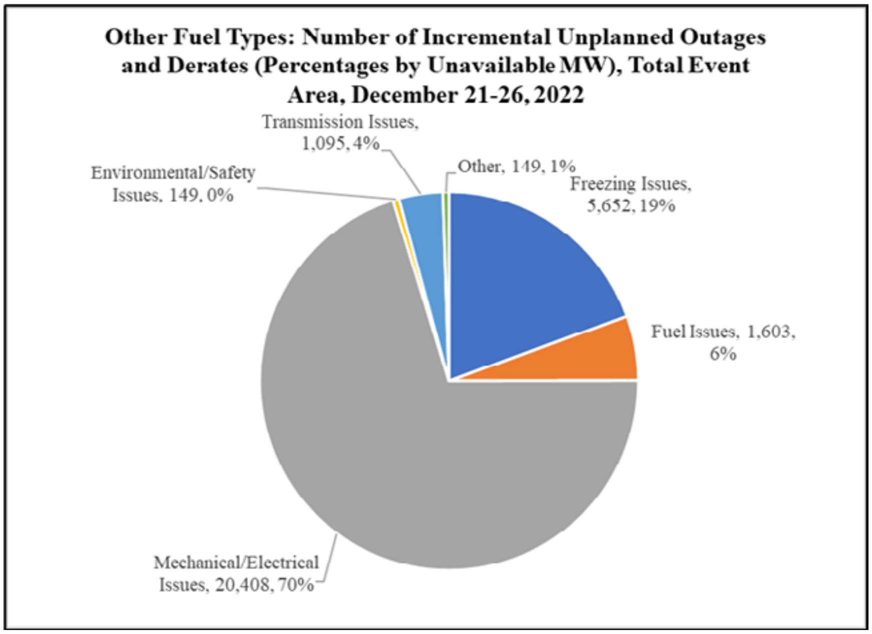

Wind: Number of Incremental Unplanned Outages and Derates (Percentages by Number of Outages), Total Event Area, December 21-26, 2022
Transmission Issues, 25, 3%
Other, 4, 0%
Environmental/Safety Issues, 0, 0%
Freezing Issues, 297, 40%
Mechanical/Electrical Issues, 272, 37%
High Wind Shutdown, 146, 20%


Wind: Number of Incremental Unplanned Outages and Derates (Percentages by Unavailable MW), Total Event Area, December 21-26, 2022
Transmission Issues, 922, 6%
Other, 670, 5%
Environmental/Safety Issues, 0, 0%
Mechanical/Electrical Issues, 4,505, 30%
Freezing Issues, 8,019, 53%
High Wind Shutdown, 936, 6%

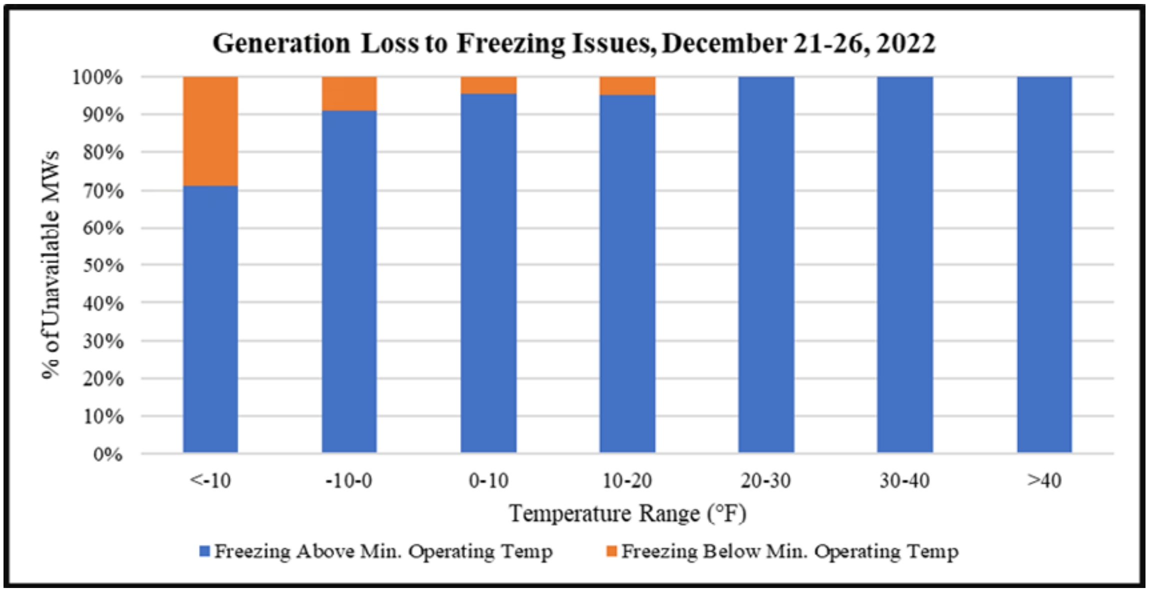

Solar: Number of Incremental Unplanned Outages and Derates (Percentages by Number of Outages), Total Event Area, December 21-26, 2022
Transmission Issues, 4, 4%
Freezing Issues, 42, 42%
Mechanical/Electrical Issues, 53, 54%

