Attachment L

MISO Resource Adequacy Business Practices Manual,
BPM-011-r31

Manual No. 011

Business Practices Manual

RESOURCE ADEQUACY

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Revision History

Doc Number	Description	Revised by:	Effective Date
BPM-011-r31	Included language related to Final PRMR allocation process in Section 5.6 and other editorial changes Updated PRA Formulations in Appendix M	MISO Staff	FEB-21-2025
BPM-011-r30	Annual Review Complete including UCAP/ISAC ratio related process improvement, GADS events/performance submission, timeline change for multiple process such as state notifying MISO on utilizing their own PRM, full responsibility transactions, confirm/convert SAC etc, edits for RBDC (MRI/RBDC curve development, RBDC opt out process, PRMR determinations for PRA and settlements etc)	MISO Staff	OCT-01-2024
BPM-011-r29	Annual Review Complete. Edits include GVTC test extension updates, 31-day rule and ZRC replacement updates, LMR and ER registration updates, OY CIL CEL removal Appendix K timeline updates and Attachment Y updates to schedule 53 resources and the UCAP/ISAC ratio process and timeline.	N. Przybilla	OCT-01-2023
BPM-011-r28	Clarify and add additional context surrounding ZRC replacement and the 31-day outage rule in section 6.4 while ensuring language is consistent with Module E-1 of the MISO Tariff.	N. Przybilla	May-31-2023
BPM-011-r27	Updates to all sections to facilitate the implementation of seasonal auctions & seasonal accreditation (FERC Docket No. ER22-495). Includes updates from annual BPM review	MISO Staff	October-31-2022
BPM-011 r26	Replacement of 4.2.12 Battery Storage Accreditation with Electric Storage Resource. Add Electric Storage Resource to section 4.2.8. BTMG Qualification Requirements. Update Appx K. Correct Appendix N – Demand and Energy Forecast Characteristics.	M. Guerriero	AUG-15-2022
BPM-011-r25	2021 Annual review complete. Edits include: Hybrid resources, detail added to States establishing PRM, detail for 90/120 day outages, clarification for BTMG wind UCAP, Updated to	MISO Staff	JUL-01-2021

	reference new DSRI tool instead of MCS, updated RAN related LMR accreditation (ER20-1846), new DR Test Deferral process, Battery Storage accreditation, reorganized Appx I XEFORd, added Process Load reporting section, updated App K Timeline.		
BPM-011-r24	2020 Annual review complete. Edits include new Appendix W (DR LOLE), Deliverable ICAP (ER20-1942, ER20-2005), GVTC testing clarification, ZDB example, and other minor clarifications.	G. Alexander	DEC-15-2020
BPM-011-r23	Revisions to address treatment of resources on long term outage which FERC approved under Dock No. ER20-129-000.	T. Bachus	MAR-31-2020
BPM-011-r22	2019 Annual Review Complete. Edits include: general clean up, ER19-2559 (PRA Process Timeline) & ER18-2363 (Locational Filing), web links, ER UCAP intermittent qualification, Appx R CONE calculation, removing Att W (ER19-650 RAN Phase 1 LMR filing) by imbedding language into applicable LMR sections.	E. Thoms	OCT-1-2019
BPM-011-r21	Added LMR Registration FAQ to address ER19-650-000	E. Thoms	FEB-20-2019
BPM-011-r20	Multiple updates. Revisions supporting changes to the out-year transfer study process. Additional revisions to support the Module E-1, Locational Tariff update which created External Resource Zones and several other changes.	M. Sutton	NOV-01-2018
BPM-011-r19	Revisions to Section 4.2.8 clarifying language when a Qualifying Facility participates as a BTMG. Addition of SER Type II resource. Annual Review completed.	J. Harmon	SEP-28-2018
BPM-011-r18	Annual Review Complete Includes revisions to Section 4.2.8.5 clarifying deliverability options for BTMG.	J. Harmon	JAN-22-2018
BPM-011-r17	Annual Review Complete	J. Harmon	AUG-25-2017
BPM-011-r16	Several updates. Updated Wind UCAP values; added section regarding Solar capacity credit; Revised provisions for Zonal Deliverability Benefit; Inclusion of Suspended resources in the PRA; Retail Choice coincident load forecast reporting process. Annual Review completed.	J. Harmon	JUL-15-2016

BPM-011-r15	Annual Review completed. Included Inter-zonal replacement, sub regional constraints in PRA, PRMR and LCR relationship, external resource and host BA qualification requirements, GVTC deferral, and refueling versus repowering. Additions to section 5.2.1 for Local Resource Zone reevaluation process and Generation Limited Transfers	J. Milli / M. Sutton / S. Quadri / J. Cole / R. Westphal	SEP-01-2015
BPM-011-r14	Annual Review completed. Remove netting of Demand Response. Update SFT and Transfer Analysis provisions.	J. Milli	SEP-01-2014
BPM-011-r13	Updated LRZ map, timeline, and added catastrophic outage provisions	C. Clark	JAN-01-2014
BPM-011-r12	Annual review and updated to reflect Tariff orders	C. Clark	AUG-01-2013
BPM-011-r11	Updated to reflect Module E-1-1 Tariff	C. Clark	OCT-01-2012
BPM-011-r10	Updated GVTC language for Hydro and ROR.	C. Clark	SEP-28-2012
BPM-011-r9	Annual Review completed and Updated Registration tables and added new section for qualifying PPAs.	C. Clark	APR-15-2012
BPM-011-r8	MISO Rebranding Changes JUL-19-2011	G. Krebsbach	JUN-13-2011
BPM-011-r8	Annual Review and added Dispatchable Intermittent Resource, minor clarifications	C. Clark	JUN-13-2011
BPM-011-r7	Updated UCAP calculations for plan year 2011/2012, undated must offer provisions, updated External Resources cross-border deliverability provisions, updated minor clarifications	M. Heraeus / C. Clark	Dec-1-2010
BPM-011-r6	Corrected errors and added “must offer” language and Units with Low Service Hours	M. Heraeus / C. Clark	JUN-1-2010
BPM-011-r5	Corrected errors and inadvertent omissions	M. Heraeus	MAR-3-2010
BPM-011-r4	Resource Adequacy Improvements Tariff Filing updates. Changed numbering to BPM -011	K. Larson	DEC-21-2009
TP-BPM-003-r3	Removed stakeholder comments from section 6.4 that were provided during drafting of TP-BPM-003-r2. Amended section 4.4.3.14.4.3.1.	T. Hillman	JUN-01-2009
TP-BPM-003-r2	Revised to reflect the December 28th, 2007 (ER08-394) filing and subsequent Commission required compliance filings through May 2009 to revise Module E-1 to comprehensively address long-term Resource Adequacy Requirements	T. Hillman	JUN-01-2009
TP-BPM-003-r1	Revised to reflect Open Access Transmission, Energy and Operating Reserve Markets Tariff for	J Moser	JAN-06-2009

	the Midwest ISO, Inc. (Tariff) relating to implementation of the Day-Ahead and Real-Time Energy and Ancillary Services Markets and to integrate proposed changes to the Balancing Authority Agreement.		
TP-BPM-003	Updated template	J. Moser	APR-01-2008
N/A	Section 3.2.1 Determination of Requirements – Non-valid statements were removed. Section 3.2.3 Default Requirements – Minor revisions were made for clarification. Section 3.2.4 Compliance with the Midwest ISO Requirements – Paragraph on after-the-fact ECAR “must offer” compliance was removed. Section 4.1 Commercial Pricing Node Load Forecast – Minor revisions were made for clarification. Section 5.2.1 Procedure for Designating a Network Resource for Resource Adequacy Purposes – LD Contracts bullet updated to reflect FERC Order 890. Section 5.2.3 Designating Network Resources External to the Midwest ISO – The second bullet point was revised for clarification. Section 5.3 Determination of Compliance with Network Resource Requirements – This section was deleted. Section 5.4 (5.3) Network Resource Must Offer Requirement – Paragraph on after-the-fact ECAR “must offer” compliance was removed. Section 5.5 Financial Transmission Rights – This section was deleted. Section 5.6 (5.4) Updating Network Resource Designations – RE references have been updated to reflect the current NERC Regions. Section 6.1.3 Liquidated Damage and Similar Contracts – Entire section updated to reflect FERC Order 890. Section 6.1.4 Hubbing Transactions – This section was deleted. Section 8 Data Requirements – Entire section updated to reflect FERC order 890		DEC-12-2007

1 Contents

1 Introduction

This introduction to the Midcontinent Independent System Operator, Inc. (MISO) *Business Practices Manual (BPM)* for Resource Adequacy Requirements includes basic information about this BPM and the other MISO BPMs. The first section (Section 1.1) of this Introduction provides information about the MISO BPMs. The second section (Section 1.2) is an introduction to this BPM. The third section (Section 1.3) identifies other documents in addition to the BPMs, which can be used by the reader as references when reading this BPM.

1.1 Purpose of the MISO Business Practices Manuals

The BPMs developed by MISO provide background information, guidelines, business rules, and processes established by MISO for the operation and administration of the MISO markets, provisions of transmission reliability services, and compliance with the MISO settlements, billing, and accounting requirements. A complete list of MISO BPMs is available for reference through MISO's website.

1.2 Purpose of this Business Practices Manual

This Resource Adequacy Business Practices Manual describes MISO's and other entities' roles and responsibilities related to maintaining Resource Adequacy, which is ensuring that Load Serving Entities (LSE) serving Load in the MISO Region have sufficient Planning Resources to meet their anticipated peak Demand requirements plus an appropriate reserve margin.

The Resource Adequacy BPM will conform and comply with MISO's Energy Markets Tariff, NERC operating policies, and the applicable Regional Entity (RE) reliability principles, guidelines, and standards to facilitate administration of efficient Energy Markets.

This document benefits readers who want answers to the following questions regarding the Resource Adequacy Requirements (RAR).

- How is Resource Adequacy determined?
- How do the multiple state jurisdictions relate regarding Resource Adequacy Requirements (RAR)?
- What are the responsibilities of the different entities regarding Resource Adequacy?
- How are specific resources identified and qualified, including contracted resources, for Resource Adequacy purposes?
- What is a Zonal Resource Credit (ZRC) and how can it be used to comply with RAR?
- What are the deliverability requirements for Planning Resources?

- How are Demand Response Resources (DRR Type I and Type II) incorporated in the Resource Adequacy process?
- How does an LSE comply with its obligations under the changes to Module E-1 of the Tariff?
- What are the procedures for participating in Planning Resource Auctions?
- What are the settlement provisions for the Planning Resource Auctions?
- What are the procedures for tracking and settling retail and wholesale customer switches?

This document provides the necessary detail to aid a MISO Market Participant's (MP) understanding of its primary responsibilities and obligations to the reliable operation of MISO's Balancing Authority Footprint, as a result of MISO's Resource Adequacy Requirements.

1.3 References

Other reference information related to this document includes:

- MISO BPMs
- MISO's Open Access Transmission, Energy and Operating Reserve Markets Tariff
- NERC – Resource and Transmission Adequacy Recommendations, dated June 15, 2004
- Federal Energy Regulatory Commission (FERC) Order Nos. 890, Order 890 - A, and Order 890 -B.
- Module E Capacity Tracking (MECT) tool Users Guide
- LOLE Study Reports
- Wind & Solar Capacity Credit Report
- PowerGADS User's Manual
- CIL/CEL Study Reports

2 Overview of Resource Adequacy

Achieving reliability in bulk electric systems requires, among other things, that the amount of resources exceeds customer Demand by an adequate margin. The margins necessary to promote Resource Adequacy needs to be assessed on both a near-term operational basis and on a longer-term planning basis.

The focus of Resource Adequacy is on the longer-term planning margins that are used to provide sufficient resources to reliably serve Load on a forward-looking basis. In the real-time operational environment, resources committed through the Resource Adequacy Requirements have a capacity obligation to be available to meet real-time customer Demand and contingencies. Therefore, Planning Reserve Margins (PRMs) must be sufficient to cover:

- Planned maintenance
- Unplanned or forced outages of generating equipment
- Deratings in the capability of Generation Resources and Demand Response Resources
- System effects due to reasonably anticipated variations in weather
- Load Forecast Uncertainty

2.1 Planning Reserve Margin Requirement Overview

Each LSE’s total obligation will be referred to as the Planning Reserve Margin Requirement (PRMR). Coincident Peak Demand forecasts are submitted by LSEs using a 50%/50% forecast (50% probability the forecast will be over, and 50% probability the forecast will be under, the projected peak Demand) which will include distribution losses. An LSE’s Initial Planning Reserve Margin Requirement (Initial PRMR) is described in Section 3 (Establishing Initial Planning Reserve Margin Requirements) of this BPM.

2.2 Planning Resources Overview

The resources used to achieve long-term Resource Adequacy are called Planning Resources, and consist of Capacity Resources, Load Modifying Resources and Energy Efficiency Resources. The relationships and key attributes of the Planning Resource types are as follows:

- Capacity Resources consist of electrical generating units, stations known as Generation Resources, External Resources (if located outside of the MISO Balancing Authority Area), Electric Storage Resources (ESR), Hybrid Resources, and resources that can be dispatched to reduce Demand known as Demand Response Resources that participate in the Energy and Operating Reserves Market and are available during Emergencies. Thermal Generation Resources are accredited based on the methodology described in Appendix Y (Schedule 53 Resources). Wind Resources will be accredited based on the ELCC study that MISO conducts. Non-wind intermittent generation resources will be accredited based on historical performance during the critical hours within each Season, where new resources will receive the class average for that resource type until enough historical data is accrued. Non-Schedule 53 Capacity Resources that report to GADS are quantified by applying seasonal forced outage rates to Installed Capacity (ICAP) values to calculate the Seasonal Accredited Capacity (SAC) for the resource.

- Load Modifying Resources (LMR) include Behind-the-Meter Generation (BTMG) and Demand Resources (DR) which are available during capacity and transmission Emergencies declared by MISO if used to meet Module E-1 requirements.
- Energy Efficiency Resources include installed measures on retail customer facilities that achieve a permanent reduction in electric Energy usage while maintaining a comparable quality of service.

A Market Participant (MP) can use Capacity Resources, LMRs, and Energy Efficiency Resources, up to their SAC values, to comply with their Resource Adequacy Requirements via a Fixed Resource Adequacy Plan or Reliability Based Demand Curve Opt Out (RBDC Opt Out) as described in Section 5.3 (Pre-PRA arrangement of capacity scheduling) of this BPM, or through self-scheduling their Zonal Resource Credits in the Planning Resource Auction(s) (PRA) as detailed in Section 5.5.6 (Resource Offers) of this BPM. A Market Participant can also sell ZRCs from Capacity Resources, LMRs, and Energy Efficiency Resources bilaterally before the Planning Resource Auction(s) or offer them in the Planning Resource Auction(s) as described in Section 5.5 (Planning Resource Auction) of this BPM.

MISO will determine Seasonal Accredited Capacity (SAC) values for all qualified Capacity Resources, Load Modifying Resources and for all Energy Efficiency Resources for each Season within the Planning Year.

2.3 Resource Adequacy Requirements Overview

Planning Resources that clear the Planning Resource Auction(s) (PRA) or that are designated in a Fixed Resource Adequacy Plan (FRAP) or RBDC Opt Out will be obligated to provide capacity in the Day-Ahead and Real Time Markets (DA/RT) for each Season cleared within the Planning Year unless replaced by another Planning Resource, as per Module E-1 Section 69A.3.1.h. Capacity Replacement Non-Compliance Charge(s) (CRNCC) may be applicable as per Module E-1 Section 69A.3.1h. Load Serving Entities (LSEs) that serve Load during the Planning Year will be obligated to pay for capacity from Planning Resources in the PRA pursuant to the relevant Auction Clearing Price (ACP) for the Local Resource Zone (LRZ) where the Load is located unless the Planning Resource was designated in a FRAP or RBDC Opt Out.

LSEs that have a Planning Reserve Margin Requirement (PRMR) will be obligated to procure capacity equal to their Final PRMR pursuant to the relevant ACP for the LRZ where they have PRMR unless, and to the extent that the LSE meets its Final PRMR via a FRAP or RBDC Opt Out per Section 5.3 of this BPM, or unless and to the extent that the LSE chooses to reduce its Final PRMR that is cleared in a given auction(s) by electing to pay the Capacity Deficiency Charge per Section 5.7 of this BPM.

2.4 Settlements/Performance Requirements Overview

The seasonal Planning Reserve Margin Requirement (PRMR) obligations of LSEs will be established for each Season of the Planning Year and will be settled based upon the applicable Planning Resource Auction(s) (PRA) clearing price for an LSE’s Final Planning Reserve Margin Requirement, unless covered by a FRAP or RBDC Opt Out, or unless the LSE elects to pay the Capacity Deficiency Charge. Once each planning period begins, LSEs and MPs will have the corresponding charges and credits from each applicable PRA included on their daily settlement statements for all loads and Planning Resources cleared in a PRA as documented in further detail in the Market Settlements BPM.

LMRs with ZRCs that either cleared the PRA or were used in a FRAP or RBDC Opt Out will have a performance obligation to be available during system Emergencies per section 4.2.7 (Demand Resource Qualification Requirements) iof this BPM.

3 Establishing Initial Seasonal Planning Reserve Margin Requirements

3.1 Overview

The Initial seasonal Planning Reserve Margin Requirement (PRMR) is the number of MWs in ZRCs required to meet an LSE's Resource Adequacy Requirements (RAR). The RAR is established to ensure that LSEs have enough Planning Resources to reliably serve load for the applicable Seasons.

The Initial seasonal PRMR is expressed in the following equation per Load Serving Entity (LSE) per Local Resource Zone (LRZ)

$$Initial\ PRMR_{LRZ} = \sum_{LBA}[(CPDf_{LBA} - FRP_{LBA} + FRS_{LBA}) \times (1 + TL_{LBA}\%) \times (1 + PRM_{RTO})]$$

Where attributes are seasonal for the following:
Initial $\mathrm{PRMR}_{\mathrm{LRZ}}$ = Initial Planning Reserve Margin Requirement per LRZ
$\mathrm{CPDf}_{\mathrm{LBA}}$ = Coincident Peak Demand forecast per LBA
$\mathrm{FRP}_{\mathrm{LBA}}$ = Full Responsibility Purchase per LBA
$\mathrm{FRS}_{\mathrm{LBA}}$ = Full Responsibility Sale per LBA
$\mathrm{TL}_{\mathrm{LBA}}\%$ = Transmission Loss Percentage of LBA
PRM $_{\mathrm{RTO}}$ = Planning Reserve Margin in Unforced Capacity set by LOLE Studies

3.1.1 Agency Contracts Supporting Resource Adequacy Requirements

An LSE may contract with other entities to comply with RAR. The contracted entity may perform functions on behalf of the applicable LSE including, but not limited to, submitting the LSE's forecasted CPD forecast or share of CPD forecast.

Each individual LSE is ultimately responsible for conformance with the RAR, even if the LSE enters a contract with a third party acting on its behalf. If requested by MISO, each LSE that contracts with another entity to comply with any part of the Resource Adequacy Requirements must notify MISO of the arrangement. The LSE must provide MISO with the name of the organization representing them, primary and alternate contact information for the individuals representing them, and the scope of responsibilities the contracted entity will provide.

3.1.2 Validation of Firm Transmission Service for Load

Each LSE shall document, as described in Module B – Transmission Service, to MISO that the LSE has obtained sufficient firm Transmission Service to serve its load for each Season in the Planning Year. Load not served by Network Integrated Transmission Service (NITS) must have Firm Point-to-Point Transmission Service or a firm Grandfathered Agreement (GFA), when applicable—however, Demand does not require firm MISO Transmission Service when the LSE meets its Initial PRMR using its own Behind-the-Meter Generation (BTMGs), Demand Resources (DRs), and Energy Efficiency Resources, and does not use the MISO Transmission System to serve such Demand.

Additionally, Energy Resource Interconnection Service (ERIS) requires a completed firm Transmission Service Request (TSR) submitted through OASIS OATI that has been approved by the Generation and Interchange team at MISO in order to be considered towards deliverability that is used to convert Seasonal Accredited Capacity (SAC) to Zonal Resource Credits (ZRCs). This information will be entered into the MECT on the Convert SAC screen by Market Participants (and in the Registrations screen, if applicable).

3.2 Demand and Energy Forecasts

MISO collects a variety of load forecasts for Resource Adequacy and other planning processes via the MECT tool. This section describes each of these forecasts and what entity is responsible for providing them. Please See Appendix O for the list of parties responsible for reporting Demand and Energy forecasts.

Demand and Energy forecasts that are not subject to retail choice load switching should be reported by the respective LSE. Demand and Energy forecasts that are subject to retail choice load switching should be reported by the respective Electric Distribution Company (EDC). The EDC calculates a Peak Load Contribution (PLC) MW value for each retail choice LSE that represents a share of the EDC’s Initial PRMR. If an LSE disagrees with their PLC value calculated by their EDC, the LSE will work with its EDC to revise the PLC prior to the final EDC forecast submission deadline. See Appendix K for all Demand and Energy forecast deadlines.

All Demand (Energy) forecasts must reflect a 50% probability that the Demand (Energy) will not exceed the forecasted Demand (Energy) for the relevant time period. Any manual or ex-post adjustments to the forecasts derived from the LSE’s chosen forecasting method that are offered due to catastrophic event impacts (such as COVID-19) must be supported analytically and quantitatively.

For a detailed description of each forecast's characteristics refer to Appendix N.

3.2.1 Non-Coincident Peak Demand and Energy for Load Forecasts

Non-Coincident Peak Demand and Energy for Load forecasts are collected for the purposes of facilitating FERC Form 714 and NERC Modeling Data and Analysis (MOD) Standards reporting along with other planning processes at MISO.

The MISO FTR Administration team uses the Non-Coincident Peak forecast value for the upcoming planning year in the annual Auction Revenue Rights (ARR) allocation process. This forecast should not include transmission losses or Grandfathered Agreements (GFAs) but should include Demand Resources and Behind-The-Meter-Generation (BTMG). Load served by GFAs is reported separately via the same MECT section.

Please refer to NERC's Reliability MOD Standards for a complete definition for the non-Coincident Peak Demand forecast and FERC's Form 714 for the Energy for Load forecast. Below are general guidelines; if a conflict should arise between the guidelines below and the respective NERC standards documents, defer to the latter.

The Non-Coincident Peak Demand and Energy for Load forecasts are reported on a monthly basis for forecast years 1 and 2 and on a seasonal basis for forecast years 3 through 10.

Seasons for the purposes of these forecasts are defined as shown below:
Summer: June through August
Fall: September through November
Winter: December through February
Spring: March through May

For seasonal reporting of the Non-Coincident Peak Demand forecast, the single highest peak hour during the Season should be reported in MW. The ARR allocation section of the Non-Coincident Peak Demand Forecast submission screen, should be calculated and submitted on an annual peak for a given Planning Year for use in the FTR annual Auction Revenue Rights process. For Energy for Load forecasts, the summation of each month or season's Energy for load (GWh) should be reported as appropriate.

For all forecasts submitted, each LSE shall ensure that it counts its customer Demand once and only once.

Non-Coincident Peak Demand and Energy for Load forecast must be reported in the MECT by 11:59 pm EST on November 1 prior to the Planning Year.

For a detailed description of each forecast's characteristics refer to Appendix N.

3.2.2 Coincident Peak Demand Forecast

The seasonal Coincident Peak Demand forecasts (CPD forecast) are used as the basis for determining each LSE's seasonal obligation. The seasonal CPD forecasts shall be based upon considerations including, but not limited to, average historical weather conditions, economic conditions and expected Load changes (addition or subtraction of Demand).

For a detailed description of each forecast's characteristics refer to Appendix N.

A document describing the desired approach to be used by LSEs in preparing the seasonal CPD forecasts, the information required in each annual filing, and the process used in reviewing the CPD Forecasts can be found on MISO's website: Peak Forecasting Methodology Review Whitepaper. This document was written for when LSEs submitted an annual Coincident Peak Forecast, but the same methodology described in the paper can be performed at a seasonal level.

The seasonal CPD forecasts must be provided for each Asset Owner/LBA combination. Providing the CPD forecasts by Asset Owner is required by MISO's settlements process. Reporting by LBA allows MISO to apply the appropriate seasonal Transmission Losses towards the Initial PRMR and Final PRMR calculation. Seasonal Transmission Losses will be made available on the public website by MISO for each LBA. For more information on Transmission Losses see Appendix L.

The CPD forecasts must be reported via the MECT tool by 11:59 EST on November 1 prior to the Planning Year.

The CPD forecasts are reported differently in non-retail choice and retail choice areas as described in the following subsections.

3.2.3 Forecast Reporting

LSEs with Demand and Energy that are not subject to retail choice load switching are required to provide MISO with Demand and Energy forecasts no later than 11:59 p.m. EST on November 1 each year, for the following Planning Year. The seasonal CPD forecasts must be reported for each Asset Owner by LBA.

LSEs with Demand and Energy that is subject to retail choice load switching are not required to provide MISO with Demand and Energy forecasts. Electric Distribution Companies (EDCs) are responsible for submitting forecasts in areas that have Demand and Energy that is subject to retail choice load switching.

EDCs are defined as the company that distributes electricity to retail customers through distribution substations and/or lines owned by the company. The EDC of a retail choice area provides MISO with a seasonal peak forecasted Demand coincident with MISO's seasonal peak and must provide this data no later than 11:59 p.m. EST on November 1 prior to the Planning Year.

EDCs must provide both MISO and the respective retail choice LSEs with each retail customer's initial seasonal Peak Load Contribution (PLC) in the EDC's service territory no later than 11:59 p.m. EST on December 15 prior to the Planning Year.

All new EDCs are required to work with the MISO Client Services and Readiness department (https://help.misoenergy.org/) to set up access to the MECT tool and identify the relationships between the EDC and the LSEs in the EDC area. A Help Center ticket will need to be created to detail the access and relationship additions for the new EDC. The MISO Client Services and Readiness team will provide the new EDC with the required registration forms. Once the EDC setup is completed, all MPs with commercial pricing nodes participating in the retail choice load switching program are required to provide the name of the EDC where the commercial pricing node is located.

3.2.3.1 Provider of Last Resort

The Provider of Last Resort (POLR) will be responsible for meeting any Initial PRMR from Demand left unclaimed by retail choice LSEs in the EDC service territory. The Transmission Provider will work with the POLR and EDC to ensure that the POLR will serve any remaining Demand that is not allocated to LSEs.

3.2.4 Wholesale Load Customers

To ensure wholesale customers are accounted for, LSEs serving wholesale customers during the prompt Planning Year must include the Demand and Energy attributed to those wholesale customers in their Demand and Energy forecasts by 11:59 p.m. EST on November 1 prior to the Planning Year via the MECT tool.

An LSE that has previously served a wholesale customer and does not intend on serving that customer for the prompt Planning Year may or may not be required to report that customer in their forecasts.

Case 1: <u>LSE knows the entity that will serve the wholesale customer next Planning Year</u>:
In this case, the existing LSE is not responsible for submitting the Energy or Demand attributed to the wholesale customer in their forecasts. However, they must state the entity responsible for serving the customer in their supporting documentation.

Case 2: <u>LSE does not know who will serve the wholesale customer next Planning Year</u>:
In this case, the existing LSE is responsible for submitting the Energy or Demand attributed to the wholesale customer in their forecasts.

MISO will work with the wholesale customer regarding their forecasts and contact the wholesale customer to determine who the responsible LSE is. Once the responsible LSE is identified, MISO will transfer the Demand from the old LSE to the new LSE prior to the Planning Resource Auction.

3.2.5 Review of CPD Forecasts

Starting November 1, MISO will begin reviewing all forecasts and a randomly chosen set of supporting documentation submitted by LSEs and EDCs in order to give all parties adequate time to resolve any identified forecasting issues with MISO. The review will focus on whether the forecast methodology adequately and reasonably forecasts peak Demand, Energy, and/or Demand reduction capability of the submitting entity. The forecast review process will be completed no later than March 1 of each year prior to the annual PRA. If necessary, MISO may develop the required seasonal CPD forecasts for any Market Participants serving Load in the Transmission Provider Region or serving Load on behalf of a Load Serving Entity or other Market Participants that do not submit CPD forecasts and supporting documentation by the November 1 deadline.

3.3 Full Responsibility Transactions

Full Responsibility Transactions (FRT) are referenced differently depending on which side of the transaction is being addressed. The sale side of an FRT is called a Full Responsibility Sale (FRS) and the purchase side is called a Full Responsibility Purchase (FRP). Both the FRS and FRP are a transfer of Demand. As a result, the seasonal obligation (Initial PRMR and Final PRMR) calculation will reflect the associated transfer of transmission losses and PRM. FRTs may only be entered for Demand that is not subject to retail choice load switching.

The FRS results in an increase in Demand and FRP results in a decrease in Demand. This can be interpreted as the purchaser paying the seller to take on Demand and its associated seasonal Initial PRMR. This transfer of Demand also results in a transfer of the associated transmission losses and PRM.

- The seller of an FRS is contractually obligated to deliver power and Energy to the purchaser with the same degree of reliability as provided to the seller's own native load. With Full Responsibility Service to an LSE within MISO's Region, sellers are responsible for all of that LSE's Initial PRMR associated with the sale.

Example:

Asset Owner MM1:
Seasonal CPDf = 10 MW
Seasonal PRM = 6.2%
Seasonal Transmission Loss % = 2%
Asset Owner MM1 is the Buyer of the FRT for the total amount of 5 MW
MM1's Initial PRMR = (10 – 5) * (1 + 0.062) * (1 + 0.02) = 5.4 MW

Asset Owner SS2:
Seasonal CPDf = 20 MW
Seasonal PRM = 6.2%
Seasonal Transmission Loss % = 2%
Asset Owner SS2 is the Seller of the FRT for the total amount of 10 MW
SS2's Initial PRMR = (20 + 10) * (1 + 0.062) * (1 + 0.02) = 32.5 MW

Asset Owner BB3:
Seasonal CPDf = 50 MW

Seasonal PRM = 6.2%
Seasonal Transmission Loss % = 2%
Asset Owner BB3 is the Buyer of the FRT for the total amount of 5 MW
Asset Owner BB3 is the Seller of the FRT for the total amount of 10 MW
BB3’s Initial PRMR = (50 – 5 + 10) * (1 + 0.062) * (1 + 0.02) = 59.6 MW

The LSE (purchaser) may contract with other entities (sellers) to be responsible for capacity payments based upon the ACP for all or part of its load delivered to the purchaser through an FRP/FRS agreement. Each purchaser and seller must agree on which of their transactions are to be reported as an FRP/FRS. If the purchaser and seller cannot agree upon whether a particular transaction is an FRP/FRS agreement, then either party may invoke the dispute resolution procedures in the Tariff. FRP/FRS agreements are treated effectively like a transfer of forecasted Demand and the associated Initial PRMR from one LSE to another. An LSE with an FRP agreement is required to input the forecasted Coincident Peak Demand information for the transferred Demand into the MECT. An MP with a FRS agreement is required to meet the RAR obligation derived from the Demand as though it was their load, as described in Section 3. If the seller under an FRP/FRS agreement is not an LSE subject to the MISO Tariff, then the purchaser under an FRP/FRS agreement will remain responsible for any capacity payments associated with the FRP/FRS agreement.

If the seller under an FRS/FRP agreement is not an LSE subject to the MISO Tariff (“non-jurisdictional”), then the purchaser who is responsible for any RAR deficiencies may coordinate with the non-jurisdictional party to ensure that any RAR obligations associated with transferred Demand are met. A purchaser may request that the seller communicate the proper validations and confirmations to the purchaser or confirm validation of RAR obligations in the MECT to the purchaser. Such purchaser also can request that MISO coordinate with the non-jurisdictional party to intermediate the exchange of information from the seller to the purchaser. Such coordination will not relieve the purchaser from their responsibility for any RAR deficiencies associated with the FRP/FRS agreement.

The LSE with the FRS is responsible for compliance with LSE requirements. The obligation to serve the load is shifted but the obligation to forecast the Demand remains with the original LSE (purchaser). Both the purchasing and selling parties will be required to enter and verify the FRT into the MECT Full Responsibility Transaction screen. The parties must enter an FRT into the MECT along with documentation detailing their contract between the purchasing and selling parties to enable MISO to track the load and capacity obligations shift. This must be done by the fifth business day of February and the settlement will be between LSEs for all FRTs.

The Initial PRMR cannot be a negative number as a result of the FRT.

3.4 Planning Reserve Margin

This section describes the Loss of Load Expectation (LOLE) study process used by MISO to establish the Planning Reserve Margin (PRM) for each Season of the prompt MISO Planning Year. A MISO Planning Year runs from June 1 through May 31.

3.4.1 Determination of Seasonal Planning Reserve Margin

MISO will perform probabilistic analyses annually to establish the system-wide seasonal PRMs. This probabilistic analysis will utilize a Loss of Load Expectation (LOLE) study which assumes that there are no internal transmission limitations. Additionally, MISO will perform probabilistic analyses to establish the seasonal Local Reliability Requirements (LRRs) for each Local Resource Zone. MISO will publish the results by November 1 preceding the applicable Planning Year.

The LOLE study shall be consistent with Good Utility Practice, the reliability requirements of the Regional Entities (RE), and applicable states in the MISO Region. The PRM analyses shall consider factors including, but not limited to: the Generator Forced Outage rates of Capacity Resources, Generator Planned Outages, expected performance of Load Modifying Resources (LMRs), Intermittent Resources, Energy Efficiency Resources, load forecast uncertainty, and the Transmission System’s import and export capabilities with external systems. The seasonal PRMs that are calculated in the LOLE probabilistic modeling software are determined on an ICAP and UCAP basis. The preliminary $PRMR_{ICAP}$ values are the sum of the ICAP ratings of the resources utilized in the simulation to achieve the reliability criteria. Similarly, the sum of the UCAP ratings of these same resources utilized in the simulation to achieve the reliability criteria is the total UCAP-rated MW needed, or the preliminary $PRMR_{UCAP}$ Values. PRMR values are finalized after MISO has received the updated LSE-submitted load forecasts on November 1 and validated the load forecasts.

MISO will calculate and publish on its website the estimated seasonal PRM for each of the nine subsequent Planning Years, to provide information for long-term resource planning, without establishing any enforceable specific resource planning reserve requirements.

See the Resource Adequacy page on MISO's public website for current and previous LOLE study reports.

3.4.2 LOLE Analysis

MISO will determine the appropriate PRM for each Season of the applicable Planning Year based on the probabilistic analyses of being able to reliably serve MISO's forecasted seasonal Coincident Peak Demand. This probabilistic analysis will utilize a LOLE study which assumes that there are no internal transmission limitations.

MISO's LOLE study will first calculate the annual PRM such that the summation of LOLE across the year is one (1) day in ten (10) years, or 0.1 day per year. The minimum PRM requirement will be determined through LOLE analyses by either adding a negative output unit with no outage rates, or by adding increments of a positive output combustion turbine (CT) Planning Resource with nominal capacity values that correspond with the most recent annual calculation of Cost of New Entry (CONE) as described in Section 6.3 and that have class average outage rates, until a 0.1 day per year solution is reached.

A minimum of 0.01 day per Season LOLE will be used to calculate the seasonal PRMs and LRRs in Seasons with less than 0.01 day per year LOLE risk upon the annual summation of LOLE reaching the 0.1 day per year reliability criteria.

The LOLE model will initially be run with no adjustments to the capacity. If the LOLE in a given Season is less than the reliability criteria day per year for that Season, a negative output unit with no outage rates will be added until the LOLE reaches the reliability criteria for that Season. This is comparable to adding Coincident Peak Demand. If the LOLE is greater than the reliability criteria, proxy units based on a unit of typical size and outage rates will be added to the model until the LOLE reaches the reliability criteria.

MISO will also determine the Local Reliability Requirement (LRR) for each LRZ consistent with the LOLE achieving 0.1 day per year for each LRZ. The minimum amount of capacity above seasonal Coincident Peak Demand required to meet the reliability criteria of a 0.1 day per year LOLE value will be utilized to establish the system-wide seasonal PRMs. The minimum amount of capacity above the seasonal Zonal Coincident Peak Demand required to meet the reliability criteria of a 0.1 day per year LOLE value will be utilized to establish the seasonal LRR for each LRZ. When determining LRRs, risk-deficient Seasons will have a minimum reliability criteria of 0.01 LOLE per Season.

3.4.3 Loss of Load Expectation (LOLE) Working Group

MISO establishes seasonal Unforced Capacity requirements applicable in the Planning Resource Auction (PRA) based on LOLE probabilistic analyses conducted by MISO Resource Adequacy and in coordination with members of the LOLE Working Group (LOLEWG). The duties of the working group are to help guide MISO in implementing the study methods outlined in this section. The analyses will conform to the Electric Reliability Organization (ERO) standards, including those established by applicable Regional Entities for reliability and resource adequacy. The LOLEWG will review and provide recommendations to MISO on the methodology and input assumptions to be used in performing the LOLE analyses, as well as reviewing the results of the LOLE analyses and related sensitivity cases. MISO will be the entity ultimately responsible for conducting the LOLE study and determining the seasonal PRMs, except as set forth in Section 3.4.5.

3.4.4 Generator Outage Data for LOLE Study

The probabilistic study will use a LOLE model capable of sequential Monte Carlo simulation. Primary inputs are the generation data submitted to MISO through the PowerGADS tool and forecasted Demands provided as described above in this Section 3. If applicable to the generator type, Asset Owners are obligated to report outage event data as well as Generator Verification Test Capacity (GVTC) for Generation Resources and External Resources through the PowerGADS tool in the MISO Market Portal. Annualized planned outage rates and seasonal forced outage rates are developed for each applicable resource from the submitted outage event data and, together with the capabilities of each resource, are the key generator inputs to the LOLE model. Outage parameters for the LOLE model are established using outage event data from the past five calendar years, as submitted to PowerGADS.

The LOLE study will account for all system-wide forced outage causes captured in the EFORd metric. The EFORd term is defined as:

> Equivalent Forced Outage Rate while in Demand (EFORd): A measure of the probability that a generating unit will not be available for the applicable Season due to forced outages or forced deratings when there is Demand on the unit to generate.

More information on EFORd calculations can be found in Appendix I of this BPM.

3.4.5 State Authority to Set PRM

The only entity other than MISO that may establish a PRM for any Season during the Planning Year is a state regulatory authority regarding those regulated entities under their jurisdiction. If a state regulatory authority establishes a minimum seasonal PRM for the LSEs under their jurisdiction, then that state-set seasonal PRM would be adopted by MISO for jurisdictional LSEs in such state. Other entities, such as reserve sharing groups or NERC regional entities, do not have the authority to establish a seasonal PRM under Module E-1. MISO will translate any state-set seasonal PRM into the same terms as MISO's seasonal PRM (e.g., utilizing a UCAP basis) to facilitate comparison and compliance with PRMR.

MISO will perform the Loss of Load Expectation (LOLE) study to establish the seasonal PRM and publish the results by November 1 preceding the Planning Year. State regulatory authorities choosing to instead elect a state set seasonal PRM must notify MISO in writing by December 1 for the upcoming PRA. The notice shall be from an authorized representative of the state regulatory authority and include the seasonal PRMs, a list of those LSEs to which the seasonal PRMs apply, and a statement that the entities to which the seasonal PRM applies have been duly notified. In scenarios where an LSE crosses state boundaries and one of the states opts to set its own seasonal PRM, the state regulatory authority must work with the impacted LSEs to submit to MISO the pro-rata distribution of seasonal Coincident Peak Forecasts and seasonal Zonal Coincident Peak Forecasts among the states.

Any disputes regarding the applicability of the seasonal PRM information submitted by a state regulatory authority and an affected entity shall be resolved in accordance with applicable dispute resolution measures established by the state regulatory authority. If the state regulatory authority makes any changes to information initially submitted to MISO as a result of such a dispute, the changed information shall be submitted to MISO by the state regulatory authority on or before December 31. If no such changes are submitted, the original information submitted by the state regulatory authority will be used by MISO.

MISO shall update the MECT with the state-set seasonal PRM by January 31.

4 Qualifying and Quantifying Planning Resources

4.1 Overview

This section identifies the qualification requirements for each type of Planning Resource.

All Planning Resources that qualify will have a SAC value determined by MISO. The benefits of SAC include:

- Fair recognition of the contribution each unit provides towards Resource Adequacy;
- Market signals that will promote generating unit availability performance; and in turn, the improved system availability will promote improved regional Resource Adequacy; and
- Supporting bilateral trades by recognizing the SAC value of each resource, while shifting the resource performance risk to owners of Planning Resources, where such risk more properly belongs.

Planning Resources consist of Capacity Resources, Load Modifying Resources, and Energy Efficiency Resources. Capacity Resources consist of Generation Resources, Electric Storage Resources, External Resources, and Demand Response Resources. Load Modifying Resources consist of Behind the Meter Generation and Demand Resources. Energy Efficiency Resources are resources registered with MISO that permanently reduce electricity Demand. A Hybrid Resource may also qualify as a Planning Resource to the extent that such Hybrid Resource is a Generation Resource or Capacity Resource.

Capacity Resources backed by behind-the-meter-generation that have met all requirements to supply capacity in the MISO Resource Adequacy construct will have SAC MWs calculated based on data submitted by the Asset Owner, as described in the Appendix H - Non-Schedule 53 Seasonal Accredited Capacity (SAC) Calculations for Planning Resources - of this document. BTMG, DR, Energy Efficiency Resources, and External Resources must follow the registration procedures documented in the applicable subsections of this document to be eligible to supply capacity in the MISO Resource Adequacy construct.

Generation Resources backed by behind-the-meter-generation that have not provided at least one Season of historical performance data will have their SAC calculated for them after they are registered in MISO's Commercial Model, provided that the Resource meets the Capacity Resource Module E-1 requirements. Planning Resources that are pseudo-tied between MISO Local Balancing Areas will be modeled in the Local Resource Zone based on the LBA in which they are physically located. The following table outlines the relationship and key attributes of the Planning Resource types that are committed to providing capacity.

	Planning Resource				
	Capacity Resource		Load Modifying Resource		Energy Efficiency Resource
	Generation, ESR, and External	Demand Response Resources	BTMG	Demand Resource	
Capacity Verification	X	X	X	X	X
Must Offer	X	X			
GADS Data Entry	X	X	X		
Must Respond to Emergency Operating Procedures	X	X	X	X	

4.2 Planning Resources

4.2.1 Generation Resource, but not Dispatchable Intermittent Resource or Intermittent Generation

4.2.1.1 *Qualification Requirements*

Generation Resources may qualify as Capacity Resources provided that:

- They are registered with MISO as documented in the Market Registration BPM.
- Generation Resources must be deliverable to Load within MISO’s Region. The deliverability of Generation Resources to Network Load within MISO’s Region shall be determined by System Impact Studies pursuant to the Tariff that are conducted by MISO, which consider, among other factors, the deliverability of aggregate resources of Network Customers to the aggregate of Network Load. Generation Resources that pass the deliverability test receive Network Resource Interconnection Service.
- Generation Resources that do not pass the deliverability test may procure firm Transmission Service (or utilize a GFA) in conjunction with Energy Resource Interconnection Service (ERIS) to meet the deliverability requirements.
  - Firm Transmission Service must either be a Firm Point-to-Point (PTP) Transmission Service Request (TSR) or a Firm Network Integration Transmission Service (NITS) Scheduling Right (SR).
    - NITS SRs should reference the OASIS NITS Application number and Resource Name used in the SR.

  - Firm transmission service (PTP TSR or NITS SR) must cover the entire applicable Season within the Planning Year in total or in aggregate and be submitted in the MECT. The resource is only deliverable to the LBA identified in the Firm Transmission study that grants the NITS SR or PTP TSR.
- Generation Resources with ERIS may participate in MISO's Interim Deliverability Study process as described in BPM-015. The following generic parameters apply for the Interim Deliverability Study:
  - MISO may grant conditional NRIS applicable for the next Planning Year
  - MISO may grant conditional ERIS applicable for the next Planning Year
  - MISO may grant conditional External-NRIS (E-NRIS) applicable for the next Planning Year.
  - MISO may implement a Quarterly Operating Limit (QOL) on a portion of a Generation Resource due to transmission study overloads. MW amount subject to QOL can qualify as capacity in the PRA. The MW amount subject to QOL is not required to procure replacement capacity if the QOL is reduced in a subsequent MISO quarterly study.
- Generation Resources with a Provisional Interconnection Agreement are not qualified to participate in the PRA.
- Generation Resources that were accepted by the Transmission Provider and confirmed by a Network Customer as a designated Network Resource under the OASIS reservation process in place prior to either the initial effective date of the Energy Market in 2005 or that Transmission Owner's integration date are considered as deliverable.
  - This may include Generation Resources that were issued 'local' NRIS through a Generator Interconnection Agreement consistent with Module E-1 Section 69.3.1.g paragraph v. In such instances, 'local' NRIS is processed in similar fashion as ERIS for the purposes of demonstrating deliverability for participation in the Planning Resource Auction. As with resources with ERIS, firm Transmission Service must be demonstrated to cover the entire auction period for the level of participation desired in order to qualify for participation in the PRA.
- Internal purchase power agreements (PPAs) will not be qualified by MISO.
- Generation Resources greater than or equal to 10 MW (based on Generation Verification Tested Capacity (GVTC)) must submit their Generator Availability Data System (GADS) data (including, but not limited to, NERC GADS) into the MISO PowerGADS database through the MISO Market Portal. Quarterly GADS Event and

Performance Data must be submitted by the end of the month following the quarter (April for Q1, July for Q2, October for Q3, and January for Q4). The submitted data must have passed Level 2 Validation without any errors. Units that fail to submit Level 2 Validated quarterly GADS data will be disqualified for participation in the PRA.

- Generation Resources less than 10 MW based upon GVTC are not required to report their GADS data.
- Generation Resources less than 10 MW based upon GVTC that begin reporting GADS data must continue to report GADS data each Planning Year.
- The seasonal XEFORd for new Generation Resources in service less than one full Season will be the seasonal EFORd class average for the resource type. A Generation Resource will use the class average value until 3 consecutive seasonal months of data is available. Forced outage rates are used for the capacity accreditation of non-Schedule 53 Generation Resources.
- Generation Resources that have been retired prior to the Planning Year will not qualify as a Planning Resource.
- Generation Resources that are in approved “Suspension” status qualify as a Planning Resource through the ICAP Deferral process.
- If Generation Resources used to meet Resource Adequacy Requirements retire or suspend during the Planning Year, they must be replaced effective with their change of status date. Generation Resources with approved “Suspension” status must participate as a Planning Resource in the next Planning Year subject to provisions regarding physical withholding in Module D of the Tariff.
- Generation Resources that plan to retire during the Planning Year will be subject to test for Physical Withholding.
- Generation Resources that are or plan to be suspended will be subject to test for Physical Withholding.
- Generation Resources that have been designated as a System Support Resource (SSR) may participate in the PRA.
- Generation Resources must demonstrate capability on an annual basis as described below.
- Generation Resources undergoing conversion to natural gas are not required to submit GVTC prior to returning. Changes in performance will be reflected in the resource’s rolling XEFORd.

When to Perform and Submit a Generation Verification Test Capacity (GVTC)

- Generation Resources, External Resources, ESR, Demand Response Resources backed by behind the meter generation, or Behind the Meter Generation (BTMG) that qualified as Planning Resources for the current Planning Year must submit their GVTC no later than October 31 in order to qualify as a Planning Resource for the upcoming Planning Year. GVTC can be completed by completing a real power test or based on operational data. The GVTC must be completed during the test period of September 1 through August 31 prior to the upcoming Planning Year.
- A real power test is required to demonstrate a modification that increases the rated capacity of a unit, and a revised GVTC should be submitted to MISO no later than March 1 prior to the Planning Year. The initial GVTC, even if a Planning Resource is unable to test and the GVTC is 0, must be submitted by October 31 prior to the Planning Year.
- A real power test is required when returning from a suspended state and the GVTC must be submitted to MISO. A real power test is required when any unit returns to service in MISO after an absence (including but not limited to, catastrophic events, or a period during which it was not qualified as a Planning Resource under Module E-1).
- A real power test is required for Planning Resources in an approved “Suspension” status. If a Planning Resource is unable to complete a real power test, the MP responsible for that Planning Resource must include this item, including timing and cost requirements, when requesting a facility specific reference level.

The GVTC for a new or returning Non-Intermittent Generation resource is due by March 1 prior to the Planning Year unless the GVTC has been deferred via the ICAP Deferral process as described in Section 4.5. See Appendix J **– GVTC Testing Requirements**.

GVTC Test Extension Request

A Market Participant for a Generation Resource required to submit GVTC results must use Reasonable Efforts to submit GVTC results by October 31 prior to the upcoming Planning Year. If circumstances prevent the Market Participant from submitting the GVTC results for the Generation Resource by October 31, the Market Participant must notify the Transmission Provider no later than five (5) Business Days after October 31 and request an extension. The extension request must include a reasonable explanation and justification for missing the deadline, estimated seasonally corrected GVTC values, and an expected completion date prior to the upcoming Planning Year. An extension may also be requested for re-testing and submitting after the October 31 deadline. The estimated seasonally corrected GVTC values are only an estimate to be used in initial SAC posting and the actual test results will be used for the final SAC posting. The Transmission Provider will review each extension request on a case-by-case basis to determine whether to approve or deny the request to extend the GVTC deadline. Denial of an extension will not preclude the Market Participant for the Generation Resource from utilizing the ICAP Deferral process. Test results for Approved GVTC Test Extension Requests must be submitted by January 15 prior to the upcoming Planning Year.

Reporting is accomplished through MISO's PowerGADS reporting system as described in the Net Capability Verification Test User Manual.

4.2.1.2 *SAC Determination*

The SAC values for a Generation Resource are based on an evaluation of the type and volume of interconnection service, GVTC values, the XEFORd value of non-Schedule 53 Generation Resources as described in Appendix H – Non-Schedule 53 Seasonal Accredited Capacity (SAC) Calculations for Planning Resources and Appendix I – XEFORd Calculation, and SAC value for Schedule 53 Resources as applicable and described in Appendix Y – SAC Calculations for Schedule 53 Resources.

Generation Resources relying either fully or in part on Energy Resource Interconnection Service (ERIS) coupled with firm Transmission Service to demonstrate deliverability must procure firm Transmission Service up to the Resource's ICAP level in order to receive their full SAC allocation.

If a Generation Resource's procured firm Transmission Service coupled with ERIS is less than the Generation Resource's ICAP value, the SAC allocation would be pro-rated based on Tariff Module E-1 Section 69A.4.5.

The SAC methodology is implemented to address the fact that not all Generation Resources contribute equally to Resource Adequacy. By adjusting the capacity rating of a unit based on its availability, SAC provides a means to recognize the relative contribution that each resource makes towards Resource Adequacy. When the PRM requirement is similarly adjusted by the weighted average EFORd of all the pooled resources, the generating units with better than average availability will reflect higher values than units with below average availability.

In order for a Generation Resource to convert its entire calculated Total SAC into Zonal Resource Credits, the Generation Resource must be fully deliverable up to its ICAP. Deliverability is determined by any combination as outlined in Module E-1 Section 69A.3.1.g of the Tariff.

If a Generation Resource is not fully deliverable up to its ICAP, the resource will be eligible to convert a value less than the Total SAC into Zonal Resource Credits as outlined in Appendix H – Non-Schedule 53 Seasonal Accredited Capacity (SAC) Calculations for Planning Resources, as well as in Appendix Y – SAC Calculations for Schedule 53 Resources.

4.2.1.3 *Intermittent Generation and Dispatchable Intermittent Resources - Qualification Requirements*

Intermittent Generation and Dispatchable Intermittent Resources are subclasses of Generation Resources and may qualify as Capacity Resources if they meet the same qualification requirements in Sec. 4.2.1.1 Qualification Requirements and the alternate GADS reporting procedure as described below:

> For existing Intermittent Generation and Dispatchable Intermittent Resources (eg. run-of-river hydro, solar, biomass), Market Participants must supply MISO with a minimum of one entire Planning Year of hourly net output data for each season in which the resource would be accredited.
>
> For existing Intermittent Generation and Dispatchable Intermittent Resources not classified as run-of-river hydro or wind, Market Participants may submit up to three (3) Planning Years of hourly net output data, for a total of 9 months considered for each seasonal lookback period, during typical seasonal peak hours, where the typical seasonal peak hours are hours ending in 15, 16, and 17 EST for the Summer, Fall and Spring Seasons, and hours ending in 8, 9, 19, and 20 EST for the Winter Season. Seasonal accreditation for existing Intermittent Generation and Dispatchable Intermittent Resources not classified as run-of-river hydro or wind is determined as an average of the hourly net output.
>
> For Intermittent Generation and Dispatchable Intermittent Resources classified as run-of-river hydro, Market Participants may submit up to fifteen (15) Planning Years of hourly net

output data, for a total of 45 months considered for each seasonal lookback period, during typical seasonal peak hours, where the typical seasonal peak hours are hours ending in 15, 16 and 17 EST for the Summer, Fall and Spring Seasons, and hours ending in 8, 9, 19 and 20 EST for the Winter Season. Seasonal accreditation for fun-of-river hydro resources is determined as a median of the provided hourly net output.

For resources on qualified extended outage where data does not exist for some or all of the previous historical seasonal months, a minimum of 30 consecutive days' worth of historical net output data during the relevant typical seasonal peak hours, must be provided prior to participating in the PRA.

New Intermittent Generation or Dispatchable Intermittent Resources that do not have a minimum of 30 consecutive days' worth of seasonal historical operating data during the typical seasonal peak hours may participate in the PRA and will receive class average accreditation values if the resource will be in operation by the start of a Season in the applicable Planning Year.

4.2.1.4 *Dispatchable Intermittent Resources and Intermittent Generation Resource - SAC Determination*

The Seasonal Accredited Capacity (SAC) for Intermittent Generation and Dispatchable Intermittent Resources will be determined by MISO based on historical performance, availability, and type and volume of Interconnection Service. Examples of SAC calculations for these resources can be found in Appendix V – Solar and Run-of-River Hydro Capacity Credit.

Intermittent Generation and Dispatchable Intermittent Resources that are powered solely by wind will have their SAC values determined based on Interconnection Service volumes and their respective wind capacity credit established via seasonal Effective Load Carry Capacity (ELCC) analyses as described in Appendix A – Wind Capacity Credit.

1.1.1.1.1 4.2.1.5 Wind Capacity Credit

MISO calculates specific wind capacity credit (%) for each wind resource and applies it to its registered maximum capability (MW) in the Commercial Model or its registered Capacity (MW) through the LMR or External Resource registration process. MISO uses historical wind availability information to calculate a seasonal Effective Load Carrying Capacity (ELCC) to determine a wind capacity credit. Wind capacity credits are determined for each individual wind resource based on its average capacity factor during MISO’s top eight (8) coincident peaks that occurred during the Season for the previous three Planning Years.

A new wind resource with no commercial operation history during the Season will receive a wind capacity credit equivalent to the MISO system wide wind capacity credit from the seasonal Effective Load Carrying Capacity (ELCC) analyses for their initial Planning Year, and thereafter metered data will be used to calculate its future resource-specific wind capacity credit.

If an existing wind resource has no historical metered data available, or was inoperable for a Season, then the existing wind resource will receive a seasonal capacity credit of 0%.

An increase in unit capacity for Intermittent Generation and Dispatchable Intermittent Resources that are solely powered by wind after the SAC values have been established will require written notification from the Market Participant to a member of the Resource Adequacy department to update the values. This notification is due by March 1 prior to the applicable Planning Year.

BTMG wind will have their SAC values determined from their historical net output during periods of MISO system peak Demand for the three Planning Years prior.

For more information regarding the methodology for calculating wind capacity credits, see Appendix A – Wind Capacity Credit of this BPM and MISO’s wesbite (misoenergy.org / Planning / Resource Adequacy / PRA Documents / select the appropriate Planning Year) for the Wind and Solar Capacity Credit Report. Additionally, Appendix H – Seasonal Accredited Capacity (SAC) Calculations for Planning Resources details the determination of convertible SAC using the deliverability-adjusted capacity factor.

1.1.1.1.2 4.2.1.6 Solar Capacity Credit

Solar resources will have their SAC values determined based on the three (3) most recent Planning Years of historical average net output during typical seasonal peak hours, where the typical seasonal peak hours are hours ending in 15, 16, and 17 EST for the Summer, Fall and Spring Seasons, and hours ending in 8, 9, 19 and 20 EST for the Winter Season.

Solar resources that have been upgraded or returning from extended outages shall submit all operating data for the prior Season with a minimum of 30 consecutive days to have their capacity registered with MISO.

Solar esources with less than 30 days of metered values would receive seasonal class accreditation for their initial Planning Year in operation. Seasonal class accreditation for a new solar resource in the Summer, Fall, and Spring Seasons is 50% and 5% for the Winter Season. Refer to Appendix V - Solar and Run-of-River Hydro Capacity Credit for additional examples and determination of convertible SAC.

4.2.2 Use Limited Resources

4.2.2.1 *Use Limited Resources – Qualification Requirements*

Use Limited Resources are defined as Generation Resources or External Resource(s), that due to design considerations, environmental restrictions on operations, cyclical requirements (such as the need to recharge or refill), or for other non-economic reasons, are unable to operate continuously, but are able to operate for a minimum set of consecutive operating hours. A Capacity Resource may be defined as a Use Limited Resource if it:

- Is capable of providing the Energy equivalent of its claimed Capacity for a minimum of at least four (4) continuous hours each day across MISO's peak;
- Notifies MISO of any outage (including partial outages) and the expected return date from the outage;
- Demonstrates GVTC and submits the results to MISO;
- Is a dispatchable resource(s) in which the unit(s) have physical limitations;
- Identifies the resource as use limited when registering the asset, subject to MISO approval.
    - MISO will review the conditions of the asset or PPA to determine if the resource qualifies as a Use Limited Resource.
    - MISO will consider how the resource has historically operated and any proposed changes in its operation to determine if the resource qualifies as a Use Limited Resource.

Use Limited Resources are a subclass of Generation Resources and may qualify as Capacity Resources if they meet the same qualification requirements in Section 4.2.1.1 Qualification Requirements.

- MISO may qualify a resource classified as a Diversity Contract as a Use Limited Resource seasonally provided the resource meets all of the requirements of both an External and Use Limited Resource.
- Use Limited Resources must demonstrate GVTC on an annual basis as described in Section 4.2.1.1 Qualification Requirements. See Appendix J – GVTC Testing Requirements for additional details.
- Use Limited Resources with any new or untested additional capacity are eligible for the ICAP Deferral Process as described in Section 4.5 ICAP Deferral.

4.2.2.2 *Use Limited Resources – SAC Determination*

The SAC values for a Use Limited Resource are based on an evaluation of the resource type and volume of Interconnection Service, GVTC value, and XEFORd value of such Use Limited Resource as described in Appendix H – Non-Schedule 53 Seasonal Accredited Capacity (SAC) Calculations for Planning Resources.

In addition, a Use Limited Resource with contract provisions that prevent the resource from meeting its Must Offer requirement will have a decrease in the SAC calculation to the extent that the contract provisions are less than the required Must Offer requirement of 4 hours across the forecasted peak for each day during the registered Season. Use Limited Resources unable to meet the Must Offer requirements will have their SAC prorated relative to the percentage of hours meeting the Must Offer requirement and to the must offer hours for the Season.

4.2.3 External Resources

MPs may register an External Resource by providing the information listed below to MISO Resource Adequacy to qualify such resources as Capacity Resources. External Resources are registered through the MECT tool for each Planning Resource Auction and reviewed and approved by MISO Resource Adequacy staff. An MP that owns an External Resource or contracts for an External Resource through a power purchase agreement (PPA) may register its External Resources. An MP must denote within the registration if the External Resource being registered is a Use Limited Resource. External Resources that are also Use Limited Resources must meet all requirements in Section 4.2.2.1 “Use Limited Resources – Qualification Requirements” and be approved by MISO Resource Adequacy.

An MP must submit the completed registration form for existing External Resources in the MECT by February 1 prior to the upcoming Planning Year. New External Resource registrations or existing registrations with increased capacity are to be submitted in the MECT by March 1 prior to the upcoming Planning Year. Existing registrations with increased capacity are required to submit the original GVTC by October 31 prior to the upcoming Planning Year. The completed registration form requires the MP to certify that the registration information is accurate and that the qualifying MWs from External Resources are not being registered by another party. MISO will notify the MP within 15 days after a completed registration form is received regarding accreditation of the External Resource. MISO will review the External Resource registration form for completeness and accuracy, and will notify the MP when it has been determined whether or not the External Resource qualifies for the applicable Planning Resource Auction, or whether there are any outstanding deficiencies in the registration.

4.2.3.1 *External Balancing Authority Qualification Options*

MISO has established host/external Balancing Authority qualification criteria that applies to Balancing Authorities that could impact Energy schedules associated with qualifying External Resources. The Balancing Authority qualification criteria ensures that Energy schedules corresponding to the qualifying External Resources will only be interrupted in a manner that provides consistency, transparency, and reliability.

An executed PPA or External Resource owned prior to April 3, 2014 will continue to qualify as a Planning Resource for the initial full term of the PPA or ownership of the resource, if it is only interruptible as a last resort under Requirement 2 of NERC Standard EOP-011. A Diversity Contract executed prior to April 3, 2014 will continue to qualify as a Planning Resource, if it is only interruptible as a last resort under Requirement 2 of the NERC Standard EOP-011 between June 1 and September 30.

Resources or PPAs that are submitted to MISO for qualification as External Resources must have their corresponding Energy schedules flow through host/external Balancing Authorities that comply with one of the three options outlined below to qualify.

A. Scheduled Interruption Linked to Performance of a Specific Generator in the External Balancing Authority

In the case of unit specific sales, if the MISO Balancing Authority Area is experiencing an Energy Emergency, the external Balancing Authority will not interrupt the schedule from the External Resource unless the generator being used to serve a unit-specific sale has a forced or planned outage.

This type of External Resource would be treated similarly to internal generation because those internal resources constitute Capacity Resources, even when they can be interrupted for forced or planned outages. This provision ensures that the generator delivering the Energy in support of the PPA can be specifically identified.

B. Slice-of-System Curtailed Pro-Rata with Load in the Source Balancing Authority when Source Balancing Authority is in Emergency Procedures
PPA or External Resource fleets in this category will qualify as Planning Resources, so long as the associated capacity schedule 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.

Under this situation and as an example, 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.

C. Slice-of-System in a Balancing Authority that Coordinates Planning Reserve Qualifications and Shares Emergency Responsibilities with MISO's Balancing Authority
In addition to the slice-of-system treatment noted in category B above, a slice-of-system PPA or External Resource fleet can qualify as External Resources under this category, and MISO and the external Balancing Authority 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. This qualification category has several requirements for the host Balancing Authority:

1. It must be in MISO's Reliability Coordination Area.
2. It must share Operating Reserves with the MISO Balancing Authority.
3. It must have a Seams Operating Agreement with MISO containing several features. The Seams Operating Agreement must:
    a. Ensure that the host Balancing Authority has established planning reserve processes and criteria similar to MISO.
    b. Specify the actions that will be taken by both entities, MISO and the host Balancing Authority, during Emergency Procedures prior to implementing Load Shedding.

c. Specify that the host Balancing Authority will submit load estimates to MISO in a similar manner as submitted by other Load Serving Entities under Module E-1, provide generator testing data for all resources used to serve firm requirements of the host Balancing Authority, and provide transparency to such resource plans in the form of a FRAP or RBDC Opt Out, pursuant to Module E-1.

With these requirements in place, when both Balancing Authorities 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.

For example, if the load of an external Balancing Authority in capacity emergency is 3,000 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.

4.2.3.2 *External Resources - Qualification Requirements*

The following information will be required to register an External Resource:

- Demonstration of firm Transmission Service from the External Resource to the MISO border, and that;
- Firm Transmission Service has been obtained within MISO to deliver the Capacity Resource MWs seeking to be qualified from the External Resource(s) to the Load Zone CPNode within MISO. The Load Zone CPNode will be interpreted as the Local Balancing Authority (LBA) that MISO’s OASIS reservation sinks in for Network Customers, or either;
    - The External Resource has Network Resource Interconnection Service under Attachment X.
    - The External Resource was accepted by the Transmission Provider and confirmed by a Network Customer as a designated Network Resource under the OASIS reservation process in place prior to either the initial effective date of the Energy Market in 2005 or that Transmission Owner’s integration date.
- External Resources may procure firm Transmission Service (or utilize a Grandfathered Agreement) to meet the deliverability requirements.
    - Firm Transmission Service must either be in the form of a firm Point-to-Point (PTP) Transmission Service Request (TSR) or firm Network Integration Transmission Service (NITS) Scheduling Rights (SR).

    - NITS Scheduling Rights should reference the OASIS NITS Application Reference number or Assignment Reference number, and Resource Name of the Scheduling Right.
  - Firm Transmission Service (PTP TSR or NITS SR) must cover the entire applicable Season within the Planning Year in aggregate and be submitted in the MECT once approved. The resource is only deliverable to the LBA identified in the firm transmission study that grants the NITS SR or PTP TSR.
- Demonstrates that any External Resources or portions of External Resources being registered as Capacity Resources to serve the Load of the LSE are not otherwise being used as capacity resources in any other RTO/ISO or in another state resource adequacy program, is available in the event of an Emergency, and performs an annual GVTC test and reports the data via MISO's PowerGADS (or alternatively, submits a populated Non-GADS Performance Template to the MECT) by October 31 for returning resources and March 1st for new resources.
- External Resources that have been retired prior to the applicable Planning Year will not qualify as a Planning Resource.
- If External Resources used to meet Resource Adequacy Requirements retire or suspend during the Planning Year, they must be replaced effective with their change of status date.
- External Resources greater than or equal to 10 MW based on their GVTC must submit generator availability data to PowerGADS through the MISO Market Portal. This 10 MW threshold applies to individual generator sizes and not to contracted capacity values in PPAs and does not apply to Intermittent Resources or Intermittent Generation. Quarterly GADS Event and Performance Data must be submitted by the end of the month following the quarter (April for Q1, July for Q2, October for Q3, and January for Q4). The submitted data must pass Level 2 Validation without any errors. Units that fail to submit Level 2 Validated quarterly GADS data will be disqualified for participation in the PRA.
- External Resources less than 10 MW based upon GVTC that begin reporting GADS data must continue to report such information.
- Border External Resources and Coordinating Owner External Resources will be modeled, for LOLE and PRA purposes, in the LRZ where their firm Transmission Service crosses the MISO border. All remaining External Resources will be modeled in an External Resource Zone based on their associated External Balancing Authority.

- A PPA may qualify as a Planning Resource if it is valid for the entire Season or is unavailable for no greater than thirty-one (31) days in total for each Season it is being used. If an amended PPA or interim operating plan exists for the Season in which the MP seeks capacity credit, this will be used in calculating the capacity value provided the PPA or interim operating plan contains a capacity amount.
- For a PPA to qualify as a Capacity Resource, it must demonstrate that it complies with the requirements found in Section 69A.3.1.c of the Tariff.
- External Resources that are in service and registering as a Planning Resource for the first time must submit GVTC, and if greater than or equal to 10 MW based on GVTC must submit GADS data (if applicable) prior to being approved as a Capacity Resource.
- An External Resource registration needs to point to a Load Zone CPNode. Along with firm Transmission Service, this acts as verification of deliverability to the load being served by the External Resource.
- All External Resources being used as a Planning Resource are required to perform a real power test according to MISO’s Generator Test Requirements and submit the GVTC data to MISO’s PowerGADS no later than October 31 to qualify as a Planning Resource. The test shall be performed between September 1 and August 31 of the prior Planning Year and be corrected to the average temperature of the date and times of MISO’s coincident seasonal peaks, measured at or near the generator’s location, for the last 5 years, or provide past operational data that meets these requirements to determine its GVTC and submit its GVTC data to MISO’s PowerGADS.
    - Resources that do not submit real power tests through GADS must submit a populated Non-GADS Performance Template via MECT as substitute. Existing resources must do this by October 31, while new resources should submit this template by March 1.
- External Resources undergoing gas conversion are not required to submit GVTC prior to returning.
- MPs who register a slice-of-system External Resource are responsible for ensuring proper outage and GVTC data is submitted to MISO through PowerGADS, unless a populated Non-GADS Performance Template is submitted via MECT for the External Resource. This information is due no later than October 31 of the prior Planning Year to qualify as a Planning Resource.

When to Perform and Submit a Generation Verification Test Capacity (GVTC)

- External Resources that qualified as Planning Resources for the current Planning Year shall submit their GVTC data no later than October 31 in order to qualify as a Planning Resource for the upcoming Planning Year. GVTC can be met by a real power test or past operational data must be provided during the test period between September 1 and August 31 prior to the upcoming Planning Year.
- A real power test is required to demonstrate a modification that increases the rated capacity of a unit, and then submit the revised GVTC to MISO by March 1. The initial GVTC should be submitted by October 31 prior to the Planning Year.
- A real power test is required when returning from a suspended state and the results of the GVTC should be submitted to MISO via the PowerGADS system.
- A real power test is required when any unit returns to MISO after an absence (including but not limited to, catastrophic events, or not qualified as a Planning Resource under Module E-1) or being qualified as a Planning Resource for the first time and must be submitted to MISO no later than March 1 prior to the Planning Year.
- The GVTC for a new External Resource is due before a Market Participant registers the new External Resource in the MECT and must be submitted by March 1 prior to the upcoming Planning Year.
- See Appendix J – GVTC Testing Requirements.
- External Resources with any new or untested additional capacity are eligible for the ICAP Deferral process as described in Section 4.5 ICAP Deferral.
- Reporting is accomplished through MISO’s PowerGADS reporting system as described in MISO’s Capacity Verification Manual, which is located on MISO’s PowerGADS > Tools > Guide.

4.2.3.3 *Submission of new External Resource Registrations*

A Market Participant must register their new External Resource via the Registrations screen in the MECT by March 1 prior to the Planning Year. To guarantee new resources can be used in an LSE’s FRAP or RBDC Opt Out, registrations must be submitted no later than February 15 prior to the Planning Year. The registering entity must be a Market Participant prior to registering an External Resource. Any entity that is not a Market Participant, but desires to register an External Resource, must contact the Client Services and Readiness team at MISO Help Center (https://help.misoenergy.org/) to become a Market Participant. The resource information submitted through the Registrations screen will require the Market Participant to certify that the registration information is accurate, complete, and that the qualified MWs from the External Resource are not being registered by another party or used in another Balancing Area for capacity purposes. Appendix F, External Resources, contains the information that must be submitted by an MP through the MECT on the Registrations screen.

4.2.3.4 *Amendments to Accredited External Resource Registration Data*

The Market Participant can amend the registration for an External Resource for an upcoming Planning Year by providing MISO notification no later than March 1 if the original registration was submitted by the deadline.

4.2.3.5 *Renewal of External Resource for Subsequent Planning Years*

Renewed External Resource registrations must be submitted by February 1 prior to the upcoming Planning Year. MISO will review the renewed External Resource registration information for completeness and accuracy and ensure it complies with the qualification requirements for an External Resource. MISO will notify the Market Participant within 15 days after the renewed registration form has been submitted as to whether or not the External Resource has been accredited as an External Resource, or whether there are any deficiencies within the registration that must be corrected. If the External Resource is accredited as an External Resource, it will be given a unique name for tracking purposes and made available in the MECT for use by the MP during the applicable Planning Year.

4.2.3.6 *Review of Power Purchase Agreements*

Market Participants that have entered into power purchase agreement(s) for future Planning Years must provide to MISO the documentation that demonstrates the active power purchase agreement and MISO will make a preliminary determination of whether the agreement(s) would qualify as External Resources from power purchase agreement(s) as set forth in sections 69A.3.1.c.(i) through 69A.3.1.c.(v) of the Tariff. PPAs meeting these requirements are considered conforming. Market Participants must submit this documentation as part of the External Resource registration process and will be reviewed by MISO Resource Adequacy staff.

MISO Resource Adequacy and Legal staff will review the submitted agreement(s) and respond within 60 days of receipt of the request. MISO will provide written confirmation as to whether the contract meets the current Tariff requirements. Any such determination is based upon the existing version of the Tariff, which may be modified from time to time subject to the acceptance of such modifications by the Federal Energy Regulatory Commission. The Market Participant requesting an advanced review of their agreements will need to follow the procedures applicable to the planning period for which such External Resource is intended to be relied upon to meet capacity requirements. This includes the provision of the appropriate GVTC and GADS data and other requirements then in effect for registering an External Resource as set forth in the Tariff and in Section 4.2.3 External Resources, to have the External Resource modeled in the MECT and qualified as a Capacity Resource. Any subsequent modifications to the PPA will be subject to a new confirmation determined by MISO regarding the portion of the term.

PPAs that do not meet the requirements of Section 69A.3.1.c (i) through (v) of the Tariff are considered non-conforming and must provide MISO with all the following information in order to qualify as a Capacity Resource:

a) The PPA was executed prior to October 20, 2008;
b) NERC regional entity has accredited the PPA to satisfy resource adequacy requirement provisions;
c) The PPA has provided reliable capacity to the Transmission Provider Region;
d) The supplier(s) of capacity in the PPA commit(s) to provide the capacity to an LSE in the Transmission Provider Region in a defined amount at a defined location based upon the supplier(s)' portfolio of generation assets;
e) Energy from the PPA cannot be interrupted for economic reasons and will only be interrupted for force majeure type conditions as a last resort during Emergency conditions;
f) Either the purchaser(s) or the supplier(s) of capacity in the PPA has committed to offer energy into the Day-Ahead Energy and Operating Reserves Market and all pre-Day-Ahead and the first post Day-Ahead Reliability Assessment Commitment processes for all periods for which Energy is available under the PPA, consistent with the must offer provisions in Section 69A.5;
g) The physical resource(s) backing the PPA are identified by the supplier of the PPA;
h) The portion of the physical resources backing the PPA has not otherwise been registered by any other entity as Capacity Resources in the MISO Region or as capacity resources in any other region; and
i) If the PPA is renewed, the PPA will be modified to comply with the terms of Section 69A.3.1.c (i) through (v) and (vii).

4.2.3.7 *External Resources – SAC Determination*

The Seasonal Accredited Capacity (SAC) for External Resources will be accredited based on seasonal GVTC values and seasonal Transmission Service, and seasonal XEFORd$_d$ (where applicable) values of such External Resources, are based on the methodology documented in

Appendix H – Non-Schedule 53 Seasonal Accredited Capacity (SAC) Calculations for Planning Resources. MISO will determine SAC values for External Resources that are Intermittent Generation as described in Section 4.2.1.4 – Dispatchable Intermittent Resources and Intermittent Generation Resource – SAC Determination. External Resources, from PPAs, with varying monthly capacity values will be credited with the monthly capacity value of the contract that corresponds with the seasonal peak Demand month, unless the resource(s) supporting the PPA are considered Intermittent Generation.

4.2.3.8 *Dually Connected Border External Resources*

Border External Resources can have interconnection facilities which connect to multiple LRZs. In those instances, these resources would be modeled in a single Local Resource Zone with which the resource has the greatest connectivity. Connectivity is measured using shift factor analysis that evaluates the generator’s impact on flows on the Transmission System. The analysis is performed based on the latest models and input files used in support for the upcoming PRA. The study model is created by ramping the resource up and sinking the output to the MISO footprint. Line loadings in the connected LRZs are compared with those of the base model to determine the impact of the unit. The study will include consideration of tie line flow, impact on historical constraints, and impacts on the connected LRZs as a whole. Results of the analysis will be posted on MISO’s website prior to the Planning Resource Auction. Details regarding the resource’s impact on individual transmission lines will not be published.

4.2.3.9 *SAC Determination – Fixed Capacity PPA*

Market Participants may register External Resources where the supplier has guaranteed delivery of a fixed MW value of capacity. Market Participants must contact MISO Resource Adequacy for a review of this type of PPA. Subsequent approval of such contracts by MISO results in an accreditation of XEFORd and the SAC will be set equal to the ICAP of the External Resource registered. PPAs backed by an Intermittent Resource do not qualify as this type of PPA.

4.2.3.10 *SAC Determination – Full Requirements PPA*

Market Participants may register External Resources to model a full requirements power purchase agreement with a counterparty. This results in the ICAP of the External Resource being increased for the Planning Reserve Margin, applicable Transmission Losses, and the Forced Outage rating. This adjusted ICAP will be used in the External Resource’s SAC and Must Offer calculations. Market Participants must contact MISO Resource Adequacy for a review of these types of contracts.

$$ICAP_{Adjusted} = \sum_{GADS\ Resources} \left(\frac{ICAP_i\ x\ (1 + PRM_{LRZ})\ x\ (1 + TL_{LBA})}{(1 - \ XEFORd_i)} \right)$$

Where:
$ICAP_{adjusted}$: PPA Percent x Resource ICAP or amount owned by MP
$XEFORd_i$: XEFORd of selected GADS resource
PRM_{LRZ}: Planning Reserve Margin Requirement for the Local Resource Zone that the External Resource will be serving Load in
TL_{LBA}: Transmission Losses for the LBA that the External Resource will be serving load in

4.2.4 DRR Type I and Type II – Qualification Requirements

Demand Response Resources (DRR) Type I and Type II may qualify as Capacity Resources provided that the following criteria are met. (All references to generation availability and testing in this section pertain to DRRs backed by generation.):

- DRR Type I and Type II backed by behind the meter generation (that are not Intermittent Generation and Dispatchable Intermittent Resources) must submit generator availability data (including, but not limited to, NERC GADS) into the PowerGADS tool through the Market Portal.
- DRR Type I and Type II must demonstrate seasonal capability on an annual basis. Verification of DRR Type I and Type II capability will be in accordance with the guidelines established by the applicable Regional Entity, unless superseded by specific verification guidelines set by the applicable state authorities.
- DRRs may qualify as Capacity Resources if they meet the same qualification requirements in Section 4.2.1.1 Qualification Requirements.
- DRRs must demonstrate seasonal corrected GVTC on an annual basis as described in Section 4.2.1.1 Qualification Requirements. See Appendix J – GVTC Testing Requirements for additional details.
- DRRs with any new or untested additional capacity are eligible for the ICAP Deferral Process as described in Section 4.5 ICAP Deferral.

4.2.4.1 *DRR Type I and Type II – SAC Determination*

MISO will determine the SAC value for each Demand Response Resources backed by behind the meter generation based on an evaluation of GVTC value and XEFORd values of such generator. If such behind the meter generation facility is interconnected to the Transmission

System, MISO will consider the type and volume of the interconnection service when determining the Unforced Capacity. If GADS data is not required to be submitted by the MP, then a class average EFORd of the resource type will be used to calculate the forced outage rate (XEFORd) for the resource.

A XEFORd value of zero will be applied to all DRR that interrupts or controls load but is not backed by behind the meter generation.

SAC MW options for units with derates prior to the GVTC test date is further explained in Appendix J.4 – Generation Verification Test Capacity During a Derate.

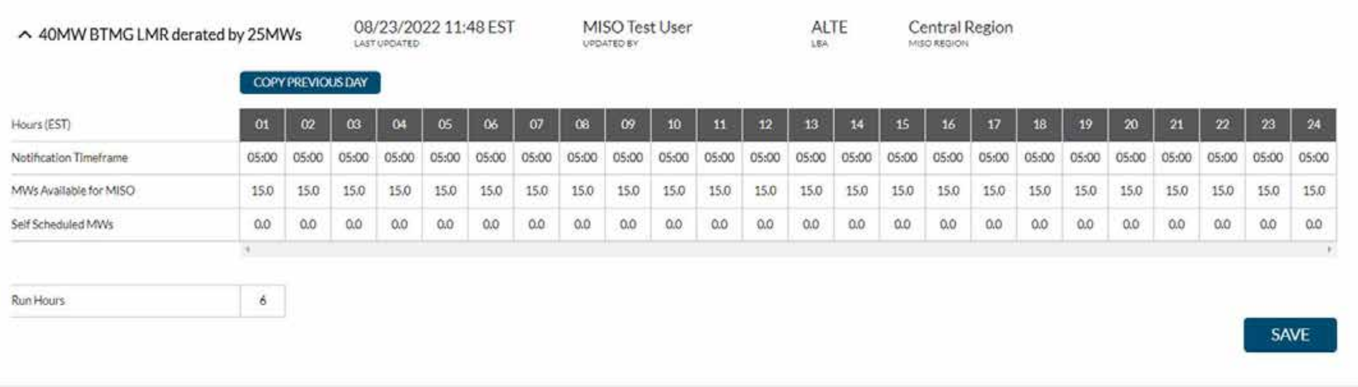
4.2.5 Load Modifying Resource Obligations and Penalties

Load Modifying Resources (LMRs) consist of Demand Resources (DR) and Behind the Meter Generation (BTMG). A Demand Resource shall mean a resource registered with MISO defined as Interruptible Load or Direct Load Control Management and other resources that result in additional and verifiable reductions in end-use customer Demand during an Emergency.

Behind the Meter Generation is defined as a generation resource used to serve wholesale or retail load that is located behind a Load Zone CPNode. BTMG is not included in MISO's Setpoint Instructions. An LMR that exclusively relies only on a generator to accomplish the load reduction and remains synchronously connected to the grid, or injects onto the grid, must register as a BTMG. In scenarios where LMRs represent an interruptible program that disconnects the load from the grid and activates a local backup generator to provide power on an asynchronous island, independent from the grid, a DR registration may be used.

BTMG and DR requirements to qualify as an LMR are covered in Sections 4.2.6 - BTMG Qualification Requirements and 4.2.7 - Demand Resource (DR) Qualification Requirements of this BPM.

LMRs differ from Capacity Resources in that they do not have a must offer requirement, however, they must be available for use within MISO as defined in this BPM during Emergency events (including capacity and transmission events) declared by MISO unless unavailable because of maintenance, Force Majeure or other reasons outlined in this BPM. LMRs communicate to MISO their availability through the Demand Side Resource Interface (DSRI). MPs with LMR assets must provide updates to availability specific to each LMR that is listed in the DSRI. The DSRI is populated with the monthly Demand Reduction Capability Forecast values provided at the time of the LMR registration. If the LMR partially clears, the value in the DSRI will be adjusted by the % of the total seasonal ZRCs a resource clears in a Planning Resource Auction (PRA) or used in a Fixed Resource Adequacy Plan (FRAP) or RBDC Opt Out times the Demand Reduction Capability Forecast. If the LMR only partially clears the PRA, MISO will grant an opportunity to adjust the monthly MW values to account for the cleared LMR ZRCs. It is critical that LMR availability always be current as the Scheduling Instructions (dispatch directives) and ultimately performance and availability review will utilize the information in the DSRI at the time the Scheduling Instruction is issued and how the Market Participant responds to the Scheduling Instruction. If the LMR is on any type of derate, outage or otherwise not available, the LMR availability should be adjusted by decrementing the availability in the DSRI by reducing the "MWs available for MISO" for the affected LMR. The following are two examples of a 40 MW BTMG LMR derated by 25 MWs, and a 25 MW DR LMR derated by the full 25 MWs and is completely in outage:



40MW BTMG LMR derated by 25MWs
08/23/2022 11:48 EST
LAST UPDATED
MISO Test User
UPDATED BY
ALTE
LBA
Central Region
MISO REGION

Hours (EST)	01	02	03	04	05	06	07	08	09	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
Notification Timeframe	05:00	05:00	05:00	05:00	05:00	05:00	05:00	05:00	05:00	05:00	05:00	05:00	05:00	05:00	05:00	05:00	05:00	05:00	05:00	05:00	05:00	05:00	05:00	05:00
MWs Available for MISO	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0
Self Scheduled MWs	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0

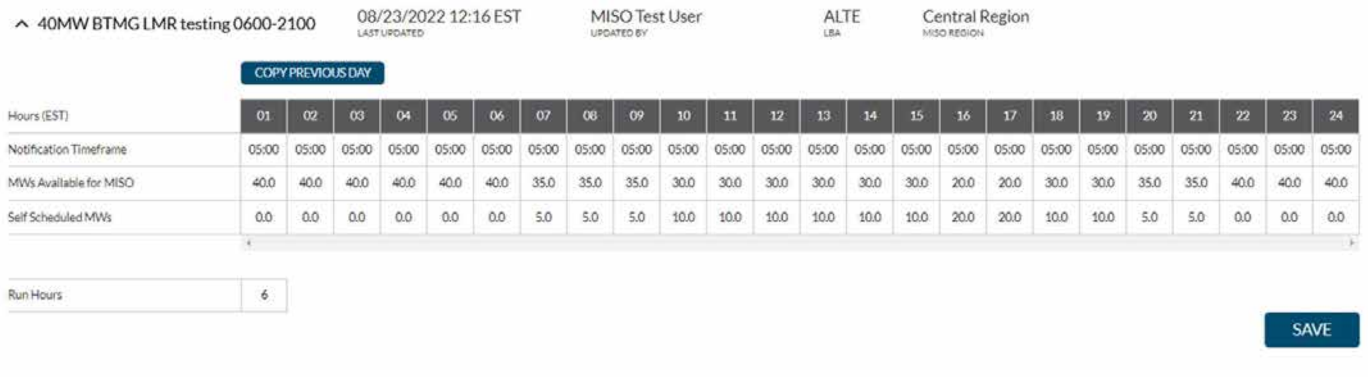
Run Hours 6

25MW DR LMR derated by the full 25MWs
08/23/2022 12:02 EST
LAST UPDATED
MISO Test User
UPDATED BY
WEC
LBA
Central Region
MISO REGION

Hours (EST)	01	02	03	04	05	06	07	08	09	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
Notification Timeframe	02:30	02:30	02:30	02:30	02:30	02:30	02:30	02:30	02:30	02:30	02:30	02:30	02:30	02:30	02:30	02:30	02:30	02:30	02:30	02:30	02:30	02:30	02:30	02:30
MWs Available for MISO	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Self Scheduled MWs	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0

Run Hours 4

If a BTMG is scheduled to be deployed by the MP, the "Self Scheduled MWs" section in the DSRI should be increased for LMR MWs that are scheduled to be deployed and the "MWs available for MISO" amount should be reduced to reflect the remaining MWs available for additional MISO deployment. If a DR is scheduled to be deployed by the MP, or it simply has reduced load for the end-use at the facility then the “Self Scheduled MWs” section in the DSRI should be increased for LMR MWs that are scheduled to be deployed or has been already reduced, and the “MWs available for MISO” amount should be reduced to reflect the remaining MWs available for additional MISO deployment. Derates and outages that occur where load is not reduced should not be entered as “MWs available for MISO” or “Self Scheduled MWs”. The following are two examples of a 40 MW BTMG LMR coming online for a test between 0600 – 2100, and a 25 MW DR LMR available for only 5 MWs for MISO because there is reduced load at the facility:



40MW BTMG LMR testing 0600-2100

LAST UPDATED: 08/23/2022 12:16 EST
UPDATED BY: MISO Test User
LBA: ALTE
MISO REGION: Central Region

Hours (EST)	01	02	03	04	05	06	07	08	09	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
Notification Timeframe	05:00	05:00	05:00	05:00	05:00	05:00	05:00	05:00	05:00	05:00	05:00	05:00	05:00	05:00	05:00	05:00	05:00	05:00	05:00	05:00	05:00	05:00	05:00	05:00
MWs Available for MISO	40.0	40.0	40.0	40.0	40.0	40.0	35.0	35.0	35.0	30.0	30.0	30.0	30.0	30.0	30.0	20.0	20.0	30.0	30.0	35.0	35.0	40.0	40.0	40.0
Self Scheduled MWs	0.0	0.0	0.0	0.0	0.0	0.0	5.0	5.0	5.0	10.0	10.0	10.0	10.0	10.0	10.0	20.0	20.0	10.0	10.0	5.0	5.0	0.0	0.0	0.0

Run Hours: 6

25MW DR LMR available for only 5MWs
(With 20MWs of reduced load not related to an outage)

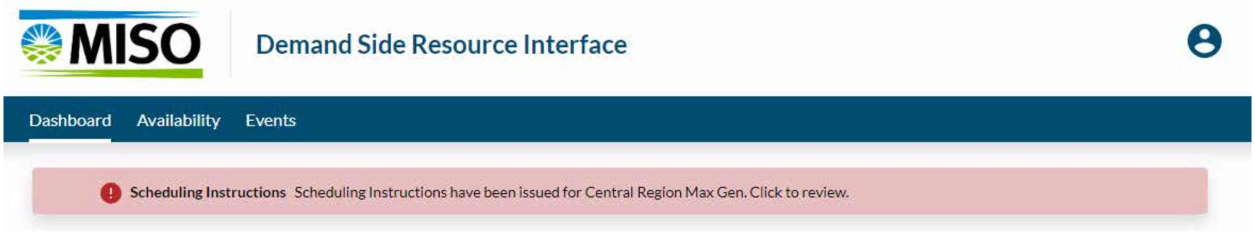
LAST UPDATED: 08/23/2022 12:17 EST
UPDATED BY: MISO Test User
LBA: WEC
MISO REGION: Central Region

Hours (EST)	01	02	03	04	05	06	07	08	09	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
Notification Timeframe	02:30	02:30	02:30	02:30	02:30	02:30	02:30	02:30	02:30	02:30	02:30	02:30	02:30	02:30	02:30	02:30	02:30	02:30	02:30	02:30	02:30	02:30	02:30	02:30
MWs Available for MISO	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0
Self Scheduled MWs	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0

Run Hours: 4

For specifics on DSRI functionality, please see the MP LMR Users Guide located in the Learning Center.

If an Emergency is declared by MISO that requires LMR deployment, MISO will issue Scheduling Instructions in the DSRI using the LMR availability information (“MWs available for MISO” and “Self Scheduled MWs”) provided by MPs. Self Scheduled MWs are included in a Scheduling Instruction to ensure that the MW deployed voluntarily by an MP continue to be deployed if required during an Emergency. Self Scheduled MWs are not subject to notification times because they are already planned to be performing at those levels, as decided by the MP; however, MWs available for MISO are subject to notification times whenever Scheduling Instructions are created. The LBA and the MP will receive a notification of the Scheduling Instructions via a MISO Communications System (MCS) message (LMR Implementation MCS message type). MPs will also receive a Scheduling Instructions event banner within the DSRI application as shown below (with audible alerts until acknowledged).



Scheduling Instructions Scheduling Instructions have been issued for Central Region Max Gen. Click to review.

Market Participants with LMRs must have personnel operating on a 24x7 basis that can receive and respond to MCS messages, Operator Interface Declarations and Messages, and LMR Scheduling Instructions events in the DSRI. The MP will need to acknowledge receipt of the Scheduling Instruction and update the remaining availability, if any, of the LMR(s) being used to meet the Scheduling Instruction in DSRI to reflect the MW amount available in the specified time(s). This update and acknowledgement should be done within one (1) hour of receiving the Scheduling Instruction from MISO. Also, before the Emergency deployment, the MP that registered the LMR(s) should submit the specific designation of LMRs and associated MWs used to meet the total MWs contained in the Scheduling Instruction via the Resource Deployment tab of the LMR Scheduling Instruction Event in the DSRI.

MPs that report LMR availability (including self-scheduled MWs) in the DSRI that is less than the performance obligation based on the MW value that is being used to meet RAR, may be requested to provide documentation and/or metering data to MISO for the dates and hours that MISO declared an Emergency. Meter data for the LMRs used to meet the MWs requested in the Scheduling Instruction mustbe uploaded in the Demand Response Tool within 103 days of the Emergency event or as requested by MISO.

MISO will not violate registration parameters (e.g., notification time) and real time availability updates provided by MPs when issuing a Scheduling Instruction. MISO does, however, rely on real time availability updates provided by MPs when issuing a Scheduling Instruction.

4.2.5.1 *LMRs with Dual Registration*

Market Participants that register LMRs are eligible to also register in the Energy market as Emergency Demand Resources and/or Demand Response Resources.

LMRs that have some capability registered as Emergency Demand Response (EDR) or Demand Response Resource (DRR) should adjust their availability in DSRI to reflect net LMR MWs available to MISO (e.g. decrement total LMR capability by EDR offer amount and DRR cleared Day-Ahead or pending Real Time offer). It is the responsibility of the Market Participant to ensure no double counting of MWs offered across the dual registration types. Double counted MWs may be subject to underperformance penalties.

1.1.1.1.3 4.2.5.1.1 LMRs Also Registered as Demand Response Resource (DRR)

DRR Type I and Type II that have converted SAC to ZRCs which were used to meet seasonal Resource Adequacy Requirements (RAR) are categorized as Capacity Resources under Module E-1 (Section 69A.3.1.b) and therefore are not LMRs. However, a DRR that does not convert all its associated SAC may also register the remaining SAC of the resource as an LMR. In this case, the SAC converted and used to meet RAR under the LMR designation would follow the respective LMR requirements and likewise the DRR SAC if converted and used to meet RAR would carry the must offer requirement. The combined SAC converted to ZRCs between the DRR designation and the LMR designation cannot exceed the assigned SAC value of the singular resource.

1.1.1.1.4 4.2.5.1.2 LMRs Also Registered as an Emergency Demand Resource (EDR)

A resource may qualify as an Emergency Demand Response (EDR) under Schedule 30 to participate in the Energy market regardless of whether it qualifies as an LMR under Module E-1. An LMR may also dually register and qualify as an EDR. In the case of a dual LMR / EDR registration, the resource may be dispatched as an EDR when there is a pending EDR offer (EDR offers are made daily). If the resource is not dispatched as an EDR, it maintains its LMR obligations, and its performance will be evaluated as such. Being dual registered requires the resource to meet the most stringent of the two designations' requirements. Also, the tolerance band allowed for an EDR does not apply when dual registered. MISO will not assign LMR penalties to Emergency Demand Response (EDR) resources that have already been assessed penalties under Schedule 30 of the Tariff.

For more information regarding the dual registration of LMRs as EDRs, please see Section 6.4 of BPM-026 Demand Response.

1.1.1.2 4.2.5.2 LMR Performance Obligations

The registered capacity of accredited LMRs that has been converted to ZRCs and has cleared in the PRA must be available as outlined above for use in the event of an Emergency declared by MISO. MISO will populate the DSRI with the monthly Demand Reduction Capability Forecast values provided at the time of the LMR registration. If the LMR partially clears, the value in the DSRI will be adjusted by the % of the total seasonal ZRCs a resource clears times the Demand Reduction Capability Forecast. MPs should keep these values up to date to ensure the availability is accurate as Scheduling Instructions will be based on the LMR Availability in the DSRI. The Available MWs for MISO should be consistent with the availability indicated in the LMR's registration. A Market Participant utilizing LMRs to meet Resource Adequacy Requirements will be subject to the penalties described in Section 69A.3.9 of the Tariff if the LMR is included in the Market Participant's response to Scheduling Instructions and the LMR fails to respond.

A Demand Resource (DR) must respond with an amount greater than or equal to the target level of load reduction or reduce Demand at or below the registered firm service level. DRs that registered with a Firm Service Level Measurement & Verification methodology that partially clear, will have the uncleared portion of the resource added to their registered firm service level (FSL) when evaluating performance. A BTMG must provide the target level of generation increase as indicated on the Market Participant's Resource Deployment tab of the LMR Scheduling Instruction Event in the DSRI when responding to Scheduling Instructions Combined, the Market Participant's DR and BTMG responses must meet the total MWs contained in their Scheduling Instruction.

This "target" level MW is indicated by the MP via the DSRI's Resource Deployment tab of the LMR Scheduling Instruction Event which outlines which LMRs were utilized and the associated MW levels to meet the total MWs contained in the Market Participant's Scheduling Instruction. An LSE shall be assessed the costs that were otherwise incurred to replace the Energy deficiency at the time the LMR was dispatched.

MISO will not assign LMR penalties to Emergency Demand Response (EDR) resources that have already been assessed penalties under Schedule 30 of the Tariff. LMR values entered in the DSRI availability will also be considered when evaluating whether target levels of generation increase, or Load reduction have been met. For more information regarding the performance assessment of an LMR, please see BPM-026 Section 6.2.

The operators of LMRs that improperly report to MISO that an LMR is unavailable in the DSRI prior to receiving a Scheduling Instruction or the LMR does not respond when included in a Market Participant's response to Scheduling Instructions will have an opportunity to provide documentation of the specific circumstances that would justify exemption from such penalties. A penalty will not be assessed for any portion of the target level of Load reduction for a DR, or target level of generation increase for a BTMG, which had already been accomplished for other reasons (*i.e.*, for economic considerations, self-scheduling at or above the amount of BTMG committed in a Planning Resource Auction, or local reliability concerns) and properly reflected in the hourly availability in the DSRI for each resource. Likewise, for certain LMRs that are temperature dependent (*e.g.*, a Demand Resource program involving air conditioning load), the target level of Load reduction or target level of generation increase may be adjusted and the hourly availability in the DSRI should be updated to properly reflect the anticipated capability of the resource.

4.2.6 BTMG Qualification Requirements

MPs with BTMGs can qualify as LMRs by:

- Submitting monthly availability (in megawatts) and notification time (in hours) for the upcoming Planning Year.
- Intermittent BTMG (e.g., solar, wind, run-of-river hydro, etc.) are exempt from submitting the additional documentation for monthly availability and notification time as they are not dispatched via the DSRI.
- Confirming through the registration process such BTMG can be available to provide Energy with no more than 6 Hours advance notice from MISO or the LBA and sustain Energy production for a minimum of four (4) consecutive Hours.
- Confirming through the registration process that the BTMG is capable of being interrupted and available at least the first (5) times as needed during the Summer and Winter and at least the first (3) times as needed during the Spring and Fall by MISO or the LBA for emergency event purposes, consistent with the registration information of the physical capability of the BTMG.
- Confirming that the BTMG is equal to or greater than 100 kW (an aggregation of smaller resources that can produce Energy may qualify in meeting this requirement if located in the same LRZ).

- Behind the Meter Generation must demonstrate GVTC on an annual basis as described in Sec. 4.2.1.1 Qualification Requirements. See Appendix J – GVTC Testing Requirements for additional details.
- Behind the Meter Generation with any new or untested additional capacity are eligible for the ICAP Deferral Process as described in Sec. 4.5 ICAP Deferral.
- Submitting generator availability data (including, but not limited to, NERC GADS) into a database through the Market Portal for non-intermittent BTMG greater than or equal to 10 MW based on GVTC. Non-intermittent BTMG less than 10 MW based upon GVTC that begin reporting generator availability data must continue to report such information. Behind the Meter Generation that is an intermittent resource must submit information in accordance with Section 4.2.1.3 Intermittent Generation and Dispatchable Intermittent Resources - Qualification Requirements. Quarterly GADS Event and Performance Data must be submitted by the end of the month following the quarter (April for Q1, July for Q2, October for Q3, and January for Q4). The submitted data must have passed Level 2 Validation without any errors. Units that fail to submit Level 2 Validated quarterly GADS data will be disqualified for participation in the PRA.
- For wind resources being registered as BTMG, the following information is required:
    - Resources with commercial operation history of metered values during at least one Season would submit metered values in MW terms for all Hours in the test period.
    - Resources with no commercial operation history of metered values during the Season would receive class average for each Season within the Initial Planning Year.
- For solar resources being registered as BTMG, the following information is required:
    - Resources with at least 30 consecutive days of metered values for that Season would submit metered values in MW terms for all hours in the test period.
    - Resources with less than 30 consecutive seasonal days of metered values would receive class average for the Seasons within the Initial Planning Year.
- For storage resources that do not report to GADS (including but not limited to, batteries, flywheels, compressed air, and pumped storage) being registered as BTMG, the following information is required:
    - Resources with commercial operation history of metered values during no less than 30 consecutive days in a specific Season would submit historic

availability for the top 8 coincident system peak hours for a minimum of one and a maximum of three of the most recent applicable Planning Years for each Season.
    - Resources with less than 30 consecutive days of metered values during a Season would receive class average accreditation for the Initial Planning Year.
- Internal purchase power agreements (PPAs) will not be qualified by MISO.
- BTMGs that have been retired prior to the Season will not qualify as a Planning Resource.
- If BTMGs used to meet Resource Adequacy Requirements retire or suspend during the Planning Year, they must be replaced effective with their change of status date.

4.2.6.1 *Submission of New BTMG Registrations*

An MP must register its new BTMG via the Registration screen in the MECT by March 1 prior to the Planning Year. The registering entity must be an MP prior to registering a BTMG. In order to guarantee new Resources can be used in an LSE’s FRAP or RBDC Opt Out, registrations should be submitted no later than February 15 prior to the Planning Year. An entity that is not a MP, but desires to register a BTMG, must contact the Customer Registration team at register@misoenergy.orgMISO Help Center (https://help.misoenergy.org/) to become a MP. During the registration process the MP will be required to certify that the registration information is accurate, complete, and that the qualified MWs from the BTMG are not being registered by another party. Appendix E contains the information that must be submitted by an MP through the MECT registration screens. MISO will review the BTMG registration information for completeness and accuracy and ensure it complies with the qualification requirements for BTMG. MISO will endeavor to notify the MP within 15 days after the registration form was submitted regarding whether the BTMG has been accredited as an LMR, or whether there are any deficiencies that must be corrected. If the BTMG is accredited as an LMR, it will be given a unique name for tracking purposes and made available in the MECT screens for use by the MP.

4.2.6.2 *Termination of BTMG Accredited as LMR*

Because BTMGs need to be accredited seasonally, the “Effective Stop Date” will default to the last day of the applicable Season.

4.2.6.3 *Amendments to Accredited BTMG Registration Data*

The Market Participant can amend the registration for a BTMG for an upcoming Planning Year by providing MISO notification no later than March 1 if the original registration was submitted by February 1.

The Market Participant may modify any of the non-end date information submitted in the registration, which may affect the BTMG's qualification, including, but not limited to, a change in operation, or either an increase or decrease in MW capability. The Market Participant shall submit new or amended registration information in the MECT by March 1 prior to a Planning Year for MISO to determine whether the resource still qualifies as a BTMG. The Market Participant will still need to provide MISO with a GVTC by the original test date as outlined in the BPM. Any modifications in the capability of an existing BTMG must have updated test and registration information submitted to MISO via the MECT by March 1.

Renewal of BTMG for subsequent Planning Years

BTMG must be reviewed for accreditation as an LMR on an annual basis. An MP can request renewal of BTMG accreditation for subsequent Planning Years through the MECT registration screens. Renewal of BTMG must be requested by February 1^{sr} prior to the Planning Year.

NOTE: BTMGs must submit GVTC and/or operational data by the October 31 deadline, per Section 4.3, to have SAC values determined. MISO will review the revised BTMG registration information for completeness and accuracy and ensure it complies with the qualification requirements for BTMG. MISO will endeavor to review the registration for approval within 15 days after the revised registration form was submitted to determine whether the BTMG has been accredited as an LMR, or whether there are any deficiencies that must be corrected. If the BTMG is accredited as an LMR, then it will be given a unique name for tracking purposes and be made available in the MECT screens for use by the MP during the applicable Planning Year.

4.2.6.4 *Behind the Meter Generation (BTMG) – SAC Determination*

The SAC value for a BTMG is based on an evaluation of the applicable type and volume of interconnection service, GVTC (or historical output at peak if intermittent), line losses if not interconnected to MISO, and XEFORd value of such BTMG.

BTMG that are intermittent resources will have their SAC determined consistent with the methodology described for similar resource fuel types as described in Section 4.2.1.3, Intermittent Generation and Dispatchable Intermittent Resources – Qualification Requirements, through 4.2.1.7, Other Intermittent Generation and Dispatchable Intermittent Resources.

4.2.6.5 *BTMG Deliverability*

Each BTMG resource owner must coordinate with their Distribution Provider (DP) to ensure local distribution service for the BTMG resource to qualify as an LMR type Planning Resource for participation in the PRA. The majority of BTMG is interconnected at distribution-level voltage; however, it is possible for BTMG to be interconnected at transmission-level voltage. Additionally, MPs with BTMG must coordinate with their LSE, DP, and Transmission Owner (TO) to determine eligibility to participate in the PRA. This section will outline the roles and responsibilities of an LSE, DP, TO, and MISO for an individual BTMG to participate in the PRA including specific methodologies available to the BTMG MP to demonstrate deliverability. Responsibilities of an entity may differ depending if the Point of Interconnection is on the distribution system or transmission system and will be noted.

1.1.1.2.1 4.2.6.5.1 Roles and Responsibilities to Determine Eligibility for PRA Participation

Additional descriptions of the role and responsibility of each entity is below. The MP owning a BTMG is responsible for providing an attestation to MISO that proper coordination has occurred with each entity.

Load Serving Entity (LSE): Collaborate with BTMG MP to establish eligibility for a BTMG to participate in the wholesale market (e.g., PRA) in accordance with the relevant state regulatory framework.

Distribution Provider (DP): Ensure reliability of distribution system and assess access to the transmission system. Typically, the DP completes an interconnection study to assess the reliability impacts on the distribution system. The DP is responsible for determining engineering studies, facility upgrades, and/or agreements required to permit access of a BTMG to the transmission system.