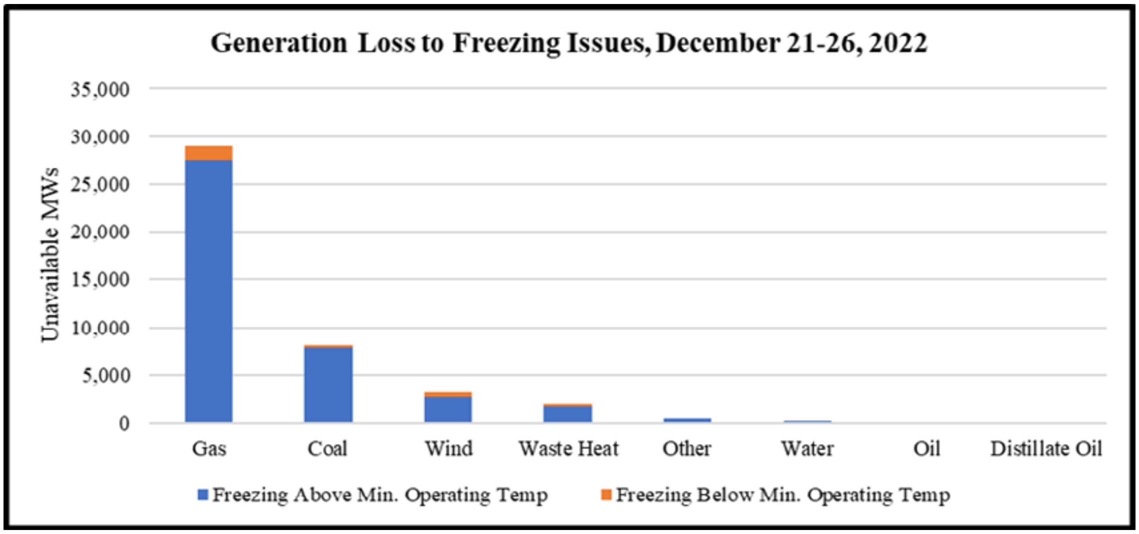

Solar: Number of Incremental Unplanned Outages and Derates (Percentages by Unavailable MW), Total Event Area, December 21-26, 2022
Transmission Issues, 116, 3%
Freezing Issues, 109, 3%
Mechanical/Electrical Issues, 3,350, 94%


Other Fuel Types: Number of Incremental Unplanned Outages and Derates (Percentages by Number of Outages), Total Event Area, December 21-26, 2022
Transmission Issues, 80, 13%
Other, 4, 1%
Environmental/Safety Issues, 3, 0%
Freezing Issues, 211, 33%
Mechanical/Electrical Issues, 257, 41%
Fuel Issues, 74, 12%

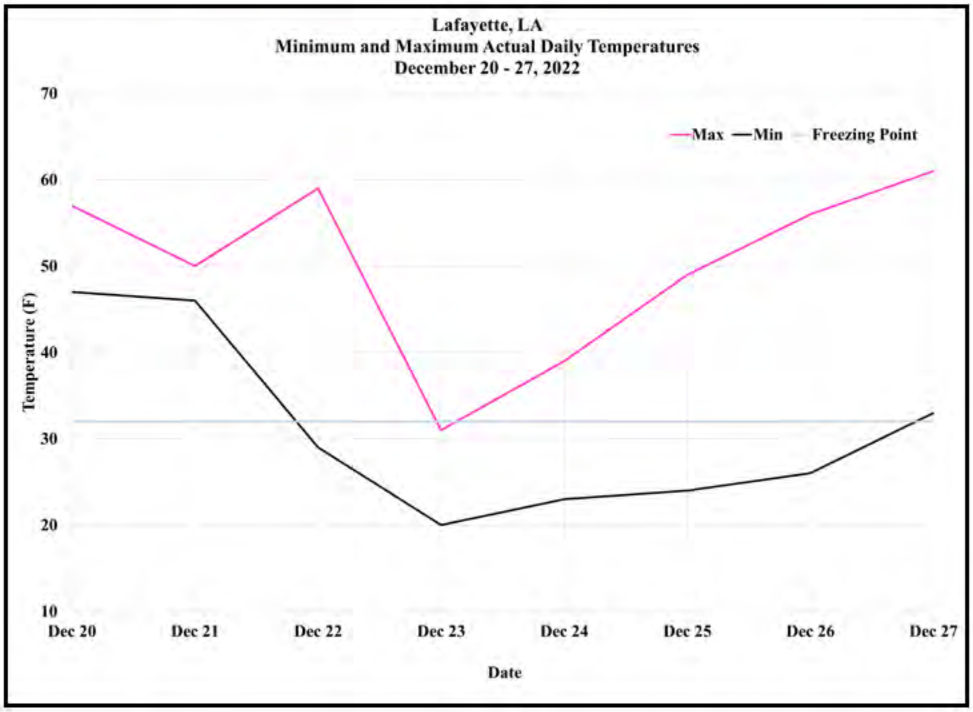

Other Fuel Types: Number of Incremental Unplanned Outages and Derates (Percentages by Unavailable MW), Total Event Area, December 21-26, 2022
Transmission Issues, 1,095, 4%
Environmental/Safety Issues, 149, 0%
Other, 149, 1%
Freezing Issues, 5,652, 19%
Fuel Issues, 1,603, 6%
Mechanical/Electrical Issues, 20,408, 70%

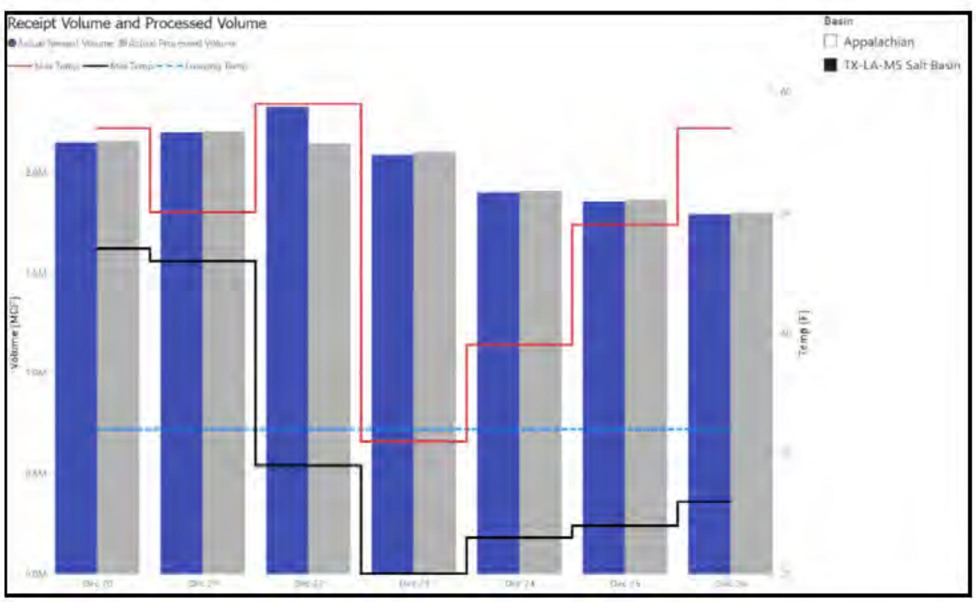
4. Cause: Freezing Issues – Additional Charts and Figures