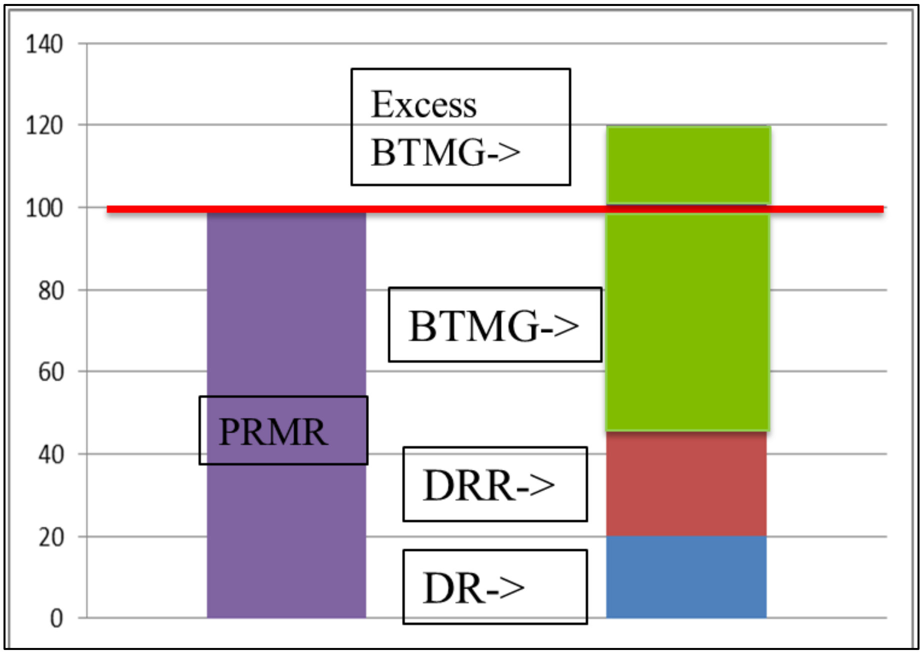
Transmission Owner (TO): Determine when the transmission system is utilized by a BTMG to serve load and coordinate with the DP and MISO on engineering and facility studies as appropriate. The TO typically ensures studies are completed, per their direction, to ensure transmission facilities (including other interconnected generators) are not impacted by an additional injection of Energy from a BTMG onto the transmission system. Studies will vary depending on the specific Point of Interconnection.

MISO: Accountable for ensuring BTMG has demonstrated deliverability for use in the PRA (additional details below) and ensuring the BTMG MP has provided attestation of coordination with the LSE, DP, and TO.

1.1.1.2.2 4.2.6.5.2 Definition of “Excess BTMG”

Deliverability of BTMG is established relative to the portfolio of total BTMG assets owned or under contract by an LSE in a singular LBA. A BTMG that utilizes the transmission system or a volume of BTMG exceeding an LSE’s “net PRMR” in a singular LBA is considered “Excess BTMG” and will need to demonstrate deliverability utilizing an option described in Sec. 4.2.6.5.3 – Options for BTMG to Demonstrate Deliverability. It is possible for the volume of “Excess BTMG” SAC to be less than the SAC of a singular BTMG. In this instance, the MP is eligible to demonstrate deliverability for a portion of a generator or multiple generators. MISO will collaborate with the BTMG MP to establish the specific Point of Injection onto the Transmission System.

The term “net PRMR” is utilized rather than Initial PRMR because it is possible for an LSE to have a portfolio of ZRCs that include registered Demand Resources (DR) and Demand backed Demand Response Resources (DRR_{demand}) that reduce the expected peak Demand by an LSE and result in a net injection onto the Transmission System. Net injection onto the Transmission System is “Excess BTMG” as represented by the figure below.



1.1.1.2.3 4.2.6.5.3 Options for BTMG to Demonstrate Deliverability

Below are the multiple options for a MP with BTMG to demonstrate deliverability:

Option 1: BTMG utilizing the distribution system to offset Initial PRMR. BTMG used to offset an LSE's load utilizing only the distribution system is considered deliverable up to the volume of "net PRMR" of an LSE in a singular LBA. No additional studies are required.

Option 2: Firm Transmission Service. The MP of the BTMG can apply for Point-to-Point or Network Integration Transmission Service using a type of "Monthly" or "Yearly" depending on the Point of Interconnection (POI). A BTMG with a POI on the distribution system can utilize "Yearly" type firm Transmission Service to facilitate a system impact study, if required. A BTMG with a POI on the Transmission System can use "Monthly" or "Yearly" type of firm Transmission Service since an ERIS study would have been completed. A Network Customer may designate a BTMG as a Network Resource through OATI OASIS utilizing firm Transmission Service.

Option 3: Interconnection Service of NRIS or External NRIS (E-NRIS). The MP of the BTMG can enter the Generator Interconnection Queue and apply for NRIS or E-NRIS. An MP can apply for E-NRIS with a BTMG that has a POI on the distribution system. A BTMG with a POI on the Transmission System is eligible for NRIS. The BTMG would be part of a MISO Definitive

Planning Phase (DPP) study and required to submit an application and deposits as appropriate. Refer to BPM-015 Generation Interconnection for additional details.

Option 4: Historical determination of deliverability. BTMG used to offset an LSE's Initial PRMR located in the same LBA and historically demonstrated deliverability prior to integration with MISO, as accepted by MISO or a Transmission Owner, is considered deliverable. Individual BTMGs may have demonstrated deliverability by confirmation by a Network Customer as a designated Network Resource or completion of a Market Transition Deliverability test prior to an LSE joining MISO.

4.2.6.6 *Measurement and Verification of BTMG*

See Attachment TT of the Tariff and BPM-026 Demand Response.

4.2.7 Demand Resource (DR) – Qualification Requirements

MPs with DR can qualify the DR as an LMR by:

- Submitting monthly availability (in megawatts) and notification time (in hours) for the upcoming Planning Year.
- Registering the reduction capability of the DR excluding transmission losses, consistent with conditions at MISO's seasonal Coincident Peak.
- Confirming through the registration process such DR can be available to reduce Demand with no more than six (6) Hours advance notice from MISO or the LBA and sustain the reduction in Demand for a minimum of four (4) consecutive Hours.
- Confirming through the registration process that the total DR load reduction is not exclusively accomplished and dependent on the dispatch of a BTMG owned or operated by a wholesale or retail customer.
- Confirming through the registration process that the DR is equal to or greater than 100 kW (an aggregation of smaller resources within an LBA that can reduce Demand may qualify in meeting this requirement if they are within the same Load Zone CPNode).
- Confirming through the registration process that the DR is capable of being interrupted at least the first (5) times during the Summer and Winter and at least (3) times as needed during the Spring and Fall as needed by MISO or the LBA for Emergency purposes, consistent with the registration information of the physical capability of the DR.

- Confirming that the Market Participant has the authority to reduce demand using the DR. In the case of an ARC registering a DR, this would include uploading into the MECT registration a copy of the signatory pages between the ARC and the load asset customers. MISO does not accept an attestation by the ARC as an artifact to demonstrate the Market Participant possesses ownership or equivalent contractual rights in a Demand Resource.
- Documenting in the MECT the DR’s capability to reduce demand to a targeted Demand reduction level or firm service level at the MISO seasonal Coincident Peak. All DR owners should demonstrate Demand reduction capability of at least 50% of their registered capability via Scheduling Instructions from a MISO Event or conduct a real power test for accreditation and provide a procedure document detailing the steps followed to implement the Demand reduction. Additional details regarding the demonstration of Demand reduction capability are in section 4.2.7.8 below. If a DR opts not to demonstrate Demand reduction capability for accreditation, one of the following options may be used for accreditation:
    - Provide documentation from the state that has jurisdiction accrediting the DR program. Additionally, if not specified in the state documentation, provide documentation supporting the capacity of the DR being registered.
    - Verification from a third-party auditor that is unaffiliated with the MP that documents the DR’s ability to reduce to the targeted Demand reduction level or firm service when called upon to perform by MISO or the LBA.
    - If past performance data does not exist to demonstrate Demand reduction capability, then a mock test can be provided. The mock test should show:
        - The Demand resource’s seasonal meter data from the previous planning year. New resources can provide documentation supporting estimated seasonal Demand.
        - Documentation showing a mock execution or drill of implementing the Demand resource without implementing the Demand reduction.
    - Accreditation documentation, including past performance data, mock test, third party audit, or state commission documentation, supporting the MW being registered should be from the calendar year (January 1 to December 31) immediately preceding the applicable Planning Year. Renewed registrations must submit revised documentation on an annual basis for accreditation.
- If the DR opts out of demonstrating Demand reduction capability via Scheduling Instruction or a real power test, then the DR will be subject to three (3) times the

underperformance penalties during a MISO Emergency event. Specifically, undelivered MWs will be penalized at a rate of LMP times three (3), rather than LMP. The RSG component of the penalty will not be multiplied times three (3), nor will any capacity penalties or lost capacity revenue. Only a DR with a regulatory restriction will be eligible to waive the penalty.

- Documenting in the MECT the Measurement and Verification (M&V) protocol that will be used to determine if such DR performed when called upon by MISO or the LBA during Emergencies. A DR that is sensitive to temperature changes must identify the extent of such temperature sensitivity with sufficient detail to enable MISO to verify whether the DR would be subject to the penalties set forth in Section 69A.3.9 of the Tariff. Temperature sensitivity must at a minimum include identifying the measure used for temperature changes and elasticity of the LSE’s load to weather. An MP that registers a DR as a Planning Resource must confirm that the DR is able to meet all of the requirements in Section 69A.3.5 of the Tariff.
- DR that has been retired prior to the Planning Year will not qualify as a Planning Resource.
- For every season an MP registers a DR, the underlying customer accounts for ARC registrations must be registered under a single DR registration name for every season in which it is registered. The registered capability and tested status can be different for each Season.

4.2.7.1 *Demand Resource Registration Process*

DR can be registered to be used as a Planning Resource and receive SAC MW that can be converted to ZRCs.

Submission of new DR Registrations

An MP may register new DR via the Registration screen in the MECT by March 1 prior to the Planning Year. To guarantee new Planning Resources can be used in an LSE’s FRAP or RBDC Opt Out, registrations of a DR intended to be used in a FRAP or RBDC Opt Out should be submitted no later than February 15 prior to the Planning Year. The registering entity must be an MP prior to registering a DR. Any entity that is not a MP, but desires to register a DR, should contact the Customer Registration team at MISO Help Center (https://help.misoenergy.org/) to become a MP. The MP will be required to certify that the registration information is accurate, complete, and that the qualified MWs from the DR are not being registered by another party. Appendix D – Registration of DRs contains the information that must be submitted by an MP through the MECT Registrations screen. MISO will review the DR registration information for completeness, accuracy, and ensure it complies with the qualification requirements for DR. MISO will endeavor to review the registration within 15 days after the registration was submitted to determine whether the DR has been accredited as an LMR, or whether there are any deficiencies that must be corrected. If the DR is accredited as an LMR, it will be given a unique name for tracking purposes and made available in the MECT screens for use by the MP.

Submission of ARC (Aggregator of Retail Customers) **LMR Registrations**

The LBA and LSE will verify the following:

- LBA name
- LSE name
- RERRA name
- CPNode name
- End use customer account number
- Meter identification number(s)
- Maximum level of participation (MWs)
- Address of the assets in the ARC registration.

The maximum level of participation for each asset within an LMR resource should be no greater than that asset’s load as evaluated by the LBA or LSE.

The assets’ load should be calculated as the average load of the assets up to the last three years’ seasonal MISO system peak hours. One or two years of load data may be used if the full three years is not available, but an explanation must be submitted as to why the full three years are not available. For example, a new facility that has only been in operation for two years would be a reason less than three years of load data is accepted.

It is the responsibility of the Market Participant to provide an explanation which demonstrates why historical average peak load is not representative of expected future peak load for an asset and propose an alternative method of calculating the maximum level of participation for review and approval by MISO and the LSE.

If during registration review, the LBA or LSE is identified to be incorrect for assets in a registration, the registration will be rejected. The Market Participant can submit a new registration once the Market Participant has identified the correct LBA or LSE. This will restart the review timeline for MISO, the LBA, the LSE, and RERRA.

Any modification to the assets during the review will restart the review timeline for MISO, the LBA, the LSE, and RERRA.

Instances where the ARC LMR's customer changes LSEs:

- The LSE identified by the ARC LMR should be correct at the time of the ARC LMR's registration submitted to the Module E Capacity Tracking (MECT) tool. Otherwise, the ARC LMR Registration will be rejected.
- If the ARC LMR's LSE changes during the registration process, the ARC LMR registration can be revised. The date the registration was submitted will be sent along to the LSE for their review.
    - It is the responsibility of the ARC LMR's customers and the ARC to identify LSE changes.
    - It is the responsibility of the ARC LMR to notify MISO, the old LSE, and the new LSE when changes to the ARC LMR's customer's LSE occur.

4.2.7.2 *Termination of Demand Resource Accredited as LMR*

Because DRs need to be accredited annually, the "Effective Stop Date" will default to the last day of the applicable Planning Year.

4.2.7.3 *Amendments to Accredited DR Registration Data*

The Market Participant can amend the registration for a DR for an existing upcoming Planning Year by providing MISO notification no later than March 1, if the original registration was submitted by the February 1 due date.

The MP may modify any of the non-end date information submitted in the registration, which may affect the DR's qualification, including, but not limited to, a change in operation, number of interruptions, advisory notice period, maximum duration, or accreditation amount as either an increase or decrease in either its targeted MW level or firm service level. The MP shall submit registration information in the MECT Registrations screen by March 1 prior to the Planning Year for MISO to determine whether the resource still qualifies as an LMR.

4.2.7.4 *Renewal of DR for subsequent Planning Years*

A DR must be reviewed annually for accreditation as an LMR. A MP can request renewal of DR accreditation for subsequent Planning Years through the MECT Registrations screen. Renewal of DR must be requested by February 1 prior to the Planning Year. MISO will review the renewed DR registration information for completeness and accuracy and ensure it complies with the qualification requirements for DR. MISO will endeavor to notify the MP within 15 days after the renewed registration form was submitted regarding whether the DR has been accredited as an LMR, or whether there are any deficiencies that must be corrected. If the DR is accredited as an LMR, it will be given a unique name for tracking purposes and made available in MECT for use by the MP during the applicable Planning Year. Section 4.2.7.3 Amendments to Accredited DR Registration Data rules also apply to renewed DRs in subsequent Planning Years.

4.2.7.5 *Demand Resources – SAC Determination*

A Demand Resource must be registered and accredited with MISO and will receive 100 percent of its capacity rating for the Planning Year. Seasonal capacity values for Demand Resources will be based on documentation from the state, third party auditor, past performance, or mock test consistent with their ability at MISO's seasonal Coincident Peak Demand. Since DR is a reduction in Demand, SAC is adjusted upward by applying the MISO PRM and transmission loss percentage for the LBA to the capacity rating.

4.2.7.6 *Demand Resource Deliverability*

The owner of ZRCs converted from DR may use them as part of a FRAP or RBDC Opt Out or offer them into the PRA. The DR ZRCs are considered deliverable regardless of the LRZ where the DR physically resides.

4.2.7.7 *Measurement and Verification of Demand Resource*

See Attachment TT of the Tariff and BPM-026 Demand Response.

4.2.7.8 *Demand Resource – Testing Requirements*

The testing period for a DR to demonstrate Demand reduction capability is the calendar year (January 1 to December 31) immediately preceding the applicable Planning Year unless a test deferral is submitted (see section 4.2.7.9 Demand Response Test Deferral). For example, the testing period for the 2025-26 Planning Year will be January 1, 2024 to December 31, 2024. DR shall demonstrate seasonal Demand reduction capability for a minimum of 1-hour duration with an attestation that the DR can continue the reduction for a minimum of 4 consecutive hours. Results should be submitted in accordance with LMR registration deadlines and attached to the LMR registration.

Test results should be adjusted to MISO seasonal Coincident Peak conditions. Upward adjustments shall not exceed +50% of each DR and may include, but not limited to, factors such as temperature, humidity, and/or other process load variations. Downward adjustments are allowed down to the 100kw minimum total for a DR registration. Adjustments to test results should be documented and submitted with the test results to support the capacity accreditation for the DR. Adjustments to DR test results are subject to MISO review and approval during the LMR registration process each year.

DR are required to demonstrate performance of at least 50% of their registered seasonal capability via Scheduling Instructions from a MISO Event or conduct a real power test. If a DR is only able to demonstrate at 50% to 80% of their intended registered MW capability, an attestation from an officer of the Market Participant registering the DR, or from a financially responsible entity, must be provided to MISO during the registration process documenting the reasons for the difference between the registered capability and the demonstrated amount (i.e., industrial process, temperature, etc.). If demonstrating greater than 80% of the registered capability, the DR shall need to provide documentation supporting the adjustments made to normalize the MW capability to seasonal peak conditions.

Results may be uploaded to the documentation section of the LMR registration in MECT and may include: (1) test results including the meter data for the entire day of the tests, (2) historical meter data for 10 days around the MISO seasonal Coincident Peak with the MISO seasonal Coincident Peak as a midpoint, to calculate the capacity baseline, and (3) any other supporting documentation necessary for the LMR capability adjustment. The templates used for submitting the requested meter data may be found on the MISO public website under Markets and Operations > Demand Response.

If a DR is unable to demonstrate performance of at least 50% of the registered MW capability of the DR [only partially performs], the DR must retest the underperforming portion(s) of the DR or create separate registrations for the portions of the DR that did not exceed the 50% performance threshold. If the DR is unable to demonstrate performance of at least 50% of the registered MW capability during the testing period, the DR may still qualify for the PRA by opting out of the testing requirement, provided that the DR will then be subject to the three (3) times penalty provisions for underperformance described in Section 4.2.9 Electric Storage Resource.

If a DR underperforms during a MISO Emergency event and that event is chosen by the DR owner to satisfy the testing requirement, the tested portion of the DR will equal the actual reduction achieved during the event. If a DR only partially tests, the entire DR may be registered, however, separate registrations will be required. For example, the tested portion of the DR would be one registration and the untested portion of the DR would be another registration. If a DR is made up of an aggregation of different physical locations, each location can demonstrate performance—or elect not to—separately. Tested locations may be aggregated together and untested locations may be aggregated together in registrations, as long as all locations are within the same Load Zone CP Node. Separate registrations for tested versus untested resources are required in order for MISO to accurately assess penalties for underperformance during a MISO Emergency event, as the untested DR would be subject to the three (3) times penalty, unless the untested DR is not required to test per qualification requirements in 4.2.9 Electric Storage Resource.

When testing a DR, accurate availability should be reflected in the DSRI by showing the DR as self-scheduled. If an MP plans to test DR greater than 20 MW, the MP should notify MISO operations two (2) Business Days prior to conducting a test by submitting the DR Testing Notification Template to the MISO ITOC (ITNOCRequests@misoenergy.org). The DR Testing Notification Template should include: (1) LMR name, (2) MP, (3) Load Zone CP Node, (4) expected MW reduction, (5) expected reduction date and hour(s), (6) notification time, and (7) operator contact information in case MISO Operations has questions. New DR and DR that did not clear the PRA will not be able to update the DSRI, however, these DR should still notify MISO by utilizing the DR Testing Notification Template.

4.2.7.9 Demand Response Test Deferral

The MP must provide written notification to MISO (https://help.misoenergy.org) of their intention to defer Demand Response testing by February 1 prior to the upcoming Planning Year. This DR Testing Deferral Notice must be from an officer of the company and include the following information:

- Company Name
- NERC ID of Company
- Planning Resource Name
- Local Balancing Authority (LBA) or External Balancing Authority (BA) where located
- Expected DR test value (MW)
- Estimated completion date of DR test

Once the DR test is completed, information pertaining to it must be submitted via written notification to MISO (https://help.misoenergy.org).

A Demand Resource providing such notice must satisfy credit requirements by March 1 prior to the Planning Year totaling the ICAP value registered, but not tested, multiplied by $2,400/MW, where $2,400 is the product of 3 * 4 * $200 to account for the three (3) times Energy penalty assumed under the waiver, the four (4) hours of LMR requirements, and a $200 LMP as a proxy for pricing under emergency conditions.

If the Market Participant submits the real power test results on or before the last business day of the month prior to the Season the DR was used in a FRAP or RBDC Opt Out or cleared the auction within the Planning Year that are equal to or greater than the expected DR test value, then the Transmission Provider will adjust the Market Participant's credit requirement to account for these changes within twenty (20) Business Days after that real power test is submitted.

If SAC associated with a Planning Resource for which DR testing has been successfully deferred are unconverted to ZRCs, the Market Participant may provide notice to the Transmission Provider that it wishes to forfeit the deferred DR value, in which case the Transmission Provider will adjust the Market Participant's DR value and credit requirement within twenty (20) Business Days.

A Market Participant that provides a DR Test Deferral Notice and that either (1) has not submitted any real power test result for such DR by the last business day of the month prior to the Season the DR was used in a FRAP or RBDC Opt Out or cleared the auction within the Planning Year, or (2) has submitted a real power test result by the last business day of the month prior to the Season the DR was used in a FRAP or RBDC Opt Out or cleared the auction within the Planning Year that demonstrates fewer megawatts are available than the expected DR test value submitted in the DR Test Deferral Notice, shall be subject to a penalty equal to three (3) times the Hourly Real-Time Ex Post LMP at the Load CPNode for any such deficiency and distributed pursuant to the Market Participants representing the LSEs in the Local Balancing Authority Area(s) that experienced the Emergency that required the use of an LMR. Such revenues shall be distributed on a Load Ratio Share basis. In addition, such Market Participant shall not have their credit released until a real power test result demonstrating the availability of all megawatts submitted in the DR Test Deferral Notice is submitted and verified by the Transmission Provider, or the end of the Planning Year, whichever is earlier.

4.2.8 Energy Efficiency Resources

Energy Efficiency (EE) Resources are installed measures on retail customer facilities that achieve a permanent reduction in electric Energy usage while maintaining a comparable quality of service. The EE Resource must achieve a permanent, continuous reduction in electric Energy consumption (during the defined EE Performance Hours) that is not reflected in the peak load forecasts used for the PRA for the Planning Year for which the EE Resource is proposed. The EE Resource must be fully implemented at all times during the Season within the Planning Year, without any requirement of notice, dispatch, or operator intervention. Examples of EE Resources are efficient lighting, appliance, or air conditioning installations; building insulation or process improvements; and permanent load shifts that are not dispatched based on price or other factors.

The reduction in electric Energy consumption due to existing EE programs that is reflected in the CPD forecast cannot qualify as an EE Resource. All the requirements to offer or commit an EE Resource in MISO's capacity planning market are detailed in the sections below. One of the major requirements includes the measurement and verification of the EE Resource's Nominated EE Value for a Season within the Planning Year. The Nominated EE Value is the expected average Demand (MW) reduction, excluding transmission losses, during the defined EE Performance Hours in each Season of the Planning Year. The EE Performance Hours are between the hour ending 13:00 Eastern Prevailing Time (EPT) and the hour ending 19:00 EPT during all days of the applicable Season the EE Resource is seeking capacity accreditation, inclusive, of such Planning Year, that are not a weekend or federal holiday.

A Measurement & Verification (M&V) plan describes the methods and procedures for determining the Nominated EE Value of an EE Resource and confirming that the Nominated EE Value is achieved. The EE Resource provider must submit an initial Measurement & Verification plan for the EE Resource by February 1 prior to the PRA in which the EE Resource is to be initially offered. The EE Resource provider must submit an updated Measurement & Verification plan for the EE Resource by February 1 prior to the next PRA in which the EE Resource is to be subsequently offered. Post-installation of the EE Resource, the EE Resource provider must submit an initial Post-Installation M&V Report for the EE Resource by March 1 prior to the first Planning Year that the EE Resource is committed to PRA. The EE Resource Provider must submit updated Post-Installation M&V Reports by March 1 prior to each subsequent Planning Year that the resource is committed. Failure to submit an updated Post-Installation M&V Report by March 1 prior to a subsequent Planning Year or failure to demonstrate that post-installation M&V activities were performed in accordance with the timeline in the approved M&V Plan will result in a Nominated EE Value equal to zero MWs of seasonal ZRCs for the Planning Year.

The last Post-Installation M&V Report submitted and approved by MISO prior to the Planning Year that the EE Resource is committed will establish the Nominated EE Value that is used to measure PRA commitment compliance during the Planning Year. Details regarding seasonal PRA commitment compliance and the associated penalty for failure to deliver the unforced value of a seasonal PRA capacity commitment are detailed below.

MISO reserves the right to audit the results presented in an initial or updated Post-Installation M&V Report. The M&V Audit may be conducted at any time, including during the defined EE Performance Hours. If the M&V Audit is performed and results finalized prior to the start of a Planning Year, the Nominated EE Value confirmed by the Audit becomes the Nominated EE Value that is used to measure seasonal PRA commitment compliance during the Planning Year. If the M&V Audit is performed and results are finalized after the start of a Planning Year, the Nominated EE Value confirmed by the M&V Audit becomes the Nominated EE Value prospectively for the remainder of that Planning Year.

Energy Efficiency installations that are installed prior to any given Planning Year are eligible to participate in seasonal PRAs or be used in a FRAP or RBDC Opt Out for that Planning Year and three subsequent Planning Years. For example, an EE Resource installed and qualified prior to June 1, 2013, could participate in the seasonal PRAs or be used in a FRAP or RBDC Opt Out for 2013/14, 2014/15, 2015/16, and 2016/17 Planning Years provided the EE Resource registers and meets the qualification requirements for each Planning Year. After four years, the EE Resource could no longer be used as a Planning Resource but would continue to be included as a reduction in the Demand forecast.

4.2.8.1 *Energy Efficiency Resource – Measurement and Verification*

See Attachment UU of the Tariff.

4.2.9 Electric Storage Resource

An Electric Storage Resource (ESR) is a resource capable of receiving electric Energy from the grid and storing it for later injection of Energy back to the grid. The ESR includes all technologies and/or storage mediums, including but not limited to, batteries, flywheels, compressed air, and pumped storage. The location of an ESR may be at any point of grid interconnection, on either the Transmission System or a local distribution system. An ESR must:

- be capable of injecting a minimum of 100 kW;
- be capable of complying with MISO’s Setpoint instructions;
- have the appropriate metering equipment installed; and

- be physically located within the MISO Balancing Authority Area.

4.2.9.1 *Electric Storage Resource - Qualification Requirements*

An ESR may qualify as a Capacity Resource for the Planning Resource Auction (PRA) provided the resource is a Use Limited Resource that is able to continuously discharge for a minimum of 4 hours across the expected peak hour each Operating Day and meets the following criteria:

- An ESR must demonstrate discharge capability during each of the seasonal auctions the ESR will be used to meet RAR.
- Verification of capability will be based on the power (MW) and the Energy rating (MWh) via data included in a populated Non-GADS Performance Template and submitted to MISO through the MECT.
- For an upcoming PRA, the following data for the ESR must be submitted to the MECT by October 31 to qualify for the PRA using the Non-GADS Performance Template: Nameplate Capacity, Net Energy Rating (MWh), and Hourly Equivalent Discharge Amount (MW) from the ESR testing (minimum of 1 hour and a maximum of 4 hours).
- An ESR must demonstrate deliverability in order to qualify as a Capacity Resource for participating in the PRA. If an ESR is interconnected to the MISO Transmission System, the Resource can either obtain Network Resource Interconnection Service (NRIS) under Attachment X or procure Firm Transmission Service in conjunction with Energy Resource Interconnection Service (ERIS). If an ESR is interconnected to the Distribution System, the Resource will be subject to coordination with Distribution Provider, Transmission Owner, and MISO Transmission Service. For more information, see section "4.2.8.5.1 - Roles and Responsibilities to Determine Eligibility for PRA Participation."

4.2.9.2 *Electric Storage Resource - Hourly Equivalent Discharge Amount (MW)*

The Hourly Equivalent Discharge Amount (MW) of an ESR will be calculated as:

$$\frac{Total\ Net\ Energy(MWh)}{Total\ Hours\ tested}$$

where The Total Net Energy Rating (MWh) and the Total Hours tested are based on the data submitted to MISO through a populated Non-GADS Performance Template.

4.2.9.3 *Reporting Historical Data*

Market Participants will use MISO's Non-GADS Performance Template found on the Resource Adequacy page of the MISO website to submit the appropriate unit and operational data for the upcoming Planning Year. A populated Non-GADS Performance Template must be submitted to MISO by October 31 of each year via the Module E Capacity Tracking (MECT) tool to be eligible for accreditation in the Planning Resource Auction applicable to the following Planning Year.

Reporting availability data for an ESR is not required if the ESR has less than 10 MW of nameplate capacity and the Market Participant has never provided such data for the ESR.

4.2.9.4 *ESR Capacity Accredited Value Determination*

MISO will determine the accreditation for each ESR based upon an evaluation of its demonstrated capability, resource availability, and Interconnection Service if applicable. ESRs must demonstrate deliverability prior to participating in the PRA. Deliverability will be demonstrated by the Market Participant and verified by MISO depending upon the Point of Interconnection of the resource. A class average unavailability rate will be applied to an ESR to determine a default class average capacity accreditation value prior to being in service long enough to calculate a unit-specific forced outage rate. A 5% unavailability rate will be assumed until sufficient ESRs exist (30 or more individual units) to come up with an average value. The accreditation of an ESR with sufficient historical data is calculated through the Non-GADS Performance Template.

4.2.10 Qualifying Facilities (QF)

Certain generators may be recognized as a Qualifying Facility under PURPA. MISO offers three modeling options that facilitate market participation for QF generators. Each of the options, described below, are reflected differently in the PRA. Each QF should coordinate with its LSE to determine eligibility.[1]

Gross Modeling: Load and generation associated with a QF are modeled separately in the PRA. Load associated with the QF would be included in the LSE's Demand forecast submitted to MISO and generation is modeled as a Generation Resource with a CPNode. QF generators utilizing this option are required to meet the accreditation requirements for testing and

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[1] Additional details can be found in MISO's Qualifying Facilities White Papers on the MISO website. Markets and Operations-> Markets and Operations-> Whitepapers.

deliverability as described in Section 4.2.1 Generation Resource but not Dispatchable Intermittent Resource or Intermittent Generation.

Hybrid Modeling: When QF generation exceeds the associated QF load, both load and generation may be modeled as a single Generation Resource CPNode. The expected net injection onto the transmission system (e.g., QF generation – process load served by QF generation) is modeled as the GVTC. QF generators utilizing this option are required to meet the accreditation requirements for testing and deliverability as described in Section 4.2.1 Generation Resource but not Dispatchable Intermittent Resource or Intermittent Generation.

BTMG Modeling: Load and generation associated with a QF are modeled separately in the PRA. Load associated with the QF would be included in the LSE's Demand forecast submitted to MISO and generation is modeled as a BTMG. QF generators utilizing this option are required to meet the accreditation requirements for testing and deliverability as described in Section 4.2.6 BTMG Qualification Requirements.

4.2.11 Hybrid and Co-Located Resources

For purposes of accreditation, Hybrid Resources and Co-Located Resources will be accredited in two phases: Phase I – Sum of Parts accreditation and Phase II – Availability-based accreditation. Phase I applies in the initial service life of a Hybrid Resource or Co-Located Resource before operating history is available. Phase II applies once a Hybrid Resource or Co-Located Resource has historical operating data. See Appendix X – Hybrid and Co-Located Resource Accreditation for details.

4.3 Confirmation and Conversion of SAC MW

A ZRC represents 1 MW-day of qualified Seasonal Accredited Capacity (SAC) from a Planning Resource for a specific Season of a Planning Year, tracked to the nearest tenth of a MW, pursuant to the applicable ZRC qualification procedures described herein. To create a ZRC, an MP must confirm the SAC MW and then convert SAC MW from each qualified Planning Resource to seasonal ZRCs through the Convert SAC screen in MECT. SAC confirmation and conversion must be completed per the timeline specified in appendix K.

When seasonal ZRCs are converted from SAC by the Asset Owner, the seasonal ZRCs are populated into the available ZRC account for that Asset Owner. MISO will keep track of how many ZRCs the MP has created, and how many remaining SAC MWs for each Planning Resource are available for conversion to ZRCs. Once created, MISO will track ZRCs back to the specific Planning Resources that they were created from to assist with establishing clearing requirements, the auction clearing process, and market mitigation monitoring.

4.4 ZRC Transactions

4.4.1 Transfer of ZRCs

Available ZRCs can be transferred between MPs using the MECT. This is accomplished in the ‘ZRC Transactions’ tab in the MECT. Both the ‘Buyer’ and ‘Seller’ are required to account for a ZRC transaction in the MECT. The ’Seller’ is required to submit the transaction in the MECT and the ’Buyer’ is required to confirm the transaction reported. Once the transaction has been submitted and confirmed by both parties, the ZRC transaction volumes will be subtracted from the seller’s available ZRC account and added to the buyer’s available ZRC account. ZRC transactions are from the transaction date to the end of that Season. In situations where the ZRC transaction is only intended for part of a Season, the ZRCs can be transferred back to the original MP and would be effective for the rest of the Season. The Market Participant that registered the Planning Resource is responsible for complying with all Tariff requirements. The MECT allows transactions based the ZRC balance in the Seller’s portfolio. ZRC transactions can occur throughout the PRA auction cycle, including during the Offer window. ZRC transactions can also be utilized during the Planning Year to facilitate ZRC replacement transactions.

a. ICAP Deferral

i. Summary

ICAP Deferrals allow Market Participants (MPs) to participate in the Planning Resource Auction (PRA) using Zonal Resource Credits (ZRCs) that have been credited to the following:

For Schedule 53 Resources:

- an untested new Planning Resource;
- new Schedule 53 Resources that have not or will not achieve the Commercial Operation Date (COD) by March 1 prior to the upcoming Planning Year, an existing Planning Resource that is returning to operation from a catastrophic outage or suspension; an existing Planning Resource where the Market Participant’s GVTC extension request was denied or the Market Participant missed the GVTC submittal deadline and failed to request an extension;
- an existing Planning Resource that is returning to the MISO market.
- For Non-Schedule 53 Resources:
- an untested new Planning Resource;

- new Non Schedule 53 Resources that have not or will not achieve the Commercial Operation Date (COD) by March 1 prior to the upcoming Planning Year
- an existing Planning Resource that is returning to operation from a catastrophic outage or suspension;
- an existing Planning Resource increasing its capability through increases to GVTC or Interconnection Service (IS);
- an existing Planning Resource where the Market Participant's GVTC extension request was denied or the Market Participant missed the GVTC submittal deadline and failed to request an extension;
- an existing Planning Resource that is returning to the MISO market.
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Schedule 53 Resources that submit ICAP Deferral will get SAC class average for the deferred season(s) while non-Schedule 53 Resources will get the lesser of GVTC or IS, multiplied by (1-class average XEFORd).

ii. Requirements and Timeline

The MP must provide written notification to MISO (https://help.misoenergy.org) of its intention to defer ICAP by February 15 prior to the upcoming Planning Year. This ICAP Deferral Notice should state that the Planning Resource will demonstrate deliverability, demonstrate commercial operation including filing a COD Notification (Appendix E to the GIA) with MISO Resource Integration (ResourceIntegration@misoenergy.org), have confirmed Transmission Service , and/or perform a real power test to submit its GVTC after March 1, but before the last Business Day, prior to the start of the deferred Season. The ICAP Deferral Notice can be found in Appendix T of this BPM. The ICAP Deferral Notice must be from an officer of the company and include the following information:

- Company Name
- NERC ID of Company
- Planning Resource Type
- Planning Resource Name/CPNode Name/Unit Number
- Local Resource Zone (LRZ) or External Resource Zone (ERZ) where Planning Resource is located
- Planning Resource Fuel Type
- Estimated ICAP Value in MW
- Estimated Completion Date of ICAP
- Reason for deferring (See Appendix U)Season(s) to be deferred

- Generator Interconnection Agreement (GIA) Number (only necessary if deferral includes upgrades to Interconnection Service)
- Expected NRIS and ERIS values
- GVTC / COD declaration for intermittent resources
- Commercial Operation Date
- TSR Number
- Other ICAP Type

Once the GVTC test is completed, information pertaining to it must be submitted via written notification to MISO (https://help.misoenergy.org/) by the last Business Day prior to a Seasons' start date for all deferred ZRCs that cleared in the PRA or were included as part of a FRAP or RBDC Opt Out. For intermittent resources COD declaration is used to meet the GVTC submittal requirement. For intermittent BTMG an attestation of COD must be submitted to MISO.

New resources must have (i) an executed GIA or an unexecuted GIA accepted by FERC and (ii) be registered in the June Commercial Model prior to the upcoming Planning Year at the time of the ICAP Deferral request. For modeling SAC in the PRA, the resource must be modeled in the March model prior to the PRA in order to offer into the PRA accordingly. For example, the resource needs to be in the March 2025 Commercial Model to participate in the 2025-2026 Planning Resource Auction.

The MP requesting the ICAP Deferral must post 90 days of credit for the ICAP value of the untested ZRCs no later than March 1 prior to the upcoming Planning Year. The credit will be based on the 90 days of daily CONE for the LRZ in which the resource is located.

MISO will adjust the Market Participant's credit requirements within ten (10) Business Days of the full ICAP being met and has been validated by MISO or when the MP provides written notification to MISO Resource Adequacy that a Planning Resource replacement has been completed.

4.5.3 Uncleared ZRCs with ICAP Deferrals

If the untested ZRCs will not be used in a FRAP or RBDC Opt Out or will not be offered into the PRA, the MP that registered the resource may provide notice to MISO by March 1 that it wishes to forfeit the deferred ICAP value. MISO will recalculate the resulting Seasonal Accredited Capacity (SAC) value and will adjust the credit requirements within ten (10) Business Days after receiving the notice. Furthermore, if the untested ZRCs do not clear the PRA, MISO will release credit back to the MP that submitted the ICAP Deferral Notice.

4.5.4 ICAP Deferral Non-Compliance Charge

The MP that submitted the ICAP Deferral request is responsible for completing ICAP or resource replacement by the last Business Day of prior to a Seasons' start date for all deferred ZRCs that cleared in the PRA or were included as part of a FRAP or RBDC Opt Out. Any ICAP not completed or replaced by the last Business Day prior to a Seasons' start date will be subject to the ICAP Deferral Non-Compliance Charge for each day the ICAP or the Planning Resource replacement is not completed.

The ICAP Deferral Non-Compliance Charge will be based on the sum of the applicable seasonal Auction Clearing Price (ACP) and daily CONE based on the LRZ or ERZ of the Planning Resource, multiplied by the number of ZRCs that have not been replaced or tested.

The distribution of ICAP Deferral Non-Compliance Charge will be allocated pro-rata based on each LSE's share of the total seasonal Final Planning Reserve Margin Requirements (PRMR) in MISO.

Please refer to Appendix U for Examples of ICAP Deferrals.

5 Resource Adequacy Requirements

5.1 Overview

MISO's Resource Adequacy construct ensures that adequate Planning Resources are maintained for each Local Resource Zone (LRZ) to meet the MISO footprint's seasonal Final Planning Reserve Margin Requirement (Final PRMR). An LSE can meet its seasonal Final PRMR by any of the following ways:

1) Self-scheduling of ZRCs
2) Fixed Resource Adequacy Plan (FRAP)
3) Participating in the Planning Resource Auction (PRA)
4) Paying the Capacity Deficiency Charge (CDC)
5) Reliability Based Demand Curve Opt Out (RBDC Opt Out)

5.2 Local Resource Zones

MISO developed Local Resource Zones (LRZ) to reflect the need for an adequate amount of Planning Resources to be in the appropriate physical locations within the MISO Region to reliably meet Demand and LOLE requirements. MISO will provide the details of each LRZ no later than September 1 of the year prior to a Planning Year. The geographic boundaries of each of the LRZs will be based upon analysis that considers: (1) the electrical boundaries of Local Balancing Authorities; (2) state boundaries; (3) the relative strength of transmission interconnections between Local Balancing Authorities; (4) the results of previous LOLE studies; (5) the relative size of LRZs; and (6) market seams compatibility. MISO may re-evaluate the boundaries of LRZs if there are changes within the MISO Region including, but not limited to, any of the preceding factors, significant changes in membership, the Transmission System and/or Resources.

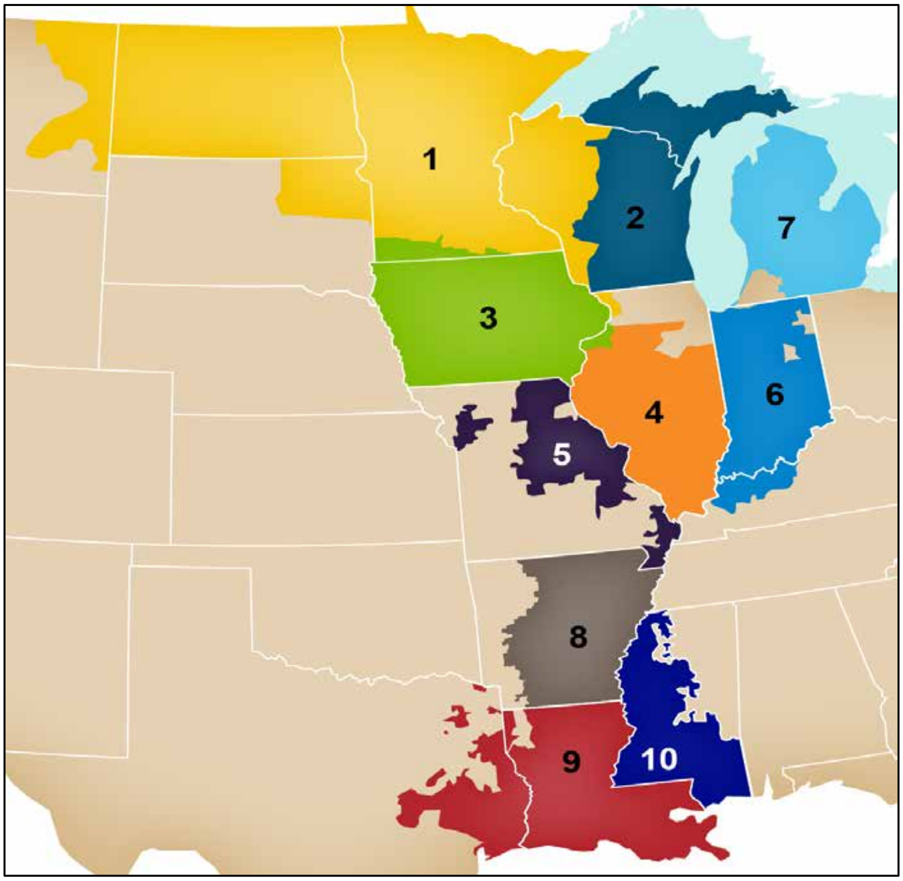

Figure 5: Local Resource Zones Map

5.2.1 Change in LRZ Configuration

MISO, after working with stakeholders and submitting a Tariff revision to Attachment VV that has been accepted by the Federal Energy Regulatory Commission, may change the configuration of the LRZs if a re-evaluation trigger has occurred and after consideration of the criteria outlined for consideration in setting LRZ boundaries. Changes to LRZ configuration will only be applicable to future Planning Years that have not already been cleared through the PRA. MISO will share any re-evaluation triggers and the results of the analysis documenting the impacts of the proposed LRZ boundary changes with stakeholders in an open and transparent manner prior to making any filings to change LRZ boundaries.

Once the boundaries of an LRZ have changed, its boundaries should stay constant for at least three years to provide stable future locational signals.

5.2.1.1 Re-evaluation Triggers

The Transmission Provider may re-evaluate the boundaries of LRZs if there are significant changes in the Transmission Provider Region. Such changes are called re-evaluation triggers, and they include, but are not limited to, the following:

1) Significant changes in membership:
   Re-evaluation may occur for LRZs where there are membership changes in the MISO system or for areas which neighbor the regions where there is a membership change. Re-evaluation may occur prior to or in the cycle immediately following the integration of new members into the MISO system.
2) Significant changes in the Transmission System:
   Transmission infrastructure must be on target to be in-service by June 1 of the year which would follow a filing for an LRZ boundary changes (i.e., the transmission must be in-service for the first summer where the zonal changes will go into effect). The changes to the transmission system should impact transmission constraints represented in the MISO Resource Adequacy construct for the zone(s) being reevaluated.
3) Significant changes in Resources:
   Changes to the resource mix may include the addition of significant new generation or the retirement of significant existing generation. The resource changes should be shown to modify the transmission system flows in the zone(s) being studied, impacting transmission constraints represented in the MISO Resource Adequacy construct.

The existence of a trigger will not guarantee that a zonal change will be implemented; the trigger will allow the analysis to proceed and will be considered as part of the final decision on whether or not to change zonal boundaries.

5.2.1.2 Re-evaluation Considerations

Once a re-evaluation trigger has been met, the geographic boundaries of the zone or zones may be re-evaluated. This re-evaluation will be based upon an analysis that considers the following factors.

1) Electrical Boundaries of Local Balancing Authorities
2) State boundaries
3) Relative strength of transmission interconnection between Local Balancing Authorities

4) Results of LOLE studies
5) Relative Size of LRZs
6) Natural geographic boundaries such as lakes and rivers

The electric boundaries of Local Balancing Authorities, state boundaries, and natural geographic boundaries will be considered by inspection. Additional information on the process used to analyze the other criteria is below.

Relative Strength of Transmission Interconnections between Local Balancing Authorities
Multiple aspects of the transmission system are considered in this portion of the evaluation. These aspects are first investigated individually, and the final assessment considers all of the factors. The assessment includes the following:

- Previously identified LOLE results (Capacity Import and Export Limit constraints)
- Constraint variation(s)
- Transmission projects
- Physical ties including post-contingency connectivity and transmission service

LOLE results identified for Capacity Import and Export Limit analysis before and after the boundary change is applied will be considered. Zonal transfer analysis yields a list of constraints. The most limiting constraint after redispatch determines a zone’s limit in the LOLE study. In the re-evaluation analysis, the less limiting constraints are also considered since reconfigurations impact the transfer level at which constraints are limiting. Also, while there can only be one limiting constraint, multiple constraints can be seen at similar transfer levels. For example, assume the most limiting constraint is at a transfer level of 100 MW. There are two additional constraints at 99 MW and one at 90 MW. Since these transfer levels are very close, all four are considered in this evaluation.

Constraint variation is caused by reconfiguration of Local Resource Zones. This variation is caused by changing the generation that is used to create the transfer. Zonal definitions determine which generators are used in the transfer analysis so any change in zonal definition may result in a difference in the impact the transfer has on the constraint. It is possible that a constraint has an impact above the threshold before reconfiguration and less than the threshold afterwards which is considered in this evaluation.

The impact of approved MTEP Appendix A and Target A transmission projects is considered. If a project mitigates a constraint and the project is expected to be in service prior to the Planning

Year under consideration, then the impact of the transmission project to the LOLE results is considered.

MISO will consider the number of ties of any reconfigured zone. Generally, a reconfigured zone should have two or more ties with the rest of MISO. Two or more ties between the zones are optimal when planning for contingencies so the zones are still connected post-contingency. Any LBA being added to an existing LRZ should have two or more ties with an LBA in the new LRZ. Any other impacted LRZs should have contiguous LBAs with two or more ties. Further consideration is needed if an LBA leaving an LRZ results in an LRZ with unconnected LBAs. In addition, confirmed transmission service between zones may be considered when evaluating reconfigurations. Confirmed long-term transmission service indicates transmission capacity between the zones has been previously evaluated.

The Results of LOLE Studies

LOLE studies will be performed with the LRZ configuration being considered. The results of this analysis will be compared with the prevailing LRZ configuration. This LOLE analysis includes a MISO PRM model analysis (Section 3.5), LRZ LRR determination (Section 5.2.2.2), and capacity import and export limit analysis (Section 5.2.2.1) for the LRZ configuration being considered and for the prevailing LRZ configuration. The results of this analysis and comparison with the prevailing system results will be used as one factor in determining whether LRZ changes are warranted, in conjunction with the other LRZ considerations.

Relative size of LRZs

The relative size of an LRZ will contain no less than 2,000 MW of Demand.

5.2.1.3 Determination of LRZ Boundaries

Following the determination of an LRZ re-evaluation trigger, the conclusion of all analysis with consideration of stakeholder feedback will determine whether the LRZ boundaries will be changed. This determination will be based upon the benefits and/or risks that the LRZ boundary changes would present on the system. MISO’s final determination will be shared with stakeholders and the changes will be filed with FERC.

5.2.1.4 External Resource Zones

MISO developed External Resource Zones (ERZs) to reflect the physical location of External Resources and establish Auction Clearing Prices for such External Resources (other than

Coordinating Owner and Border External Resources)*.* An ERZ will be created for each External Balancing Authority adjacent to MISO with Planning Resources participating in the MISO PRA. Current External Resource Zones:

ERZ	Area(s)
EZ20	KCPL, OPPD, WAUE
EZ22	PJM
EZ23	OVEC
EZ24	LGEE
EZ26	AECI
EZ27	SPA
EZ28	TVA

External resources ZRCs are counted toward the MISO North/Central region and the MISO South region based on transmission shift factors that are calculated annually.

5.2.1.5 Establishing Sub-Regional Resource Zones (SRRZ)

MISO will also establish SRRZs applicable for each Planning Year. A SRRZ is a zone, comprised of an LRZ or combination of two or more LRZs, to administer constraints in accordance with applicable seams agreements, coordination agreements, or transmission service agreements.

Currently, MISO has two SRRZs: MISO South, defined as LRZs 8, 9 and 10, and MISO Midwest, defined as LRZs 1-7. These SRRZs are a result of the settlement agreement between MISO, SPP, and the other Joint Parties. This agreement established Regional Directional Transfer Limits (RDTL) that limit the amount of total transfer between these two SRRZs in the PRA. The RTDL from South to Midwest is 2,500 MW and the RTDL from the Midwest to South is 3,000 MW.

MISO shall establish the Sub-Regional Export Constraint (SREC) and Sub-Regional Import Constraint (SRIC) for each Season by March 1 prior to the Planning Year. The methodology for determining the SREC and SRIC for each SRRZ is described below.

1.1.1.2.4 5.2.1.5.1 Determination of Seasonal SREC and SRIC

The following steps describe the steps MISO will utilize to calculate the SREC and SRIC.

1. Begin with the Regional Directional Transfer Limits (RDTL) between the two SRRZs

2. Complete a feasibility analysis to review operational events from the previous seasonal peaks to determine if a further reduction to the Regional Directional Transfer Limit is warranted for reliability.
3. Decrement the initial RDTL (from step 1) based upon completed feasibility analysis
4. Subtract from the net RDTL (from step 3) the sum of Firm Reservations on MISO OASIS that utilize the contract path between South and Midwest and are exporting the MISO BA for the applicable Season of the Planning Year. This difference determines the SREC and SRIC to be utilized for that Season of the Planning Year.

Example from the 2016-2017 Planning Year

1. The RDTL from South to Midwest is 2,500 MW and from Midwest to South is 3,000 MW.
2. MISO's feasibility analysis for the 2016-2017 Planning Year determined that no additional reduction of the RDTL was required; 0 MW.
3. The net RDTL for 2016-2017 is equal to the initial RDTL; South to Midwest is 2,500 MW and from Midwest to South is 3,000 MW.

4. The MISO OASIS Reservations, in each direction, that exported from the MISO BA for the 2016-2017 Planning Year were summed:
   South to Midwest Direction: 1,624 MW
   Midwest to South Direction: 206 MW

Final SREC and SRIC applied for the 2016-2017 Planning Year:
South SRRZ SREC: 876 MW
South SRRZ SRIC: 2,794 MW
North SRRZ SREC: 2,794 MW
North SRRZ SRIC: 876 MW

1.1.1.2.5 5.2.1.5.2 Regional Directional Transfer Limit Feasibility Analysis

On an annual basis, prior to administrating the PRA, MISO will review operational data from the previous seasonal peaks to determine if operational events experienced in the past and forecasted expected conditions for the applicable Planning Year Season warrant a reduction in the initial RDTL between the MISO South and Midwest Regions. MISO will review the results of the feasibility analysis with stakeholders prior to implementing in a PRA.

The following data sources are considered for the feasibility analysis:

- Studies that assess MISO transfer capability between Regions
- Studies that assess load diversity between Balancing Authorities
- Transmission system constraints
- Congestion history on relevant transmission constraints
- Capacity or Transmission Emergency alerts, warnings, or events

5.2.2 Local Requirements and Transfer Capability

5.2.2.1 Calculation of Transfer Limits for the Planning Resource Auction(s)

MISO will determine the seasonal import and export limits for each LRZ by performing a transfer analysis study. The study produces Zonal Import Ability (ZIA) and Zonal Export Ability (ZEA) values which represent a zone’s ability to import and export capacity in every Season, respectively. The seasonal ZIA and ZEA values are adjusted by the amount of exports (Controllable Exports (CE)) to non-MISO load from the zone to determine a zone’s seasonal CIL and CEL. Seasonal CIL and CEL determine the maximum amount of ZRCs that can be imported or exported respectively to/from that zone in that Season. The seasonal ZIA is an input to the calculation of the seasonal Local Clearing Requirement (LCR) for each LRZ, as described in Section 5.2.2.3 (Establishment of Local Clearing Requirement). Seasonal LCR, CEL, and CIL are inputs to the Planning Resource Auction clearing process. Transfer analysis will be performed on seasonal Powerflow models appropriate for the upcoming Seasons in the next planning year.

Transfer analysis is not required to calculate an ERZ CEL; instead, MISO will determine the seasonal CEL of each ERZ by determining the volume of SAC for External Resources within that zone. The seasonal CEL will be set to the MW SAC in the ERZ no later than eight (8) business days before the last business day in March.

Transfer Analysis

Transfer capability is the measure of the ability of interconnected electric systems to reliably transfer power from one area to another under certain system conditions. The incremental amount of power that can be transferred will be determined through First Contingency Incremental Transfer Capability (FCITC) analysis. First Contingency Total Transfer Capability

(FCTTC) indicates the total amount of power able to be transferred before a constraint is identified. FCTTC is the base power transfer plus the incremental transfer capability.

$$Total\ Transfer\ Capability\ (TTC) = Base\ Power\ Transfer + \ FCITC$$

Linear FCITC analysis will identify limiting constraints with a minimum Distribution Factor (DF) cutoff of 3%, meaning the transfer and contingency must increase the loading on the overloaded element by 3% or more. In addition, facilities must have loadings 100% or more of the normal rating for system-intact conditions and loadings 100% or more of the emergency rating for N-1 contingencies.

Export and import capabilities of subsystems will be respected and machine limits are enforced. Exporting an LRZ’s available capacity will include offline units. A pro-rata dispatch is used which ensures all available generators will reach their max dispatch level at the same time. The pro-rata dispatch is based on the MW reserve available for each unit and the cumulative MW reserve available in the subsystem. The MW reserve is found by subtracting a unit’s base dispatch from its maximum dispatch, which reflects the available capacity of the unit. Refer to Table 2 and the equation below for an example of how one unit’s dispatch is set, given all machine data for the source subsystem.

Machine	Base Model Unit Dispatch (MW)	Minimum Unit Dispatch (MW)	Maximum Unit Dispatch (MW)	Reserve MW (Max dispatch – Unit Dispatch)
1	20	20	100	80
2	50	10	150	100
3	20	20	100	80
4	450	0	500	50
5	500	100	500	0
			Total Reserve	310

Table 2: Example Subsystem

$$Machine\ 1\ Post\ Transfer\ Dispatch = \frac{(Machine\ 1\ Reserve\ MW)}{(Source\ Subsystem\ Reserve\ MW} \times Transfer\ Level\ MW$$

$$Machine\ 1\ Post\ Transfer\ Dispatch = \frac{80}{310} \times 100 = 25.8$$

$$Machine\ 1\ Post\ Transfer\ Dispatch = 25.8$$

General Assumptions

Power flow models and input files are required to determine the import and export limits of each LRZ in each Season. Input files (subsystem and contingency) from MTEP studies built for timeframes matching the effective period of the transfer limit study will be used. Single-element contingencies in MISO and seam areas are evaluated. Other than the power flow model, all other input files will be the same across all Seasons within the Planning Year.

Subsystem files will be modified to include required source and sink definitions, details are provided in the next two sections (Import and Export Limit Determination Sections). The monitored file will include all facilities under MISO functional control and Seam facilities 100 kV and above.

Power flow models will contain approved MISO MTEP Appendix A and Target A projects with effective dates on or before the effective date of the study model. Planning Resources, internal and external to MISO will be dispatched in the base model according to the Generator Modeling and Transactions/Interchanges sections of the Transmission Planning Business Practices Manual, or BPM-020. The following generators are excluded from the incremental transfer analysis dispatch:

- Nuclear
- Generators with negative dispatch
- Hydro
- Wind
- Solar

Wind and solar will be ramped down for transfers and will not be ramped up. Maximum wind output will be limited to base dispatch in the power flow model which is set by the wind capacity credit. MISO and external area interchange in the base case will be set to the net of the expected firm transactions with its neighbors.

If a Transmission Owner has identified a zonal import limit that is binding as a result of the exclusion of nuclear (headroom) or other resources in the sink of the transfer study, the TO may inform MISO of the limitation and MISO will evaluate the ZIA and update accordingly, at MISO’s sole discretion.

Seasonal Zonal Import Ability (ZIA) and Seasonal Capacity Import Limit (CIL) Determination

To determine an LRZ’s seasonal limits, a generation-to-generation transfer is modeled from a source subsystem to a sink subsystem. For import limits, the limit is determined for the sink subsystem. Import limits are found by increasing MISO generation resources in adjacent Local Balancing Authorities (LBAs) while decreasing generation inside the LRZ under study. LBAs that are interconnected with the LRZ under study are considered adjacent. Tiers are used to define the generation pool used for import studies and are comprised of the adjacent systems of the zone being studied.

- Tier 1 – Generation in the MISO LBAs adjacent to the LRZ under study
- Tier 2 – Tier 1 plus generation in MISO LBAs adjacent to Tier 1

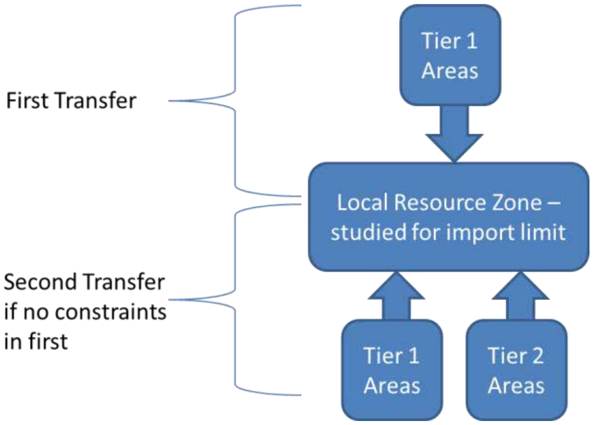

Figure 5.1: Tiered import illustration

Import limit studies are analyzed first using Tier 1 generation only. If no constraint is identified, the source is expanded to include Tier 2 and the transfer is retested. If a constraint is identified, redispatch is tested. If redispatch mitigates the constraint completely and an additional constraint is not identified, the source is expanded to include Tier 2 and the transfer is retested. If constraints are identified using Tier 1 generation, Tier 2 generation is not needed to determine the zone’s import limit.

The results of the analysis produce the seasonal Zonal Import Ability. This value will be used to determine the seasonal CIL after accounting for exports to non-MISO load.

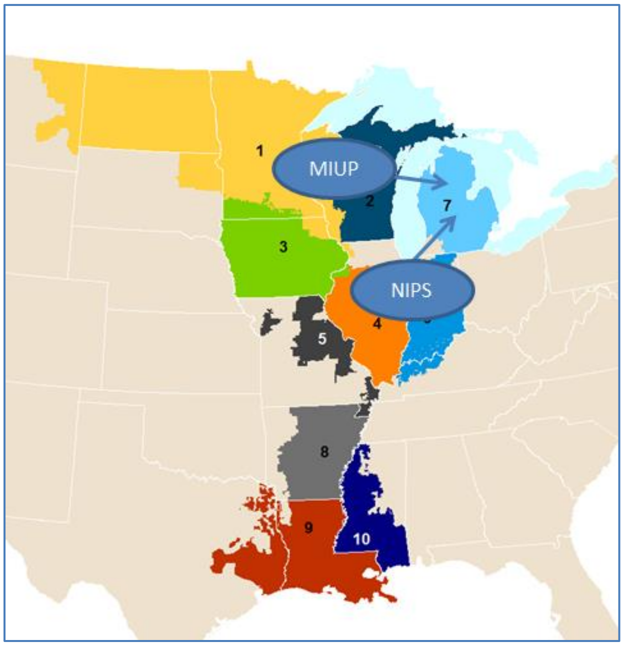

Figure 5.2: Example - MISO LBAs Used for First Test of LRZ 7 import limits

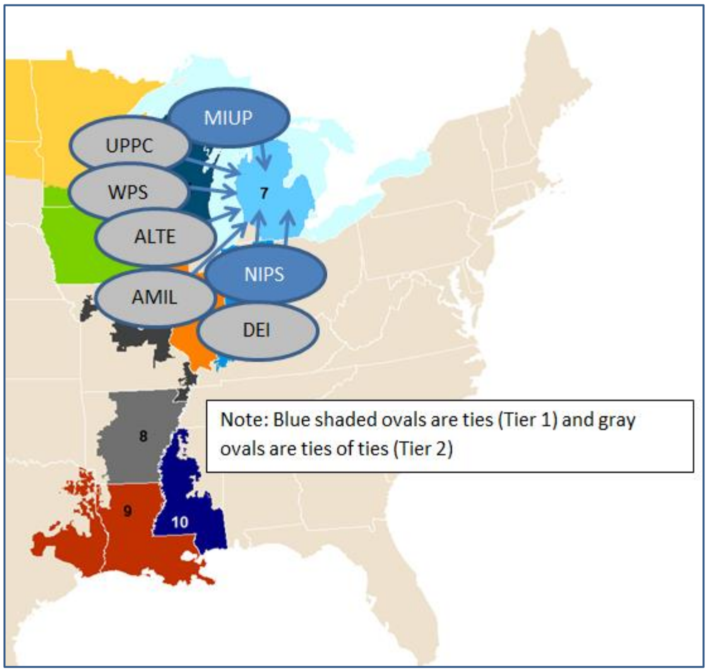

Figure 5.3: Example - MISO LBAs Used for Second Test of LRZ 7 import limits

Seasonal Zonal Export Ability (ZEA) and Seasonal Capacity Export Limit (CEL) Determination

The LRZ being studied for a seasonal export limit, is the source subsystem for the transfer. Available generation within the LBA(s) contained in that particular LRZ is increased proportionately while all generation dispatched, except for nuclear, wind and other intermittent resources, in all other MISO LBAs is decreased proportionately. This method produces the seasonal ZEA which is used to determine the seasonal CEL after accounting for exports to non-MISO load.

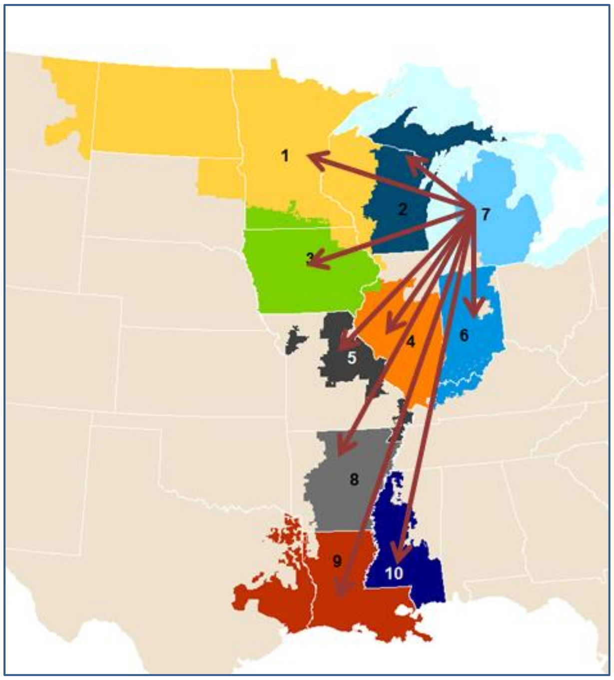

Figure 5.4: Example - MISO LBAs Used for LRZ 7 export limits

Redispatch

LOLE study redispatch is based on prior MTEP study methods. The base assumptions are as follows:

- No more than 10 conventional plants or wind plants will be used
- Redispatch limited to 2,000 MW total (1,000 MW up and 1,000 MW down)
- Nuclear units are excluded
- Wind and other intermittent resources can only be ramped down

For import redispatch scenarios, all generation resources in the zone being studied and adjacent systems (Tier 1 or Tiers 1 & 2) used for the transfer will be eligible to be ramped up. All MISO generation resources will be eligible to be ramped down. If the limiting constraint is a Reciprocal Coordinated Flowgate (RCF), MISO will work with the Seam entity to determine if an adjustment to external dispatch is appropriate and impactful.

For export redispatch scenarios, only MISO generation resources within the zone being studied are eligible to be ramped up. All MISO generation resources are eligible to be ramped down. As with import redispatch, if the limiting constraint is a Reciprocal Coordinated Flowgate (RCF), MISO will work with the Seam entity to determine if an adjustment to external dispatch is appropriate and impactful.

Adjustment for Exports to Non-MISO Load

FERC issued an order on December 31, 2015 which required studies to be neutral to units within MISO areas that are exporting to non-MISO load. MISO identifies and removes the impact of these exporting units on zonal area interchange. These adjustments result in an increase to CIL and decrease to CEL for zones with exports to non-MISO load.

Generation Limited Transfer

When conducting transfer analysis, the source subsystem might run out of generation to dispatch before identifying a constraint caused by a transmission limit. MISO has developed a process referred to as Generation Limited Transfer, or GLT, to identify transmission constraints in these situations.

After running the FCITC analysis to determine import and export limits for each LRZ, MISO will determine whether a zone is experiencing a GLT. If the LRZ is experiencing a GLT, MISO will adjust the base model dependent on whether the analysis is an import or export study and re-run the transfer analysis.

For an export study, when a transmission constraint has not been identified after dispatching all generation within the exporting system (LBAs under study) MISO will decrease load and generation dispatch in the study zone. The objective of the adjustment is to create additional capacity to export from the zone. After the adjustments are complete, MISO will perform transfer analysis on the adjusted model to be in line with section 5.2.2.1 (Calculation of Transfer Limits for the PRA). If a GLT is observed again, further adjustments will be made to the load and generation of the study zone.

For an import study, when a transmission constraint has not been identified after (a) decreasing all generation within the LRZ under study, (b) or dispatching all generation within Tiers 1 & 2, MISO will adjust load and generation in the source subsystem, Tiers 1 & 2. This will increase the capacity available to import into the study zone. After the adjustments are complete, the transfer analysis will be completed on the adjusted model to be in line with section 5.2.2.1. If a

GLT is observed again, further adjustments to the model would be made to the load and generation in Tiers 1 & 2.

FCITC could result in the transmission system supporting large thermal transfers for some zones which might result in some additional considerations. First, large GLT adjustments for export limits could result in reactive-power issues in the zone. Additionally, any load scaling beyond 50% of the zone's load in the base model could result in unrealistic modeling for a summer peak scenario and could lead to unreliable limits and constraints. Therefore, load scaling for both import and export studies will be limited to 50% of the zone's load.

If the GLT does not produce a limit for a zone(s), whether due to a valid constraint not being identified or due to other considerations as listed in the prior paragraph or in the case of a Zone where no valid limit is found in a particular Season, then the seasonal CIL or seasonal CEL will use the following equation where Capacity is the amount available to export or import from Tier 1 & 2 LBA's in the Base Case and where Base Case Flows is the Area Interchange for the study LRZ in the base Powerflow model.

$$\text{ZIA/ZEA} = \text{Capacity} + \text{Base Case Flows}$$

MISO shall report that LRZ as having no seasonal CIL/CEL limit and ensure that the transfer amount in the PRA will not bind in the first iteration of the Simultaneous Feasibility Test (SFT).

Voltage Limited Transfer for import studies

Zonal imports may be limited by voltage constraints due to a decrease in the generation dispatch in the zone being studied. Voltage constraints might occur at lower transfer levels than thermal limits that are determined by linear FCITC. As such, LOLE studies may include evaluation of Power-Voltage curves for major disturbances for LRZs with known voltage-based transfer limitations. Known transfer limitations will be identified through existing MISO or member Transmission Owner studies. Additionally, a study could be considered if an LRZ's import reaches a level where the majority of the zone's load would be served using imports from non-zonal resources. MISO will coordinate with stakeholders as these scenarios are encountered.

Processing and Reporting Results

The transfer analysis results for each LRZ consist of a list of constraints and their corresponding FCITC and FCTTC values up to the requested transfer level. The constraint with the smallest

FCTTC will be used to determine each Seasons' ZIA, ZEA, CIL and CEL. The limits are the total transfer capability of the corresponding limiting constraint. Refer to Section 5.2.2.3 Establishment of Local Clearing Requirementregarding how the seasonal ZIA impacts the seasonal Local Clearing Requirement (LCR) calculation. Stakeholder review of the constraints will occur through the LOLE working group.

If a zone's seasonal Local Clearing Requirement (LCR) is greater than the zone's seasonal Initial Planning Reserve Margin Requirement (PRMR) and an existing MTEP project is not expected to increase the seasonal ZIA, MISO will follow the process outlined in section 4.5.1 of the Transmission Planning BPM to identify a project to increase the zone's seasonal CIL.

Timeline and Posting of Results
Posting of power flow models and input files will be completed before analysis begins, if stakeholders have feedback for the models, it should be provided to MISO in a timely manner. The models and associated input files will be made available to the same location where MTEP Powerflow models are shared (https://misoenergy.sharefile.com/).

The outcome of this process will identify a ZIA, ZEA, CEL and CIL for each of the LRZs for each Season within the next Planning Year. MISO will publish the values for each LRZ by November 1 preceding the applicable Planning Year.

5.2.2.2 Establishment of Local Reliability Requirement

Each LRZ's seasonal Local Reliability Requirement (LRR) is the amount of SAC MWs required, located within the specific LRZ, to yield a 0.1-day-per-year LOLE at the load level for the LRZ at the time of the LRZ peak, without assistance from resources outside the respective LRZ (other than Border External Resources and Coordinating Owner External Resources modeled in the zone as described in section 4.2.3.2 (External Resource Qualification Requirements)). The LOLE study process is further described in the annual LOLE Study report posted on MISO's website.

Each Seasons' LRR will be established using the following iterative process:

- Use the LOLE model to determine the resources required in the LRZ to maintain 1 day in 10 years LOLE, representing the LRZ as isolated from the rest of MISO with no transmission ties to the outside world.
- Each LRZ contains the same load and internal resources from the PRM Analysis.

- For each LRZ, the model will initially be run with no adjustments to the capacity. If the LOLE is less than 0.1 day per year, a perfect negative unit with zero forced outage rate will be added until the LOLE reaches 0.1 day per year for the LRZ. This is comparable to adding Coincident Peak seasonal Demand. If the LOLE is greater than 0.1 day per year, proxy units based on a unit of typical size and forced outage rate will be added to the LRZ until the LOLE reaches 0.1 day per year for the LRZ.
- After solving for 0.1 day per year on an annual basis, risk-deficient Seasons will have a minimum reliability criteria set to 0.01 LOLE and adjustments to capacity in the model will be made until the LOLE reaches 0.01 day per Season.

The minimum amount of capacity above the zonal seasonal Coincident Peak Demand required to meet the reliability criterion of a 0.1 day per year LOLE value will be utilized to establish the Local Reliability Requirement (LRR) for each Local Resource Zone for each Season within the Planning Year. The LRR study utilizes the Year 2 zonal seasonal Coincident Peak Demand supplied by LSEs in the prior Planning Year PRA cycle. The per-unit LRR values are annually calculated by MISO and reviewed with stakeholders through the Loss of Load Expectation Working Group. The zonal per-unit seasonal LRR values are multiplied by the total zonal seasonal Coincident Peak Demand forecast (which is the sum of all CPD forecasts submitted by LSEs in each LRZ) for the prompt Planning Year PRA(s), inclusive of transmission losses, to calculate each Local Resources Zone’s Local Reliability Requirement that will be enforced in each annual and Transitional Planning Resource Auction.

5.2.2.3 Establishment of Local Clearing Requirement

The final steps in calculating an LRZ’s seasonal LCR is to account for the external transmission ties and controllable exports to non-MISO systems, by reducing the seasonal LRR by the seasonal ZIA determined in accordance with Section 5.2.2.1 (Calculation of Transfer Limits for the PRA) and by controllable exports. Controllable exports are firm capacity commitments from MISO units to non-MISO load and may be committed and dispatched by MISO during emergencies. All 10 LRZs have LCRs for each season and they must be met by resources internal to the zone, or by Border External Resources. For example, an LSE with Initial PRMR in LRZ 1, must meet that with ZRCs originated in LRZ1 to meet LRZ1’s Local Clearing Requirement. ZRCs from other zones can be used to meet the incremental PRMR greater than LCR up to that zone’s Initial PRMR subject to CIL/ CEL and SRIC / SREC.

The formula for determining the seasonal LCR is as follows:

$$\text{Seasonal LCR}_{z1} = \text{Seasonal LRR}_{z1} - \text{Seasonal ZIA}_{z1} - \text{controllable exports}_{z1}$$

MISO will publish preliminary seasonal LCR determinations as part of the preliminary PRA data. These values will be updated no later than mid-March with final, updated controllable export values and seasonal ZIAs.

5.3 Pre-PRA arrangement of capacity scheduling

5.3.1 Fixed Resource Adequacy Plan (“FRAP”)

The FRAP will identify resources for which an LSE has ownership or contractual rights that will be relied upon to meet the LSE’s Planning Reserve Margin Requirement while also conforming to the Local Clearing Requirement (“LCR”) in each LRZ where the LSE has a Initial PRMR in each Season within the Planning Year. An LSE must submit its FRAP for applicable Season(s) via the MECT by the 7th business day of March prior to each Planning Year. MISO will review the FRAP and endeavor to notify the LSE of any issues by March 15. LSEs will have until the PRA(s) offer window opens to resolve any issues identified by MISO.

An LSE can designate its seasonal ZRCs in the FRAP up to the LSE’s seasonal Initial PRMR. The seasonal ZRCs used in a FRAP will be deducted from the available seasonal ZRC balance of Planning Resources in the MECT. Any portion of an LSE’s seasonal Initial PRMR not covered by the FRAP (or met through paying the Capacity Deficiency Charge) will be cleared in the seasonal PRA.

An LSE submitting a FRAP may be subject to a Zonal Deliverability Charge (ZDC). The ZDC is the difference between the seasonal ACP in the LRZ where the LSE has Initial PRMR obligation and the ACP in the LRZ or ERZ where the ZRC associated with the FRAP is physically located multiplied by the volume of the ZRC associated with the FRAP. An LSE can obtain a ZDC Hedge as a hedge against zonal price differences in each Season within the Planning Year.

Seasonal ZRCs and seasonal obligation included in a FRAP will be modeled in the PRA for the applicable Season.

5.3.2 RBDC Opt Out

An LSE may elect to use the RBDC Opt Out for the upcoming and the next two years’ PRAs with an obligation (Final PRMR) that is calculated as shown in section 3.1, and with the RBDC Opt Out Adder determined at the first year of RBDC Opt-Out utilizing the following formula:

$$Final\ PRMR_{LSE} = \sum_{LBA}[(CPDf_{LBA} - FRP_{LBA} + FRS_{LBA}) \times (1 + TL_{LBA}\%) \times \left(1 + PRM_{RTO} + Adder_{RBDC\ Opt\ Out}\right)]$$

Where attributes are seasonal for the following:
Final $PRMR_{LRZ}$ = Final Planning Reserve Margin Requirement per LSE
$CPDf_{LBA}$ = Coincident Peak Demand forecast per LBA
FRP_{LBA} = Full Responsibility Purchase per LBA
FRS_{LBA} = Full Responsibility Sale per LBA
$TL_{LBA}\%$ = Transmission Loss Percentage of LBA
PRM $_{RTO}$ = Planning Reserve Margin in Unforced Capacity set by LOLE Studies
$Adder_{RBDC\ Opt\ Out}$= RBDC Opt Out Adder (Defined in Module A 72.0.0)

In MECT, the LSE’s choice of RBDC Opt Out is administrated at the granularity of Asset Owners that have load obligations.

5.3.2.1 Establishment of RBDC Opt Out Adder

MISO will use the systemwide and regional RBDCs, and historical market clearing data (e.g., last three Planning Years’s market data) to determine the initial RBDC Opt Out Adder that will be applicable to LSEs that elect the RBDC Opt Out starting with Planning Year 2025-2026. MISO will post the determination of the RBDC Opt Out Adder on the MISO website per the timeline defined in Appendix K.

5.3.2.2 Request for RBDC Opt Out and ZRC designation

A Market Participant representing an LSE that plans to use the RBDC Opt Out must submit its initial intent to do so through the MECT. Such request must include the name and contact information of the RERRA(s) (email, phone number), where its load is subject to jurisdiction, and must be submitted no later than January 15 prior to the upcoming Planning Year. Market Participants representing the LSE need to contact MISO if there are complexities regarding the RERRA-LSE relationship (e.g., an LSE is subject to the jurisdiction of multiple RERRAs). MISO will verify the information and notify the RERRA(s) within five (5) business days following deadline of the LSEs initial submission. The RERRA(s) has up to twenty (20) Business Days to notify MISO whether the requested RBDC Opt Out has been authorized, on or before timeline listed in Appendix K.

If the RERRA(s) notifies MISO that the LSE is not authorized to use the RBDC Opt Out in the upcoming PRA, MISO will deny the LSE's initial submission in MECT. If the LSE is subject to the jurisdiction of more than one RERRA, MISO will deny the LSE's initial submission proposing to use the RBDC Opt Out if any one RERRA indicates that the LSE is not authorized to use the RBDC Opt Out. The LSE may withdraw its initial submission even if it receives authorization from RERRA(s). Otherwise, the LSE must submit its final confirmation to use the RBDC Opt Out in the MECT and must demonstrate that the LSE has designated ZRCs for each Season to meet the LSE's Final PRMR, and its share of LCR, by the 7th business day of March prior to each Planning Year. An LSE that elects the RBDC Opt Out may not use any other options to participate in the PRA (e.g., self schedule, FRAP, participating auction) to meet its Final PRMR, but may offer any ZRCs in excess of its Final PRMR into the PRA that is consistent with Section 64.1.1.d of Module D.

MISO will notify the LSE prior to March 15th before the applicable Planning Year whether the ZRCs submitted for the RBDC Opt Out meets the LSE's final PRMR and share of LCR for each LRZ requirement for each Season during the applicable Planning Year. An LSE that does not demonstrate sufficient ZRCs to meet its seasonal Final PRMR and share of LCR on LRZ basis before the PRA offer window opens will be subject to the Capacity Deficiency Charge based on the amount of shortfall in each Season.

An LSE that elects the RBDC Opt Out may be subject to a Zonal Deliverability Charge (ZDC). The ZDC is the difference between the seasonal ACP in the LRZ where the LSE has Final PRMR obligation and the ACP in the LRZ or ERZ where the ZRC associated with RBDC Opt Out is physically located, multiplied by the volume of the ZRC associated with the RBDC Opt Out. An LSE can obtain a ZDC Hedge as a hedge against zonal price differences in each Season within the Planning Year.

Seasonal ZRCs and associated seasonal obligations related to the RBDC Opt Out will be modeled in the PRA for the applicable Season.

5.3.3 LSE's Local Clearing Requirement for LSE's Using a FRAP or RBDC Opt-Out

LSEs that choose to use a FRAP or RBDC Opt Out must designate a sufficient volume of Planning Resources located in the same LRZ to meet the LRZ's LCR requirement in each Season individually. The amount of resources that must be sourced from within the LRZ to satisfy the LSE's seasonal LCR share is equal to the load ratio share of the LSE multiplied by the total seasonal LCR for its LRZ. The following formula is used to determine each LSE's FRAP or RBDC Opt Out LCR requirements for each Season.

$$LSE\ LCR = \left[\frac{LSE\ PRMR\prime}{Zonal\ PRMR\prime}\right] * Zonal\ LCR$$

$$Minimum\ LSE\ \ ZONE\ = \max\left(0, \left[\frac{LSE\ LCR * LSE\ \ NON\ ZONE}{(LSE\ PRMR\prime - LSE\ LCR)}\right]\right)$$

$$for\ the\ given\ LSE\ \ NON\ ZONE$$

$$Maximum\ LSE\ \ NON\ ZONE\ = \max\left(0, \left[\frac{LSE\ \ ZONE * (LSE\ PRMR' - LSE\ LCR)}{LSE\ LCR}\right]\right)$$

$$for\ the\ given\ LSE\ \ ZONE$$

Where:

LSE LCR:	Amount of ZRCs that must be supplied from the same LRZ where the LSE's Initial PRMR is located
LSE ZONE:	ZRCs that are in the same LRZ as the Initial PRMR that is being met through a FRAP or RBDC Opt Out by the LSE
LSE NON ZONE:	ZRCs from an ERZ or that are not in the same LRZ as the Initial PRMR that is being met through a FRAP or RBDC Opt Out by the LSE
LSE PRMR':	Total Initial PRMR the LSE has in the LRZ
ZONAL PRMR':	Total Initial PRMR for all LSEs in the LRZ
Zonal LCR:	The minimum amount of ZRCs that are located within an LRZ that is required to meet the LOLE while fully using the Capacity Import Limit for such LRZ.

EXAMPLE :

All LSE Initial PRMR in following example is calculated based on the MISO-established PRM, even if the LSE is subject to the jurisdiction of a state that has established its own PRM

LSE Initial PRMR = 100 MW in LRZ 1
LSE LCR = 80 MW in LRZ 1

To apply ZRCs from other LRZs or an ERZ in the FRAP (or RBDC Opt Out), the following condition must be satisfied when the LSE LCR≤ LSE Initial PRMR:

$$\left[\frac{(LSE\ ZONE + \ LSE\ NON\ ZONE)}{LSE\ PRMR}\right] \leq \left[\frac{LSE\ \ ZONE}{LSE\ LCR}\right]$$

When the LSE LCR>LSE Initial PRMR, the LSE should only use ZRCs inside the resource zone to meet its Initial PRMR:

$$LSE\ NON\ ZONE = 0$$

Substituting the value for *LSE LCR* from above, the above formula can be rearranged and rewritten as:

$$\min\,(1, \left[\frac{Zonal\ LCR}{Zonal\ PRMR}\right]) \leq \left[\frac{LSE\ ZONE}{(LSE\ ZONE + LSE\ NON\ ZONE\ )}\right]$$

Where *LSE Total* is simply the sum of the FRAP from within and outside of the zone. To state more simply, an LSE must maintain a balance of FRAP (or RBDC Opt Out) in zone to total FRAP (Or RBDC Opt Out) greater than or equal to the ratio of the zone's LCR and Initial PRMR.

Case 1: LSE ZONE = 40MW in LRZ 1
LSE NON ZONE = 10 MW from LRZ 2

$$\left[\frac{(40+10)}{100}\right] \leq \left[\frac{40}{80}\right] \Rightarrow \left[\frac{1}{2}\right] \leq \left[\frac{1}{2}\right] \Rightarrow Pass\text{: } 10\ MW\ of\ ZRCs\ from\ other\ LRZ\ is\ allowed$$
$$for\ the\ given\ LSE\ \ NON\ ZONE\ of\ 10\ MW,$$

$$Minimum\ LSE\ \ ZONE\ \ = \left[\frac{80 * \ 10}{(100-80)}\right] = 40\ MW$$

NOTE: 40 MW represents the minimum amount of FRAP (or RBDC Opt Out) that must be fulfilled by the ZRCs in LRZ 1 in this case.

Case 2: LSE ZONE = 60 MW
LSE NON ZONE = 20 MW

$$\left[\frac{(60+20)}{100}\right] \leq \left[\frac{60}{80}\right] \Rightarrow \left[\frac{4}{5}\right] \leq \left[\frac{3}{2}\right] \Rightarrow Fail\text{: } 20\ MW\ of\ ZRCs\ from\ other\ LRZ\ is\ not\ allowed$$

$for\ given\ LSE\ ZONE\ of\ 40\ MW,$

$$Maximum\ LSE\ \ NON\ ZONE\ = \left[\frac{60 * \ (100 - 80)}{80}\right] = 15\ MW$$

NOTE: 15 MW represents the maximum amount of ZRCs from other zones which can be used to FRAP or RBDC Opt Out LSE's Initial PRMR in LRZ 1 in this case.

5.4 Hedges and Zonal Deliverability Benefit

5.4.1 Zonal Deliverability Benefit

Price separation between Local Resource Zones (LRZs), External Resource Zones (ERZs), or groupings of LRZs, including Sub-Regional Resource Zone (SRRZs) occurs due to constraints binding in the Planning Resource Auction(s) (PRA). Zonal Resource Credits (ZRC) will receive the Auction Clearing Price (ACP) based upon the LRZ or ERZ where the Planning Resource underlying the ZRC is physically located for each Season within the Planning Year.

As a result of price separation, the Transmission Provider may collect more debits from LSEs than it credits the owners of the seasonal ZRCs. Excess amounts will be distributed as follows:

1. Historical Unit Considerations (HUCs) and Zonal Deliverability Charge (ZDC) Hedges owed payment.
2. Any remaining excess revenue shall be distributed on a *pro rata* basis to Deliverability Benefit Zones (DBZs). A DBZ is a group of one or more LRZs with equal ACPs driven by the same auction constraint.

5.4.1.1 Zonal Deliverability Benefit Pro Rata Allocation Methodology

The *pro rata* distribution is applied to each applicable Season and is based upon the LSE's eligible Adjusted Final PRMR. . Adjusted Final PRMR is the Final PRMR minus HUCs and ZDC Hedges.

MPs with Fixed Resource Adequacy Plans or RBDC Opt Out are eligible to receive ZDB.

The *pro rata* methodology to allocate ZDB uses a weighted average approach to calculate the benefit, in dollars, to importing DBZs of all exports within MISO – a weighted average exporting ACP. This weighted average pool of dollars is then allocated to importing DBZs within MISO on a *pro rata* methodology based upon the difference between the importing DBZ ACP and the weighted average exporting ACP and the MW amount of imports into a DBZ. The ACP for each LRZ within an importing DBZ is adjusted by dividing the benefit dollars allocated to the DBZ by the total PRMR of all LRZs within a specific DBZ. The specific steps to allocate ZDB are described below.

1. Subtract Final PRMR and ZRCs associated with HUCs and ZDB Hedges to derive an adjusted Final PRMR (Adjusted Final PRMR) and ZRC (Adjusted ZRC).
2. Create a DBZ for each group of LRZs that have equal ACPs which result from the same auction constraint.
3. For each DBZ, subtract the sum of Adjusted Final PRMR for each LRZ within the DBZ from the sum of Adjusted ZRCs for each LRZ within the DBZ. A DBZ will be considered a net importing DBZ if the sum of Adjusted Final PRMR is greater than the sum of Adjusted ZRCs. A DBZ will be considered a net exporting DBZ if the sum of the Adjusted Final PRMR is less than the sum of Adjusted ZRCs. A net exporting DBZ shall not receive any ZDB credit. A net importing DBZ shall receive a ZDB credit allocation based upon this weighted average approach.
4. Calculate the weighted average ACP of all net exporting DBZs (Weighted Average Export ACP) to determine a financial value of export capacity within the Transmission Provider region per the formula below:

$$\text{Weighted Average Export ACP} = \frac{\sum(\text{Net Export}_\text{j} \times \text{ACP}_\text{j})}{\sum \text{Net Export}_\text{j}}$$

Where j = Each net exporting DBZ

5. Calculate the ZDB credit allocation, in dollars, for each net importing DBZ:

$$\text{ZDB Credit}_\text{k} = \text{Net Import}_\text{k} \times (\text{ACP}_\text{k} - \text{Weighted Average Export ACP})$$

Where k = Each net importing DBZs

6. Distribute the ZDB credit in each DBZk by dividing the ZDB credit by the sum of Adjusted Final PRMR of the LRZs within each DBZk. Subtract this amount from the initial ACP calculated for each LRZ from the PRA.

FRAP or RBDC Opt Out Contribution to ZDB

Furthermore, ZDB includes credits collected from FRAPs or RBDC Opt Out that contain ZRCs located in LRZs that have a greater ACP than the respective PRMR's LRZ. This ZDB will be allocated on a *pro rata* basis by Adjusted Final PRMR to all LSEs within the DBZ where the ZRC associated with the FRAP or RBDC Opt Out is physically located.

Allocation of Zonal Deliverability Charge ("ZDC")

A FRAP will be subject to a ZDC if the ACP of the LRZ where the ZRC is physically located is less than the ACP of the LRZ where the Final PRMR associated with the FRAP or RBDC Opt Out is physically located. ZDC collected by the Transmission Provider that is not associated with a ZDC Hedge will be allocated on a *pro rata* basis by Adjusted Final PRMR to all LSEs within the DBZ where the Final PRMR associated with the FRAP or RBDC Opt Out is physically located.

A detailed example of ZDB *pro rata* allocation methodology is in Appendix P.

5.4.2 Historical Unit Considerations (HUCs)

A HUC is a financial hedge against ACP differentials between LRZs or between an LRZ and an ERZ. HUCs for existing capacity agreements hold LSEs harmless from price separation to the extent that excess auction funds are sufficient. HUCs for existing LSEs will be eligible until the end of the original term of the arrangement, not including any evergreen extensions, or for two years – whichever is longer.

The following criteria must be satisfied for HUC approval:

- LSE must have ownership or contractual rights to the resource
- Must have resource and load located in two different LRZs or a resource located in an ERZ
- Must have either NRIS or firm transmission service from the resource LRZ to the load LRZ
- Contracts and its associated NRIS or firm transmission service must be valid through the entire Planning Year
- Contracts must be a) Grandfathered Agreements, b) arrangements executed and in place on or before July 20, 2011, or c) arrangements that predate March 26, 2018 and pertain to External Resource represented in External Resource Zones
- For both new and existing LSEs, HUCs will expire at the end of the contract term, unit ownership change or unit retirement date, whichever is sooner. Contracts expiring during the upcoming Planning Year are not eligible for a HUC covering the planning year. Contracts that have been renewed by evergreen contract provisions are only valid for two Planning Years from the date of the HUC registration

- A HUC must be registered in the MECT by November 1 prior to each Planning Year[2]. HUC Registrations will need to have all information populated except for the Planning Resource, Asset Owner, Resource Zone and TSR and/or NITS identification number(s). Once the SAC MW for Planning Resources is published, MISO will allow Market Participants to update the Planning Resource, Asset Owner, Resource Zone, and TSR and/or NITS ID number information only. Updates will need to be completed by February 1 prior to the Planning Year
- A separate HUC registration is required for each Planning Resource and load within each LRZ or a resource located in an ERZ
    - One Planning Resource in a registration can only select one LRZ or ERZ
- The MW in HUC registrations that are paid will not exceed the LSE's seasonal Final PRMR minus their LCR.
- If there are more HUCs than a DBZ's Final PRMR minus its LCR, then HUC payments will be pro-rated by multiplying the difference between Final PRMR and LCR divided by the total HUCs.
- If Market Participants enter a seasonal ZRC transaction to fulfill contracts that meet the criteria for a hedge, MISO must be able to determine the source of the ZRCs in order to apply the HUC financial hedge to the auction results
    - ZRCs transacted to fulfill existing contracts will need to have specific unit identifiers from aggregate deliverable generators
- Based on the ZRCs transacted, MISO will work with the MP that qualified the HUC to determine in which LRZ or ERZ the Planning Resource is located

If a Load is in an LRZ with a higher ACP than the LRZ or ERZ where the Resource is located, the MP serving the Load will pay an amount equal to the difference of the ACPs between the LRZ and the LRZ or ERZ where the Resource is located, multiplied by the amount of the unhedged load if a HUC Hedge does not exist. This distribution will be limited by the excess auction revenue collected in a given PRA.

A combination of capacity agreements that require the delivery of capacity throughout the Planning Year will qualify for treatment as HUCs, provided that the agreements otherwise satisfy the criteria.

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[2]

Facilities under construction on or before July 20, 2011 that subsequently become Planning Resources will be eligible for the HUC Hedge provided that the HUC criteria is satisfied.

Firm resources that meet HUC Hedge criteria may be included as part of a FRAP or RBDC Opt Out or offered into the annual auction. Any MWs of ZRCs in a FRAP or RBDC Opt Out that are qualified under a HUC will not be subject to a Zonal Deliverability Charge assessment and will not receive a HUC payment

5.4.3 Zonal Deliverability Charge Hedge

LSE can obtain a ZDC Hedge as described herein as a financial protection from zonal price differences. Market Participants will be eligible for a hedge against congestion in the auction if the LSE invests in new or upgraded transmission to serve the LSE’s load if located in a different LRZ. Network upgrades made for interconnection service (NRIS/ERIS) do not qualify for a ZDC Hedge. Also, any cost shared upgrades would not be eligible for a ZDC Hedge. The participant that funds the upgrades and submits the transmission service request is the participant who is eligible for the ZDC Hedge. However, Network upgrades associated with a Transmission Service Reservation (TSR) from the new resource to load located in a different LRZ would qualify. The volume of a ZDC Hedge will be the incremental increase in the CIL that resulted from the Network Upgrades identified in the approved firm transmission service request. Market Participants must register the ZDC Hedge and provide supporting documentation in the MECT by November 1 prior to the Planning Year to demonstrate eligibility. ZDC Hedges will be granted only to LSEs that have Planning Resources that cleared in a PRA.

5.5 Planning Resource Auction (PRA)

5.5.1 Timing of Auctions

Seasonal Planning Resource Auctions will be conducted in the first 20 business days of April, with results posted near the end of April which is approximately one month before the beginning of the first Season of the associated Planning Year (PY). All four seasonal (Summer, Fall, Winter and Spring) PRA’s will be conducted in April prior to the PY.

5.5.2 Amount of Capacity Cleared in Each Auction

The seasonal PRA(s) and Transitional PRA shall clear seasonal ZRC offers in order to satisfy 100% of the seasonal Final PRMR for each LSE, less the amount of seasonal Initial PRMR associated with the Capacity Deficiency Charge and inclusive of any resources used in a seasonal FRAP or RBDC Opt Out, in each LRZ. For a Season, if the total volume of seasonal

ZRC offers is less than total seasonal Final PRMR, MISO will clear the total volume of offered ZRCs for that Season respecting established CIL, CEL, SRIC and SREC.

For LSEs not selecting the RBDC Opt Out, the Final PRMR is established as a result of the PRA clearing using RBDCs. For LSEs selecting the RBDC Opt Out, Final PRMR is the same as Initial PRMR, which is based on the sum of the applicable PRM plus the applicable RBDC Opt Out Adder, as demonstrated in section 3.1. LSEs under state jurisdiction where the state has elected to establish its own planning reserve margin will have a Final PRMR based on the planning reserve margin established by the state.

5.5.3 Conduct of the PRA

The seasonal Planning Resource Auctions shall be sealed bid auctions, which will determine the seasonal Auction Clearing Prices (ACP) for each Local Resource Zone (LRZ) and External Resource Zone (ERZ) modeled in that auction. The auction shall determine the outcome of all seasonal ZRC offers accepted during the qualification process and submitted during the auction offer window.

Step 1: Compilation of Offers

Offers for each of the seasonal auctions must be submitted in the MECT's Submit Offer screen for each specific seasonal auction during the auction offer window period. The offer window for the auction will be opened during the last four business days in the month of March prior to the start of the new Planning Year. Owners of jointly owned facilities can individually offer their share of any such resources into the seasonal PRAs, either as self-schedule price takers or with specific offers or use their share of such resources as part of a seasonal FRAP or RBDC Opt Out.

MISO shall compile all of the offers for each Season, as follows: The MP acting on behalf of any Planning Resource accepted in the qualification process for participation in the auction may submit an offer consisting of price and quantity pairs, indicating the minimum acceptable price and the associated quantity of seasonal ZRCs that the MP would commit to provide from the Resource in the associated modeled LRZ and/or ERZ during the Season within the Planning Year. An offer shall be defined by the submission of up to five price and quantity pairs, each having a strictly greater price than the previous price in the submission. Each price shall be expressed in dollars per megawatt-day, and each quantity shall be expressed in 0.1 MWs. The MW/Price pairs must be monotonically increasing for each price. Each segment of each offer is separately evaluated.

Step 2: Determination of the Outcome

MISO shall use the seasonal ZRC offers to determine the aggregate supply curves for each MISO modeled LRZ and/or ERZ. MISO will use the seasonal offers in conjunction with the seasonal import and export constraints, seasonal local clearing requirements, and other inputs to determine the least cost set of offers that respects the various constraints expressed as described in the Tariff. The Transmission Provider will clear offers based on the needs of the LRZ and not the size of a Resource (i.e., if an LRZ needs 50 MW, but a Market Participant has a 100 MW Resource; only 50 MW will clear). At any non-zero clearing price, a pro-rated clearing from tied bids will be applied in conjunction with need, location of resources subjected to tied bids, and import and export limits of respective LRZs. At a zero-clearing price, all zero-price and price-taking offers will be accepted.

Inadequate Supply

While the auction process will endeavor to select seasonal ZRC offers sufficient to meet the seasonal requirements of each LRZ, it is possible that sufficient resources are not available in the LRZ and the LRZ would thus be short of Planning Resources for that Season within the Planning Year. In such cases, the auction will clear all seasonal ZRC offers in the LRZ for that Season and, if the LRZ is short ZRC's to meet the seasonal requirements, the entire LRZ will clear at the LRZ's seasonal CONE value. If the LRZ is short of ZRC's to meet the requirements for more than one Season within the Planning Year, then the ACP for such Seasons will be determined as described in section 69A.7.1 of Tariff Module E-1.

5.5.4 Market Monitoring

All participation by Market Participants is subject to the market power mitigation rules regarding physical and economic withholding of capacity as described in Module D of MISO's Open Access Transmission Tariff and Market Monitoring BPM-009. All Planning Resources except for External Resources, Load Modifying Resources, and Energy Efficiency Resources are subject to physical and economic withholding monitoring. Below are additional details regarding the application of these market monitoring provisions. In addition to these details, please refer to Module D and BPM-009 Market Monitoring and Mitigation for additional details.

5.5.4.1 Physical Withholding

Sec. 64.1.1.d of Module D describes the Physical Withholding Provisions in the PRA. The IMM has established a Physical Withholding Threshold Limit of 50 MW per LRZ that is applied as a sum to a Market Participant (MP) and its Affiliates. Thus, there is a total of 50 MW of deliverable

SAC (ZRCs) whose rights are owned by an MP and its Affiliates in each LRZ that are not required to submit an offer into the PRA or be part of a FRAP or RBDC Opt Out. If the sum of deliverable SAC MW withheld exceeds the Physical Withholding Threshold Limit, the MP and its Affiliates would fail for conduct (Conduct Test) for physical withholding and be subject to the Impact Test described in Module D.

5.5.4.2 Economic Withholding

Sec. 64.1.2.d of Module D describes the Economic Withholding Provisions in the PRA. By default, each Planning Resource subject to economic withholding has an initial Reference Level for their PRA offer of $0/MW-Day. A Conduct Threshold equal to 10% of the LRZ Daily CONE (Daily CONE = LRZ CONE / 365) is allowed for a PRA offer without failing conduct (Conduct Test) for economic withholding and be subject to the Impact Test described in Module D.

An MP may submit a request for a Facility Specific Reference Level (FSRL) to the IMM. The request must be accompanied by evidence and documentation of Going Forward Costs (operating and capital) to operate the Planning Resource for the next Planning Year. Going Forward Costs must be sufficient detail to specify costs specific to suspension or retirement. Refer to BPM-009 Market Monitoring and Mitigation for additional details.

Market Participants have the option to use Default Technology Specific Avoidable Costs (DTSAC) calculated by the IMM as specified in Module D for operating cost recovery in lieu of submitting their own documentation for operating costs. The DTSAC values in Module D are broken down by different generator classifications for suspension and retirement requests. Refer to BPM-009 Market Monitoring and Mitigation for additional details.

5.5.5 Target Reliability Value

The resultant target reliability value for each Season for each LRZ will be the greater of the system-wide seasonal Planning Reserve Margin Requirement based on MISO’s seasonal PRM or the seasonal LCR value. The sum of these seasonal LRZ target reliability values will be the system’s target seasonal reliability value, that is, the amount of SAC MW that must be obtained, if available, from the auction.

5.5.6 Resource Offers

Any seasonal ZRCs that were not used in a FRAP or RBDC Opt Out can be offered into the seasonal PRA during the auction window period. The following business rules are applied to the seasonal ZRC offers for the seasonal PRA:

- Offer cannot be changed or withdrawn after the auction window is closed.
- Smallest Offer MW = 0.1 MW.
- Offer Segment defined as a price-quantity pair.
- Up to 5 Offer Segments per Planning Resource.
- Lowest Offer price is $0.00/MW-Day.
- Highest Offer Price for each Season and zones (LRZ and ERZ) is the annual LRZ/ERZ CONE divided by the total number of days in the Season.
- The Transmission Provider will clear offers based on the needs of the LRZ and not the size of a Resource (i.e., LRZ needs 50 MW, but Market Participant has a 100 MW Resource; only 50 MW will clear). At a zero-clearing price, all zero-price and price-taking offers will be accepted.

Self-Scheduling

LSEs that "self-schedule" ZRCs by submitting offers into the PRA(s) with a price of $0.00 will always clear the auction.

Sub-Regional Constraints

The Sub Regional Import Constraint (SRIC) and the Sub Regional Export Constraint (SREC) for each Sub Regional Resource Zone (SRRZ) are the transmission constraint parameters which must be respected, in addition to CILs and CELs for each LRZ, when conducting the PRA or in the Resource Replacement process. A SRRZ consists of more than one LRZ. The North/Central SRRZ consists of LRZs 1-7, and the South SRRZ consists of LRZ 8-10.

The Transmission Provider will establish and publish, on the Transmission Provider's public website, SRRZs, seasonal SRECs and seasonal SRICs as soon as practical but no later than the first business day of March for the following Planning Year.

5.5.7 Seasonal Simultaneous Feasibility Test (SFT)

Background

The test identifies transmission constraints resulting from power transfers between LRZs and imports to the MISO system from ERZs. To the extent transmission constraints cannot otherwise be mitigated via redispatch of seasonal Planning Resources while holding LRZ imports and exports constant, new seasonal CIL and CEL values (as applicable) are established. Resulting transfers in the auction will be simultaneously reliable and feasible. The seasonal SFT is completed after the seasonal auction clears and is driven by section 69A.7.1 of Tariff Module E-1.

Base Model

Base modeling represents the transmission topology and associated transmission ratings, Demand, and anticipated net interchange for the associated Season: summer, fall, winter, and spring. This is accomplished by the following modeling assumptions:

- Base model
    - Latest available MISO model with expected generation and transmission topology for the effective date of each Season within the Planning Year
- Transmission Topology
    - Includes Appendix A and other Model On Demand projects in-service by the effective date of the specific Season within the Planning Year
- Load
    - Final PRMR cleared through seasonal auction
    - LMRs are modeled as reduction of seasonal Final PRMR where LMRs are physically located
- Dispatch
    - Seasonal FRAP
    - Seasonal RBDC Opt Out
    - Seasonal ZRC offers cleared through the auction

- External representation
    - Latest Eastern Interconnection Reliability Assessment Group Multiregional Modeling Working Group series model matching Planning Year timeframe for each Season where applicable within the Planning Year

The latest seasonal models from the annual MISO series model build provides the best representation of the system and is a better representation than the one-year-old LOLE model used to establish the seasonal CIL and CEL limits. The latest model contains up-to-date topology and has gone through more recent stakeholder review.

Interchange Detail

External units that clear the auction are accounted for by Balancing Authority Area and then the interchange between MISO and the Balancing Authority Areas with cleared units is adjusted to represent the cleared amount. Units within MISO with an external capacity commitment will be dispatched to external load. Interchange will be adjusted to reflect the transaction.