APPENDIX D: NATURAL GAS PROCESSING DATA FOR TEXAS-LOUISIANA-MISSISSIPPI SALT BASIN





APPENDIX E: PROGRESS ON 2021 INQUIRY REPORT

FERC-NERC-Regional Entity Cold Weather Inquiry Reports - Recommendations Completion Tracking (as of October 2023)				
URI Report Recommendations	**URI / Percent Completed**	**Completion Notes**		**Elliott Report Recommendations (abbreviated text)**
Extreme Cold Weather Event Prevention and Preparedness-Oriented Recommendations				
Rec. 1: Develop Reliability Standards for electric generator cold weather reliability	70%	Submitted Part of Ph. 2 Stds. to FERC by 11-1-23	Related to Elliott Rec.	Rec. 1: Robust implementation monitoring of freeze protection Standards to determine if reliability gaps exist
Rec. 2: Generator compensation opportunities for investments	(states)			—
Rec. 3: Generator winter readiness technical conference	100%	FERC/ERO conference held April 2022		—
Rec. 4: Generator freeze protection inspection and maintenance timing	20%	observation from Elliott event inquiry	Related to Elliott Rec.	Rec. 1: Seven recommendation sub-parts (1a-1g) for assuring freeze protection sufficiency
Rec. 5: Require natural gas facility cold weather preparedness plans and measures	20%	Now Required in Texas	Related to Elliott Rec.	Rec. 4a: Establish reliability rules for natural gas infrastructure, requiring cold weather plans, freeze protection, and operating measures for extreme cold weather periods
Rec. 6: Voluntary measures for natural gas facility cold weather preparedness	(states)		Related to Elliott Rec.	Rec. 6: Commission consider whether to have jurisdictional gas entities provide one-time reports on assessing, responding to natural gas vulnerabilities in extreme cold weather
Rec. 7: Establish natural gas-electric reliability forum	100%	NAESB, Commission Forums, NAESB Report		—
Rec. 8: Understanding generator natural gas contract risks	50%	NERC drafting new fuel assurance/risk guideline		—
Rec. 9: (Seasonal) Peak load forecasts and reserve margin calculations	100%	Incorporated in NERC Winter Assessment	Related to Elliott Rec.	Rec. 10: joint-regional reliability assessments of electric grid conditions during extreme cold weather periods, for use in power supply planning to reduce the risk of firm load
Rec. 11: Generator cold weather effects-mechanical, electrical systems	0%	observation from Elliott event inquiry	Related to Elliott Rec.	Rec. 2: Technical review of root causes of generator cold-related mechanical/electrical outages to identify prevention measures, determine if additional Standards are needed
Rec. 12: Generator use of weather forecasts for operating plans	50%	observation from Elliott event inquiry		—
Rec. 14: Natural gas production facilities SCADA control	(states)			—
Rec. 16: Improve Near-term Load Forecasts	0%	observation from Elliott event inquiry	Related to Elliott Rec.	Rec. 9: BAs should improve their short-term load forecasts for extreme cold weather periods cold weather periods by implementing the lessons and practices identified below and sharing newly identified effective practices with peer BAs for continuous improvement
Rec. 17: Analyze Intermittent Generation to improve Load Forecasts	50%	observation from Elliott event inquiry		
Rec. 19: Retail Incentives for Energy Efficiency Improvements	(states)			—
Rec. 23: Report Times for Generation and Transmission Outages	25%	observation from Elliott event inquiry		—
Rec. 24: Study: Measures to Address Natural Gas Supply Shortfalls	50%	NERC & NERC RAS	Related to Elliott Rec.	Rec. 7: Study: analyze whether additional natural gas infrastructure, including interstate pipelines and storage, is needed to support reliability of electric grid, meet needs of LDCs
Rec. 28: Study: Guidelines to Identify Critical Natural Gas Facility Loads	(states)	Now Required in Texas	Related to Elliott Rec.	Rec. 4c: Establish rules requiring designation of critical natural gas infrastructure loads for priority treatment during load shed
Average Percent Addressed (excluding state-level recs.) - URI:	**49%**			Rec. 4b: Establish rules requiring establishing regional natural gas communications coordinators, with situational awareness ofnatural gas infrastructure similar to grid's RCs
Number of state-level recommendations to help support prevention - URI:	5			Rec. 5: The North American Energy Standards Board should convene natural gas / electric grid / LDC entities to identify communication improvements during extreme cold
				Rec. 8: BAs assess whether new or modified processes, such as multi-day risk assessment processes or advance reliability commitments are needed to address anticipated capacity shortages or transmission reliability problems during extreme cold weather
Emergency Response-Oriented Recommendations				
Rec. 10: Improve rotational load shed plans	90%	NERC RAS & RTOS		—
Rec. 13: Study of ERCOT generators to review low-frequency effects	10%	PRC-024 SDT, combined with Rec. 27 effort		—
Rec. 15: Develop or enhance emergency response centers	(states)			—
Rec. 18: Additional Rapidly-Deployable Demand Response	(states)			—
Rec. 20: Perform Bi-Directional Seasonal Transfer Studies	90%	NERC RAS & RTOS		—
Rec. 21: Operator-Training Rotational Firm Load Shed Simulations	100%	NERC RTOS		—
Rec. 22: Generator Protection Settings/ UFLS Coordination	100%	ERCOT completed		—
Rec. 25: Study: Additional ERCOT Interconnection Links	100%	ERCOT, completed		—
Rec. 26: Study: ERCOT Black Start Unit Reliability	98%	FERC/ERO Report near completion	Related to Elliott Rec.	Rec. 3: Study: Black start unit reliability covering all portions of the U.S. not already studied
Rec. 27: Study: Low-Frequency Effects in Eastern, Western Interconnects	10%	NERC SME staff assigned; gathering data	Related to Elliott Rec.	Rec. 11: Study: examine potential stability risks on December 23-24 for periods of decreased frequency and low responsive reserves during Winter Storm Elliott
Average Percent Addressed (excluding state-level recs.) - URI:	**75%**			
Number of state-level recommendations to help support response - URI:	2			

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Committees, Task Forces, Forums – Acronyms Key

ERATF:	Energy Reliability Assessment Task Force
IRPWG:	Inverter-Based Resource Performance Working Group
RAS:	Reliability Assessment Subcommittee
RS:	Resources Subcommittee
RSTC:	Reliability and Security Technical Committee
RTOS:	Real Time Operations Subcommittee
SPCWG:	System Protection and Control Working Group
SPIDERWG:	System Planning Impacts from Distributed Energy Resources Working Group