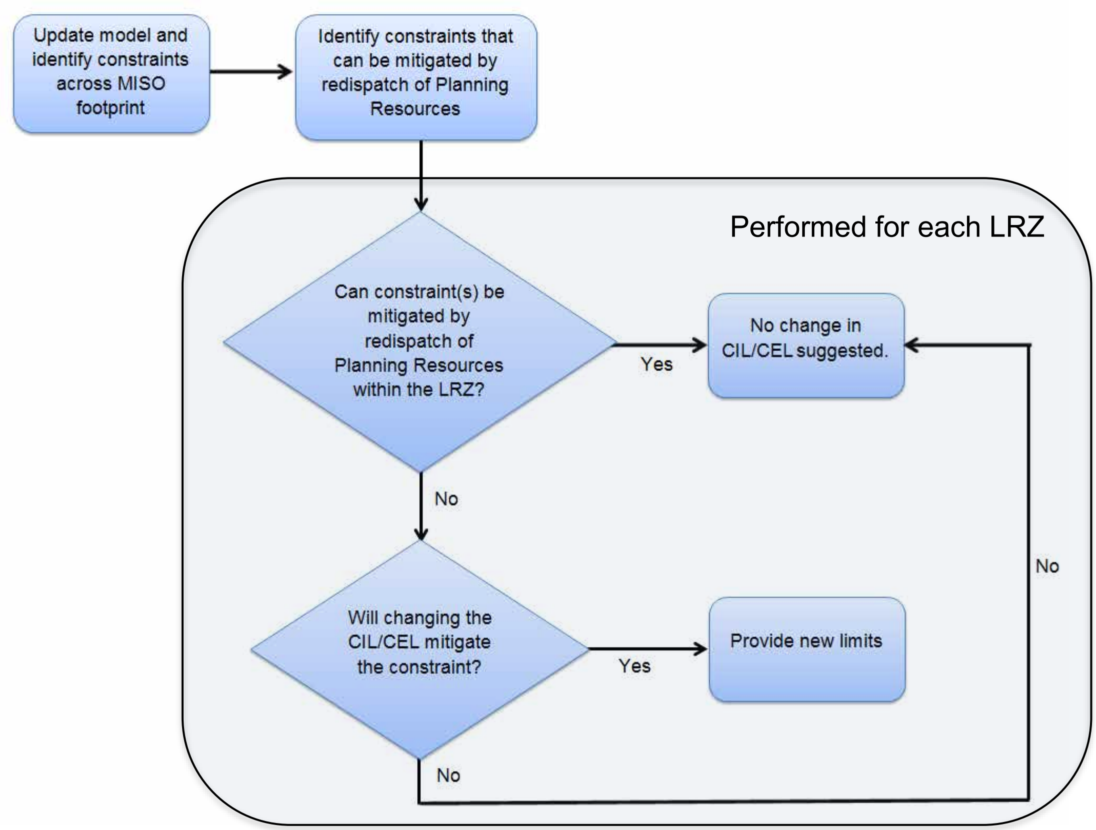
Topology Validation

Model checks are performed prior to the SFTs and PRAs. First, the ratings of facilities found to be limiting in the LOLE study are checked for rating changes. If the facility ratings are updated, the impact on seasonal CEL, CIL and/or ZIA must be determined and included as inputs to the PRAs. Transmission projects included in the LOLE models that were supposed to be in service by the effective date of the model, are validated and updated accordingly if a project's in-service date changes.

Power flow Analysis

The only controllable elements of the auction are the seasonal CIL and CEL. The seasonal SFT determines if any changes to CIL and CEL are required. The initial limits are determined in the annual LOLE study where seasonal CIL and CEL limits are established. These limits are an input to the initial auction clearing process. The SFT process is outlined in Figure 5.5 below.

Figure 5.5: SFT Process Flow



Seasonal CIL and CEL may be modified when the dispatch of Planning Resources within that Season outside the LRZ is the only action to mitigate constraints. To determine if changes are required, it must first be determined if the LRZ is an exporter or importer from the auction results of that Season. If the LRZ is an exporter within the seasonal CEL bounds, no change to limits should cause the LRZ to export more. Similarly, no change to limits should cause an importing LRZ to import more. The changes to limits that are impactful for exporters and importers are outlined as:

- Potential change if Planning Resources outside an LRZ is the only mitigation identified
- Decrease export or import limit if Planning Resources outside LRZ can be ramped up or down respectively to mitigate the constraint
- Decrease limit by MW amount needed to mitigate constraint

The Tariff allows for up to three iterations of the auction clearing process. The first iteration uses the seasonal CIL and CEL values from the LOLE study while the second and third iteration use any updated CIL and CEL values as determined by the seasonal SFT. The second and third iterations are performed only if needed. The clearing iterations are outlined as:

1st Pass

- Inputs to the auction clearing process are seasonal CILs and CELs from LOLE study, seasonal LCR, seasonal SRECs, and seasonal SRICs as applicable
- If all LRZs pass the SFT in that Season, auction results are final and the 2nd and 3rd iteration of auction clearing is not required.

2nd Pass

- Inputs to the auction clearing process are updated. Seasonal CILs and CELs from the 1st Pass and
- If all LRZs pass the SFT, results are final.

3rd Pass

- Inputs to the seasonal auction clearing process are updated. Seasonal CILs and CELs from the 2nd Pass if all zones pass the SFT, results are final. If at least one LRZ does not pass the SFT, the iteration with the fewest MWs of network violations will be deemed as the final auction result.

5.5.8 Auction Results Posting

MISO will post the summary of the Planning Resource Auction results on its website twenty (20) Business Days after the auction offer window is closed. The summary includes the following information for MISO system wide and each LRZ for each Season within the Planning Year: Final PRMR, Total Offer + FRAP+RBDC Opt Out, Offer Cleared + FRAP+RBDC Opt Out, LCR, Import Limit (CIL), Export Limit (CEL), Import/Export amount, ACP, deficient amount, and Total Offer Cleared volume for the system.

One month following the completion of any PRA, MISO will post the ZRC Offers in price/quantity pairs on its website without revealing the names of the Market Participants submitting such offers and the names of the Planning Resources offered.

Resource Adequacy Settlement

Transmission Provider will settle each PRA using the following steps:

1. Determine the ACP for ZRCs within each LRZ for every Season.
2. Determine each LSE’s Final PRMR. For details see 5.6.

3. Provide HUC credits equal to the zonal ACP differential to Load subject to HUCs in every Season in the Planning Year.
4. Provide ZDC Hedge credits equal to the zonal Auction Clearing Price differential to ZDC Hedge Load amounts in every Season in the Planning Year.
5. Provide ZDB credits to all remaining Final PRMR in the LRZ. The ZDB is a credit against the ACP paid by LSEs with Final PRMR in each LRZ in every Season in the Planning Year.

Settlement calculations for each Season in the PRA will be conducted on a daily basis and the results will be shown under the Real Time Settlements statement. Please refer to the Market Settlements BPM for further details. Below are charge types under the PRA(s) Settlement:

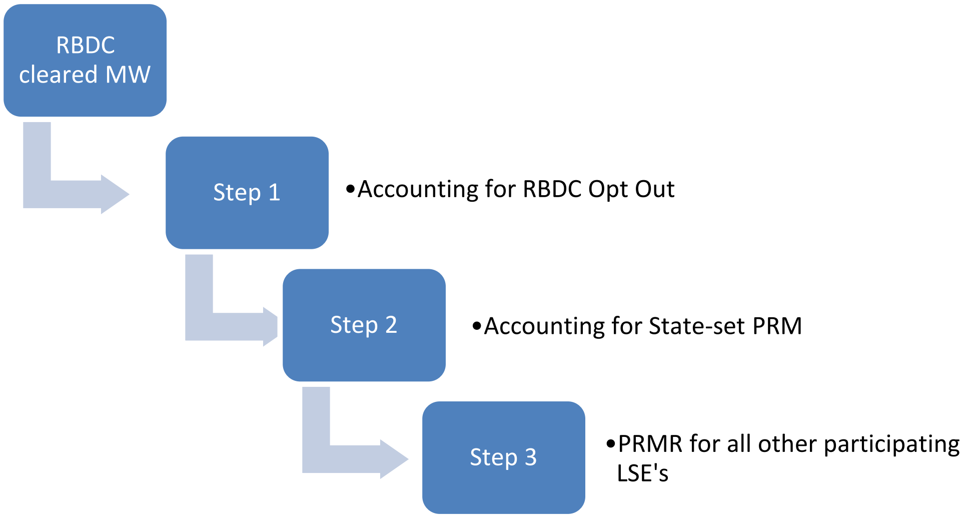
- PRA Charge
- Distribution of PRA Charge
- Zonal Deliverability Charge (ZDC) (*Only applies to the FRAP or RBDC Opt Out)
- Distribution of ZDC
- Capacity Deficiency Charge (Covered outside of the daily settlements)

Cleared seasonal ZRCs from Diversity Contracts that are not self-scheduled or in the LSE's seasonal FRAP or RBDC Opt Out will receive reduced payment based on the total number of days the external resource identified in the Diversity Contract are dedicated to MISO load when an LSE clears more seasonal ZRC in the PRA than its seasonal Final PRMR. The LSEs that converted SAC MW to seasonal ZRCs will receive the seasonal auction clearing price for the entire Season for those seasonal ZRCs that cleared in the seasonal PRA.

5.6 Final PRMR Allocation Process

The Final PRMR of an LSE is determined based on RBDC clearing and the LSE's participation option (such as RBDC Opt Out, market participation, etc.) in the PRA. The RBDC cleared MWs determined during the PRA clearing process will be allocated to determine LSE's Final PRMR using the steps outlined below (Figure 5.6).

Figure 5.6: Overview of Final PRMR allocation process



Step 1: Accounting for RBDC Opt Out

First, determine cumulative MWs corresponding to PRMR obligation of LSEs choosing the RBDC Opt Out option as per Section 5.3.2. Then, deduct this cumulative MWs from the total cleared MW from the PRA clearing. Remaining cleared MWs, if any, are then passed on to step 2.

Step 2: Accounting for State-set PRM

Then, the Final PRMR for LSEs who are under State jurisdiction with the State defined PRM is determined. For such LSEs, their Final PRMR is calculated based on the PRM defined by the respective State. Then, the sum of Final PRMR of LSEs who are under State jurisdiction with the State defined PRM is deducted from the remaining cleared MWs that were calculated in step 1. At the end of step 2, remaining cleared MWs, if any, are determined and then passed on to step 3.

Step3: Determine Final PRMR for other LSEs (Neither RBDC Opt Out nor under State-set PRM)

If the remaining cleared MWs after step 2 of the Final PRMR allocation process are greater than zero, then step 3 of the Final PRMR allocation process will be executed. In this step, remaining cleared MWs, determined in step 2 of the Final PRMR allocation process, will be distributed across remaining LSE’s not covered under step 1 or step 2 on a pro-rata basis with respect to their Coincident Peak Load Forecast including transmission losses.

For LSEs participating using FRAP provisions, the quantity that is covered through FRAP provisions will be considered after step 3 of the Final PRMR allocation process. Any additional ZRCs that such LSEs need to procure from the market to meet their share of Final PRMR, will be charged the applicable ACP.

Example 1: RBDC Out Out, No State setting PRM, & Final PRMR higher than Initial PRMR

Consider a system with three LSEs (LSE A, LSE B, and LSE C) and a system peak demand of 100 MW (accounting for the CPD forecast plus transmission losses).

PRA Participation:

- LSE A has a 15MW load and participates in the PRA using RBDC Opt Out provisions.
- LSE B has 50 MW load, and
- LSE C has 35 MW load.

Assumptions:

- No State has defined PRM for its jurisdictional entities
- MISO defined PRM to be 9%
- RBDC Opt Out Adder to be 4%
- Systemwide RBDC clearing in the PRA to be 112 MW (indicating RBDC clearing at 12% above load forecast)
- No SRIC/SREC binding

Final PRMR allocation calculation:

Step 1: Accounting for RBDC Opt Out

In this example, LSE A has 15 MW of load participating in the PRA using RBDC Opt Out provisions. Given a PRM of 9% and an RBDC Opt-Out Adder of 4%, the final PRMR for LSE A will be **16.95 MW**, calculated as 15 * (1 + 9% + 4%). After this allocation, 95.05 MW of cleared RBDC capacity will remain (112 MW - 16.95 MW) for further distribution in the following steps.

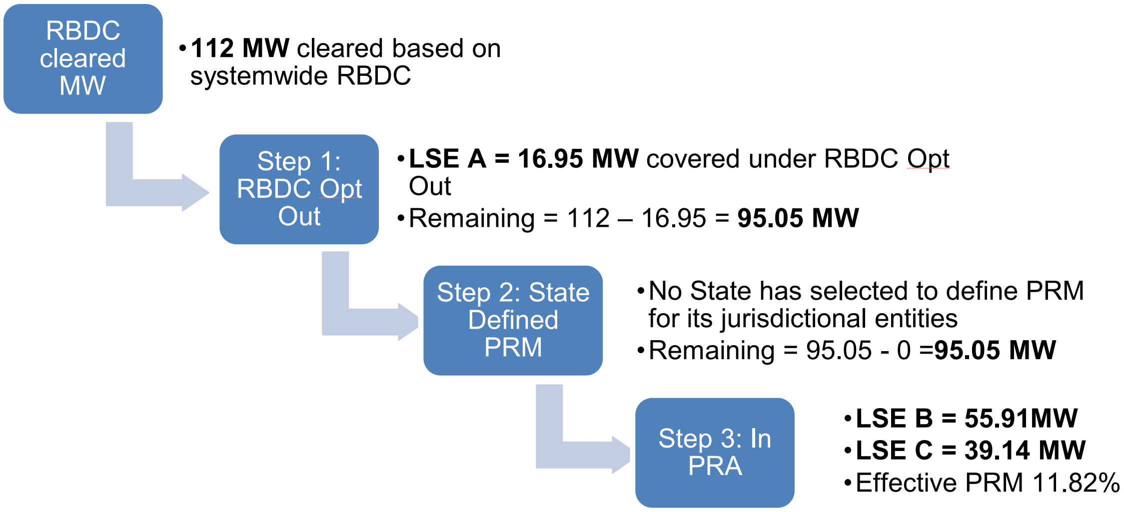
Step 2: Accounting for State-set PRM

In this example, there is no load subjected to State defined PRM. Hence, no Final PRMR is allocated in this step and 95.05 MW of cleared RBDC capacity will still remain (112 MW - 16.95 MW) for further distribution in the following step.

Step 3: Determine Final PRMR for other LSEs (Neither RBDC Opt Out nor under State-set PRM)

In step 3, remaining RBDC cleared 95.05 MW, determined after step 2 of the Final PRMR allocation process, will be distributed across remaining load which is not covered under step 1 or step 2 on a pro-rata basis. In this example, the remaining load after step 1 and step 2 is 85 MW. Hence, the Final PRMR for LSE B will be **55.91 MW**, calculated as 50 * (95.05/85), and the Final PRMR for LSE C will be **39.14 MW**, calculated as 35 * (95.05/85). The effective PRM for load participating in the PRA outside of RBDC Opt Out and State defined PRM is 11.82%.

The example is graphically summarized ahead.



- **112 MW** cleared based on systemwide RBDC
- **LSE A = 16.95 MW** covered under RBDC Opt Out
- Remaining = 112 – 16.95 = **95.05 MW**
- No State has selected to define PRM for its jurisdictional entities
- Remaining = 95.05 - 0 =**95.05 MW**
- **LSE B = 55.91MW**
- **LSE C = 39.14 MW**
- Effective PRM 11.82%

Example 2: RBDC Opt Out, State setting PRM, & Final PRMR higher than Initial PRMR

Consider a system with three LSEs (LSE A, LSE B, and LSE C) and a system peak demand of 100 MW (accounting for the CPD forecast plus transmission losses).

PRA Participation:

- LSE A has a 15 MW load and participates in the PRA using RBDC Opt Out provisions
- LSE B has 50 MW load and subjected to State defined PRM of 10%
- LSE C has 35 MW load

Assumptions:

- MISO defined PRM to be 9%
- RBDC Opt Out Adder to be 4%

- Systemwide RBDC clearing in the PRA to be 112 MW (indicating RBDC clearing at 12% above load forecast)
- No SRIC/SREC binding

Final PRMR allocation:

Step 1: Accounting for RBDC Opt Out

In this example, LSE A has 15 MW of load participating in the PRA using RBDC Opt Out provisions. Given a PRM of 9% and an RBDC Opt-Out Adder of 4%, the final PRMR for LSE A will be **16.95 MW**, calculated as 15 * (1 + 9% + 4%). After this allocation, 95.05 MW of cleared RBDC capacity will remain (112 MW - 16.95 MW) for further distribution in the following steps.

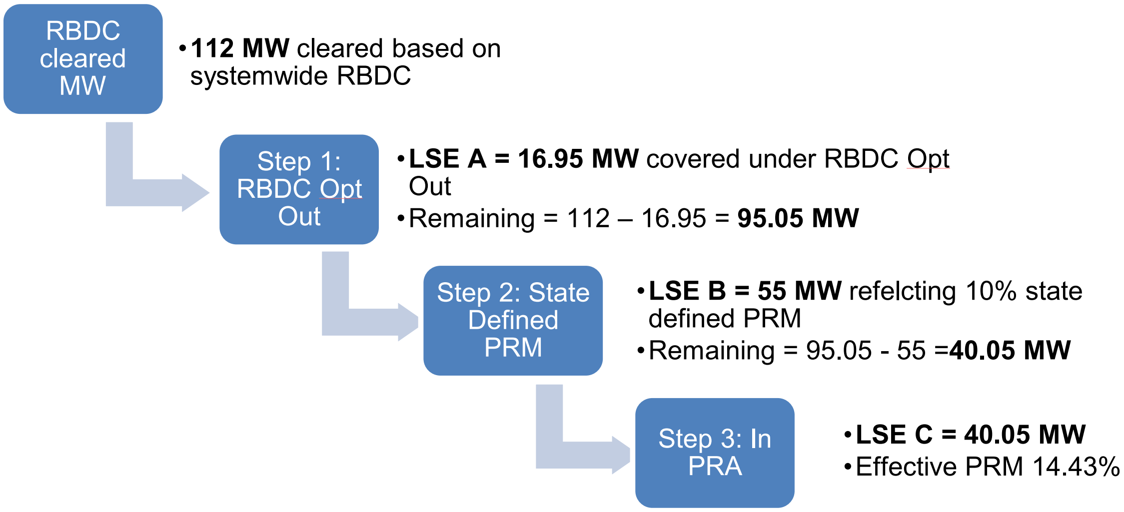
Step 2: Accounting for State-set PRM

In this example, LSE B’s load is subjected to State defined PRM of 10%. Hence, the Final PRMR for LSE B is **55 MW**, calculated as 50*(1 + 10%). After this allocation, 40.05 MW of cleared RBDC capacity will remain (95.05 MW – 55 MW) for further distribution in the following step.

Step 3: Determine Final PRMR for other LSEs (Neither RBDC Opt Out nor under State-set PRM)

In step 3, the remaining RBDC cleared 40.05 MW, determined after step 2, will be distributed across remaining load which is not covered under step 1 or step 2 on a pro-rata basis. In this example, the remaining load after step 1 and step 2 is 35 MW. Hence, the Final PRMR for LSE C will be **40.05 MW**, calculated as 35 * (40.05/35). The effective PRM for load participating in the PRA outside of RBDC Opt Out and State defined PRM is 14.43%.

The example is graphically summarized ahead.



- **112 MW** cleared based on systemwide RBDC

- **LSE A = 16.95 MW** covered under RBDC Opt Out
- Remaining = 112 – 16.95 = **95.05 MW**

- **LSE B = 55 MW** refelcting 10% state defined PRM
- Remaining = 95.05 - 55 =**40.05 MW**

- **LSE C = 40.05 MW**
- Effective PRM 14.43%

Example 3: RBDC Opt Out, State setting PRM, & Final PRMR lower than Initial PRMR

Consider a system with three LSEs (LSE A, LSE B, and LSE C) and a system peak demand of 100 MW (accounting for the CPD forecast plus transmission losses).

PRA Participation:

- LSE A has a 15 MW load and participates in the PRA using RBDC Opt Out provisions.
- LSE B has 50 MW load and subjected to State defined PRM of 10%.
- LSE C has 35 MW load.

Assumptions:

- MISO defined PRM to be 9%
- RBDC Opt Out Adder to be 4%
- Systemwide RBDC clearing in the PRA to be 108 MW (indicating RBDC clearing at 8% above load forecast, lower than PRM)
- No SRIC/SREC binding

Final PRMR allocation:

Step 1: Accounting for RBDC Opt Out

In this example, LSE A has 15 MW of load participating in the PRA using RBDC Opt Out provisions. Given a PRM of 9% and an RBDC Opt-Out Adder of 4%, the final PRMR for LSE A will be **16.95 MW**, calculated as 15 * (1 + 9% + 4%). After this allocation, 91.05 MW of cleared RBDC capacity will remain (108 MW - 16.95 MW) for further distribution in the following steps.

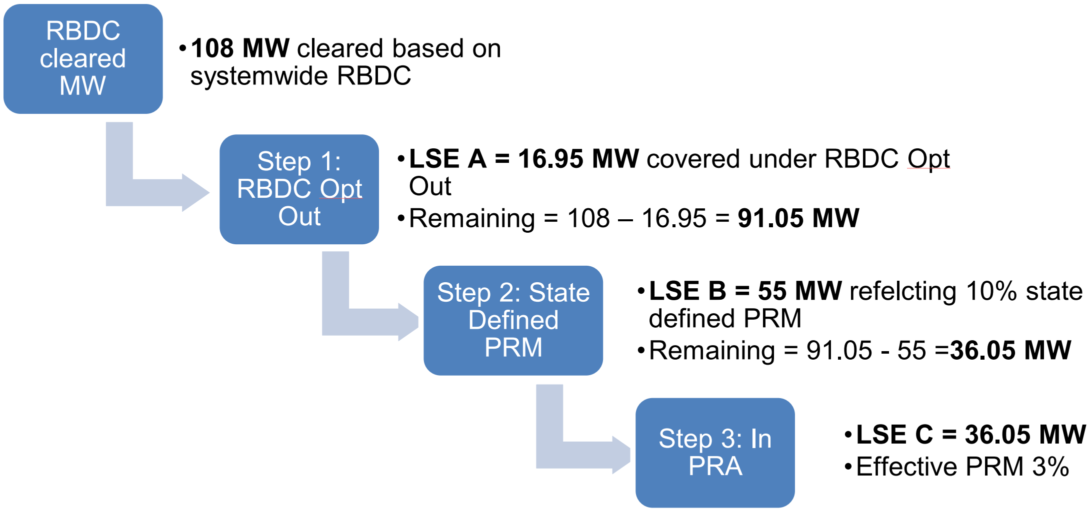
Step 2: Accounting for State-set PRM

In this example, LSE B's load is subjected to State defined PRM of 10%. Hence, the Final PRMR for LSE B is **55 MW**, calculated as 50*(1 + 10%). After this allocation, 36.05 MW of cleared RBDC capacity will remain (91.05 MW – 55 MW) for further distribution in the following step.

Step 3: Determine Final PRMR for other LSEs (Neither RBDC Opt Out nor under State-set PRM)

In step 3, the remaining RBDC cleared 36.05 MW, determined after step 2 of the Final PRMR allocation process, will be distributed across remaining load which is not covered under step 1 or step 2 on a pro-rata basis. In this example, the remaining load after step 1 and step 2 is 35 MW. Hence, the Final PRMR for LSE C will be **36.05 MW**, calculated as 35 * (36.05/35). The effective PRM for load participating in the PRA outside of RBDC Opt Out and State defined PRM is 3%.

The example is graphically summarized ahead.



- **108 MW** cleared based on systemwide RBDC

- **LSE A = 16.95 MW** covered under RBDC Opt Out
- Remaining = 108 – 16.95 = **91.05 MW**

- **LSE B = 55 MW** refelcting 10% state defined PRM
- Remaining = 91.05 - 55 =**36.05 MW**

- **LSE C = 36.05 MW**
- Effective PRM 3%

5.7 Retail and Wholesale Load

Retail and Wholesale Load switching between LSEs can be tracked through the MECT after the start of the in each Season within the new Planning Year. As a result of load switching, the seasonal Final PRMR of the LSEs involved in the load switching will change. Switching of seasonal Retail load will not change an Electric Distribution Company's (EDC) total area seasonal Final PRMR. Similarly, wholesale seasonal load transaction will not change the total MISO seasonal Final PRMR.

5.7.1 Retail Load Switching

By January 15 11:59 p.m. EST prior to the start of the new Planning Year, retail supplier LSEs will confirm their share (e.g. PLC) of the EDC's area seasonal Initial PRMR. After the Planning Year starts, the Retail LSE's seasonal Final PRMR will change during each Season within the Planning Year when the load from one LSE is switched to another LSE within the EDC area.

Market Participants with Demand in areas subject to retail choice are required to provide the name of the EDC and the CPNode names associated with the LSEs within the EDC area at the time of registration. The CPNode to EDC mapping information is important for determining LSEs' retail load switching method.

EDCs are responsible for updating the seasonal Final PRMR associated with each retail choice LSE in the MECT. The Retail Load screen in the MECT is provided for EDCs in Retail Choice states to track the Retail LSE's day-to-day migration of loads at the Asset Owner (AO) level.

Using the daily retail load switching information in the MECT, MISO Settlements calculates each retail choice LSE's new seasonal Final PRMR. The LSEs' PRMR are subject to resettlement calculations based on the resubmission of load switching information.

The daily retail load switching information includes:

- Name of the EDC
- Name of the LBA
- Operating Date of Retail load switching
- Season (Summer, Fall, Winter or Spring)
- Name of AO(s)
- AO's new Retail MW (with granularity of tenth of a MW)

5.7.2 Wholesale (Non-Retail) Load Switching

A Wholesale Load obligation can be switched from one LSE to another using the Wholesale Load Switching screen in the MECT during each Season of the Planning Year. When Wholesale Load switching occurs, the daily capacity charges of the Wholesale Load will be transferred from the current LSE to the new LSE. The seasonal Final PRMR for affected LSEs will be decreased or increased, as appropriate, by the amount of the wholesale load plus the seasonal PRM. Procedures for billing, settlement, and credit requirements will be as specified in the appropriate BPMs. LSEs with wholesale contracts that change during the Season within the Planning Year may enter a Wholesale Load switching contract representing seasonal Final PRMR in the MECT.

For the case of Wholesale Load switching, the amount of the seasonal Final PRMR transferred via the wholesale load transaction process will transfer the Final PRMR of the current LSE to the new LSE starting with the effective date specified in the wholesale transaction for the applicable Season. The transaction must be confirmed in the MECT by both parties before the start of the effective date.

5.7.3 Peak Load Contribution (PLC)

The EDC calculates each retail LSE's load ratio share of the retail LSEs peak Demand of the EDC's peak Demand at the MISO seasonal Coincident Peak Load prior to the Planning Year. The aggregate PLCs will be set equal to the seasonal Initial PRMR of the EDC. Specific methods used by the EDC to calculate each Retail LSE's PLC must be provided to both MISO and LSEs no later than December 15 prior to the upcoming Planning Year. LSEs will have until January 15 prior to the upcoming Planning Year to verify the seasonal EDC provided data in the MECT.

5.7.4 Settlements of Wholesale and Retail Switching

All confirmed load switching information submitted by the Settlements deadline (per the Market Settlements BPM) will be transferred to Market Settlements for settlement calculation purposes.

An LSE's seasonal Final PRMR will change based on the information submitted in the MECT for both Wholesale and Retail Load Switching.

MISO will calculate the new charges and credits by applying the seasonal Auction Clearing Price ("ACP") for the applicable LRZ to the new daily seasonal Final PRMR for each AO.

At the end of each weekly billing cycle, MISO will sum up the daily charges for each LSE for the weekly invoicing. The Market Settlements BPM provides more information regarding this process. An LSE's seasonal Final PRMR will change if Retail Load switching information in the

MECT or daily load data for Settlements is resubmitted per the Settlement's rerun process (i.e., S55, S105). Please see Market Settlements BPM for the Market Settlements Timeline.

5.8 Capacity Deficiency Charge

LSEs are allowed to opt out all or a portion of their seasonal Initial PRMR from participating in the auction by paying the Capacity Deficiency Charge. This is achieved by making a voluntary entry into the "Capacity Deficient Amount (MW)" field of the MECT equal to the MW amount of seasonal Initial PRMR opting out of the seasonal auction before the auction window opens. The Capacity Deficiency Charge for an LSE is the MW amount in the "Capacity Deficient Amount (MW)" field multiplied by 2.748 times the seasonal Cost of New Entry ("CONE") which is calculated by Annual CONE/365 multiplied by the days in the Season for the LRZ where the LSE's seasonal Initial PRMR is located.

LSEs that choose the RBDC Opt Out must demonstrate sufficient ZRCs to meet their seasonal Final PRMR (equal to the Initial PRMR) before the PRA auction window opens. Otherwise, the shortfall is subject to the Capacity Deficiency Charge by multiplying 2.748 times the seasonal CONE price.

Capacity Deficiency Charge revenues received by the Transmission Provider will be distributed on a *pro rata* basis based upon the cleared MW of seasonal Final PRMR to other LSEs in the Transmission Provider's footprint who did not opt to pay the Capacity Deficiency Charge. If the LRZ where the LSE opted to pay the Capacity Deficiency Charge failed to meet its seasonal LCR, then seasonal Capacity Deficiency Charge revenues will be allocated solely to LSEs within that LRZ that did not opt out of the seasonal auction by paying the seasonal Capacity Deficiency Charge. MISO will assess the seasonal Capacity Deficiency Charge on the first business day after the results of the seasonal PRA have been published.

6 Performance Requirements

6.1 Must Offer Requirement

The must offer requirement applies to any Market Participant who converts the SAC of a Capacity Resource to seasonal ZRCs, and those ZRCs are used in a seasonal FRAP or RBDC Opt Out or clear in a seasonal auction within the Planning Year. The must offer volume is the effective ICAP times the % of the total seasonal ZRCs a resource clears (for example, a unit eligible for 10 ZRCs that clears 5 will have a must offer of 50% of its ICAP), except for

Intermittent Resources. The effective ICAP equals the lesser of GVTC or Interconnection Service (NRIS+ERIS) for each Season (e.g. effective ICAP = Min(GVTC, IS)). The must offer obligation for Intermittent Resources is based on the cleared seasonal ZRCs, or ZRCs used in a FRAP or RBDC Opt Out, divided by the seasonal Resource credit (e.g. wind capacity credit for a wind resource) as described in Section 4.2.1.5 – Wind and Solar Capacity Credit. Additionally, no must offer requirement will exceed the resource's firm level of transmission service. LMRs do not have a must offer requirement, their obligations are covered in section 4.2.5 - Load Modifying Resource Obligations and Penalties.

6.1.1 Generation Resource but not Dispatchable Intermittent Resource or Intermittent Generation

MPs that own a Capacity Resource with ZRCs that clear in the PRA or are identified in a Fixed Resource Adequacy Plan (FRAP) or RBDC Opt Out must offer the ICAP equivalent of the cleared and FRAP or RBDC Opt Out ZRCs into the Day-Ahead Energy Market and the first post Day-Ahead Reliability Assessment Commitment (RAC) for every hour of every day, except to the extent that the Capacity Resource is unable to provide Energy, Contingency Reserve, or Short-Term Reserve due to a forced or planned outage or other physical operating restrictions consistent with MISO's Tariff. Outages and derates must be reported in the MISO Outage Scheduler (CROW).

Compliance with "must offer" requirements will be evaluated by MISO on a non-discriminatory basis. MISO will analyze compliance with "must offer" requirements in both the Day-Ahead and RAC by considering information provided by the MISO Outage Scheduler (CROW) and operational limitations, including, but not limited to, those related to fuel limited, Energy output limited or Intermittent Generation and Dispatchable Intermittent Resources.

6.1.2 Dispatchable Intermittent Resource and Intermittent Generation

An MP that owns a Capacity Resource that has ZRCs identified as part of a Fixed Resource Adequacy Plan (FRAP) or RBDC Opt Out or ZRCs which clear in a PRA must submit the ICAP equivalent MW value of the cleared ZRCs into the Day-Ahead Energy Market, and each pre Day-Ahead and the first post Day-Ahead Reliability Assessment Commitment (RAC) for every hour of every day, except to the extent that the Intermittent Resource is unable to provide Energy, Contingency Reserve, or Short-Term Reserve due to a forced or planned outage or other physical operating restrictions consistent with MISO's Tariff.

The must offer requirement applies to the effective ICAP of the Intermittent Generation and Dispatchable Intermittent Resources, and not to the SAC amount. The must offer obligation for Intermittent Resources is replaced with the forecast in the DA market based on the weather forecast and performance of the Intermittent Resources.

For wind resources, the ICAP-equivalent must offer obligation is cleared ZRCs and/or ZRCs used in a Fixed Resource Adequacy Plan divided by the wind capacity credit. For non-wind Intermittent Generation and Dispatchable Intermittent Resources, the XEFORd will be set equal to the SAC divided by the ICAP, where the ICAP shall be the maximum value registered in the Commercial Model. For non-wind Intermittent Resources not modeled in the Commercial Model, the ICAP will be the nameplate capacity value as provided by the MP.

DA Reliability Forecast submissions for Intermittent Generation and Dispatchable Intermittent Resources received by the close of both the DA and Forward Reliability Assessment Commitment (FRAC) market offer periods will be used to monitor compliance with the must offer requirement when the unit’s availability is affected by non-mechanical and/or non-maintenance reasons. The must offer monitoring process for Intermittent Generation and Dispatchable Intermittent Resources that submit a DA Reliability Forecast by DA Market close and FRAC close will check that the offers submitted are greater than or equal to the volumes submitted via the DA Reliability Forecast. The same Intermittent Forecast data file used in Day-Ahead Must Offer compliance shall be utilized in FRAC if no further update is provided. If a DA Reliability Forecast is submitted on time and in the correct format, it replaces the cleared Installed Capacity as the mustoffer requirement. Intermittent Resource Generation cannot submit a DA Reliability Forecast if being registered as a Use Limited Resource.

When submitting data to the Intermittent Resource Forecast Update tool, a header row should be included at the beginning of the file in this format; Resource, Day, Hour Ending (HE), and MW. The must offer monitoring process for Intermittent Generation and Dispatchable Intermittent Resources that do not to provide the DA Reliability Forecast by the DA Market close and the FRAC close, will be based on offers submitted and outages or derates submitted in MISO’s Outage Scheduler (CROW). The must offer process will be based on the daily and hourly offers submitted by the Asset Owner. Additionally, maintenance and mechanical outages to Intermittent Forecasts will be based on the forecasts only. The thresholds established in Section 6.1 will not be used for Intermittent Generation and Dispatchable Intermittent Resources that provide the DA Reliability Forecast.

6.1.3 Use Limited Resource

An MP that commits a Capacity Resource that has ZRCs which clear in a Planning Resource Auction (PRA) or are used in a Fixed Resource Adequacy Plan must submit the ICAP value of ZRCs which either clear the PRA or is used in a Fixed Resource Adequacy Plan in the Day-Ahead Energy Market, each pre Day-Ahead, and the first post Day-Ahead Reliability Assessment Commitment (RAC) for every hour of every day, except to the extent that the Generation Resource is unable to provide Energy, Contingency Reserve, or Short-Term Reserve due to a forced or planned outage or other physical operating restrictions consistent with MISO’s Tariff.

A Use Limited Resource is required to submit into the Day-Ahead Market to satisfy the must offer requirement of at least four (4) continuous hours daily across MISO’s forecasted daily peak (including weekends). The must offer period of four (4) hours includes the two (2) hourly intervals prior to the forecasted peak hour, the peak hourly interval, and one (1) hourly interval after the forecasted peak load. This approach enables MISO to have an opportunity to schedule the Resource for the period in which the Use Limited Resource will not be recharging or replacing depleted resources. MISO’s peak period will be based on the forecast published one day prior to the operating day in the Market Report section of the MISO website:
https://www.misoenergy.org/markets-and-operations/real-time--market-data/market-reports
>Select “Summary” under Navigator to find the latest reports.
All outages and derates for Use Limited Resources need to be reflected in MISO’s Outage Scheduler (CROW) or SDX. Thresholds for Use Limited Resources will only be applied during the four continuous hours across MISO’s peak. MISO will not call upon a Use Limited Resource during its recharge hours, except in the case of an Emergency.

6.1.4 External Resources

The maximum must offer requirement applies to the registered capacity of the External Resource.

An MP that owns a Capacity Resource that has ZRCs which are identified in a Fixed Resource Adequacy Plan (FRAP) or RBDC Opt Out or clear in a PRA must submit the ICAP-equivalent value of FRAP or RBDC Opt Out or cleared ZRCs as Energy offers into the Day-Ahead Energy Market for every hour of every day, except to the extent that the Generation Resource is unavailable due to a full or partial forced scheduled outage or the offers are from a Use Limited Resource. The must offer requirement will be capped at the resource's ICAP value.

Offers in the Day-Ahead Energy Market can only be Normal Energy type, with the transaction type of either fixed or dynamic. Dispatchable and market type of Day-Ahead cleared schedules are accounted for in the first post Energy and Operating Reserve Market. In addition, the Normal Energy type with the transaction type of either Fixed or Dispatchable offers with market type of Real-Time Energy and Operating Reserve Market only will also be considered in Day-Ahead Forward Reliability Assessment Commitment (FRAC).

Therefore, the must offer requirement for External Resources in FRAC is met by being available for declared capacity emergencies via MISO Market Capacity Emergency SO-P-EOP-00-002.

The MP that has either identified ZRCs from a FRAP or RBDC Opt Out or cleared ZRCs in a Planning Resource Auction (PRA) from an External Resource shall ensure the resource operator is reporting its outages and derates with their respective reliability coordinator. External Resources must be available to schedule Energy into MISO during Emergencies if needed by MISO. MISO Market Capacity Emergency SO-P-EOP-00-002 includes a mechanism to schedule all External Resources into MISO's Balancing Authority Area. BPM 007 Physical Scheduling Systems Section 15 explains how External Resources should be identified as Capacity Resources. External Resources should select "YES" in the Miscellaneous (MISC) field of the E-tag and the Token field must contain "MISOCR" in all capital letters with no spaces. In the Value field, the MP should list the Capacity Resource name that matches the Module E External Resource registration name in the MECT.

External Resources that are Use Limited Resources must follow the Day-Ahead must offer requirements for Use Limited Resources as documented in Section 4.2.2.1 of this BPM.

Compliance with must offer requirements will be evaluated by MISO on a non-discriminatory basis. MISO will analyze the compliance with must offers in both the Day-Ahead and RAC by considering information provided by MISO's CROW Outage Scheduler, and operational limitations, including, but not limited to, those related to fuel limited, Energy output limited, or Intermittent Generation.

6.1.5 DRR T*ype I and Type II*

The same must offer requirement described in Sec. 6.1 applies to the Installed Capacity of DRR Type I and Type II, (and not the SAC rating) used to meet Resource Adequacy Requirements. Installed Capacity refers to the amount of ZRCs cleared in an PRA and/or used in a Fixed Resource Adequacy Plan divided by (1 – XEFORd) of the Capacity Resource.

6.2 Must Offer Monitoring

MISO will monitor whether the offers submitted by the Asset Owner of each Capacity Resource in the Day-Ahead Energy and Operating Reserve Market, and first post Day-Ahead RAC process meets the seasonal must offer requirements. The must-offer requirements are in terms of Installed Capacity (ICAP) of the resource, where ICAP is the minimum of GVTC and Total Interconnection Service.

The offers should be greater than or equal to the seasonal must offer requirement minus approved outages or derates minus the applicable threshold as detailed in this section, but not to exceed the firm level of established Transmission Service. This excludes Capacity Resources that submit Intermittent Forecasts that have been accepted by MISO including DIR- registered Hybrid Resources.

[Firm Service] > [Offer] ≥ [Offer requirement] – [Outage or Derate] – [tolerance threshold]

If the offer amount is greater than or equal to the must offer requirement minus the approved outage or derate in CROW minus the appropriate threshold, then the MP will have passed the must offer monitoring check. Otherwise, the MP will not pass the must offer monitoring check. MISO will notify MPs through a report published on the market portal of their must offer status.

Outages & Derates

If the Offers for Day-Ahead and first post Day-Ahead RAC are less than the must offer requirement, then MISO will compare the difference to approved outages or derates in MISO's Outage Scheduler (CROW) for such resources. Approved outages, approved derates, and offers will be captured based on the information provided at both the Day-Ahead Energy Market close and first post Day-Ahead RAC close. DA Market close and first post Day-Ahead RAC close times are addressed in the Energy and Operating Reserve Markets BPM.

Tolerance Threshold

MISO will apply a tolerance threshold to all resources based on the must offer requirement listed in the MECT for the applicable Season. The thresholds were developed to recognize that data entry errors could occur when providing derate volumes through MISO’s Outage Scheduler (CROW). Importantly, this does not relieve the MP of the obligation to meet the overall seasonal must offer requirement. The tolerance threshold volume will be applied at the CPNode level except for those resources noted otherwise in this BPM. The thresholds are as follows:

- The lesser of 10 MW or 10% for Capacity Resources greater than or equal to 50 MW
- The greater of 1 MW or 10% for Capacity Resources less than 50 MW

Market Participant Review

If a Market Participant believes there is a discrepancy in their must offer report, the Market Participant can notify MISO via the MISO Help Center of the discrepancy and submit supporting documentation. Outage information should include all revisions from the outage submission to the completion of the outage.

MISO will review the information submitted and notify the Market Participant within seven (7) Business Days via email of the outcome of the review.

IMM Access

The IMM also has access to the reports published on the market portal and may contact Market Participants directly on any compliance issues.

6.3 Annual Calculation of CONE

MISO will work with the Independent Market Monitor (IMM) to recalculate the CONE value for each LRZ annually by September 1 of each year for the following Planning Year. The CONE value for each individual LRZ will be the same in every Season (Summer, Fall, Winter and Spring).

In calculating CONE values, the IMM and MISO will consider the following factors:

- Physical factors: type of resource, location, costs for fuel
- Financial factors: debt/equity ratio, cost of capital, ROE, taxes, interest, insurance
- Other factors: permitting, environmental, Operating and Maintenance costs, etc.

MISO and the IMM will not consider anticipated net revenues from the sale of capacity, Energy, or Ancillary Services as factors in the annual recalculation of the CONE.

Once the IMM and MISO have calculated the CONE for each LRZ, MISO will make a filing with the Commission under Section 205 of the Federal Power Act seeking approval from the Commission for the re-calculated CONE. CONE values approved by FERC are posted on the MISO website.

Net CONE will be determined as per the section 69A.8 of Tariff Module E-1.

6.4 Replacement Resources

6.4.1 Maximum Outage & Derate Threshold (Greater than 31 day rule)

If a Planning Resource for which a Market Participant converts Seasonal Accredited Capacity into ZRCs is unable to meet the applicable performance requirements for the cleared ZRCs as described in Section 69A.5 for greater than thirty-one (31) Days in total due to full or partial Generator Planned Outage during the Season of the Planning Year in which the ZRCs cleared, or for Planning Resources that are subject to Diversity Contracts or Power Purchase Agreements for greater than one (1) Month during any Season of the Planning Year in which the ZRCs cleared, such Market Participant must replace the cleared ZRCs with uncleared ZRCs or new resources per Section 6.4.5 (On Ramping New Resources Mid-Planning Year for ZRC Replacement) to transfer the performance requirements applicable to the planning Resource or pay the Capacity Replacement Non-Compliance Charge (Tariff Module E-1 Section 69A.3.1.h). The CRNCC charge will be calculated after the completion of the season in the timeliest manner by MISO and the IMM.

The Must Offer Monitoring threshold described in section 6.2 (Must Offer Monitoring) will not apply when evaluating charges and ZRC replacement regarding the 31-day outage rule. The performance obligation is in terms of effective ICAP and thus the amount of ZRCs needed to be replaced will back calculate to ZRC values.

For example, a wind resource that has a 100 MW ICAP and 20 MW SAC and clears 20 ZRCs in the market will have a must offer requirement of 100 MW. The forecasts submitted to the DA market will overwrite the 100 MW requirement based on projected wind performance on an hourly basis. If the wind resource undergoes planned maintenance or repowering and planned derates the facility to 80 MW ICAP for an entire Season, they will need to replace ZRCs when outages in a Season exceed 31 days since derate ICAP (must offer requirement – derates of facility 100-80=20MW) is greater than zero, and the amount of ZRCs to be replaced will be in SAC/ZRC terms. The original ICAP is 100 MW which resulted in 20 MW SAC, the resource is on a derate of 20 MW down to 80 MW, thus resulting in only 4 ZRCs needing replacement. 20 MW SAC / 100 MW ICAP = 20%, 20MW derate ICAP *20% = 4ZRCs. To complete the example, 80 MW ICAP*20% = 16 MW SAC. The cleared SAC obligation is 20 ZRCs, and the derate results in 16 ZRCs, therefore 4 ZRCs must be replaced, or charges assessed for any days over 31 in that Season.

$$\frac{20\,ZRC}{100\,ICAP} = 20\%\ Original; 20MW\ ICAP\ derate * 20\% = 4\ ZRC$$

Similarly, for conventional resources the conversion process is the same. For example, a 100 MW ICAP thermal resource has 50 MW SAC, if they clear all 50 ZRCs in the auction for that Season the must offer obligation is still 100 MW. If the resource is derated to 80 MW, the ZRCs needing to be replaced will be: 80 MW *50% = 40 MW, with a 50 MW SAC obligation, so 10 ZRCs would need to be replaced or charges assessed when the outage exceeds 31 days within that Season.

For resources that are completely offline due to planned or reasonably known outages for greater than 31 days, the penalty would be assessed on the cleared ZRCs of that resource, regardless of resource type. The CRNCC would be charged to the asset owner who converted SAC to ZRCs.

6.4.2 Attachment Y Retirement or Suspend Status

A Planning Resource used to meet seasonal RAR must be replaced by the registering Market Participant prior to the effective date of a status change to ‘retired’ or ‘suspend’ via an Attachment Y filing.

6.4.3 Transfer of Resource Adequacy Requirement and Performance Requirements through ZRC Replacement

ZRC replacement is available for use by Planning Resources that cleared a Season in the Planning Year and that go on suspension, retirement, catastrophic outage, ICAP Deferral, or that experience a Generator Planned Outage or derate greater than 31 days in that Season. Planning Resources already on a forced outage or knowingly offline during the effective date, cannot be used for ZRC Replacement. ZRC replacements are not allowed for any other reason.

In the event of such ZRC Replacement any performance requirements associated with the Resource that is being replaced (e.g., must offer obligation) will be transferred to the substituting Resource(s) for the duration of the ZRC Replacement period. ZRC Replacement is forward looking, MPs cannot replace ZRCs retroactively.

A Resource being used for ZRC replacement must not be on a full or partial Generator Planned Outage during the term of the ZRC replacement and must otherwise meet the applicable performance requirements set forth in section 69.A.3.1.h of Module E-1 of the Tariff.

6.4.4 ZRC Replacement Transactions

Replacement transactions in each Season can be entered at any time during the Planning Year and, unless otherwise modified, are valid through the end of the applicable Season within the Planning Year.

Replacement ZRCs may be sourced from any LRZ or ERZ subject to LCR, CIL, CEL, SREC, and SRIC constraints from the associated seasonal PRA. A replacement calculator is available in the MECT to check for any constraint violation. Planning Resource replacement transactions should be entered into the MECT tool at least seven (7) Calendar Days prior to effective date of replacement to ensure it has been entered and validated properly. This ensures adequate time for MPs and MISO staff to review and confirm accurate and proper entry of the ZRC replacement.

Replacement ZRCs can be from the Market Participant’s own Planning Resources or ZRCs procured through a bilateral transaction from another Market Participant in the same seasonal auction These ZRCs can be sourced from other LRZ’s provided they do not violate any LCR, CIL, CEL, SRIC or SREC. ZRC replacements from LRZs other than the original resource will be processed in accordance with the following parameters:

- ZRC replacement shall be processed on a first come, first served basis.
- The amount of cleared seasonal ZRCs in each LRZ at the time of a ZRC replacement shall be based upon the current amounts of cleared seasonal ZRCs, including any previous replacement transactions.

Replacement ZRCs should be input in the MECT with an intended effective date. The termination date of a Replacement ZRC transaction will be set as end of the Season by default. Market Participants can update the termination date to a different date before end of the

Season, provided that replacement capacity must be designated for RAR until at least 95% of its ZRCs have been replaced.

ZRC replacement shall have no impact on settlements from the PRA and FRAPs and RBDC Opt Out. The "Replacement Calculator" option is available in the MECT which can be used for verifying if the Planning resource being used for the replacement will meet all of the required LRZ parameters including LCR, CIL and CEL, as well as ERZ CEL.

6.4.5 On Ramping New Resources Mid-Planning Year for ZRC Replacement

If a new resource is expected to be available at the start of a Season within the Planning Year, the preferred course for the Market Participant would be to enter the ICAP Deferral process.

However, if a new resource is unable to utilize the ICAP Deferral Process, the new resource may be eligible to receive uncleared Zonal Resource Credits (ZRCs) in the middle of the Planning Year and prior to the start of a Season only under the following conditions:

i. Market Participant must coordinate with the IMM to obtain confirmation the new resource did not physically withhold capacity from a particular seasonal auction.
ii. The new resource must be in Commercial Model at time of request.
iii. The new resource must submit applicable testing (i.e. GVTC into MISO PowerGADS or Non-GADS Performance Template into MECT, DR tests, etc.).
iv. The new resource must become commercially operable as of date of replacement.
v. Requests must be submitted at least 3 weeks prior to start of replacement.
vi. If the new resource is an LMR no part of the Behind-The-Meter Generation (BTMG) or Demand Response (DR) assets can have been previously registered for the Planning Resource Auction by the registering Market Participant.
vii. If the new resource is an ARC LMR the contract with the customer/asset must have been signed after the March 1 Registration deadline.

6.4.6 MECT ZRC Replacement Calculator

The Replacement Calculator screen in the MECT is used to help MPs assess whether the ZRCs being used for the replacement will meet all of the required parameters including seasonal LCR, CIL, CEL, SREC, and SRIC.

For each Local Resource Zone, the Replacement Calculator screen displays the seasonal Final PRMR, LCR, CIL, CEL, sum of cleared Offers, sum of FRAP and sum of RBDC Opt Out, , Total Import and Total Export for each LRZ, and Total Export for each ERZ from the seasonal PRA.

Import Available and Export Available numbers are updated each time the Resource Replacement process is completed.

- Import Available number represents the maximum ZRCs allowed to import into the LRZ without violating the CIL in that Season. Import Available for the LRZ is calculated as:
  Seasonal Import Available = CIL – Total Import from PRA + (Sum of all Export* - Sum of all Imports*)
- LRZ Export Available number represents the maximum seasonal ZRCs allowed to export out of the LRZ without violating the CEL. Export Available for the LRZ is calculated as:
  LRZ Export Available = CEL – Total Export from PRA + (Sum of all Import - Sum of all Exports*)

ERZ Export Available represents the maximum ZRCs allowed to export out of the ERZ without violating the CEL. It is calculated as: ERZ Export Available = ERZ CEL – ZRCs cleared, including FRAPs and RBDC Opt Out, in ERZ

Example:

LRZ 1 has an LCR of 15,070 MW; and Import Available of 4,628.7 MW
LRZ 2 has an Export Available of 1,023.7 MW
LRZ 3 has an Export Available of 1,759.4 MW
ERZ 1 has an Export Available of 1,000 MW

Total MW needing replacement in LRZ 1: = 200 MW (Original Resource = AAA1)

Replacement ZRCs from LRZ 1: Of that 200 MW, 100 MW will be replaced by other Planning Resources located in LRZ 1 (Substitution Resource = AAA2)

ZRCs in LRZ 1 (after same LRZ replacement): LRZ 1’s total ZRCs from LRZ 1 after replacement = Offers Cleared + FRAP +RBDC Opt Out - Total MW needing replacement + Replacement ZRCs from the same LRZ = 18,522.3 – 200 + 100 = 18,422.3

LCR Test: Since 18,422.3 > LRZ 1’s LCR of 15,070, the LCR Test result is “Pass”

Amount Exported: Remaining Replacement ZRCs of 100 MW are imported from LRZ 2 and LRZ 3:

- o LRZ 2’s Exported ZRCs = 40 MW (Substitution Resource = BBB3)
- o LRZ 3’s Exported ZRCs = 60 MW (Substitution Resource = CCC4)

Import Test: LRZ 1’s total Imported ZRCs = 100 MW (40 MW + 60 MW). Since 100 MW < Import Available of 4,628.7, the Import Test result is “Pass”

Export Test: Since LRZ 2’s Export of 40 MW < Export Available of 1,023.7 MW and LRZ 3’s Export of 60 MW < Export Available of 1,759.4 MW, the Export Test results for LRZ 2 and 3 are “Pass”.

This scenario will require the following 3 separate Resource Substitution Registrations to replace AAA1 for the full amount of 200 MW in LRZ 1:

- o First 100 MW of AAA1: replaced by AAA2 for 100 MW from LRZ 1
- o Second 40 MW of AAA1: replaced by BBB3 for 40 MW from LRZ 2
- o Remaining 60 MW of AAA1: replaced by CCC4 60 MW from LRZ 3
- o No change for ERZ 1

6.4.7 Capacity Replacement Non-Compliance Charge and Distribution

Any combination of cleared or replaced ZRCs that are on full or partial Generator Planned Outage for greater than thirty-one (31) Days in total during a Season, or for any other reason including full or partial Generation Outages that were not planned but were known or could have been reasonably anticipated at the time of the PRA, as set forth in the Market Monitoring and Mitigation Business Practices Manual, or unavailable because subject to a Diversity Contract that is not available for greater than one (1) Month during a Season, will be assessed a Capacity Replacement Non-Compliance Charge. The charges will be applied to the asset owner that converted the SAC to ZRCs for the resource . MISO’s Control Room Operations Window (CROW) includes the following 4 categories of out of service (OOS) and derates: Planned, Urgent, Emergency and Forced. For purposes of calculating CRNCCs, MISO will use CROW outages prioritized as Planned. In addition, all outages not prioritized as Planned in CROW, but that were: (1) known or reasonably known at the time of the PRA, or (2) were determined by the IMM to be incorrectly prioritized in CROW shall be included in calculation of the CRNCC. See BPM-008 and the CROW users guide for outage prioritization codes and definitions.

Capacity Non-Compliance Charge = [# days failure to comply with replacement] * [# ZRCs failed to be replaced] * [Seasonal Zonal ACP + Daily Zonal CONE]

The number of Days counted will be on an hourly basis (31 days x 24 hours = 744 hours) since outages may only cover a portion of some Days. The number of hours that failed to comply or replace will be determined by ranking generator performance across the Season and applying charges to hours with the least violations in the Season beyond 744 hours. The charges assessed will round down to the number of whole Days in excess of 31 Days. For example, 815 hours minus 744 hours and then divided by 24 hours = 2.96 Days. In this case, the penalty charged for will be for two days.

Capacity Replacement Non-Compliance Charge revenues received by the Transmission Provider will be distributed to Market Participants representing LSEs that have met their Final PRMR during the applicable Season of the Planning Year on a pro rata basis, based upon their respective LSEs’ share of total Final PRMR for the Transmission Provider Region.

6.5 LMR performance

6.5.1 BTMG Performance

When a BTMG that either is used in a seasonal FRAP or RBDC Opt Out or cleared in a seasonal PRA fails to perform during an Emergency when included in a Market Participant’s Resource Deployment response to a Scheduling Instruction, the penalties are calculated for each hour in which a BTMG fails to respond in an amount greater than or equal to the target level of generation increase entered in the Resource Deployment screen of the LMR Scheduling Instruction Event in the DSRI as the sum of: (1) the product of (a) the amount of increased generation not achieved and (b) the LMP at the CPNode associated with the BTMG; and (2) applicable Revenue Sufficiency Guarantee (RSG) Charges. The amount of increased generation not achieved for BTMG is equal to the greater of: (1) the difference between (a) the target level of generation increases and (b) actual increased generation; and (2) zero. The applicable RSG Charges are equal to the product of: (1) the difference between (a) the target level of increased generation and (b) actual increased generation; and (2) the applicable RSG charges.

If advanced reporting is not entered in response to Scheduling Instructions into the Resource Deployment screen of the LMR Scheduling Instruction Event in the DSRI, then the full amount of Scheduling Instructions will be penalized.

The revenues from charges resulting from BTMGs that fail to respond in an amount greater than or equal to the MP responses to Scheduling Instructions shall be allocated, *pro rata*, to MPs representing LSEs in the LBA area(s) that experienced the Emergency, on a load ratio share basis.

For any situation where a BTMG does not increase generation in response to a Scheduling Instruction or where the resource is claimed to be unavailable as indicated in the DSRI as a result of maintenance requirements or for reasons of Force Majeure, MISO shall initiate an investigation into the cause of the BTMG not being available as needed during Emergency and may, if deemed appropriate, disqualify that resource from receiving ACP payments for that Planning Year. The BTMG may be called but not required to respond if the Emergency call is outside the resource's registration limitations (i.e. less than the registered time to respond, the event lasts longer than the registered duration, is made outside the BTMG's registered availability period; or the resource has reached its registered maximum number of deployments for that Season). However, should a BTMG resource indicate availability in the DSRI at any time in any Season of the Planning Year, it is considered available in the event of an Emergency during that Season and may receive Scheduling Instructions.

In the event the same BTMG does not sufficiently respond or is unavailable, except for reasons of Force Majeure or other acceptable reasons defined in the Tariff or in this BPM on a second occasion during a Season within the Planning Year (with a separation period of at least 24 hours), the MP that registered the BTMG will be subject to the penalties described herein (if that BTMG fails to increase generation to the level instructed). Such BTMG shall be assessed the same penalty as indicated above for its first performance failure, and the BTMG will no longer be eligible to receive ACP payments for the current Planning Year and for the next Planning Year.

If, in review of the BTMG's measurement and verification data following an Emergency, MISO determines that the MP has committed fraud to receive excess payments or to avoid penalties, MISO will have the right to ban the MP or its customers from participation in the wholesale electricity markets, as well as, pursue other legal options at the sole discretion of MISO.

6.5.2 DR Performance

If a DR that either is used in a seasonal FRAP or RBDC Opt Out or cleared in the seasonal PRA fails to perform during an Emergency when included in a Market Participant's Resource

Deployment response to Scheduling Instructions, penalties will be calculated for each hour in which a DR fails to respond in an amount greater than or equal to the target level of Load reduction entered in the Resource Deployment screen of the LMR Scheduling Instruction Event in the DSRI as the sum of: (1) the product of (a) the amount of load reduction not achieved, including Load above the registered firm service level for those DR registered as such and (b) the LMP at the CPNode associated with the DR; and (2) applicable Revenue Sufficiency Guarantee (RSG) Charges. The amount of Load reduction not achieved for DRs is equal to the greater of: (1) the difference between (a) the target level of Load reduction and (b) actual Load reduction; and (2) zero. The RSG Charges are equal to the product of: (1) the difference between (a) the target level of Load reduction and (b) actual Load reduction; and (2) the applicable RSG charges.

If advanced reporting is not entered in response to Scheduling Instructions into the Resource Deployment screen of the LMR Scheduling Instruction Event in the DSRI, then the full amount of Scheduling Instructions will be penalized.

Unless already entered as Self Scheduled for the event, DRs registered with a firm service level must still show a load reduction. Advanced Reporting should reflect the best estimate of load reduction available (i.e. load above the firm service level) during the event. Penalties will still be measured as load above the registered firm service level.

The revenues from charges resulting from DRs that fail to respond in an amount greater than or equal to the MP responses to Scheduling Instructions shall be allocated, *pro rata*, to MPs representing LSEs in the LBA area(s) that experienced the Emergency, on a load ratio share basis.

For any situation where a DR does not respond in an amount greater than or equal to the target level of Load reduction or registered firm service level or the resource is unavailable, including those circumstances where the resource is unavailable for maintenance reasons or Force Majeure, MISO shall initiate an investigation into the cause of the DR not being available when called upon, and may, if deemed appropriate, disqualify that resource from ACP payments for that Planning Year. The DR may be called but not required to respond if the Emergency call is outside the resource's registration limitations (i.e. less than the registered time to respond, the event lasts longer than the registered duration is made outside the DR's registered availability period, or the resource has reached its registered maximum number of deployments for that Season). However, should a Demand Resource indicate availability in the DSRI at any time in a

Season within the Planning Year, it is considered available in the event of an Emergency during that Season and may receive scheduling instructions.

In the event the same DR is not sufficiently responsive, including being unavailable, on a second occasion during a Season within the Planning Year (with a separation period of at least 24 hours) when included in a Market Participant's response to Scheduling Instructions; except when unavailable due to maintenance reasons, Force Majeure or other acceptable reasons as outlined in the Tariff or this BPM, the MP that registered the DR that was used to meet Resource Adequacy Requirements will be subject to the penalties described herein. The MP using the DR shall be assessed the same penalty as indicated above for a first performance failure, and the DR will no longer be eligible to receive ACP payments for the remainder of the current Planning Year and for the next Planning Year (s).

If, in review of the DR's measurement and verification data following an Emergency, MISO determines that the MP has committed fraud to receive excess payments or avoid penalties, MISO will have the right to ban the MP or its customers from participation in the wholesale electricity markets, as well as pursue other legal options at the sole discretion of MISO.

7 Integration of New LSEs

This section serves as a guide for those new Load Serving Entities (LSEs) integrating into MISO's region between the time MISO has completed the PRA(s) and the next Planning Year starts.

Once the integration date is set, MISO will work with both existing and new LSEs to ensure that the newly integrating LSEs have sufficient Planning Resources to meet their anticipated Coincident Peak Load Forecast plus an appropriate planning reserve margin.

To ensure the PRMR for new LSEs is met, MISO may conduct a Transitional PRA following the same registration requirements and auction protocols as the PRA.

MISO may provide the following when integrating new LSEs for applicable Season(s):

1. Define, as needed, new Local Resource Zone and their associated zonal parameters including:
    - Calculate CONE for the LRZ
    - Determine ZIA, ZEA, CIL and CEL

    - LOLE Analysis (Section 3.4.2)
    - Establishment of Local Reliability Requirement (Section 5.2.2.2)
2. Calculate Seasonal Planning Reserve Margin and Transmission Losses for the new LBAs
    - Determination of Seasonal Planning Reserve Margin (Section 3.4.1)
    - Review of CPD Forecasts (Section 3.2.5)
3. Conduct Transitional Planning Resource Auction
    - Amount of Capacity Cleared in Each Auction (Section 5.5.2)
    - Conduct of the PRA (Section 5.5.3)
    - Auction Results Posting (Section 5.5.8)

MISO may coordinate the proper timing of the data collection effort with the new LSEs for the successful completion of the Transitional PRA. The Transitional PRA will ensure that sufficient Planning Resources are procured to meet the Final PRMR of the newly integrating MISO region for the applicable Seasons in the remaining Planning Year.

The Resource Adequacy Timeline for the seasonal PRAs is shown in Appendix K. MISO will determine the Resource Adequacy timeline for the Transitional PRA and will publish it on the Resource Adequacy webpage under the Planning Section of the MISO public website. The Resource Adequacy timeline for the Transitional PRA will be reviewed by stakeholders prior to publishing on the MISO public website.

8 Testing Procedures and Requirements

8.1 Generator Real Power Verification Testing Procedures

MISO has developed generator test standards as documented in Appendix J that apply for Planning Years 2011-2012 and beyond.

9 Appendices

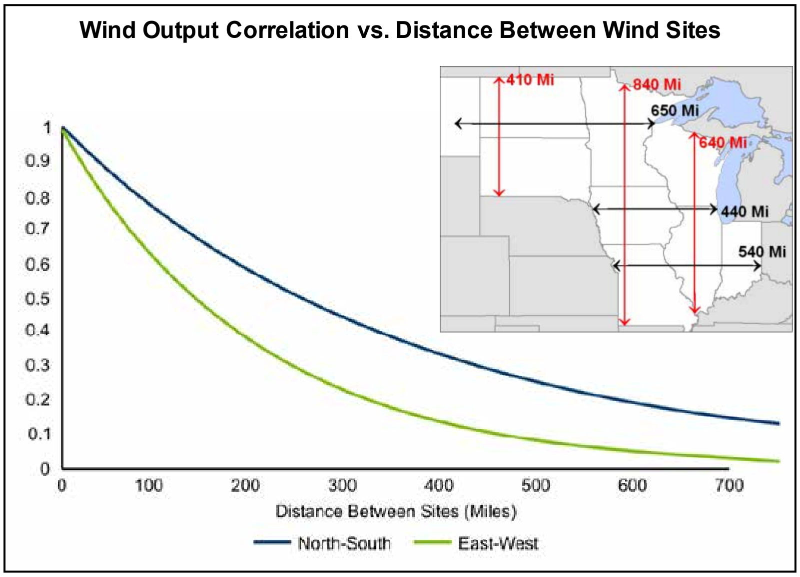
Appendix A – Wind Capacity Credit

The goal of establishing wind accreditation is to estimate the reliable output of wind as a percentage of the Installed Capacity (ICAP), for each Season, for the MISO system and by Commercial Pricing Node (CPNode). The data driving wind accreditation includes the following:

- The hourly load and the hourly wind output for the sampled peak load period for each Season. This concurrent load and wind data, along with the normal complement of generator data in an LOLE simulation, is essential for determining the system-wide seasonal Effective Load Carrying Capacity (ELCC) of the wind fleet.
- The hourly wind output for the top 8 seasonal MISO coincident daily peak hours for the most recent 3 years' worth of operational data per Season, both for the MISO system and by individual wind CPNodes. The system-wide and individual CPNode performance and ICAP data is used to allocate the system-wide seasonal wind ELCC among the individual wind CPNodes currently in operation.
- The hourly amounts by which individual wind CPNodes are dispatched downward are part of Dispatchable Intermittent Resources (DIR) activity in the market. Non-DIR resources are not required to submit Day-Ahead Energy Market offers—subsequently, curtailments are only considered for DIR wind resources that do offer into the Day-Ahead Energy Market.

Since 2009, MISO has embarked on a process to determine the capacity value for the increasing fleet of wind generation in the system. The MISO wind accreditation process, as developed and vetted through the MISO stakeholder community, consists of a two-step method. The first step utilizes a probabilistic approach to calculate the MISO seasonal system-wide ELCC value for all wind resources in the MISO footprint. The second step employs a deterministic approach using unit-specific metrics to allocate the single seasonal system-wide ELCC value across all wind CPNodes in the MISO system, resulting in an individual wind capacity credit for each wind node in operation for the sampled peak load period for each Season.

As the geographical distance between wind generation increases, the correlation in the wind output decreases. This leads to a higher average output from wind for a more geographically diverse set of wind plants, relative to a closely clustered group of wind plants. Due to the increasing diversity and the inter-annual variability of wind generation over time, the process needs to be repeated annually to incorporate the most recent historical performance of wind resources into the analysis. For each upcoming Planning Year, the wind capacity credit values in MISO are updated to account for both the stochastic nature of wind generation and the increasing integration of new resources into the system. The sections of this appendix and current results illustrated here are broken down to provide an example detailing the two-step method adopted by MISO for determining wind accreditation from the 2012-13 Planning Year.



Step-1: MISO System-Wide Wind ELCC Analysis

Probabilistic Analytical Approach

The probabilistic measure of load not being served is known as Loss of Load Probability (LOLP) and when this probability is summed over a time frame, e.g. one year; it is known as Loss of Load Expectation (LOLE). The accepted industry standard for what has been considered a reliable system has been the “Less than 1 Day in 10 Years” criteria for LOLE. This measure is often expressed as 0.1 days/year, as one year is the period for which the LOLE index is calculated.

Effective Load Carrying Capability (ELCC) is defined as the amount of incremental load a resource, such as wind, can dependably and reliably serve, while considering the probabilistic nature of generation shortfalls and random forced outages as driving factors to load not being served. Using ELCC in the determination of capacity value for generation resources has been around for nearly half a century. In 1966, Garver demonstrated the use of loss-of-load probability mathematics in the calculation of ELCC [1].

To measure ELCC of a particular resource, the reliability effects need to be isolated for the resource in question, from those of all the other sources. This is accomplished by calculating the LOLE of two different cases: one “with” and one “without” the resource. Inherently, the case “with” the resource should be more reliable and consequently have fewer days per year of expected loss of load (smaller LOLE).

The new resource in the example shown in Fig. 1 made the system 0.07 days/year more reliable, but there is another way to express the reliability contribution of the new resource besides the change in LOLE. This way requires establishing a common baseline reliability level and then adjusting the load in each case “With” and “Without” the new resource to this common LOLE level. A common baseline that is chosen is the industry accepted reliability standard of 1 Day in 10 Years (0.1 days/year) annual LOLE criteria.

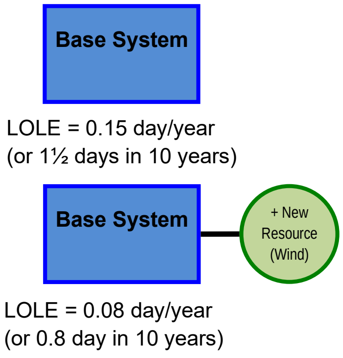


Figure 1: Example System “With” and “Without” New Resource

With each case being at the same reliability level, as shown in Fig. 2, the only difference between the two cases is that the load was adjusted. This difference is the amount of ELCC expressed in load or megawatts, which is 300 MW (100 minus -200) for the new resource in this example. This number may be divided by the ICAP of the new resource and then expressed in percentage form. ICAP for a wind resource is defined as the lesser of a wind resource’s Maximum Output as it is registered in the Commercial Model and its total Interconnection

Service. The new resource in the ELCC example Fig. 2 has an ELCC of 30 percent of the resource’s nameplate capacity, assuming nameplate capacity is equivalent to ICAP.

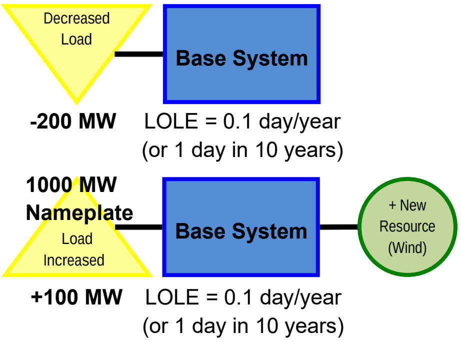


Figure 2: ELCC Example System at the same LOLE

The same methodology illustrated in the simple example of Fig. 2 was utilized as the analytical approach for the determination of the seasonal system-wide ELCC of the wind resource in the much more complex MISO system. For each historic year studied, there were two types of cases analyzed: cases with and cases without the wind resources included in the model. Each case was adjusted to the same common baseline LOLE and the ELCC was measured off those load adjustments. [2]

LOLE Model Inputs & Assumptions

To apply the ELCC calculation methodology, MISO uses an LOLE model capable of sequential Monte Carlo simulation to calculate LOLE values with and without the wind resource modeled. This analysis primarily considers three major inputs:

- Generator Forced Outage Rates (EFORd)
- Actual Historic Hourly Load Values
- Actual Historic Hourly Wind Output Values

Forced outage rates are used for the conventional type of units in the LOLE model. These EFORd are calculated from the Generator Availability Data System (GADS) that MISO uses to collect historic operation performance data for all conventional types units in the MISO system.

To incorporate historical performance, the actual historical hourly concurrent load and wind output at the wind CPNodes is used to calculate the historic seasonal ELCC values for the wind generation in the MISO on a system-wide basis.

Step-2: Wind Capacity Credit by CPNode Calculation

Deterministic Analytical Technique

Since there are many wind CPNodes throughout the MISO system, a deterministic approach involving a historic-period metric is used to allocate the system-wide seasonal ELCC values of wind to all the registered and in-service wind CPNodes. While evaluation of all CPNodes captures the benefit of the geographic diversity, it is important to assign the capacity credit of wind at the individual CPNode locations, because location relates to deliverability due to possible congestion on the transmission system in the MISO market. Also, in a market it is important to convey the correct incentive signal regarding where wind resources are relatively more effective. The location and relative performance are valuable inputs in determining the tradeoffs between constructing wind facilities in high-capacity factor locations, that in the case of the MISO system are located in more remote locations far from load centers, and requiring more transmission investment versus locating wind generating facilities at less effective wind resource locations that may require less transmission build-out.

The fleet-wide wind ELCC value (%) for a particular Season multiplied by the total ICAP for registered and in-service wind resources results in the total seasonal fleet-wide allocatable wind accreditation (MW). The total seasonal fleet-wide wind accreditation is then allocated to the applicable wind CPNodes in the MISO system.

Allocation considers the historic output, both in terms of with and without curtailments, for each wind CPNode over the top 8 daily peak hours for each Season included in the analysis. A capacity factor for each CPNode during all historical daily peak hours is represented in the Wind CPNode Equations contained in this appendix by “$\text{PKmetric}_{\text{CPnode}}$” for a particular CPNode, which is also referred to as the peak performance capacity factor.

This peak capacity factor for each Season is calculated using two methods:

- one method includes (adds back in) megawatts of a wind resource that were curtailed
- a second method excludes (does not add back in) those same curtailed megawatts

The larger of the two methods above, for each individual resource, forms the basis for allocating the total seasonal fleet-wide wind accreditation to the CPNodes.

New wind CPNodes that do not have sufficient historic output data will receive the seasonal fleet-wide wind capacity credit percentages applied to their ICAP as their default seasonal capacity accreditation for their first year in operation.

Tracking the top 8 daily peak hours in a Season is sufficient to capture the peak load times that contribute to the annual LOLE of 0.1 days/year. For example, in the LOLE run for year 2011, all of the 0.1 days/year LOLE occurred in the month of July, but only 4 of the top 8 daily peaks occurred in the month of July. Therefore, no more than 4 of the top daily peaks contributed to the LOLE. Other years have LOLE contributions due to more than 4 days, however 8 days was found sufficient to capture the correlation between wind output and peak load times in all cases. If many more years of historical data were available, one could simply utilize the single peak hour from each year as the basis for determining the $\text{PKmetric}_{\text{CPnode}}$ over multiple years.

Wind CPNode Equations

The relationship of the wind accreditation to a CPNode’s ICAP and Capacity Credit (%) is expressed as:

$$(\text{Wind Capacity Rating})_{\text{CPNode n}} = \text{ICAP}_{\text{CPNode n}} \times (\text{Capacity Credit } \%)_{\text{CPNode n}} \quad (1)$$

Where $\text{ICAP}_{\text{CPnode n}}$ = Installed Capacity of the wind facility at the CPNode level.

The right most term in equation (1) above, the $(\text{Capacity Credit } \%)_{\text{CPNode n}}$, can be replaced by the expression (2):

$$(\text{Capacity Credit } \%)_{\text{CPNode n}} = \text{K} \times (\text{PKmetric}_{\text{CPNode n}} \%) \quad (2)$$

Where “K” for was found by obtaining the PKmetric at each CPNode over the time period, and solving expression (3):

$$K = \frac{\text{ELCC}}{\sum_{1}^{n}(\text{ICAP}_{\text{CPNoden}} \times \text{PKmetric}_{\text{CPNoden}})} \quad (3)$$

This results in the sum of the Wind Capacity Rating (MW) calculated for the CPNodes approximately equal to the total fleet-wide seasonal wind ELCC.

References

[1] Garver, L.L.; "Effective Load Carrying Capability of Generating Units," Power Apparatus and Systems, IEEE Transactions on, vol. PAS-85, no. 8, pp. 910-919, Aug. 1966

[2] Keane, A.; Milligan, M.; Dent, C.J.; Hasche, B.; D'Annunzio, C.; Dragoon, K.; Holttinen, H.; Samaan, N.; Soder, L.; O'Malley, M.; "Capacity Value of Wind Power," Power Systems, IEEE Transactions on, vol. 26, no. 2, pp. 564-572, May 2011

Appendix B – GADS Events Outside Management Control (OMC Codes)

There are a number of outage causes that may prevent the Energy coming from a power generating plant from reaching the customer. Some causes are due to the plant operation and equipment while others are outside plant management control. Such outages include (but are not limited to) ice storms, hurricanes, tornadoes, poor fuels, interruption of fuel supplies, etc.

A list of GADS causes and their cause codes for OMC events are listed on the following page. MISO has generated a list of OMC codes accepted by MISO for GADS purposes. For more detailed information regarding OMC outages and codes please refer to Appendix K of the NERC GADS Data Reporting Instructions.

The lists of GADS Cause Codes applicable to reporting outages to MISO are as follows:

GADS Cause Codes Outside Plant Management Control (OMC)

3600	Switchyard transformers and associated cooling systems – external
3611	Switchyard circuit breakers – external
3612	Switchyard system protection devices – external
3619	Other Switchyard equipment – external
3710	Transmission line (connected to powerhouse switchyard to 1st Substation)
3720	Transmission equipment at the 1st Substation (see code 9300 if applicable)
3730	Transmission equipment beyond the 1st Substation (see code 9300 if applicable)
9000	Flood
9001	Drought
9010	Fire, not related to a specific component
9015	Pandemic
9020	Lightning
9025	Geomagnetic disturbance
9030	Earthquake
9031	Tornado
9035	Hurricane
9036	Storms (ice, snow, etc.)
9040	Other catastrophe

9130	Lack of fuel (water from rivers or lakes, coal mines, gas lines, etc.) where the operator is not in control of contracts, supply lines, or delivery of fuels
9132	Wet Fuel – Biomass
9135	Lack of water
9139	Ground water or other water supply problems
9150	Labor strikes company-wide problems or strikes outside the company’s jurisdiction such as manufacturers (delaying repairs) or transportation (fuel supply) problems
9200	High ash content
9210	Low grindability
9220	High sulfur content
9230	High vanadium content
9240	High sodium content
9250	Low Btu coal due to low BTU vane of coal not expected (Outside Management Control)
9260	Low Btu oil
9270	Wet coal
9280	Frozen coal
9290	Other fuel quality problems
9300	Transmission system problems other than catastrophes (do not include switchyard problems in this category; see codes 3600 to 3629, 3720 to 3730)
9320	Other miscellaneous external problems
9500	Regulatory (nuclear) proceedings and hearings - regulatory agency initiative
9502	Regulatory (nuclear) proceedings and hearings - intervener initiated
9504	Regulatory (environmental) proceedings and hearings - regulatory agency initiated
9506	Regulatory (environmental) proceedings and hearings - intervener initiated
9510	Plant modifications strictly for compliance with new or changed regulatory requirements (scrubbers, cooling towers, etc.)
9520	Oil spill in Gulf of Mexico
9590	Miscellaneous regulatory (this code is primarily intended for use with event contribution code 2 to indicate that a regulatory-related factor contributed to the primary cause of the event)

Appendix C – Registration of Energy Efficiency Resources

Energy Efficiency	
Registration Requirements	**Explanation**
Name	Enter the name of the Energy Efficiency Resource
Plan Year	The Auction you are registering your Energy Efficiency Resource for displays in this field.
Description	Enter type of resources and additional names and sizes if registering more than one unit.
Asset Owner	Select the name of the entity that owns or has rights to this asset.
Local Resource Zone (LRZ)	The LRZ where this Energy Efficiency Resource is located displays once the Asset Owner and LBA is selected and the registration is saved.
Local Balancing Area (LBA)	Select the LBA where this Energy Efficiency Resource is located.
Documentation	Attach supporting documentation.
Program Information	Indicate if this is a new program or previously registered program.
Program Inception Auction	Select auction program began
Program Name	Name of program that is being registered.
Added Capability	Enter MW capability of program for given Auction
Total Capability	Total cumulative MW capability of program.
Eligible Capability	Sum of MW capability of 4 most recent Planning Years.
Forecast Capability	Total Capability minus Eligible Capability.
Energy Efficiency Capability at MISO Peak	MW value of program at MISO Peak.
Certify that registrant possesses ownership or equivalent contractual rights	Indicate whether registrant has all necessary rights to register this resource.
Comments	Submit any comments for this registration.

Appendix D – Registration of DRs

Demand Resource (DR)	
Registration Requirements	**Explanation**
Auction	The Season(s) in the PY you are registering your DR for displays in this field.
Name	Enter Name of the DR.
Description	Enter type of resources, additional names, and sizes if registering more than one unit.
Asset Owner	Select the name of the entity that owns or has rights to this asset.
Local Resource Zone (LRZ)	The LRZ where this DR is located displays once the Asset Owner and LBA is selected and the registration is saved.
Local Balancing Area (LBA)	Select the LBA where this DR asset is located.
Load Zone CP Node	Enter the CP Node where the DR asset is located.
CP Node Override	Check box if the Load Zone CP Node and Asset Owner combination that is needed, is not in the dropdown. MECT would allow then any Load Zone CPNode to be selected for any Asset Owner, assigned to the MP.
Aggregate Retail Customer (ARC)	Check box if resource registered as an ARC and fill out appropriate account and address information.
Retail Choice	Check box if Resource is for Retail Choice and if yes, type in name of Retail Choice Customer.
Accreditation Method	Choose accreditation method and attach supporting documentation.
Demand Reduction Capability Forecast	Monthly values shall be provided for the first two years from the Effective Start Date. Provide monthly MW levels associated with the amount of MW you can reduce in a given month consistent with the actual physical availability of the resource limited by any relevant regulatory or contractual restrictions.

Demand Resource (DR)	
Registration Requirements	**Explanation**
	Seasonal values shall be provided beyond the 2-year monthly window. Provide seasonal (Summer and Winter) MW levels associated with the amount of MW you can reduce in a given month consistent with the actual physical availability of the resource, limited by any relevant regulatory or contractual restrictions.
Operator Contact Name	Enter who to contact for deployment of the DR. The contact should be available 24 x 7 for commitment by MISO or LBA.
Operator Contact Phone Number	Enter phone number for 24 x 7 operator.
Operator Contact Email	Enter email address for 24 x 7 operator.
M&V protocol to be applied to this DR	Select the protocol that should be applied. This is used for determination of whether the LMR performed if called on during a MISO Emergency. If other selected, please describe in box.
Exclude Season	Check this box to exclude the registration from participation in the specified Season.
Capability at MISO Peak	Enter MW capability being registered at MISO's Seasonal Peak.
DRR Registered	Check box if resource is registered as a DRR. If yes, select the name of the DRR CP Node.
Emergency Demand Response (EDR)?	Check box if DR registered as an EDR. If yes, select the name of the EDR resource.
Load Control Method	Select if load is direct control or interruptible load.
Max Interruptions	Select the max interruptions for the resource.
Max duration (hours)	Select the max duration for the resource.
Notification	Enter the notification time required for this DR. Notification time(s) must cover all hours and cannot be more than 6 hours and should be available 24 hours/Everyday (From 0000 to 2300 acceptable for 24 hours). Multiple notification times should start and stop

Demand Resource (DR)	
Registration Requirements	**Explanation**
	with different hours (from 0000 to 0700, 0800 to 1600, 1700-2000, 2100 to 2300).
EP Node Details	Add an appropriate EP Node by clicking “Add EP Node” and upload documentation for details on the EP Node. Note: This is an optional upload on DR Registration
Accept terms and conditions of the MISO Tariff	Indicate whether registrant accepts the terms and conditions of the MISO Tariff applicable to this resource
Certify that registrant holds all permits in place to operate resource	Indicate whether registrant has all necessary permits to operate this resource
Certify that registrant holds all rights in place to operate resource	Indicate whether registrant has all necessary rights to operate this resource
Comments	Submit any comments for this registration

Appendix E – BTMG registration

Behind the Meter Generation (BTMG)	
Registration Requirements	**Explanation**
Auction	The Season(s) within the PY you are registering your BTMG for displays in this field.
Name	Enter Name of the BTMG.
Description	Enter type of resources and additional names and sizes if registering more than one unit.
Asset Owner	Enter the name of the entity that owns or has rights to this asset.
Local Resource Zone (LRZ)	The LRZ where this BTMG is located displays once the Asset Owner and LBA is selected, and the registration is saved.

Behind the Meter Generation (BTMG)	
Registration Requirements	**Explanation**
Local Balancing Area (LBA)	Select the LBA where this BTMG asset is located.
Load Zone CP Node	Enter the CP Node where the BTMG asset is located.
Documentation	Add supporting documentation as necessary.
Demand Reduction Capability Forecast	Monthly values shall be provided for the first two years from the Effective Start Date. Provide monthly MW levels associated with the amount of MW you can inject in a given month consistent with the actual physical availability of the resource, limited by any relevant regulatory or contractual restrictions. Summer and Winter values shall be provided beyond the 2-year monthly window for levels associated with the amount of MW you can inject in the given Summer and Winter Season consistent with the actual physical availability of the resource, limited by any relevant regulatory or contractual restrictions.
Operator Contact Name	Enter who to contact for deployment of DRBTMG. The contact should be available 24 x 7 for commitment by MISO or LBA.
Operator Contact Phone Number	Enter phone number for 24 x 7 operator.
Operator Contact Email	Enter email address for 24 x 7 operator.
M&V protocol to be applied to this BTMG	Select the protocol that should be applied. This is used for determination of whether the LMR performed if called on during a MISO declared Emergency. If other selected, please describe in box provided.
Exclude Season	Check this box to exclude the registration from participation in the specified Season
Generators	Select the name of the Generator(s)
Wind Capacity Factor %	If a wind unit is selected, the Wind Capacity Factor will be displayed.
Transmission Loss %	Indicates the Transmission Loss % to be applied to the UCAP calculation based on the LBA selected.
Capability at MISO Peak	Indicates the calculated MW value for the BTMG resource based on its GVTC

Behind the Meter Generation (BTMG)	
Registration Requirements	**Explanation**
XEFORd	Displays the XEFORd to be applied in the UCAP calculation for the BTMG resource. If multiple Generators are selected, this field will display the weighted average XEFORd.
Emergency Demand Response (EDR)?	Check box if BTMG registered as an EDR and if yes, select the name of the EDR resource
Max Interruptions	Select the maximum interruptions for the resource
Max Duration (hours)	Select the maximum runtime hours for the resource
Startup notification time details (in hours)	Enter the notification time required to deploy this BTMG. Needs to be no more than 6 hours and cover all hours. Needs to be available 24 hours/Everyday (From 0000 to 2300 acceptable). Multiple notification times should start and stop with different hours (from 0000 to 0700, 0800 to 1600, 1700-2000, 2100 to 2300)
EP Node Details	Add an appropriate EP Node by clicking “Add EP Node” and upload documentation for details on the EP Node. Note: This is an optional upload on BTMG Registration
Accept terms and conditions of the MISO Tariff	Indicate whether registrant accepts the terms and conditions of the MISO Tariff applicable to this resource
Certify that registrant holds all permits in place to operate resource	Indicate whether registrant has all necessary permits to operate this resource
Certify that registrant holds all rights in place to operate resource	Indicate whether registrant has all necessary rights to operate this resource
Comments	Submit any comments for this registration

Appendix F – External Resources

External Resources	
Registration Requirements	**Explanation**
Name	Enter name of the External Resource.
Description	Enter type of resources and additional names and sizes if registering more than one unit.
BER/COR	Indicate if this Resource is a Border External Resource or Coordinating Owner Resource by checking this box.
Auction	The Season(s) in the Planning Year you are registering the resource for displays in this field.
Asset Owner	Select the name of the entity that owns or has rights to this asset.
Load Zone CP Node	Select the required Load Zone CP Node where this Resource is serving load.
Local Balancing Area (LBA)	Select the LBA where the External Resource sinks within MISO.
Local Resource Zone (LRZ)	Indicates the Local Resource Zone where the load served by this resource is located.
Ownership	Indicate if the External Resource is directly owned or from a PPA.
Entitled Capacity	Enter MW value the Market Participant can register.
PPA Type	Select whether PPA MWs are defined in MISO ICAP or UCAP.
Generator	Select name of GADS or Non-GADS Generator.
Ownership Share Type	Select Megawatt or Percent to indicate how much capacity corresponds to the registration.
External Balance Area where Resource are located	Enter Balancing Authority where the resource is physically located.

External Resources	
Registration Requirements	**Explanation**
Capacity at MISO Peak (Calculated)	The amount of seasonal capacity on a megawatt basis corresponding to the registration in terms of NRIS and ERIS.
Interface CPNode	Select Interface Load Zone CPNode.
XEFORd	The seasonal forced outage rate associated with the Generator(s) from GADS, excluding Outside Management Control (OMC) events. Can be overridden by the Market Participant.
NERC Regional Entity	Select NERC Regional Entity where the resource is located.
Use-Limited Resource Qualification	Indicate if this resource meets all Use Limited Resource qualification requirements.
Diversity Contract	Indicate whether this resource is part of a Diversity Contract exchange.
IDC Name	Indicate the IDC name used for entering outages via the SDX. List separate IDC name for each unit being registered. This is used for the must offer requirement.
Documentation	If Resource is not owned directly, attach supporting PPA or other pertinent documentation here.
Firm transmission to the MISO Border	Input effective date and OASIS reservation number and select Transmission Provider.
Firm transmission within the MISO Transmission System	Input effective date and OASIS Reservation number.
Have you accepted the terms and conditions of the MISO Tariff ?	Indicate whether registrant accepts the terms and conditions of the MISO Tariff applicable to this Resource.
Have you notified the host BA?	Indicate if you have contacted your host BA of this registration.
Will this External Resource be used exclusively as a Capacity Resource for MISO?	Indicate that you certify that this External Resource is being used as a Capacity Resource exclusively for MISO.
Is this External Resource available the entire auction?	Indicate if this External Resource is available for the entire Season within the upcoming Planning Year.

External Resources	
Registration Requirements	**Explanation**
Have all other requirements been met?	Indicate if all other requirements have been met.
Resource Operator Contact Name (24x7)	Enter who to contact for deployment of External Resource. The contact should be available 24x7 for commitment by MISO or LBA.
Resource Operator Contact Phone Number (24x7)	Enter phone number for 24x7 operator.
Resource Operator Contact Email (24x7)	Enter email address for 24x7 operator.
Season(s) registration is being submitted for	Summer ☐ Fall ☐ Winter ☐ Spring☐
Comments	Submit any comments for this registration.

Appendix G – Reliability Based Demand Curve

Overview

The key features of the Reliability Based Demand Curve include:

Target point defined by: (a) x-axis centered on MISO's reliability requirement at a loss of load expectation (LOLE) of 0.1 days per year; and (b) y-axis centered on the estimated Net CONE that would be needed to attract new resources. This target point reflects the central concept that price levels must be consistent with achieving system reliability objectives.

- Curve proportional to incremental reliability value, such that prices decline with increasing quantities of capacity, and such that pricing levels are rationalized against reliability risk across each of the four seasons.
- Price cap at 1 × Cost of New Entry (CONE, or Gross CONE) in each season, and 4 × CONE in total across the four seasons.

RBDCs are developed for the entire MISO system as well as for the two subregions (North/Central & South) of the MISO system, utilizing the same reliability-based concept. The demand curves for the subregions will reflect the additional reliability value that capacity resources can contribute by being located in a subregion with more acute reliability needs than the broader system. The total reliability value (and price) awarded to capacity in a particular subregion will reflect the sum of its contribution to avoiding system-wide reliability events (reflected in the system-wide RBDC) plus its contribution to avoiding additional reliability events that would occur in the subregion (reflected by the subregional RBDC).

In total, MISO utilizes twelve (12) RBDCs for any particular Planning Year: four (4) seasonal curves for the system-wide RBDC, four (4) seasonal curves for the North/Central subregion, and four (4) seasonal curves for the South subregion.

RBDCs are drawn in proportion to reliability value at each quantity point and are drawn through the target point at the reliability requirement and Net CONE.

System-wide Reliability Based Demand Curves

The system-wide RBDC is defined in proportion to system-wide Marginal Reliability Impact (MRI), which is measured as avoided Expected Unserved Energy (EUE), or the reductions to load shedding that would be achieved by adding one more MW of perfect capacity (or UCAP) to the system. This is derived from the seasonal Loss of Load Hours (LOLH) predicted at a specific quantity of supply, and the observation that 1 MW of perfectly-available UCAP supply would have avoided 1 MW-hour of outages across all of the simulated events. Mathematically, MRI is defined as:

$$\text{MRI} = \text{Avoided EUE from Incremental Capacity} = \text{LOLH x 1 MW UCAP}$$

Where:

- MRI (MWh per UCAP MW) is the incremental reliability value of adding 1 UCAP MW of capacity to the system.
- Avoided EUE (MWh per season) is the reduction in expected involuntary load shedding caused by adding incremental capacity.
- Incremental Capacity (UCAP MW) is the volume of perfectly-available capacity added.
- LOLH (hours per season) is the number of shortage hours predicted in reliability simulations across the season in question, in correlation with a specific quantity of UCAP MW available in that season.

To calculate MRI as a function of capacity, MISO utilizes the same resource adequacy model used in the determination of resource adequacy Requirements.

MRI curves are convex and monotonically downward-sloping, reflective of the declining marginal reliability value of capacity when supply is abundant, as well as the increasing marginal reliability value of capacity when supply is scarce. MRI is calculated above and below the reliability requirement by first establishing the supply quantity at which the system achieves the reliability target, and then adding/subtracting perfectly-available UCAP MW (in equal increments of no less than 50 MW and no more than 250 MW) to determine the marginal reliability value of the incremental capacity.

EUE is calculated at consistent variances in incremental and decremental amounts of capacity in the model for each season. The starting point for the seasonal MRI curves is the amount of capacity (in terms of UCAP) that results in the LOLE criteria corresponding with the demonstrated risk for each season. The Monte Carlo modeling for the system-wide MRI curve is copper plate, which assumes no internal transmission limitations within the MISO system.

Subregional Reliability Based Demand Curves

The development of subregional MRI curves follows the same process used for developing the system-wide curves—however, with the addition of bi-directional subregional transfer limits in the resource adequacy model that exists between the two subregions.

The starting point for each subregion's MRI curve is the PRMR from the system-wide analysis. Decrease/increase capacity in one region and simultaneously increase/decrease capacity in the other by the same amount and record reliability metrics for each region individually and MISO as a whole.

Subregion-specific Net CONE values are used to calculate subregional scaling factors, which are multiplied by the subregional MRI curves in each season to calculate the subregional RBDCs. Subregional RBDCs reflect the additional reliability value associated with capacity that can avoid reliability events that occur only in that subregion due to import limits, but that are not experienced system-wide.

Beyond the import capability, only capacity located in that subregion can help to avoid those localized shortfall events, so the incremental reliability and pricing value awarded would only apply to local capacity resources. The subregional RBDCs are calculated considering only local outage events, not considering system-wide outage events that are driven by system-wide supply shortfalls. Therefore, the subregional RBDCs are defined as additive in nature to the system-wide RBDCs.

The role of the system-wide demand curve is to signal the value of adding more capacity in total in MISO, regardless of where it is located. The role of the subregional RBDCs is to signal where within the system capacity is most needed (and where additional capacity cannot be as effectively utilized).

The steps for calculating subregional RBDCs include:

1. <u>Initialize the resource adequacy model with each subregion at a target of 0.1 days per year</u>: Beginning with the system-wide resource adequacy model, apply subregional transfer limits. Then subtract capacity in each season until each subregion is at a minimum seasonal LOLE criteria of 0.01 days/season for seasons demonstrating minimal risk. This reliability target reflects the subregional interpretation resource adequacy criteria in the MISO Tariff used as the basis for setting starting points in the subregional RBDCs.

2. Calculate Subregional Seasonal resource adequacy metrics Across Reserve Margins for Each Subregion: From this starting point, add (or subtract) perfectly-available UCAP MW
capacity to the subregion in each season. Adding capacity to the system and the relevant subregion and observing the change in LOLE, LOLH, and EUE measures the incremental value of locating capacity in that region. When the subregion in question becomes highly import-dependent, events in that subregion will become large (even though the broader system will maintain similar levels of reliability). When the region becomes a large exporter of capacity, local events will drop to zero (even though system-wide events will not drop to zero given that the maximum capacity limit will be enforced more often and local excess supply will not be possible to export in all cases).
3. Calculate Seasonal Subregional MRI Curves: The subregional MRI curve has a somewhat different meaning as compared to the system-wide MRI curve, in that the subregional MRI curve aims to measure the additional value achieved by locating capacity within a particular import-constrained region (beyond the value already reflected by the system-wide curve). Subregional MRI will be positive when the region is import-constrained and zero when the subregion has excess capacity. Therefore, the MRI curve for each subregion is first calculated as the total MRI including both system-wide and subregional events (the direct model result), and then the share of system-wide events is subtracted out. The resulting MRI curve reflects subregional events only.
4. Calculate the Subregional Scaling Factor: Calculate the subregional scaling factor from the subregional Net CONE value, divided by the subregional MRI at a quantity consistent with the resource adequacy target LOLE of 0.1 days/year from Step 1.
5. Calculate Seasonal Subregional RBDCs: Calculate the RBDCs for capacity in each subregion based on the MRI curve times the Subregional Scaling Factor from Step 4. The
resulting subregional RBDC will produce a positive price whenever the subregion is anticipated to be import constrained during times of potential shortage, and incremental capacity in that subregion would help to alleviate the shortfall.

Translating MRI Curves to RBDC

Translating the MRI curves (in units of incremental EUE per MW) into a capacity demand curve (in units of dollars per MW-day) requires a system scaling factor. The system scaling factor is calculated so as to support annual average prices at annualized Net CONE when the system is at the annual LOLE requirement of 0.1 days/year. If more than one season shares a meaningful portion of the LOLE risk, the LOLE risk could be summed from the estimated values across 2–4 seasons. Mathematically, system scaling factor is defined as:

System Scaling Factor = Average System Annual Net CONE ÷ System MRI @ 0.1 LOLE

Where:

- System Scaling Factor ($/MWh) is the payment rate at which the system-wide Reliability Based Demand Curves would incentivize investment in additional supply.
- System Annual Net CONE ($/UCAP MW-year) is the administrative estimate of the net annualized cost to develop new capacity resources (i.e., the long-run marginal cost of supply) on a system-wide basis.
- System MRI @ 0.1 LOLE (MWh/UCAP MW-year) is the marginal impact of additional capacity, as estimated on a system-wide copper-sheet basis (i.e., without considering transmission constraints) when the system is at the annual LOLE requirement of 0.1 days/year.

The prices on all the curves are derived by multiplying the MRI curves by the uniform system scaling factor (in $/MWh of EUE avoided) given by the annual break-even revenue requirement from the capacity market at the LOLH corresponding to a LOLE of 0.1 days/year.

Once the System Scaling Factor is calculated, the same value is utilized to calculate the RBDCs across all four seasons. The four RBDCs reflect a set of economic parameters that signal the relative value of capacity across each season. These four RBDCs will therefore support differentiated prices in each season that are always consistent with the level of events that are likely to be faced in each season given its respective supply-demand balance. The curves are all of a convex shape, reflective of the diminishing value of reliability at higher quantities but have different horizontal placements relative to peak load and different rates of diminishing return that reflect the unique system challenges faced across each season.

Summer has the highest peak load, so the curve is at the highest overall quantity in the summer—however, the other seasons face more uncertainty in net load across weather years and so their curves are more right-shifted compared to seasonal peak load. A season that faces greater variability and uncertainties in outage and resource availability risks may also produce a somewhat flatter curve (e.g., Winter and Summer), while a season facing fewer such uncertainties may produce a steeper curve (e.g., Spring).

Similar to System Scaling Factor, scaling factor to scale subregional MRI curve is determined as follows.

Subregional Scaling Factor = Average respective subregion Annual Net CONE ÷ subregional MRI @ 0.1 LOLE

Where:

- Subregional Scaling Factor ($/MWh) is the payment rate at which the Subregional Reliability Based Demand Curves would incentivize investment in additional supply.
- Subregional Annual Net CONE ($/UCAP MW-year) is the administrative estimate of the net annualized cost to develop new capacity resources (i.e., the long-run marginal cost of supply) on a subregional basis.
- Subregional MRI @ 0.1 LOLE (MWh/UCAP MW-year) is the marginal impact of additional capacity, as estimated on a subregional basis when the system is at the annual LOLE requirement of 0.1 days/year.

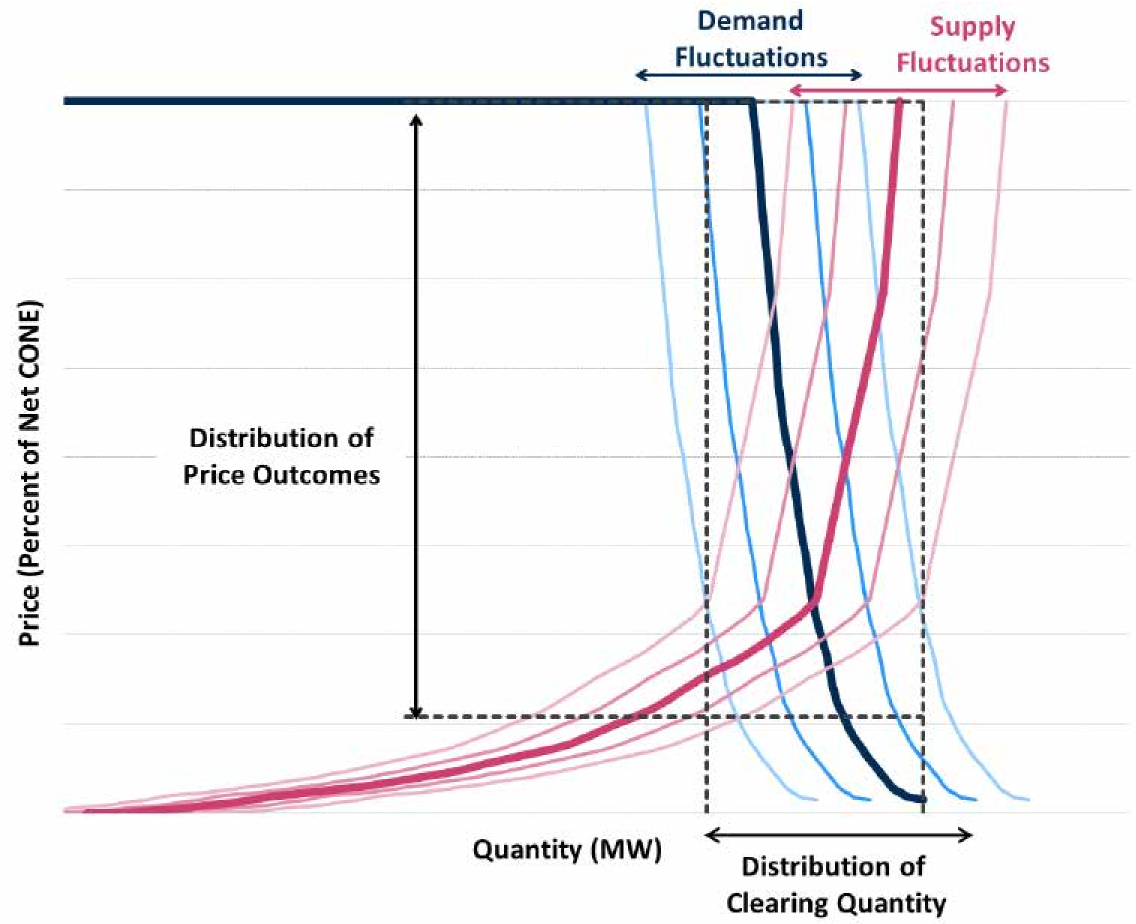
Once the Subregional Scaling Factor is calculated, the same value is utilized to calculate the RBDCs across all four seasons. The four RBDCs reflect a set of economic parameters that signal the relative value of capacity across each season. On subregion basis, these four RBDCs will therefore support differentiated prices in each season that are always consistent with the level of events that are likely to be faced in each season given its respective supply-demand balance. The curves are all of a convex shape, reflective of the diminishing value of reliability at higher quantities but have different horizontal placements relative to peak load and different rates of diminishing return that reflect the unique system challenges faced across each season.

Summer has the highest peak load, so the curve is at the highest overall quantity in the summer—however, the other seasons face more uncertainty in net load across weather years and so their curves are more right-shifted compared to seasonal peak load. A season that faces greater variability and uncertainties in outage and resource availability risks may also produce a somewhat flatter curve (e.g., Winter and Summer), while a season facing fewer such uncertainties may produce a steeper curve (e.g., Spring).

Long-run Equilibrium Analyses

Monte Carlo simulations are performed on supply curves and potential RBDCs to assess the achievement of long-run equilibrium conditions where the objective is for the average of all seasonal prices to be equivalent to Net CONE. Seasonal ACP and supply quantity outcomes are modeled in the simulations to account for variability in supply curve shapes, supply quantity, demand quantity, and opt out quantity. All model inputs are derived from historic MISO market data. Long-run equilibrium analyses should result in an expected distribution of price, quantity, and reliability outcomes that, when compared to the design objectives of RBDC, achieve the reliability objectives, produce better capacity market price signaling, and accurately recognize the reliability value of incremental capacity.

The long-run equilibrium analyses involve separate Monte Carlo simulations and will be performed every three (3) Planning Years.



In-market supply curves consist of three (3) component pieces:

6. Price Offers: supply offers at prices above zero, shape based on historic MISO offer curves, and independent of demand curve shape.
7. Year-to-Year Variability in Supply: zero-priced supply block, quantity varies with each draw to generate variability in supply offers, and tuned to true historic availability in supply.
8. Market Entry and Exit: zero-priced annual supply block with seasonal capacity ratings proportional to a combustion turbine reference resource, quantity varies across draws so that the average of seasonal clearing prices across all seasons is equal to the annual net CONE.

Appendix H – Non-Schedule 53 Seasonal Accredited Capacity (SAC) Calculations for Planning Resources

The following sets of equations establish how the SAC values (NRIS SAC, including E-NRIS SAC, and ERIS SAC) are determined for Planning Resources to account for resource performance and availability. Schedule 53 resource accreditation is outlined in Appendix Y.

H.1 Planning Resource SAC calculation for a Generation Resource, a Demand Response Resource backed by a generator, or a Behind-the-Meter Generator, with a Point of Interconnection on MISO’s Transmission System

The Seasonal Accredited Capacity (SAC) calculation is based on resource type and volume of seasonal Interconnection Service, seasonal GVTC, and seasonal forced outage rate (XEFORd).

H.1.1 Planning Year SAC Calculation for each Season

The following steps are used to calculate NRIS SAC and ERIS SAC for each Planning Resource.

Determine ICAP:

The first step is to determine the Installed Capacity (ICAP) that the Planning Resource can reliably provide, which is equal to the lesser of its GVTC or its total volume of Interconnection Service (Network Resource Interconnection Service and/or Energy Resource Interconnection Service) granted either through MISO’s Generation Interconnection Procedures or through a market transition deliverability test. The equation is shown below.

$$ICAP = \begin{cases} Total\ Interconnection\ Service,\ If\ GVTC > Total\ Interconnection\ Service \\ GVTC,\ If\ GVTC \leq Total\ Interconnection\ Service \end{cases}$$

Determine Total SAC:

The next step is to convert the resultant ICAP value into a Total SAC value by applying its seasonal forced outage rate (XEFORd).

A forced outage rate class average for each Season is used if the Planning Resource has a GVTC < 10 MW and has not submitted generator availability data or does not have sufficient generator availability data to calculate a forced outage rate specific to the Planning Resource. A

Planning Resource has sufficient generator availability data when it has a minimum of 12 months of generator availability data between September 1 and August 31 for the previous 3 years. The applicable class average for a Planning Resource is based on its unit size and type.

$$Total\ SAC = ICAP \times (1 - XEFOR_d)$$

If the Planning Resource has provisional Interconnection Service, then the Planning Resource will receive zero Interconnection Service and therefore the calculated Total SAC will be zero.

If the Planning Resource does not report historical outage data to GADS, its historical performance during seasonal peak hours should be provided to MISO through the Non-GADS Performance Template, which will leverage prior performance to establish seasonal GVTC values indicative of typical seasonal capabilities. In this case, XEFORd would not be used to reduce Total SAC. This process excludes Demand Response Resources.

<u>Allocate Total SAC into NRIS SAC and ERIS SAC based on Interconnection Service:</u>

The Resource's Total SAC is allocated into NRIS SAC and ERIS SAC based upon its type of Interconnection Service.

$$Total\ SAC = NRIS\ SAC + ERIS\ SAC$$

To the extent the Planning Resource has Network Resource Interconnection Service (NRIS) or was determined to be aggregate deliverable through the market transition deliverability test, then that quantity will be allocated first to calculate the NRIS SAC.

$$NRIS\ SAC = \begin{cases} ICAP * (1 - XEFORd), & If\ ICAP = NRIS \\ \left(Minimum\ of\ (NRIS, GVTC)\right) * (1 - XEFORd), & If\ ICAP > NRIS \end{cases}$$

The remaining balance of Total SAC is allocated to ERIS SAC (i.e. ERIS SAC = Total SAC – NRIS SAC.

$$ERIS\ SAC = \begin{cases} 0, & If\ ICAP =\ NRIS \\ Total\ SAC - NRIS\ SAC, & If\ ICAP > NRIS \end{cases}$$

Eligibility of NRIS SAC and ERIS SAC Conversion into seasonal Zonal Resource Credits

The NRIS SAC represents capacity in MW that is eligible to be converted into seasonal Zonal Resource Credits.

Effective ICAP

In determining the amount of ERIS SAC eligible for conversion into seasonal ZRCs, the deliverability of any ERIS must be determined prior to ERIS SAC conversion. ERIS must be paired with firm Transmission Service that covers the entire Season to be considered deliverable. NRIS is automatically considered deliverable and does not require an additional Transmission Service Request. The full amount of ERIS SAC can be converted to ZRCs if the resource is fully deliverable to its ICAP amount.

Total SAC which can be converted into seasonal ZRCs are the summation of the Planning Resource's NRIS SAC plus the lesser of the resource's ERIS with firm Transmission Service.

$$Total\ SAC\ Eligible\ for\ ZRC\ Convsersion\ = (NRIS\ SAC) +\ (ERIS\ SAC\ with\ TSR)^{*}$$

*Amount of TSR needed is dependent on ICAP amount

Ex	Size	NRIS	SAC	Total IS	GVTC	ICAP	Total SAC	NRIS SAC	ERIS SAC	TSR	ZRC
1	100	**100**	0	100	100	**100**	**75.0**	75.0	0.0	0.0	**75.0**
2	100	**50**	50	100	100	**100**	**75.0**	37.5	37.5	50.0	**75.0**
3	100	**50**	50	100	75	**75**	**56.3**	37.5	18.8	25.0	**56.3**
4	100	**0**	100	100	100	**100**	**75.0**	0.0	75.0	100.0	**75.0**

Examples for Illustrative Purposes

In example 3 above, a 100 MW Resource with 50 MW NRIS and 50 MW ERIS submitted a GVTC value at 75.

The ICAP will be 75 MW because the GVTC is less than the Interconnection Service of 100 MW.

Since the 50 MW NRIS is less than the Resource's ICAP, the Total SAC value of 56.3 MW of the Resource is not fully allocatable to NRIS SAC.NRIS SAC in example 3 was determined to be 37.5 MW. The remaining Total SAC minus the NRIS SAC is allocated into the resource's ERIS SAC. Thus, ERIS SAC level is 56.3 MW – 37.5 MW = 18.8 MW.

The resource would be credited with 56.3 MW of Total SAC which is comprised of 37.5 MW NRIS SAC + 18.8 MW ERIS SAC with firm Transmission Service for the corresponding seasonal PRA.

The resource was able to convert its entire Total SAC into seasonal ZRCs because the resource obtained full deliverability up to its ICAP, where 50 MW of NRIS plus 25 MW of firm Transmission Service is equal to its ICAP of 75 MW.

H.2 SAC calculation for a GADS-reporting External Resource that qualified as a Capacity Resource

The External Resource Capacity Resource SAC calculation is based on its seasonal GVTC and seasonal forced outage rate (XEFORd). The ERIS SAC is calculated by applying its seasonal XEFORd to its seasonal GVTC.

$$ERIS\ SAC = GVTC \times (1 - XEFOR_d)$$

A seasonal forced outage rate class average is used if the Capacity Resource has a GVTC < 10 MW and has not submitted generator availability data or does not have sufficient generator availability data to calculate a Planning Resource specific forced outage rate. A Planning Resource has sufficient generator availability data when it has a minimum of 12 months of generator availability data between September 1 and August 31 for the previous 3 years. The applicable class average for a Planning Resource is based on its unit size and type.

The ERIS SAC represents the capacity in MW that are eligible to be converted into seasonal Zonal Resource Credits with valid transmission service.

H.3 SAC calculation for a Planning Resource that is classified as Intermittent Generation and Dispatchable Intermittent Resources

For resources that don't report outage data to GADS, MISO calculates the Total SAC based on the past historical season-specific output assessing either the median for Run-of-River Hydro or average for all other intermittent resources that are not wind resources. The calculation requires a minimum of 30 consecutive seasonal days of output for a unique seasonal accreditation value. If that is not available, a class average seasonal accreditation value will be applied to the nameplate of the resource. A capacity factor adjusted by the resource's deliverability is applied to the resource's Total SAC to determine the amount of Total SAC eligible to be converted into seasonal ZRCs.

For wind resources, MISO produces an annual wind capacity credit study for every Season in the upcoming Planning Year using the Effective Load Carrying Capability (ELCC) methodology, as described in Appendix A, to determine a fleet-wide SAC value to be allocated across all in-front-of-the-meter wind resources in that Season. Deterministic allocation of the total fleet-wide wind SAC across the studied wind resources is dependent on the reliability value of the entire wind fleet (as determined through probabilistic modeling) at the aggregate level and the historical performance history of the wind resources at the unit level during specific historical MISO system Coincident Peak Demand hours.

A capacity factor adjusted by the resource's deliverability is applied to the resource's Total SAC to determine the amount of Total SAC eligible to be converted into seasonal ZRCs.

BTMG wind Resource owners are required to submit the historical performance history of their BTMG wind Resources during specific historical MISO system Coincident Peak Demand hours for the purpose of accrediting these resources with a SAC value based on their performance during periods of MISO system seasonal peak Demand for the three prior applicable years for each Season. This results in resource-specific SAC values for each BTMG wind Resource in operation.

> *BTMG Wind SAC = [capacity factor over the 8 seasonal peaks over the past 3 years] * [k] * [ICAP]*
>
> *Where k = [seasonal MISO Fleet ELCC] / Sum of [Fleet ICAP * PKmetric] (see BPM-011 Appendix A)*

New wind Resources that do not yet have historical performance history for an entire Season would receive the class average wind capacity credit for that Season (as determined by the Wind and Solar Capacity Credit study produced every year) applied to the wind Resource's ICAP to derive an appropriate Total SAC value. Please reference Appendix A for more details regarding the accreditation procedure for wind Resources.

The amount of SAC eligible to be converted into seasonal Zonal Resource Credits will be based on the application of a deliverability-adjusted capacity factor.

H.3.1 Intermittent Generation and Dispatchable Intermittent Resources with a Point of Interconnection on MISO's Transmission System

The following sections establish how SAC values (NRIS SAC and ERIS SAC) are determined for Intermittent Generation and Dispatchable Intermittent Resources that have a Point of Interconnection on MISO's Transmission System to account for resource performance and deliverability.

H.3.1.1 Planning Year SAC Calculation for Wind Resources

The first step is to determine the total installed capacity of the wind Planning Resource, which is the Installed Capacity (ICAP). It is equal to the lesser of its seasonal GVTC (Registered maximum output in the Commercial Model) or its total volume of Interconnection Service (Network Resource and Energy Resource Interconnection Service) granted either through MISO's Generation Interconnection Procedures or through a market transition deliverability test.

The next step is to determine the resource's total SAC. MISO determines a unit-specific seasonal wind capacity credit, by CPNode, for each Planning Resource that is fueled by wind by allocating the total fleet-wide seasonal ELCC capacity. The wind capacity credit is determined by applying the larger of two allocation methodologies, as noted in Appendix A:

- one method which includes (adds back in) megawatts for wind resources that were curtailed (applies to DIR wind resources only)
- a second method excludes (does not add back in) those same curtailed megawatts

The larger of the two results becomes the individual resource's Total SAC.

$$Total\ \ SAC = GVTC \times (Wind\ Capacity\ Credit_{CPNode})$$

Determining Convertible SAC based on a Deliverability Adjusted Capacity Factor

The next step is to determine how much of the total SAC is eligible to be converted into seasonal ZRCs.

The total SAC for a wind resource is distributed into two categories for the purpose of determining the amount of Capacity eligible for conversion into seasonal ZRCs, either convertible SAC or undeliverable ERIS SAC.

To calculate convertible SAC, which is eligible to be converted into seasonal ZRCs, a Deliverability Adjusted Capacity Factor is first applied. The Deliverability Adjusted Capacity Factor uses historical seasonal peak observances of an intermittent resource and is calculated by ‘capping’ historical intermittent output during seasonal peak load observances to the resource’s demonstrated deliverable amount divided by the resource’s ICAP. Whereas a peak performance capacity factor also uses the same historical seasonal peak observances divided by the resource’s ICAP but does not cap those observances.

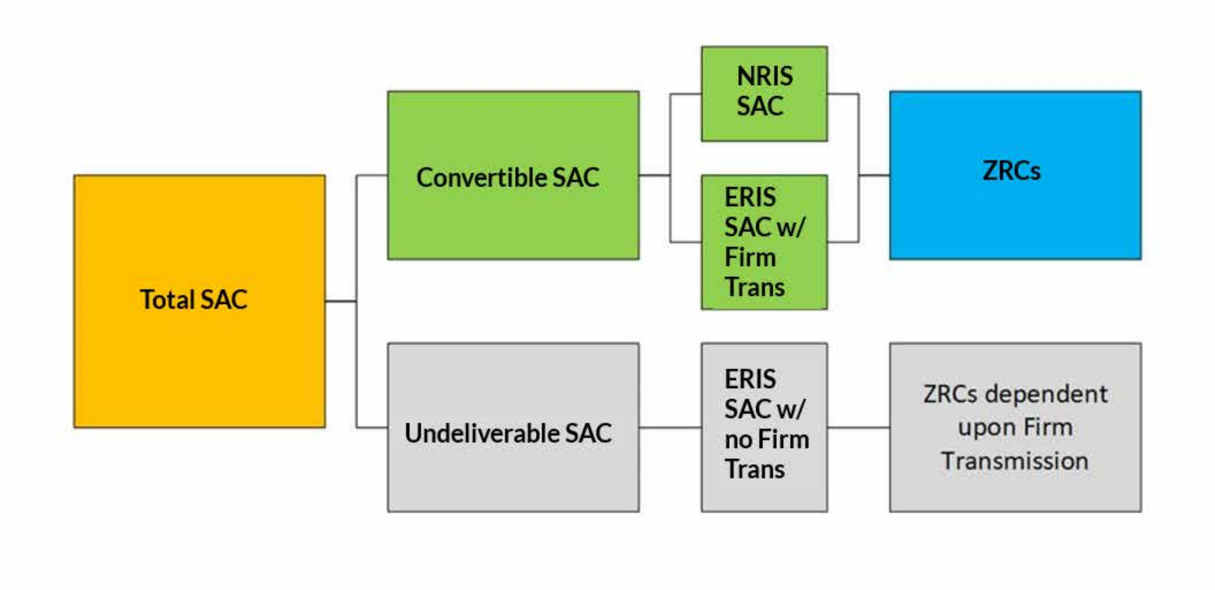
Formula for determining Convertible SAC

$$Convertible\ SAC = Total\ \ SAC * \frac{Deliverability\ Adjusted\ Capacity\ Factor}{Peak\ Capacity\ Factor}$$

The remaining Total SAC that is left after calculating Convertible SAC is considered the undeliverable ERIS SAC.

$$ERIS\ SAC = \begin{Bmatrix} 0, Total\ Interconnection\ SAC =\ Convertible\ SAC \\ Total\ Interconnection\ SAC - Convertible\ SAC, Total\ Interconnection\ SAC > Convertible\ SAC \end{Bmatrix}$$

Optionally, the classified undeliverable ERIS SAC can become eligible to be converted into seasonal ZRCs by procuring firm Transmission Service.

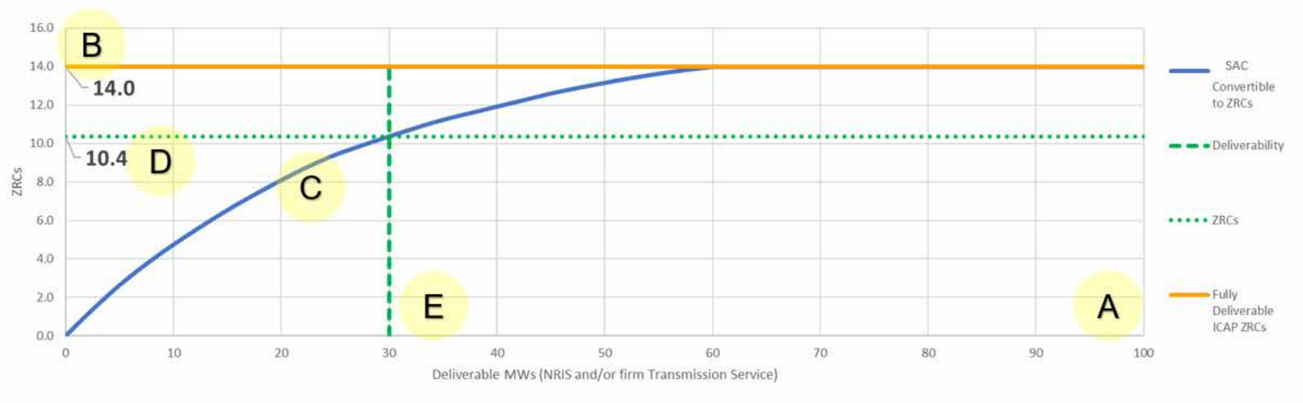


Converting ERIS SAC to Convertible SAC using the Resource’s Deliverability Adjusted Historical Performance

ERIS SAC is not generally convertible to seasonal ZRCs at a one-to-one MW ratio. Each resource will have unique conversion data generated based on its past seasonal performance and deliverability which indicates the level of firm Transmission Service necessary to be obtained to gain a given level of seasonal ZRCs.

An example and further explanation is shown in the figure below:

ZRC Deliverability Curve Chart



Where:

A: Equals the maximum output of resource (RMax). In this example, this resource is 100 MW.

B: Total SAC, or SAC (Max) that can potentially be converted into seasonal ZRCs. This also represents the share of the total fleet-wide seasonal ELCC capacity. This value is based on the size and performance of the resource.

C: This is the Convertible SAC function which is the resource’s Total SAC multiplied by the ratio of its Deliverability Adjusted Capacity Factor divided by its Peak Capacity Factor. Convertible SAC varies depending on the amount of Deliverability of the resource.

D: This is the resulting Convertible SAC value for a corresponding Deliverable amount in MW.

E: This is the amount of Deliverable MWs, or Deliverability. The point at which E intersects C provides the amount of seasonal ZRCs the Market Participant would obtain based on the size, performance, and deliverability of the resource.

H.3.1.2 Non-wind Intermittent Generation and Dispatchable Intermittent Resources

The first step is to determine the Total Installed Capacity that the Planning Resource can reliably provide, which is the Installed Capacity (ICAP). It is equal to the lesser of its GVTC, or its total volume of Interconnection Service (Network Resource and Energy Resource Interconnection Service) granted either through MISO's Generation Interconnection Procedures or through a market transition deliverability test.

The next step is to allocate the Total SAC based upon its type of Interconnection Service. To the extent the Planning Resource has Network Resource Interconnection Service (NRIS) or was determined to be deliverable through the market transition deliverability test then that quantity will be allocated first to NRIS SAC. The remaining Total SAC will then be allocated to ERIS. If the Planning Resource has provisional Interconnection Service, then the Planning Resource will receive zero Interconnection Service and therefore the calculated SAC will be zero.

$$NRIS\ SAC = \begin{cases} Total\ \ SAC,\ Total\ \ SAC \leq NRIS \\ NRIS,\ Total\ \ SAC > NRIS \end{cases}$$

$$ERIS\ SAC = \begin{cases} 0,\ Total\ \ SAC \leq NRIS \\ Total\ \ SAC - NRIS,\ Total\ \ SAC > NRIS \end{cases}$$

Determining Convertible SAC based on a Deliverability Adjusted Capacity Factor

The total SAC for an intermittent non-wind resource is distributed into two categories for the purpose of determining the amount of Capacity eligible for conversion into seasonal ZRCs. This would be considered Convertible SAC, either NRIS SAC or ERIS SAC coupled with firm Transmission, or undeliverable ERIS SAC (no associated firm Transmission).

To calculate convertible SAC, which is eligible to be converted into seasonal ZRCs, a Deliverability Adjusted Capacity Factor is first applied. The Deliverability Adjusted Capacity Factor uses historical summer peak observances of an intermittent non-wind resource and is calculated by 'capping' historical intermittent output during peak load observances to the resource's demonstrated deliverable amount divided by the resource's ICAP. (See Appendix V for examples)

H.3.2 Intermittent Generation and Dispatchable Intermittent Resources that does not have Point of Interconnection on MISO's Transmission System

The following sections apply to Intermittent Generation and Dispatchable Intermittent Resources that do not have a Point of Interconnection on MISO's Transmission System. The ERIS SAC represents the capacity in MWs that are eligible to be converted into seasonal ZRCs.

Appendix I – XEFORd Calculation

XEFORd is equivalent forced outage rate Demand excluding events outside of management control (OMC). XEFORd will be calculated on a seasonal basis. A description and list of the MISO OMC events can be found in Appendix B. The MISO equation is:

$$\frac{(FOHd + EFDHd)}{(FOHd + SH + Synch\ Hours)} * 100\%$$

where:

SH = service hours

Synch Hours = synchronous hours

RSH = reserve shutdown hours

FOH_d = forced outage hours Demand = f_f x FOH

f_f = full forced outage Demand factor = $\frac{(\frac{1}{r}+\frac{1}{T})}{(\frac{1}{r}+\frac{1}{T}+\frac{1}{D})}$

r = average forced outage duration = (FOH)/(# of FO occurrences)

D = average Demand time = (SH + Synch Hours)/(# of unit actual starts)

T = average reserve shutdown time = (RSH)/(# of unit attempted starts)

FOH = forced outage hours

$EFDH_d$ = (f_p x EFDH)

AH = available hours

f_p = partial forced outage Demand factor = (SH + Synch Hours)/AH

EFDH = equivalent forced derated hours

Special cases are evaluated in the following order:

If reserve hours < 1, then f_f =1,

then if (SH + Synch hours) = 0, then f_f = 1,

then if (1/r + 1/T + 1/D) = 0, then f_f = 0,

then if # of FO occurrences = 0 or FOH = 0, then 1/r = 0,

then if RSH = 0 or # of unit attempted starts = 0, then 1/T = 0,

then if # of unit actual starts = 0 or (SH + Synch Hours) = 0, then 1/D = 0,

then if (SH + RSH + Synch Hours) = 0, then f_p = 0,

then if ((FOHd + SH + Synch Hours) = 0, then EFORd = 0

SH, RSH and Synch Hours are reported through the MISO Market Portal in the PowerGADS application by the users in their Performance data. The rest of the statistics are calculated by PowerGADS based on the user submitted Event data. Forced outage rates for each unit can be found in the Generator Outage Rate Program (GORP) report. The statistics used in calculating forced outage rates can be found in the Statistics Report, Performance Report, and the Seasonal XEFORd Report.

The MISO calculation is based on the EFORd equation defined in the NERC Generating Availability Data System Data Reporting Instructions Appendix and the IEEE Standard No. 762-2006 Standard *Definitions for Use in Reporting Electric Generating Unit Reliability, Availability and Productivity*. The MISO XEFORd calculation differs as follows:

- The NERC and IEEE EFDH formula is (Derated Hours * Size of Reduction)/Net Max Capacity while the MISO formula uses net dependable capacity rather than net max capacity and is (Derated Hours * Size of the Reduction)/Net Dependable Capacity. The size of the reduction is the Net Dependable Capacity minus the Net Available Capacity.
- MISO also includes synchronous hours in the XEFORd, average Demand time (D), and the partial Demand factor (f_p) calculations while NERC and IEEE do not.

Example XEFORd Calculations

Raw Data									
Unit	SH	Synch Hours	RSH	AH	Actual Starts	Attempted Starts	EFDH	FOH	FO Events
1	4,856	0	2,063	6,919	34	34	146.99	773	12
2	4,556	0	1,963	6,519	31	31	110.51	407	5
3	3,942	132	3,694	7,768	36	36	19.92	504	11
4	6,460	0	516	6,976	17	18	131.03	340	14
5	6,904	0	62	6,966	16	16	35.81	138	12

Calculated Values								
Unit	**1/r**	**1/T**	**1/D**	**f_f**	**FOHd**	**f_p**	**EFDHd**	**XEFORd**
1	0.0155	0.0165	0.0070	0.8205	634.25	0.7018	103.16	13.43%
2	0.0123	0.0158	0.0068	0.8049	327.61	0.6989	77.23	8.29%
3	0.0218	0.0097	0.0088	0.7813	393.78	0.5245	10.45	9.05%
4	0.0412	0.0349	0.0026	0.9666	328.63	0.9260	121.34	6.63%
5	0.0870	0.2581	0.0023	0.9933	137.08	0.9911	35.49	2.45%

Unit 3 Example XEFORd Calculation Detail

r = average forced outage duration = $\frac{FOH}{FO\ events} = \frac{504}{11} =$ 45.82 hours, then 1/r = 0.0218

T = Average reserve shutdown time = $\frac{RSH}{attempted\ starts} = \frac{3694}{36}$ = 102.61 hours, then 1/T = 0.0097

D = average Demand time $= \frac{(SH+synch\ hours)}{actual\ starts} = \frac{3942+132}{36} =$ 113.17 hours, then 1/D = 0.0088

f_f = full forced outage Demand factor = $\frac{(\frac{1}{r}+\frac{1}{T})}{(\frac{1}{r}+\frac{1}{T}+\frac{1}{D})} = \frac{(0.0218+0.0097)}{(0.0218+0.0097+0.0088)} = 0.7816$

FOHd = forced outage hours Demand = f_f x FOH = 0.7813 x 504 = 393.78 hours

f_p = partial forced outage Demand factor = $\frac{(SH+synchhours)}{AH} = \frac{(3942+132)}{7768}$ = 0.5245

EFDH = fp x EFDH = 0.5245 x 19.92 = 10.45 hours

XEFORd = $\frac{(FOHd+EFDHd)}{(FOHd+SH+synch\ hours)} * 100 = \frac{(393.78+10.45)}{(393.78+3942+132)} * 100 = 9.05\%$

Units with 12 or more consecutive months of actual data: The XEFORd of a unit in service twelve or more full calendar months prior to the calculation month will be based on the number of consecutive months that that unit has data for up to 36 months.

Units with less than 12 consecutive months of actual data: The XEFORd of a unit in service less than twelve full calendar months shall be determined by the class average rate for units of the same type and within the same range of capability. A unit will use the class average value until 12 consecutive months of data is obtained and a new Planning Year begins. The class average will be the 5-year forced outage rate from the latest Loss of Load Expectation (LOLE) Study.

Units with Low Service Hours

Units with an average of less than 20 service hours per Season and attempted starts greater than zero will have their service hours adjusted if the unit has at least 12 consecutive seasonal months of GADS data. The adjusted service hours will be based on 60 service hours (20 service hours x 3 Seasons) or a fraction of 60 if there is less than 9 consecutive seasonal months of GADS data. This adjustment will be performed in the MECT. The calculation for the adjustment is as follows:

MO = consecutive seasonal months in operation
If SH = Service Hours < (MO/9*60) and attempted starts is greater than zero, then

SH' = seasonal adjusted low service hours = $\left[\left(\frac{actual\ starts}{atempted\ starts}\right) * \left(\frac{MO}{9} * 60 - SH\right)\right] + SH$

External Resources

Market Participants are responsible for making sure that GADS data is submitted for the External Resources that they are seeking qualification as ZRCs. The Market Participant can submit this data to MISO's GADS tool for the external resource or they can have the external resource submit the data. If an external resource is going to submit the GADS data, then they must receive access to the MISO Market Portal through their Local Security Administrator. If an External Resource does not have a Local Security Administrator, then it is the Market Participant's responsibility to receive and submit this data for the External Resource.

Catastrophic Outages

Catastrophic Outages are defined as forced outages that result in a unit being unavailable for a minimum of six (6) continuous months. A catastrophic outage may be a forced full or partial (forced derating) outage. A scheduled outage (planned, planned extension, maintenance, or maintenance extension) cannot be a catastrophic outage. For an outage to be considered catastrophic, the MP must notify the MISO Resource Adequacy team in writing within 75 days of determining the outage is a Catastrophic Outage, including a description of the Catastrophic Outage, start date of outage, expected return date, etc.

> If the MP chooses not to replace a Planning Resource that suffers a Catastrophic Outage, then the XEFORd will be based on actual GADS data.

If the MP chooses to replace a Planning Resource that suffers a Catastrophic Outage, the XEFORd will be based on class average when the unit returns to service. The class average value will be used until 12 consecutive months of data is obtained and a new Planning Year begins.

Resource replacement must be completed within 75 days of catastrophic outage.
Resource replacement must be in accordance with section 6.4 of this BPM.
Once the unit returns from Catastrophic Outage, Planning Resource qualification requirements still apply. Partial replacements are allowed.

If the outage is a forced derate with total or partial replacement, or a full forced outage with partial replacement, the resources XEFORd upon returning to service will be the class average for the portion of the resource replaced and the actual XEFORd for the remainder of the unit. A blended XEFORd will be calculated by MW weighting the class average and actual XEFORd values.

For Schedule 53 resources that experience a catastrophic outage and replaced the ZRCs accordingly during the time the resource was unavailable, the time it is out will be considered non-RAR and would not be counted in the SAC calculation consistent with ZRC replacement section of this BPM and Appendix Y. In situations where this leads the resource to have less than 60 days of RAR performance history during the 3-year lookback period, the Schedule 53 resource would be granted Schedule 53 class averages for the impacted seasons.

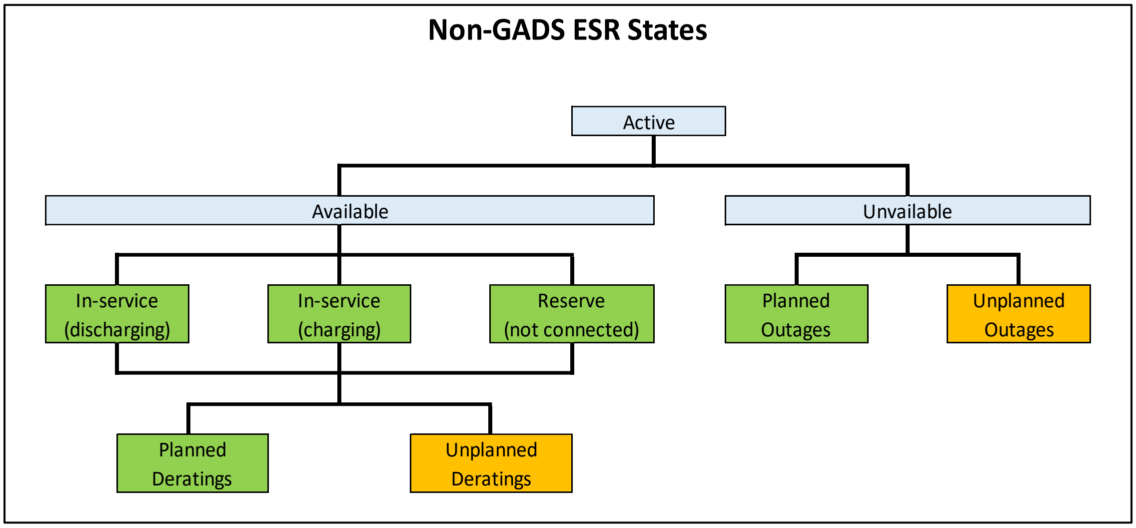
Fleet Weighted Average Forced Outage Rates

External Resources may participate using a fleet of resources. A weighted average forced outage rate is calculated using the individual unit forced outage rates and GVTC values. The resulting rate is applied to the total fleet GVTC to determine the fleet UCAP. See Appendix Q for more information regarding the Fleet XEFORd Calculation.

XEFORd for Non-GADS Electric Storage Resources (ESR)

The XEFORd for a non-GADS ESR is its Forced Unavailability and will be determined as follows.

A non-GADS ESR is forced unavailable when it is in an unplanned outage or an unplanned derating (see oranges boxes). All other states are unforced availability and include in-service (discharging or charging), reserve (not connected), planned outages, or planned deratings (see green boxes).



An available resource that is not derated is 100% available. If a resources availability changes during an hour, the Forced Availability should be pro-rated. For example, if a 10 MW resource experiences a 23-minute Unplanned Outage during the hour, its equivalent Forced Unavailability would be (23 min/60 min) * 10 MW = 3.8 MW or 38%. Similarly, for an Unplanned Derating of 2.4 MW for 47 minutes of the hour the equivalent Forced Unavailability would be (47 min/60 min) * 2.4 MW = 1.9 MW or 19%.

Examples for a 10 MW resource	Unforced Availability (MW)	Forced Unavailability (MW)	Unforced Availability (%)	Forced Unavailability (%)
The resource is 100% available and in-service discharging	10.0	0.0	100.0%	0.0%
The resource is 100% available and charging	10.0	0.0	100.0%	0.0%
The resource is 100% available and in reserve not discharging	10.0	0.0	100.0%	0.0%
A portion of the resource is unavailable due to a planned derating and the remainder is available	10.0	0.0	100.0%	0.0%
4 MW of the resource is unavailable due to an unplanned derating and 6 MW is available	6.0	4.0	60.0%	40.0%
4.5 MW of the resource is unavailable due to a planned derating and 5.5 MW is unavailable due to an unplanned	4.5	5.5	45.0%	55.0%
The resource is unavailable due to a planned outage	10.0	0.0	100.0%	0.0%
The resource is unavailable due to a unplanned outage	0.0	10.0	0.0%	100.0%
23 minutes unplanned outage	6.2	3.8	62.0%	38.0%
2.4 MW unplanned derate for 47 minutes	8.1	1.9	81.0%	19.0%

Additional information:

- Pumped Storage Resources submit their availability and GVTC data through the MISO PowerGADS application.
- All other ESR types must submit their availability and GVTC (Hourly Equivalent Discharge Amount) data using the Non-GADS Performance template.
  - The template provides the 8 MISO coincident peak hours per Season for the last three years.
  - The average of these 24 seasonal unforced availability values is divided by the Hourly Equivalent Discharge Amount (MW) to calculate a seasonal unavailability factor.
  - Market Participants with less than 8 availability values in a Season will be given the default unavailability factor.
- Availability Reporting is optional for resources less than 10 MW. Resources that choose not to report, will be given the default unavailability factor. Once a resource chooses to report for the first time, they will be required to report every year thereafter.

Appendix J – GVTC Testing Requirements

J.1 Overview

All Generation Resources, External Resources, Behind the Meter Generation (BTMG) and Demand Response Resources backed by BTMG that intend to qualify as a Planning Resource are required to perform a real power test or provide past operational data. This test, or past operational data, shall be used to determine a planning resource's GVTC value. GVTC data is submitted through the MISO Market Portal into MISO PowerGADS.

Each seasonal corrected net test capability is the gross output (MW) that a planning resource can sustain averaged over the test period, if there are no equipment, operating, or regulatory restrictions, less station service and process load served, corrected to MISO coincident seasonal peak conditions.

		(A)	(B)	(C)	(D)= (A)-(B)-(C)	(E)	(F)	(G)	(H)= (D)+(E)+(F)+(G)
NERC Unit Type	Example Unit	Gross (MW)	Station Service (MW)	Process Load Served (MW)	Net Test Capacity (MW)	Air Temperature Correction (MW)	Relative Humidity Correction (MW)	Cooling Water Temperature Correction (MW)	Net Corrected (MW)
Combined Cycle CC	CT1	95.0	1.0	0.0	94.0	-15.0	-0.1	N/A	78.9
Combined Cycle CC	ST1	300.0	15.0	0.0	285.0	N/A	N/A	-1.0	284.0
Combined Cycle CC	Unit 4	250.0	5.0	100.0	145.0	-3.5	-0.1	-0.5	140.9
Combustion Turbine CT	CT3	50.0	0.1	0.0	49.9	3.0	0.1	N/A	53.0
Diesel DS	Diesel 5	2.5	0.0	0.0	2.5	N/A	N/A	N/A	2.5
Fluidized Bed Combustion FB	Unit 4	200.0	10.0	0.0	190.0	N/A	N/A	-2.0	188.0
Hydro HD	Hydro 12	10.0	0.0	0.0	10.0	N/A	N/A	N/A	10.0
Nuclear NU	Unit 1	1,000.0	50.0	0.0	950.0	N/A	N/A	-1.5	948.5
Pumped Storage PS	Unit 5	300.0	1.0	0.0	299.0	N/A	N/A	N/A	299.0
Fossil Steam ST	Unit 2	600.0	30.0	0.0	570.0	N/A	N/A	-3.0	567.0

GVTC Table J.1 – Examples of net corrected net test capability for different unit types. **Examples may not be representative of your situation. If you have unit specific questions, please contact Resource Adequacy.

If a Planning Resource fails to perform a real power test and report the test data to MISO's PowerGADS byOctober 31 prior to the start of the planning year t, it will result in the Planning Resource not qualifying as a Planning Resource and will receive zero SAC MWs for the upcoming Planning Year.

J.1.1 Test Period and Reporting Deadline

The real power test shall be performed between September 1 and August 31 prior to the upcoming planning year. The test data shall be submitted no later than October 31.

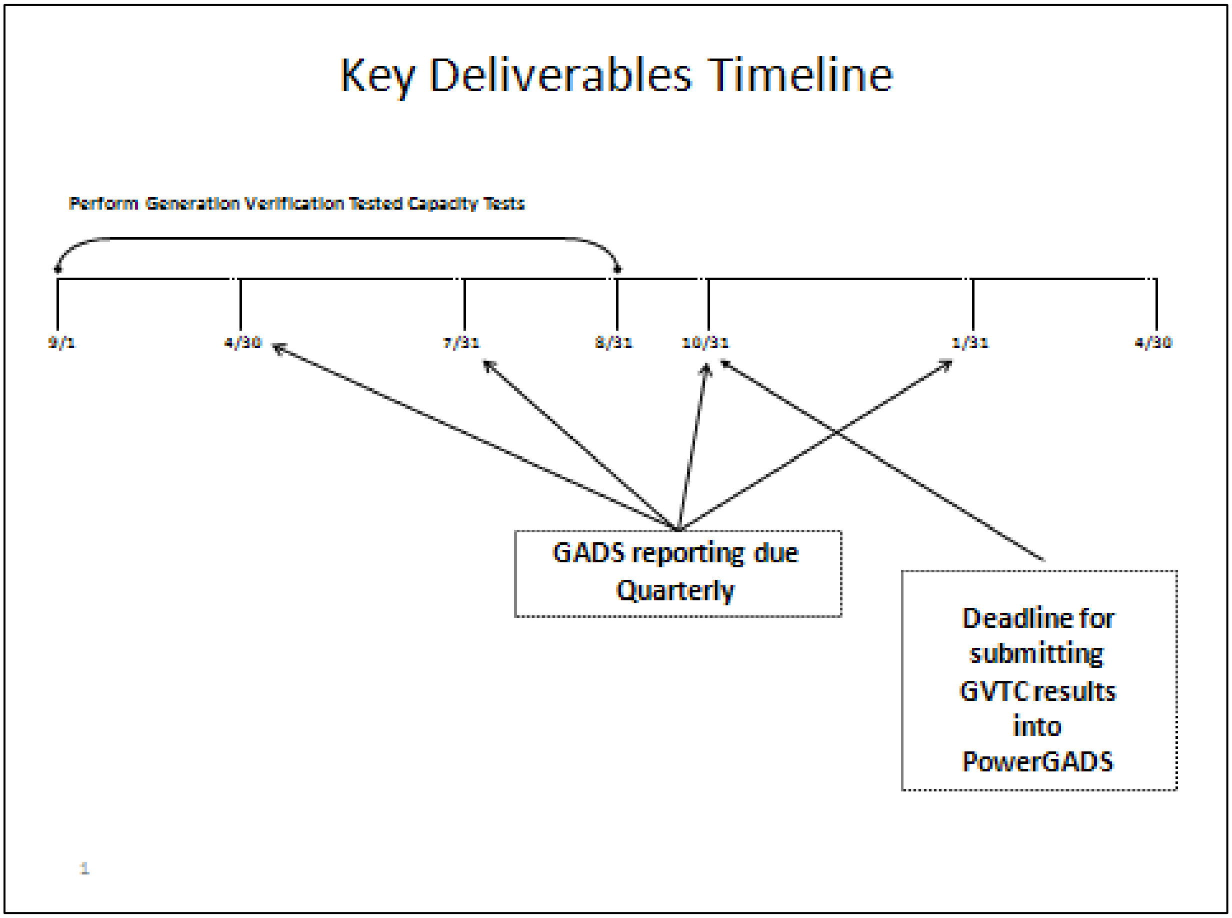
Example: For the 2023-2024 planning year (June 1, 2023 through May 31, 2024), the test must be conducted between September 1, 2021 and August 31, 2022, and submitted no later than October 31, 2022 to qualify as a Planning Resource for the upcoming Planning Year.

J.2 When to Perform and Submit a Generation Verification Test Capacity

Generation Resources, External Resources, Demand Response Resources backed by behind the meter generation, or Behind the Meter Generation that qualified as Planning Resources for the current Planning Year shall submit their GVTC no later than October 31 to qualify as a Planning Resource for the upcoming Planning Year. A real power test shall be performed, or past operational data may be used, during the period between September 1 and August 31 prior to the upcoming Planning Year. In addition to performing and submitting GVTC data to qualify as a planning resource for the annual capacity auction, a planning resource must conduct a test and submit data when:

- a modification that changes, increases, or decreases, the rated capacity of a unit is completed,
- returning from a suspension,
- returning to MISO after an absence including but not limited to, catastrophic events,
- not qualifying as a Planning Resource under Module E-1
- being qualified as a Planning Resource for the first time
- or for a Planning Resources in an approved “Suspension” status.

If a Planning Resource is unable to complete a real power test, the responsible MP must include the timing and cost requirements to complete a test when requesting a facility specific reference level.



J.3 Corrections to Establish GVTC

The GVTC shall be corrected to the average conditions of the date and times of MISO’s four seasonal coincident Peaks, measured at or near the generator’s location, for the last 5 years. MISO publishes the date and time of the past 5 seasonal coincident Peaks. When local weather records are not available at the plant site, the values shall be determined from the best data available (i.e., local weather service, local airports, river authority, etc.).

The corrections required to establish the GVTC of a unit include, as appropriate for each electric generating technology, dry air temperature, relative humidity, cooling water temperature, fuels, steam heating loads, reservoir level, nuclear fuel management programs and scheduled reservoir discharge.

J.3.1 Process Load Reporting in MISO PowerGADS to Establish GVTC

The Generator Owner shall forecast the maximum process load (PL) expected to be present at the time of the upcoming MISO seasonal peaks. MISO publishes the date and time of past coincident seasonal peaks as a reference for predicting the PL that is forecasted to be present at the time of the upcoming MISO peaks.

For calculating GVTC, the PL being forecasted and reported by the Generator Owner is allocated to the underlying generating unit of the Planning Resource and deducted from a unit's gross MW unless provisions are in place to curtail the load in the event of a MISO Capacity Emergency, or for electric load, is included in an LSE forecast. If such provisions for curtailment are in place or, for electric load, it is included in an LSE forecast, the PL is non-firm for the purpose of calculating GVTC.

Process Load can be electric load or thermal load in the case of a Combined Heat and Power (CHP) facility. Thermal PL is converted to units of MW by determining the reduction of power output caused by serving that load. Thermal loads can be PL because steam that would have otherwise been used to drive turbines to produce electricity may have been diverted to support process load, thus reducing the electrical capacity of the overall plant relative to the MISO system.

Thermal load that causes an increase in power output, as served from a back-pressure turbine for example, is not a PL for these purposes. However, the GVTC test should be performed or corrected for conditions that are a conservative expectation of the amount of thermal load that would be present coincident with MISO peak load conditions.

PL can be firm or non-firm. The following criteria should be applied to determine whether the PL is firm or non-firm:

- PL is firm if it continues to exist when one or more of the underlying generating units of the Planning Resource are derated or out of service. Such firm PL would be served by one or more of the underlying generating units of the Planning Resources at the same location or from the MISO system.
- PL is non-firm if it does not continue when the underlying generating unit of the Planning Resource is out of service.
- To the extent that PL that continues to exist when the underlying generating unit of the Planning Resource is out of service is served by resources that are not Planning Resources, such as auxiliary boilers, that portion of the PL is non-firm.

The amount of firm PL will be adjusted by multiplying by (1+PRM) and dividing by (1-XEFORd). The sum of the firm and non-firm PL will be reported in PowerGADS.

PL = (adjusted firm PL) + (non-firm PL)

Adjusted firm PL = firm PL * (1 + PRM) / (1 - XEFORd)

PL calculations are performed outside of PowerGADS and the MECT. PL is only deducted from an underlying generating unit of the Planning Resource's gross MWs one time. PL is part of the GVTC calculation that is entered into PowerGADS. MISO performs a PowerGADS integration that retrieves the GVTC value from the PowerGADS data base and populates the MECT. A Planning Resource may be comprised of one or more underlying PowerGADS units.

The UCAP PRM is from the most recent LOLE Study Report. The XEFORd is the appropriate value for the 36-months ending on August 31 proceeding the planning year, which can be found in PowerGADS.

J.4 Generation Verification Test Capacity During a Derate

A Market Participant that performs a GVTC when a unit has a documented derate in MISO PowerGADS can request MISO to adjust its GVTC if the documented derate in MISO PowerGADS lasted a minimum of 90 consecutive days prior to the test date and generator availability data has been reported to MISO prior to any adjustments to the GVTC. The Market Participant shall contact MISO's Resource Adequacy Department for a review of its request.

J.4.1 Interconnection Service Limitations

All Planning Resources GVTC are subject to Interconnection Service limitations to the bus to which the facility is currently or about to be connected to as verified by the Transmission Service Planning Department of MISO.

J.5 GVTC Real Power Test Requirements by NERC Unit Type

J.5.1 Fossil Steam (FS), Fluidized Bed Combustion (FB), and Nuclear (NU)

The test shall be at least two (2) continuous hours and data shall be averaged over the test period.

The impact of the observed steam turbine exhaust pressure will be corrected to the past five years average rated daily maximum circulating water temperature measured at the unit location, at the date and time of MISO's coincident peaks.

J.5.2 Combined Cycle (CC)

The determination of the GVTC of a combined-cycle unit will depend on the structure of the unit and its components. The steam turbine and combustion turbine(s) shall adhere to the guidelines in this manual. In the case of thermally dependent components the determination of the GVTC shall require the operation of both combustion and steam turbine components simultaneously. The output of the components can be netted to determine the combined-cycle unit GVTC.

The test shall be at least two (2) continuous hours and data shall be averaged over the test period.

For each Season, the impact of the observed steam turbine exhaust pressure will be corrected to the past five years average daily maximum circulating water temperature measured at the unit location on the day of MISO's Coincident Peak.

The impact of the observed ambient air temperature and relative humidity on combustion turbine performance will be corrected to the past five years average rated conditions experienced at the unit location measured at the date and time of MISO's Coincident Peaks. Where inlet cooling is used to reduce inlet air temperature, the temperature at the discharge of the inlet coolers shall be the basis for ambient temperature adjustment.

J.5.3 Miscellaneous (MS)

The test shall be at least two (2) continuous hours and data shall be averaged over the test period.

The test will be seasonally corrected per J.3 Corrections to Establish GVTC.

J.5.4 Combustion Turbine (CT)

The test shall be at least one (1) continuous hour and data shall be averaged over the test period.

The impact of observed dry air temperature and relative humidity on combustion turbine performance will be corrected, for each Season, to the past five years average rated conditions experienced at the unit location measured at the date and time of MISO's seasonal coincident peaks. Where inlet cooling is used to reduce turbine inlet air temperature, the temperature at the discharge of the Inlet coolers shall be the basis for air temperature correction.

J.5.5 Hydro (HD) and Pumped Storage (PS)

The test shall be at least one (1) continuous hour and data shall be averaged over the test period.

The GVTC established for hydroelectric plants shall recognize the head available considering environmental, operational, and regulatory restrictions and ambient conditions such as forecasted reservoir levels or water flow conditions. The test capability shall be corrected to historic median head conditions as specified below.

The seasonal historic median head shall be determined as the median of all head measurements from the most recent five (5) years up to the most recent fifteen (15) years. If 15 years of historic data is not available for this period when the 15-year time period is chosen, or is no longer relevant due to environmental, operational, regulatory or other restrictions, all available relevant data shall be used and accumulated until the 15-year requirement is met. The hours ending 1500, 1600, and 1700 EST apply to all days of the Summer (June, July, August), Fall (September, October, November), and Spring (March, April, May). The hours ending 0900, 1000, 1900, and 2000 EST apply to all days of the Winter (December, January, February).

Once the number of years and methodology is chosen and submitted as GVTC requirements, the same number of years must be submitted in future GVTC data collection.

Each hydro unit shall be verified individually.

The entire hydro plant shall be verified if the sum of individual unit capabilities is greater than the total plant capability.

MISO PowerGADS does not accept seasonal corrections for Hydro and Pumped Storage resources. If a Generation Operator (GO) elects to submit seasonal corrections they can use the Hydro and Pumped Storage GVTC Corrections template which can be found at https://www.misoenergy.org/planning/resource-adequacy/#nt=/planningdoctype:RA%20Guides%20and%20References/raguidetype:GVTC. If a GO elects to submit seasonal corrections, they must submit a test in MISO PowerGADS and the Hydro and Pumped Storage GVTC Corrections template to the MISO Help Center help.MISOEnergy.org.

J.5.6 Diesel (DS)

The test shall be at least one (1) continuous hour and data shall be averaged over the test period.

No corrections apply to this unit type.

J.5.7 Electric Storage Resources (ESR)

This section is for all ESR except Pumped Storage. For pumped storage see J.5.5.

The test shall be at least one (1) continuous hour and data shall be averaged over the test period. The test shall be conducted at the discharge rate that would be expected if the ESR were dispatched for four (4) continuous hours. The test results must be submitted in the Module E Capacity Tracking (MECT) tool (Planning Resources > Non-GADS Resource Registration) using the Non-GADS Performance Template posted on the MISO Website.

J.5.8 General Requirements

If a generating unit has not been in operation for five years, then as many years as the unit has been in operation shall be used. The GVTC for new generating units will be corrected based on estimated average daily maximum circulating water temperature measured at the date and time of MISO's Peaks.

The unit shall be operated with the regularly available type and quality of fuel.

The Station Service shall be representative of the conditions expected to occur during MISO's coincident peaks.

For facilities consisting of multiple units, shared station power and process load served shall be allocated to the individual units to compute unit net capability.

J.6 Reporting

The following information shall be reported to MISO's PowerGADS as described in MISO's *Net Capability Verification Test User Manual*. Certain data will be reported or calculated for each of the 4 Seasons – summer, fall, winter and spring.

CARD	Must be "90"
Utility	Required

Unit	Required
Year	Required
Test Index	Must be a "1"
REVISIONCODE	Must be "0" for initial upload, "R" to Revise, or "D" to Delete
Corrected Net - Seasonal	Calculated by PowerGADS
Test Start Date	Required
Test End Date	Required
Gross MW	Required
Station Service	Required
Process Load Served	Required
Net Test Capability	Required, Gross MW – Station Service – Process Load Served
Reactive Generation MVAR	Optional
Total Power MVA	Calculated by PowerGADS if Reactive Generation MVAR entered
Power Factor	Calculated by PowerGADS if Reactive Generation MVAR entered
Dry Air Temperature Observed - Seasonal	Required for certain unit types
Dry Air Temperature Rated - Seasonal	Required for certain unit types
Air Temperature Correction	Required, may be zero
Relative Humidity Observed - Seasonal	Required for certain unit types
Relative Humidity Rated - Seasonal	Required for certain unit types
Relative Humidity Correction	Required, may be zero
Cooling Water Temperature Observed - Seasonal	Required for certain unit types
Cooling Water Temperature Rated - Seasonal	Required for certain unit types
Cooling Water Temperature Correction	Required, may be zero
STANDARD	Must be "MISO"

Appendix K – Resource Adequacy Timeline for activities for the Planning Year 2025-2026

Please check for the latest online version posted on the Resource Adequacy webpage of MISO's corporate website.

Date	Process and Notes	Responsible Entity	Tariff Reference
Sep 01, 2024	Start Cost of New Entry (CONE) calculation in coordination with IMM.	MISO/IMM	69A.8(a)(3)
Sep 09, 2024	MISO to publish historical monthly and seasonal Coincident Peak Load hours and LRZ seasonal coincident factors.	MISO	69A.1.1.(c)
Oct 01, 2024	Last day to submit outage exemption related resolution requests regarding Schedule 53 resources through the MISO Help Center.	Resource Owner	
Oct 01, 2024	MISO opens the new Planning Year in the MECT for all 4 Seasons. (1st Business Day - October)	MISO	
Oct 01, 2024	Transmission losses by Local Balancing Authority are posted by MISO. (1st Business Day - October)	MISO	69A.1.1(b)
Oct 15, 2024	MISO posts RA hours to be used for accreditation calculation	MISO	
Oct 31, 2024	Generation Verification Test Capacity (GVTC) due. Resource Owners submit operational data or real power test for September 1 - August 31 period.	Resource Owner	69A.3.1.a, b, & c, 69A.3.6
Oct 31, 2024	Populated Non-GADS Performance Templates due in MECT.	Resource Owner	69A.3.1.a(1)(d)
Oct 31, 2024	Generator availability data due in GADS for resources required to report for Q3. Resource Owners must ensure at least 36 months of data is provided.	Resource Owner	69A.3.1.a(1)(c)
Nov 01, 2024	Seasonal Coincident and Non-Coincident Peak Demand forecasts by LSE/EDC, monthly peak Demand, seasonal peak Demand and energy-for-load forecast values by LSE due. No action needed by Retail Choice LSEs.	LSE, EDC	69A.1.1(a)
Nov 01, 2024	Loss of Load Expectation study results published by MISO.	MISO	68A.2 68A.4 68A.5

Date	Process and Notes	Responsible Entity	Tariff Reference
Nov 07, 2024	MP must request an extension from within 5 business days after October 31 deadline.	Resource Owner	69A.3.1.a, b, & c, 69A.3.6
Nov 15, 2024	Review list of units with conditional Interconnection Service for results of annual study. Units may have NRIS/ERIS balance re-allocated.	MISO	
Dec 01, 2024	For individual States establishing their own seasonal PRM, submission of written letter by authorized State regulatory authority representative notifying MISO.	State Regulatory Authority	68A.1
Dec 15, 2024	RBDC opt out adder % posted on MISO website	MISO	69A.9.1 (l)
Dec 15, 2024	Initial UCAP/ISAC ratio, initial Seasonal Capacity accreditation values and validation files are published by MISO.Resources that do not meet the October 31 deadline will have their initial capacity accreditation calculated using estimated capacity submitted along with GVTC extension requests. MP may begin submitting resolution requests though the MISO Help Center.	MISO	
Dec 15, 2024	PLC submissions by EDC due. EDC will send the details of the PLCs to the respective LSEs and to MISO for review. The EDC-provided PLC data will be the default value for the LSE’s Retail Choice Coincident Peak.	Retail Choice EDCs	69A.1.1(e)
Dec 15, 2024	Last day for MPs to submit to March Network & Commercial Model changes to qualify for ICAP Deferral.	Resource Owner	
Jan 15, 2025	LSE submit initial RBDC Opt Out Plan in MECT, including its RERRA contact	LSE	69A.9.1 (c)
Jan 15, 2025	Generation Verification Test Capacity (GVTC) due for generators that requested an extension.	Resource Owner	69A.3.1.a, b, & c, 69A.3.6
Jan 15, 2025	LSEs confirm the seasonal Retail Choice PLC in the MECT. LSEs should have all PLC questions resolved by this date. If an LSE desires a change in their PLC value, the appropriate EDC should be contacted directly.	LSEs, Retail Choice EDC	69A.1.1.1
Jan 15, 2025	Evidence for seasonal HUC/ZDC hedges due.	LSE	69A.7.7(b)

Date	Process and Notes	Responsible Entity	Tariff Reference
Jan 20,2025	MISO notifies RERRA its regulating LSE's initial plan for opting out RBDC	MISO	69A.9.1 (d)
Jan 31, 2025	Default technology-specific avoidable costs posted by the IMM. Resource owners may use the default costs in lieu of submitting facility specific operating costs for a facility specific Reference Level request. (59 days prior to deadline for offers)	IMM	64.1.4(f)(ii)
Jan 31, 2025	Generator availability data due in GADS for resources required to report for Q4.	Resource Owner	69A.3.1.a, b, & c, 69A.3.6
Feb 01, 2025	Last day to submit non-exemption related resolution requests on ISAC posted for Schedule 53 resources through the MISO Help Center.	Resource Owner	
`Feb 01, 2025	Existing Load Modifying Resource, Energy Efficiency, and External Resource registrations due for prompt Planning Year.	LMR/EE/ER Owner	
Feb 01, 2025	Loss of Load Expectation study begins for next Planning Year.	MISO	
Feb 01, 2025	Evidence of Demand Resource testing due. Last day to submit evidence. DR testing or performance must take place during the calendar year prior to the upcoming Planning Year.	DR Owner	69A.3.5
Feb 01, 2025	Written letter from officer of company stating intention to leverage DR testing deferral provisions due.	DR Owner	69A.3.5(l)
Feb 07, 2025	Last day to submit a Full Responsibility Transaction. (due the 5th business day of February)	LSE	
Feb 14, 2025	If utilizing FSRL, last day to submit request to IMM regarding Going-Forward Cost determination. Submit data for facility ZRC reference levels to IMM. (45 days prior to close of PRA offer deadline)	Generation Owner	64.1.4.f.iii.b
Feb 15, 2025	Final UCAP/ISAC ratio and SAC values for Schedule 53 resources will be posted on MECT. Schedule 53 resource owners can start confirming SAC and converting SAC into ZRCs.	MISO	
Feb 15, 2025	New Load Modifying Resource, Energy Efficiency Resource, and External Resource registrations must be submitted for approval to be considered for inclusion in seasonal FRAP or RBDC Opt Out.	LSE	69A.9(a)

Date	Process and Notes	Responsible Entity	Tariff Reference
Feb 15, 2025	LSEs submit request to revise seasonal Coincident Peak Demand forecast originally submitted on November 1. MISO will review and either approve or deny request.	LSE	
Feb 15, 2025	Written letter from officer of company stating intention to leverage ICAP Deferral provisions.	Resource Owner	69A.7.9(a)
Feb 17, 2025	Last day that RERRA notifies MISO if it denies any of the LSE's plan for opting out RBDC	RERRA	69A.9.1 (d)
Feb 28, 2025	Capacity accreditation updated for resources granted ICAP Deferral.	MISO	
Mar 01, 2025	Seasonal Generator Verification Test Capacity and generator availability data for new resources or resources with increased capacity due for prompt Planning Year.	Generation Owner	69A.3.1.a(d)
Mar 01, 2025	New Load Modifying Resource, Energy Efficiency Resource, and External Resource registrations must be submitted for approval in the MECT for the prompt Planning Year.	LMR/EE/ER Owner	69A.9(a)
Mar 01, 2025	Deadline to satisfy credit requirements for DRs opting out of or deferring testing. Credit posting only required if DR doesn't have regulatory restrictions or contractual obligations that preclude testing.	DR Owner	69A.3.5 (j)(2)&(l)
Mar 01, 2025	MISO to complete its seasonal Coincident Peak Demand forecast review process.	MISO	69A.1.1(c)
Mar 01, 2025	Satisfy credit posting requirement for seasonal capacity accreditation issued from resources granted ICAP Deferral.	Resource Owner	69A.7.9(b)
Mar 01, 2025	Resource Owners submit Attachment Y requests for units scheduled for retirement/suspension between 3/30 and 5/31 to receive exemption from physical withholding.	Resource Owner	38.2.7.a.(i)
Mar 03, 2025	Publish seasonal Sub Regional Import Constraint (SRIC) and seasonal Sub Regional Export Constraint (SREC) for each Sub Regional Resource Zone (SRRZ) no later than first business day in March.	MISO	68A.3.1
Mar 10, 2025	Finalize and submit HUC registrations in the MECT.	LSE	
Mar 11, 2025	Seasonal Fixed Resource Adequacy Plan due by LSE. (7th Business Day of March)	LSE	69A.9(a)
Mar 11, 2025	LSE confirms its RBDC Opt Out Plan in MECT (7th Business Day of March)	LSE	69A.9.1(c)
Mar 14, 2025	Last day to notify IMM of deliverable resources requesting to be excluded from offering into seasonal PRAs or included in a FRAP or RBDC Opt Out.	Generation Owner	
Mar 15, 2025	Fixed Resource Adequacy and RBDC Opt Out Plan review completed by MISO. The LSE will have until the auction	MISO(LSE)	69A.9(a) 69A.9.1(c)

Date	Process and Notes	Responsible Entity	Tariff Reference
	offer window opens to remedy any deficiencies in their FRAP or RBDC Opt Out.		
Mar 19, 2025	Final date to update seasonal CIL and CEL values for each LRZ prior to the Planning Resource Auction. Changes due to firm capacity commitments from MISO resources to neighboring regions established prior to the PRA.	MISO	68A.4
Mar 19, 2025	CEL determined for each ERZ. Equal to the ZRC quantity of the External Resources registered to participate in the PRA. (8th business day in March prior to the last business day)	MISO	68A.4
Mar 19, 2025	Final posting by MISO of preliminary seasonal PRA data, reflective of updated information from LSEs, Resource Owners and PJM auction results. Coincides with seasonal CIL/CEL calculations.	MISO	
Mar 27, 2025	Provide Facility Specific Resource Level(s) to MPs 5 days prior to the close of the PRA offer window.	IMM	64.1.4.f
Mar 25, 2025	Final day for confirming/converting SAC in MECT.	Resource Owner	
Mar 26, 2025	Planning Resource Auction offer window is opened for all Seasons. Auction Offer window is opened at 8:00 AM EPT, 3 business days prior to the last business day in March.	MISO	69A.7.1(a)
Mar 31, 2025	Planning Resource Auction offer window is closed for all Seasons. Auction Offer window is closed at 6:00 PM EPT on the last business day of March.	MISO	69A.7.1(a)
Apr 01, 2025	Iterations of seasonal auction runs with adjusted seasonal CILs and CELs may be required to ensure that a network loading is not violated. Additionally, MISO will work with the IMM to evaluate potential withholding. The reference levels are used to determine financial withholding. The mitigation of financial withholding can be expected to reduce the Auction Clearing Price. (First 20 Business Days of April)	MISO/IMM*	69A.7
Apr 28, 2025	Seasonal Planning Resource Auctions results posted. (20th Business Day of April)	MISO	69A.7
Apr 30, 2025	Generator availability data due in GADS for resources required to report for Q1.	Resource Owner	69A.3.1.a, b, & c, 69A.3.6
May 01, 2025	MISO to assess seasonal Capacity Deficiency Charges for applicable LSEs.	MISO	69A.10(a)

Date	Process and Notes	Responsible Entity	Tariff Reference
May 8, 2025	MISO sends Capacity Deficiency Charges to applicable LSEs 5 business days after assessment.	MISO	
May 19, 2025	Capacity Deficiency Charge payments distributed to MPs. Payment made within 7 business days of receipt.	MISO	
May 28, 2025	Publish details of the seasonal ZRC offers submitted in the PRA. Market Participant IDs are not revealed. (One month after PRA)	MISO	69A.7.4
May 28, 2025	MISO publishes cleared LMRs to DSRI. MISO publishes must offer performance requirements in the applicable Operations tool.	MISO	
May 30, 2025	Information due to satisfy ICAP Deferral must be submitted to MISO to avoid ICAP Deferral Non-Compliance Charge for Summer Season. (Last business day of Planning Year)	LSE	69A.7.9(a) (2)
May 30, 2025	Information due to satisfy DR Deferral Notice must be submitted to MISO in order to release credit requirements and avoid LMP performance penalties.	DR Owner	69A.3.5
Jun 01, 2025	Summer Season in new Planning Year starts.	All	69A.7
Jun 01, 2025	Daily settlements for the Summer Season starts.	All	
July 31, 2025	Generator availability data due in GADS for resources required to report for Q2.	Resource Owner	69A.3.1.a, b, & c, 69A.3.6
August 29, 2025	Information due to satisfy ICAP Deferral must be submitted to MISO to avoid ICAP Deferral Non-Compliance Charge for Fall Season. (Last business day)	LSE	69A.7.9(a) (2)
Sep 01, 2025	Fall Season in new Planning Year starts.	All	69A.7
Sep 01, 2025	Daily settlements for the Fall Season starts.	All	
November 26, 2025	Information due to satisfy ICAP Deferral must be submitted to MISO to avoid ICAP Deferral Non-Compliance Charge for Winter Season. (Last business day)	LSE	69A.7.9(a) (2)
Dec 01, 2025	Winter Season in new Planning Year starts.	All	69A.7
Dec 01, 2025	Daily settlements for the Winter starts.	All	

Date	Process and Notes	Responsible Entity	Tariff Reference
February 27, 2026	Information due to satisfy ICAP Deferral must be submitted to MISO to avoid ICAP Deferral Non-Compliance Charge for Spring Season. (Last business day)	LSE	69A.7.9(a) (2)
Mar 01, 2026	Spring Season in new Planning Year starts.	All	69A.7
Mar 01, 2026	Daily settlements for the Spring Season starts.	All	

Appendix L – Transmission Losses Calculation

The Transmission Provider will calculate the seasonal LBA Transmission loss percentages using the process described as follows:

1. The Transmission Provider's State Estimator calculates transmission losses (MW) as part of the solution output process every five (5) minutes.
2. The transmission losses (MW) are computed on all transmission lines and transformers by summing up real power at both ends for each transmission element (retaining the convention for flow direction) or as the difference in real power (without the sign convention for flow direction) for each State Estimator solution.
3. The individual transmission losses (MW) for each element are summed to a total transmission value for each Local Balancing Authority (LBA) level.
4. These LBA transmission loss values are then integrated across each hour to calculate an hourly transmission loss value (MW) for each LBA.
5. The total transmission loss value (MW) for each LBA will be the hourly integrated transmission losses value (MW) for the hour of the Transmission Provider's system peak during each of the four previous Seasons.
6. The LBA transmission loss percentages are calculated as the total LBA transmission losses divided by the total LBA load, at each seasonal MISO peak hour.

The seasonal LBA transmission loss percentage calculated by the Transmission Provider will apply to the LSE's applicable seasonal LBA Coincident Peak Demand forecast to determine the LSE transmission losses for the calculation of the seasonal Initial PRMR. The LBA transmission loss percentage calculated by the Transmission Provider coincident with each LRZ’s seasonal Peak Demand forecast will determine the LSE transmission losses for the calculation of LRR. Both the MISO and Zonal Transmission Losses will be posted on the MISO public website by November 1 before the upcoming Planning Year.

Initial PRMR met with Behind-the-Meter-Generation Resources that are interconnected to the Transmission System shall be treated like other Resources with respect to transmission losses. Initial PRMR met with Behind-the-Meter-Generation Resources that are not interconnected to the Transmission System shall be adjusted to account for serving load without incurring transmission losses by grossing up the MW quantity of such resources by (1.0 + the appropriate LBA transmission loss percentage).

APPENDIX M: PLANNING RESOURCE AUCTION FORMULATION WITH RELIABILITY-BASED DEMAND CURVES

Disclaimer

This document is prepared for informational purposes only and is intended to help the user understand how the MISO Tariff provisions relating to Resource Adequacy Requirements and Reliability-Based Demand Curves are implemented in MISO's Planning Resource Auction (PRA). MISO may revise or terminate this document at any time at its discretion without notice. However, every effort will be made by MISO to update this document and inform its users of changes as soon as practicable. Nevertheless, it is the user's responsibility to ensure you are using the most recent version posted on the MISO website. In the event of a conflict between this document and the Tariff, the Tariff will control, and nothing in this document shall be interpreted to contradict, amend or supersede the Tariff. MISO owns the intellectual property of this document and content.

Purpose of this document

MISO's Resource Adequacy construct provides LSEs in the MISO footprint an ability to procure planning resources through a PRA for each Season within the Planning Year (PY). A Linear Programming (LP) based optimization tool has been developed to clear the auction and calculate Auction Clearing Prices (ACP). This document provides a detailed mathematical representation of the constrained optimization formulation that is used for clearing the seasonal PRA and explains how the zonal Auction Clearing Prices are calculated for each Season within the PY.

1 Overview of Auction Clearing Processes

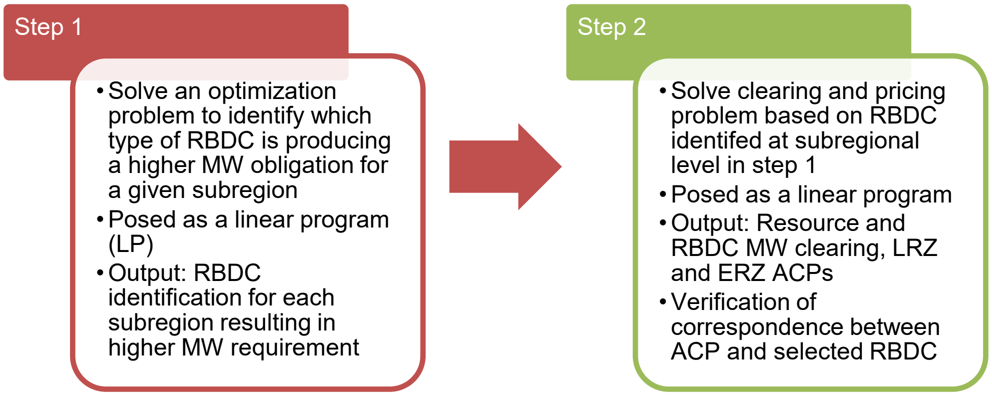
MISO is introducing sloped demand curves in its Resource Adequacy construct through the implementation of Reliability-Based Demand Curve (RBDC) in the 2025 PRA. Specifically, MISO utilizes distinct sloped demand curves at both the systemwide and sub-regional levels: one systemwide RBDC and separate subregional RBDCs for the North/Central (N/C) and South subregions (also called planning areas). 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 will utilize one systemwide RBDC and two sub-regional RBDCs in the PRA, totaling twelve RBDCs over the course of a Planning Year.

A subregional RBDC acknowledges the specific reliability needs of each sub-region. It is crucial to provide a price signal that reflects this regional diversity to promote efficient capacity pricing, resource planning, and grid reliability across MISO. Since MISO's footprint is divided into two subregions, each subregion will have two obligations to meet for resource adequacy: one from its share of the systemwide RBDC and the other from its own subregional RBDC. The share of systemwide RBDC is the systemwide RBDC weighted by the coincident peak demand share (with transmission losses) of the subregion. To ensure resource adequacy, the higher of these two obligations should be prioritized; meeting the higher obligation will automatically satisfy the lower one. The method for PRA clearing and pricing is outlined below.

Step 1 (RBDC identification): For each subregion, identify the RBDC curve between (i) share-of-systemwide RBDC and (ii) subregional RBDC that produces higher MW obligation in the neighborhood of the intersection of supply and demand curves.

Step 2 (Clearing and pricing): Use specific RBDCs identified in step 1 for each subregion and solve the clearing and pricing problem.

This solution methodology is summarized in **Error! Reference source not found.**.



- Solve an optimization problem to identify which type of RBDC is producing a higher MW obligation for a given subregion
- Posed as a linear program (LP)
- Output: RBDC identification for each subregion resulting in higher MW requirement

- Solve clearing and pricing problem based on RBDC identifed at subregional level in step 1
- Posed as a linear program
- Output: Resource and RBDC MW clearing, LRZ and ERZ ACPs
- Verification of correspondence between ACP and selected RBDC

Figure 1. Overview of solution methodology

2 Preliminaries

This section defines the notation used in the optimization problem. In cases of ambiguity, we use the superscript SR to denote parameters or decision variables associated with subregional RBDC clearing, while the superscript SYS is used in reference to systemwide RBDC clearing. The optimization variables are in orange font.

2.1 Sets

Set DC = {Systemwide RBDC (SYS-RBDC), North/Central subregion RBDC (NC-RBDC), South subregion RBDC (S-RBDC)}

Set R = {North/Central subregion (NC), South subregion (S)}

Set Z = {All local resource zones (LRZs) in the transmission planning area}

Set Z_r = {All local resource zones (LRZs) in the subregion $r \in R$}

Set Z_n = {All North/Central subregion LRZs (LRZ 1 through 7)}

Set Z_s = {All South subregion LRZs (LRZ 8 through 10)}

Set E = {All external resource zones (ERZs) participating in the PRA}

Set F = {All resource offers in the system including LRZs and ERZs}

Set G = {All resources in LRZs}

Set G_k = {All resources in LRZ k}

Set G_r = {All resources in the LRZs within subregion $r \in R$}

Set H = {All resources in external zones (including dual connected external zones)}

Set H_e = {All resources in external zone *e*}

Set J_{dc} = {All demand segments in RBDC $dc \in DC$}

Set J_r = {All demand segments in subregional RBDC for subregion $r \in R$}

Set MC = {All resources which are part of fixed resource adequacy plans (FRAPs), or self-scheduled resources ($0 offer price), or resources covered by RBDC Opt Out}

2.2 Parameters

The following parameters are used to set up the constrained optimization problem for the PRA:

$INITIALPRMR_k$	Initial Planning Reserve Margin Requirement (PRMR) for LRZ *k*. Initial PRMR refers to PRMR for achieving the seasonal systemwide LOLE target (1-day-in-10 for Summer and 1-day-in-100 for other seasons)
$CPDF_k$	Coincident Peak Demand Forecast (CPDF) for LRZ *k*
LCR_k	Local Clearing Requirement for LRZ *k*
CIL_k	Capacity Import Limit for LRZ *k*
CEL_k	Capacity Export Limit for LRZ *k*
CEL_e	Capacity Export Limit for external zone *e*
$SREC_r$	Subregional export constraint (SREC) for subregion $r \in R$
$SRIC_r$	Subregional import constraint (SRIC) for subregion $r \in R$
$OFFERPRICE_i$	The offer price for resource *i*[3]
$OFFERMW_i$	Offered MW value for resource *i*
$SF_{r,e}$	Shift Factor $\in [0, 1]$ to subregion *r* for resources in external zone *e*[4]

ACP_k	Auction Clearing Price for Zone k
$CONE_k$	Annualized cost of new entry (CONE) for LRZ *k*
$CONE_n$	Average annualized CONE for LRZs in the North/Central subregion
$CONE_s$	Average annualized CONE for LRZs in the South subregion
$CONE_{SYS}$	Average annualized CONE for all LRZs in MISO
$SEASONALCONE_k$	Annualized CONE for LRZ *k* divided by number of days in the season
$SEASONALCONE_e$	For dual connected ERZ e: maximum annualized CONE of all LRZ*s* divided by number of days in the season. For ERZ e connected to a single subregion: maximum annualized CONE of all LRZ*s* in that subregion divided by number of days in the season.
$DAILYCONE_k$	Annualized CONE for LRZ *k* divided by number of days in the planning year
$RBDCPRICE_{j,dc}$	RBDC Price ($/UCAP MW-day) for demand curve segment $j \in J_{dc}$ for demand curve version $dc \in DC$
$RBDCSTEP_{j,dc}$	RBDC Step Size (UCAP MW) for demand curve segment $j \in J_{dc}$ for demand curve version $dc \in DC$
u_r	Binary parameter for MISO subregion $r \in R$ indicating the RBDC selected for step 2 of the solution methodology: 0 refers to share-of-systemwide RBDC, and 1 refers to the subregional RBDC
α_k^{SYS}	CPDF share of LRZ *k* with respect to all the LRZs in the system given by the following equation: $$\alpha_k^{SYS} \overset{def}{=} \frac{CPDF_k}{\sum_{k \in Z} CPDF_k} \in [0,1]$$
α_r	CPDF share of region $r \in R$, given by: $$\alpha_r \overset{def}{=} \sum_{k \in Z_r} \alpha_k \in [0,1]$$
α_k^r	CPDF share of LRZ *k* in subregion $r \in R$ with respect to all the LRZs in that subregion, given by:

$$\alpha_k^r \overset{def}{=} \frac{\alpha_k}{\alpha_r} \in [0,1]$$

2.3 Decision Variables

The optimization variables for the two linear programs are as follows (**all variables are non-negative**):

$clearedMW_i^{SYS}$	Cleared MW value of offer *i* to meet systemwide RBDC demand in step 1
$clearedMW_i^{SR}$	Cleared MW value of offer *i* to meet systemwide RBDC demand in step 1
$clearedMW_i$	Cleared MW value of offer *i* to meet selected RBDC demand in step 2
$clearedDemand_{j,r}^{SYS}$	Cleared MW value of systemwide RBDC segment *j* for subregion $r \in R$ [5]
$clearedDemand_{j,r}^{SR}$	Cleared MW value of subregional RBDC segment *j* for subregion $r \in R$
S_k^{SYS}	MW amount by which LRZ *k* is short of its local clearing requirement (LCR) or initial PRMR - CIL while meeting systemwide RBDC demand in step 1
S_k^{SR}	MW amount by which LRZ *k* is short of its local clearing requirement (LCR) or initial PRMR - CIL while meeting subregional RBDC demand in step 1
S_k	MW amount by which LRZ *k* is short of its local clearing requirement (LCR) or initial PRMR - CIL in step 2

3 Step 1: RBDC identification

The objective of the RBDC identification procedure is to determine which RBDC between share-of-systemwide RBDC and subregional RBDC is producing a higher MW requirement for each subregion. The requirements are determined through a solution to a linear program.

The identification of the RBDC producing a higher requirement is challenging, a priori. This difficulty is illustrated via the two plots on the first row of **Error! Reference source not found.** c orresponding to the summer season in the MISO N/C region and MISO South region, respectively: on the left, the subregional RBDC will always result in a higher MW requirement as compared to the share-of-systemwide RBDC for any clearing price point. However, on the right, both RBDCs are intertwined and depending on supply and demand curve intersection either systemwide or subregional RBDC could result in a higher MW requirement. This systemwide and the subregional RBDC interaction increases the complexity of the PRA clearing process. To address this, an LP based optimization approach is utilized for the determination of the correct RBDC (higher MW requirement) for each subregion in a given season; this selected RBDC is used for the optimization in step 2.

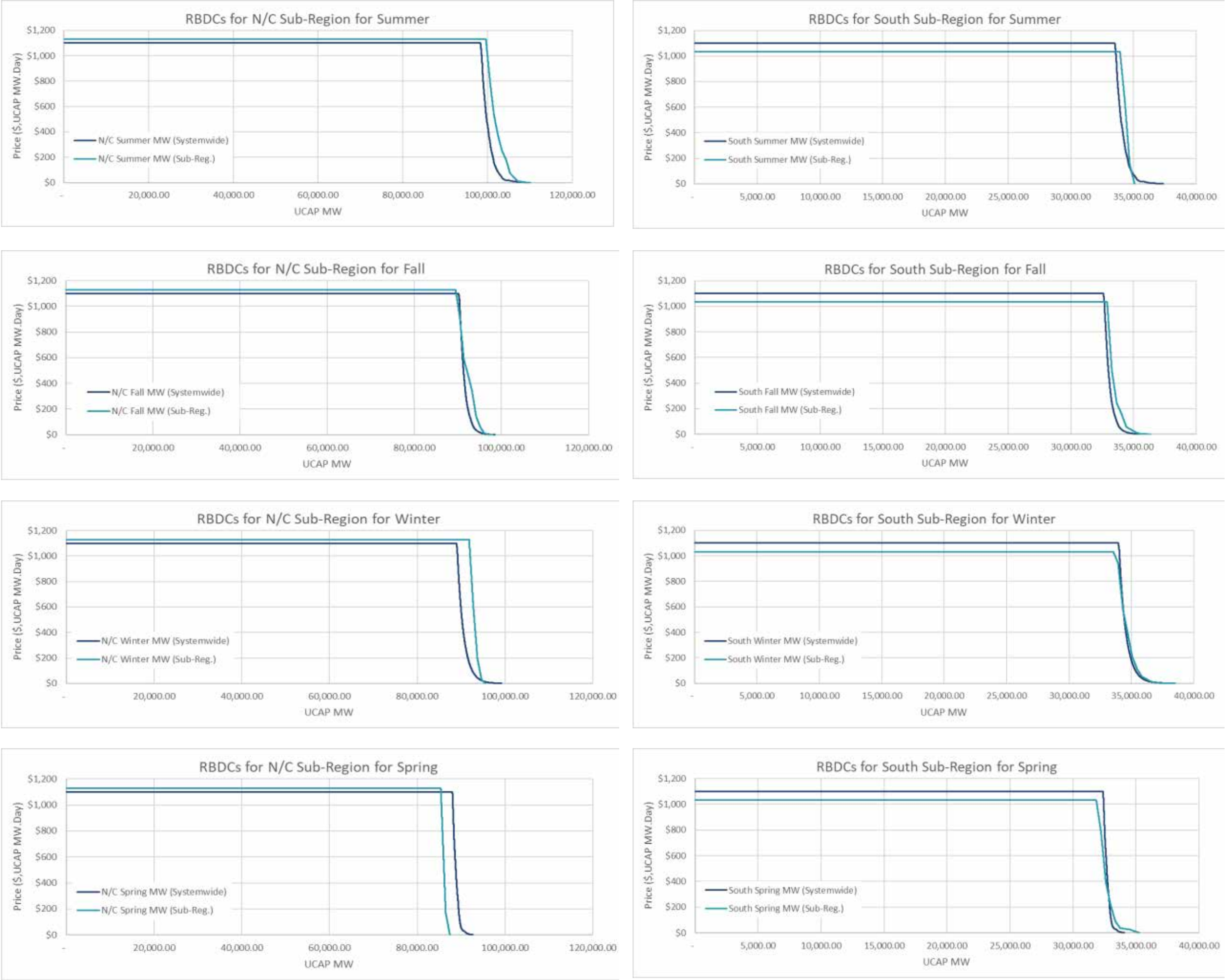


Figure 2. Indicative seasonal RBDC curves for N/C and South subregions, also showing the load-share-based projection of systemwide RBDC on to the sub-region.

3.1 Step 1 Formulation

The optimization problem for the RBDC identification step is posed as a linear program with the objective to minimize the cost of balancing capacity & demand for two scenarios: (i) demand is from share-of-systemwide RBDC in each subregion, and (ii) demand is from subregional RBDC in each subregion. In this formulation, these two scenarios are enforced independently. Subregional power balancing constraints and zonal clearing constraints are also enforced independently for each scenario.

After solving the LP, the demand cleared on the basis of share-of-systemwide RBDC is compared with the demand cleared on the basis of the subregional RBDC clearing for both N/C and south subregions: for each subregion, the type of RBDC (share-of-systemwide RBDC or subregional RBDC) which produces the higher MW requirement is identified and selected for use in step 2 of the clearing process. The optimization formulation for step 1 is presented in the following.

3.1.1 Objective Function

The linear minimization objective is as follows:

Minimize $f \stackrel{\text{def}}{=} SC - (SB + RB) + \Lambda,$ (3.1.a)

with SC referring to the supply cost which is the area under the offer curve, SB and RB referring to the reliability benefits from the systemwide and subregional RBDCs which are the areas under the systemwide RBDC and subregional RBDCs, respectively, and Λ as the shortage penalty for zonal LCR shortage or initial PRMR shortage beyond the capacity import limit (CIL) of the zone. These terms are expressed as follows:

$$SC \stackrel{\text{def}}{=} \sum_{i \in F} OFFERPRICE_i \times (clearedMW_i^{SYS} + clearedMW_i^{SR}) \quad (3.1.b)$$

$$SB \stackrel{\text{def}}{=} \sum_{j \in J_{SYS-RBDC}} \sum_{r \in R} \alpha_r \times RBDCPRICE_j \times clearedDemand_{j,r}^{SYS} \quad (3.1.c)$$

$$RB \stackrel{\text{def}}{=} \sum_{r \in R} \sum_{j \in J_r} RBDCPRICE_j \times clearedDemand_{j,r}^{SR} \quad (3.1.d)$$

$$\Lambda \stackrel{\text{def}}{=} \sum_{k \in Z} SEASONALCONE_k \times (S_k^{SYS} + S_k^{SR}) \quad (3.1.e)$$

3.1.2 Constraints

The optimization constraints are based on system, subregional, and zonal balancing requirements, in addition to bounds on resource and segment clearing. Note that all decision variables are restricted to be in the domain of non-negative real values.

3.1.2.1 Resource Offer Bounds

Resource clearing should not exceed the MWs offered by the resources

$$clearedMW_i^{SYS} \leq OFFERMW_i, \qquad \forall i \in F \quad (3.2.a)$$

$$clearedMW_i^{SR} \leq OFFERMW_i, \qquad \forall i \in F \quad (3.2.b)$$

3.1.2.2 RBDC segment bounds

Price sensitive demand, characterized by different RBDCs, has limits based on the segments of the RBDC; MWs cleared in RBDC segments should not exceed the RBDC segment limits:

$$clearedDemand_{j,r}^{SYS} \leq RBDCSTEP_j, \qquad \forall j \in J_{SYS-RBDC}, \qquad \forall r \in R \tag{3.3.a}$$

$$clearedDemand_{j,r}^{SR} \leq RBDCSTEP_j, \qquad \forall j \in J_r, \qquad \forall r \in R \tag{3.3.b}$$

3.1.2.3 Power balance constraints

Systemwide supply-demand balance constraints. To properly value the reliability given the clearing outcome, the supply-demand balance equations enforce the condition that cleared supply is greater than or equal to cleared demand.

In step 1, the supply-demand balance must hold for both the system and subregional RBDC curves: the cleared quantity of demand from each RBDC curve must be met by corresponding supply-side variables.

$$\sum_{i \in F} clearedMW_i^{SYS} \geq \sum_{j \in J_{SYS-RBDC}} \sum_{r \in R} \alpha_r \times clearedDemand_{j,r}^{SYS} \tag{3.4.a}$$

$$\sum_{i \in F} clearedMW_i^{SR} \geq \sum_{r \in R} \sum_{j \in J_r} clearedDemand_{j,r}^{SR} \tag{3.4.b}$$

Subregional supply-demand balance constraints. These constraints ensure that the difference between the cleared supply available within a subregion and the cleared demand associated with the subregion is within the subregional import and export limits (SRIC and SREC, respectively). In step 1, the constraints are imposed for clearing associated with both systemwide and subregional RBDCs as follows, respectively:

$$\begin{aligned} -SRIC_r \leq \sum_{i \in G_r} clearedMW_i^{SYS} + \sum_{e \in E} SF_{r,e} \times \sum_{k \in H_e} clearedMW_k^{SYS} - \\ \sum_{j \in J_{SYS-RBDC}} \alpha_r \times clearedDemand_{j,r}^{SYS} \leq SREC_r, \qquad \forall r \in R \end{aligned} \tag{3.5.a}$$

$$\begin{aligned} -SRIC_r \leq \sum_{i \in G_r} clearedMW_i^{SR} + \sum_{e \in E} SF_{r,e} \times \sum_{k \in H_e} clearedMW_k^{SR} - \\ \sum_{j \in J_r} clearedDemand_{j,r}^{SR} \leq SREC_r, \qquad \forall r \in R \end{aligned} \tag{3.5.b}$$

3.1.2.4 Zonal Clearing Constraints

Local Clearing Requirement (LCR) and Capacity Import Limit (CIL) constraints ensure that the quantity of cleared supply in the zone must exceed the minimum of the LCR and the share of Initial PRMR that cannot be met by imports. If the quantity of cleared supply falls short of either of these limits, the shortfall variable is penalized at the zone's seasonal CONE value in the objective function (3.1.a). In Step 1, the LCR and CIL are enforced for both the systemwide and subregional RBDC clearing outcomes. The LCR constraints are as follows:

$$\sum_{i \in G_k} clearedMW_i^{SYS} + S_k^{SYS} \geq LCR_k, \quad \forall k \in Z \tag{3.6.a}$$

$$\sum_{i\in G_k} clearedMW_i^{SR} + S_k^{SR} \quad \geq \; LCR_k, \quad \forall k \in Z \tag{3.6.b}$$

The quantity of imports in the zone to meet initial PRMR requirements must be below CIL. Only the tighter of the LCR and CIL constraints will bind, so we can use the same shortage variables for both LCR and CIL constraints. The CIL constraints are as follows:

$$INITIALPRMR_k - \sum_{i\in G_k} clearedMW_i^{SYS} - S_k^{SYS} \; \leq \; CIL_k, \qquad \forall k \in Z \tag{3.7.a}$$

$$INITIALPRMR_k - \sum_{i\in G_k} clearedMW_i^{SR} - S_k^{SR} \quad \leq \; CIL_k, \qquad \forall k \in Z \tag{3.7.b}$$

Capacity Export Limit (CEL) constraints ensure that the quantity of exports for the zone does not exceed the available transfer capabilities (CEL). The exports are the difference between the cleared supply in the LRZ and the load obligations of the LRZ. The load requirement for an LRZ is calculated based on the CPDF share of the LRZ with respect to the cleared demand in the subregion. Consequently, the LRZ obligations based on systemwide RBDC clearing and subregional RBDC clearing are given by, respectively,

$$LRZReq_k^{SYS} \; = \; \sum_{j\in J_{SYS-RBDC}} \alpha_k^{SYS} \times clearedDemand_{j,r}^{SYS}, \quad \forall k \in Z_r, \forall\, r \in R \tag{3.8.a}$$

$$LRZReq_k^{SR} \; = \; \sum_{j\in J_r} \alpha_k^{r} \times clearedDemand_{j,r}^{SR}, \qquad \forall k \in Z_r, \forall\, r \in R \tag{3.8.b}$$

The CEL constraints for each LRZ corresponding to the systemwide RBDC and the subregional RBDCs are given by, respectively,

$$\sum_{i\in G_k} clearedMW_i^{SYS} - LRZReq_k^{SYS} \; \leq \; CEL_k, \quad \forall k \in Z \tag{3.9.a}$$

$$\sum_{i\in G_k} clearedMW_i^{SR} - LRZReq_k^{SR} \quad \leq \; CEL_k, \quad \forall k \in Z \tag{3.9.b}$$

Since ERZs have no load obligations, their CEL constraints for systemwide RBDC and subregional RBDCs are given by, respectively,

$$\sum_{i\in H_e} clearedMW_i^{SYS} \; \leq \; CEL_e, \quad \forall e \in E \tag{3.9.c}$$

$$\sum_{i\in H_e} clearedMW_i^{SR} \; \leq \; CEL_e, \quad \forall e \in E \tag{3.9.d}$$

4 Step 2: Clearing and Pricing

Following step 1: RBDC identification, the effective RBDCs for each subregion are established. In step 2, these identified RBDCs are used to determine resource and RBDC MW clearing along with the Auction Clearing Prices (ACPs). This clearing and pricing optimization problem is an LP problem.

In the social welfare optimization problem in step 2, for each subregion, we select the RBDC (between share-of-systemwide RBDC and subregional RBDC) that resulted in a higher requirement in that subregion. This selection is done via parameter u_r: for a given subregion $r \in R$, the parameter u_r is a binary parameter which is determined based on the clearing results of step 1. Parameter u_r is set to 0 if share-of-systemwide RBDC resulted in a higher clearing in step 1 (i.e., share-of-systemwide RBDC is selected for step 2), while it is set to 1 if the subregional RBDC resulted in a higher clearing in step 1 (i.e., subregional RBDC selected for step 2). The parameter selection for each subregion is given by the following equation:

$$u_r = 1\left(\left\{\sum_{k \in Z_r} LRZReq_k^{SYS} \leq \sum_{k \in Z_r} LRZReq_k^{SR}\right\}\right), \qquad \forall r \in R, \tag{4.1}$$

where 1 is the indicator function[6], and the LRZ clearing requirements are from step 1 as defined in (3.8).

4.1 Step 2: Formulation

Since we are selecting the RBDCs using the parameter u_r, step 2 does not require separate supply variables or constraint equations to distinguish between systemwide RBDC and subregional RBDCs. The details of the LP formulation for the clearing-and-pricing step 2 are as follows.

4.1.1 Objective Function

The linear minimization objective is given by the following equations, with the same terminology as defined in Section 3:

$$\text{Minimize } f \stackrel{\text{def}}{=} SC - (SB + RB) + \Lambda, \tag{4.2.a}$$

$$SC \stackrel{\text{def}}{=} \sum_{i \in F} OFFERPRICE_i \times clearedMW_i \tag{4.2.b}$$

$$SB \stackrel{\text{def}}{=} \sum_{j \in J_{SYS-RBDC}} \sum_{r \in R} (1 - u_r) \times \alpha_r \times RBDCPRICE_j \times clearedDemand_{j,r}^{SYS} \tag{4.2.c}$$

$$RB \stackrel{\text{def}}{=} \sum_{r \in R} \sum_{j \in J_r} u_r \times RBDCPRICE_j \times clearedDemand_{j,r}^{SR} \tag{4.2.d}$$

$$\Lambda \stackrel{\text{def}}{=} \sum_{k \in Z} SEASONALCONE_k \times S_k \tag{4.2.e}$$

4.1.2 Constraints

In step 2, the power balancing constraints and the segment bounds are imposed for the selected RBDC using the parameter u_r. This subsection provides expression for the constraints in the LP.

4.1.2.1 Resource Offer Bounds

Resource clearing should not exceed the MWs offered by the resources

$$clearedMW_i \leq OFFERMW_i, \quad \forall i \in F \tag{4.3}$$

4.1.2.2 RBDC segment bounds

MWs cleared in RBDC segments should not exceed the RBDC segment limits:

$$clearedDemand_{j,r}^{SYS} \leq (1-u_r) \times RBDCSTEP_j, \ \forall j \in J_{SYS-RBDC}, \quad \forall r \in R \tag{4.4.a}$$

$$clearedDemand_{j,r}^{SR} \leq u_r \times RBDCSTEP_j, \quad \forall j \in J_r, \quad \forall r \in R \tag{4.4.b}$$

The multiplication involving the parameter u_r in the above equation ensures that the segment-wise clearing variables are allowed to take non-zero values only for the selected RBDC; the segment-wise clearing variables will be zero for the non-selected RBDC.

4.1.2.3 Power balance constraints

The system power balance constraint is represented below: the cleared systemwide supply should exceed the total system cleared demand from the selected RBDCs.

$$\sum_{i\in F} clearedMW_i \geq \sum_{r\in R}\sum_{j\in J_r} u_r \times clearedDemand_{j,r}^{SR}$$

$$+ \sum_{r\in R}\sum_{j\in J_{SYS-RBDC}} (1-u_r) \times \alpha_r \times clearedDemand_{j,r}^{SYS} \tag{4.5}$$

The subregional power balancing constraints ensure that the difference between the selected RBDC cleared demand and subregion cleared supply, including external resources clearing for the subregion, respects the subregional import and export constraints, as follows:

$$-SRIC_r \leq \sum_{i\in G_r} clearedMW_i + \sum_{e\in E} SF_{r,e} \times \sum_{k\in H_e} clearedMW_k - \sum_{j\in J_r} u_r \times clearedDemand_{j,r}^{SR} - \sum_{j\in J_{SYS-RBDC}} (1-u_r) \times \alpha_r \times clearedDemand_{j,r}^{SYS} \leq SREC_r, \quad \forall r \in R \tag{4.6}$$

4.1.2.4 Zonal Clearing Constraints

The LCR and CIL are requirements that need to be met with local resources or penalized in cases of shortage. These constraints are represented as follows, respectively,

$$\sum_{i\in G_k} clearedMW_i + S_k \geq LCR_k, \ \forall k \in Z \tag{4.7}$$

$$INITIALPRMR_k - \sum_{i \in G_k} clearedMW_i - S_k \leq CIL_k, \qquad \forall k \in Z \tag{4.8}$$

The CEL constraints are imposed with respect to the load obligation for each LRZ. The load obligation for LRZs is expressed as the zonal CPDF share of the cleared demand from the selected RBDC. This is given by,

$$LRZReq_k = \sum_{j \in J_{SYS-RBDC}} (1 - u_r) \times \alpha_k^{SYS} \times clearedDemand_{j,r}^{SYS}$$

$$+ \sum_{j \in J_r} u_r \times \alpha_k^r \times clearedDemand_{j,r}^{SR}, \quad \forall k \in Z_r, \forall\, r \in R \tag{4.9}$$

The difference between the zonal cleared supply and the LRZ load requirement should be below CEL:

$$\sum_{i \in G_k} clearedMW_i - LRZReq_k \leq CEL_k, \quad \forall k \in Z \tag{4.10.a}$$

Since ERZs do not have load obligations, their CEL constraints are given by:

$$\sum_{i \in H_e} clearedMW_i \leq CEL_e, \quad \forall e \in E \tag{4.10.b}$$

4.2 Verification of selected RBDC for Step 2

For a given subregion, if both the share-of-systemwide RBDC and the subregional RBDC are intertwined near the intersection of the supply and demand curves, then the RBDC producing higher requirement may be inconsistent between step 1 and step 2. Therefore, additional verification is performed to ensure that the curve selected for step 2 results in an appropriate requirement. This verification process is described below.

Verification step 1: Determine the subregional clearing price for subregion $r \in R$ as the sum of the shadow prices corresponding to the system and subregional power balancing constraints, i.e., the sum of the shadow prices (which are the dual variables) for the constraints (4.5) and (4.6).

Verification step 2: For the subregional clearing price calculated in verification step 1, determine the associated UCAP MW for the share-of-systemwide RBDC and the subregional RBDC for each subregion *r*. Note the RBDC that results in the higher requirement.

Verification step 3: For a given subregion, if the RBDC with the higher UCAP MW as determined in verification step 2 matches with the RBDC selected via the binary parameter u_r (0 implies selection of share-of-systemwide RBDC and 1 implies selection of subregional RBDC), then the PRA clearing solution is valid and we can proceed with the computation of clearing prices and obligations for the market participants.

If the verification fails for a given subregion, then this failure implies that the RBDC with the higher UCAP MW as determined in verification step 2 is different from the type of RBDC (share of systemwide or subregional) selected via the parameter u_r; hence, the PRA clearing solution is not valid. In such a case, the value of the parameter u_r for the subregion is switched to its complement (0 to 1, or 1 to 0), and step 2 of the PRA clearing process is solved again with this updated parameter.

4.3 Auction clearing Price calculations

Following the PRA clearing solution obtained in the step 2 optimization problem, the clearing prices are calculated for every LRZ and ERZ. This section describes the methodology for computing the auction clearing price (ACP).

4.3.1 ACP determination

The initial auction clearing price is calculated using the shadow prices (SP) of the system, subregional, and zonal power balancing constraints, which are defined below. All prices in this document are in units of $/MW-day.

$systemBalanceSP$ — Non-negative shadow price corresponding to the systemwide supply demand balancing constraint (4.5). This SP applies to all LRZs and ERZs.

$SRICSP_r$ — Non-negative shadow price corresponding to the subregional import constraint: left-hand side inequality of (4.6). A positive shadow price implies that the imports for subregion *r* are equal to the SRIC limit. The shadow price applies to all local zones in the respective subregion *r*. For external zones, the shadow price is assigned proportionally based on the respective subregional shift factors.

$SRECSP_r$ — Non-positive shadow price corresponding to the subregional export constraint: right-hand side inequality of (4.6); a negative value implies that the exports for subregion *r* are equal to the SREC limit. The shadow price applies to all local zones in the respective subregion *r*. For external zones, the shadow price is assigned proportionally based on the respective subregional shift factors.

$LCRSP_k$ — Non-negative SP for the LCR constraint (4.7) for LRZ $k \in Z$. This only applies to LRZs. A positive SP for the LRZ implies that the total cleared generation in LRZ *k* is either exactly equal to the LCR for *k*, or that the total generation offered in LRZ *k* is short of the LCR for *k* (in which case, seasonal CONE pricing is used as a shortage penalty).

$CILSP_k$ — Non-negative SP for the CIL constraint (4.8) for LRZ $k \in Z$. This only applies to LRZs. A positive SP implies that the difference between the initial PRMR and the total cleared generation in the LRZ is either exactly equal to CIL or is more than CIL in case of a shortage.

$CELSP_k$ — Non-positive SP for the CEL constraint (4.10) for zone $k \in Z \cup E$. This applies to both LRZs and ERZs.

The ex-ante ACP for an LRZ $k \in Z_r$ in subregion $r \in R$, prior to the calculation of LCR price adder is the minimum of (i) seasonal CONE of the LRZ and (ii) the sum of shadow prices corresponding to the LRZ (for zones without multi-season shortage, the ex-ante ACP will also be the ex-post ACP for the LRZ):

$$ACP_k^{EA} = min\,\{SEASONALCONE_k, systemBalanceSP + SRICSP_r + SRECSP_r + LCRSP_k + CILSP_k + CELSP_k\} \qquad (4.11.a)$$

The ACP for an ERZ $e \in E$ is the minimum of (i) the maximum seasonal CONE of all the LRZs in the subregion to which the ERZ is connected (for dual connected ERZs, this is the maximum seasonal CONE of all LRZs in the entire transmission area; and (ii) the sum of the shadow prices corresponding to the ERZ:

$$ACP_e = min\,\{SEASONALCONE_e, systemBalanceSP + CELSP_e + \sum_r SF_{r,e} \times (SRICSP_r + SRECSP_r)\} \qquad (4.11.b)$$

4.3.2 ACP under multi season LRZ shortages, or near-shortages, on local clearing requirement

When an LRZ has more than one season in any combination of ZRC shortage conditions and/or ZRC near-shortage conditions, the final Auction Clearing Price (ACP) for the LRZ will be determined as follows.

Let $\tilde{Z}$ the set of all LRZs with multi-season LCR or CIL shortage or near-shortage conditions. Let N_k^S denote the total number of shortage or near-shortage days for the LRZ $k \in \tilde{Z}$ across the entire planning year. Then, the LCR price adder for LRZ k is given by,

$$LCRPRICEADDER_k = CONE_k / N_k^S \qquad (4.12)$$

The ex-post ACP for an LRZ k with multi-season shortage or near-shortage is,

$$ACP_k^{EP} = min\{SEASONALCONE_k,\ systemBalanceSP + SRICSP_r + SRECSP_r + LCRPRICEADDER_k\}, \qquad \forall k \in \tilde{Z} \qquad (4.13)$$

5 Final Auction Clearing Quantities for LRZs

The Final PRMR of an LSE is determined based on RBDC clearing in the corresponding subregion and the LSE's participation option (such as RBDC Opt Out, market participation, etc.)

in the PRA. The detailed procedure to determine Final PRMR is presented in Section 5.6 of this Business Practice Manual.

6 Examples

6.1 Small System Examples

Assume a system as shown in **Error! Reference source not found.** below. It consists of two LRZs and two subregions. There is a limited transfer capability between the subregions, and it is reflected in the subregional power balance constraint limit (SRPBC): the SRPBC limit in the following examples is a simplified representation of the SRIC/SREC constraints included in the preceding mathematical formulation.

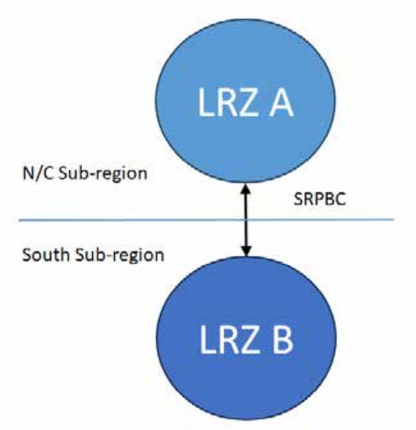
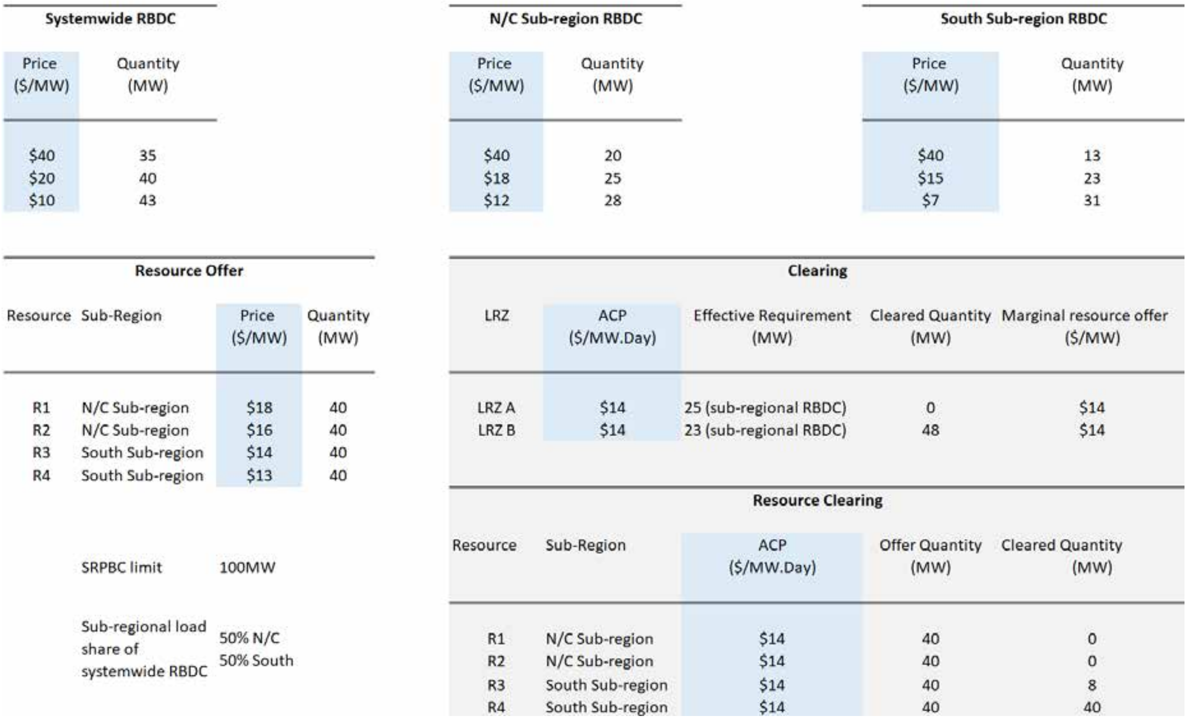


Figure 3. System setup for clearing examples: Two LRZ system with two subregions

Case 1: Regional RBDCs in both subregions are resulting in higher requirements than the share-of-systemwide RBDC, and there are no binding subregional import/export constraints. The offer and RBDC information along with the optimal clearing are shown in the following figure.



Systemwide RBDC

Price ($/MW)	Quantity (MW)
$40	35
$20	40
$10	43

N/C Sub-region RBDC

Price ($/MW)	Quantity (MW)
$40	20
$18	25
$12	28

South Sub-region RBDC

Price ($/MW)	Quantity (MW)
$40	13
$15	23
$7	31

Resource Offer

Resource	Sub-Region	Price ($/MW)	Quantity (MW)
R1	N/C Sub-region	$18	40
R2	N/C Sub-region	$16	40
R3	South Sub-region	$14	40
R4	South Sub-region	$13	40

SRPBC limit	100MW
Sub-regional load share of systemwide RBDC	50% N/C 50% South

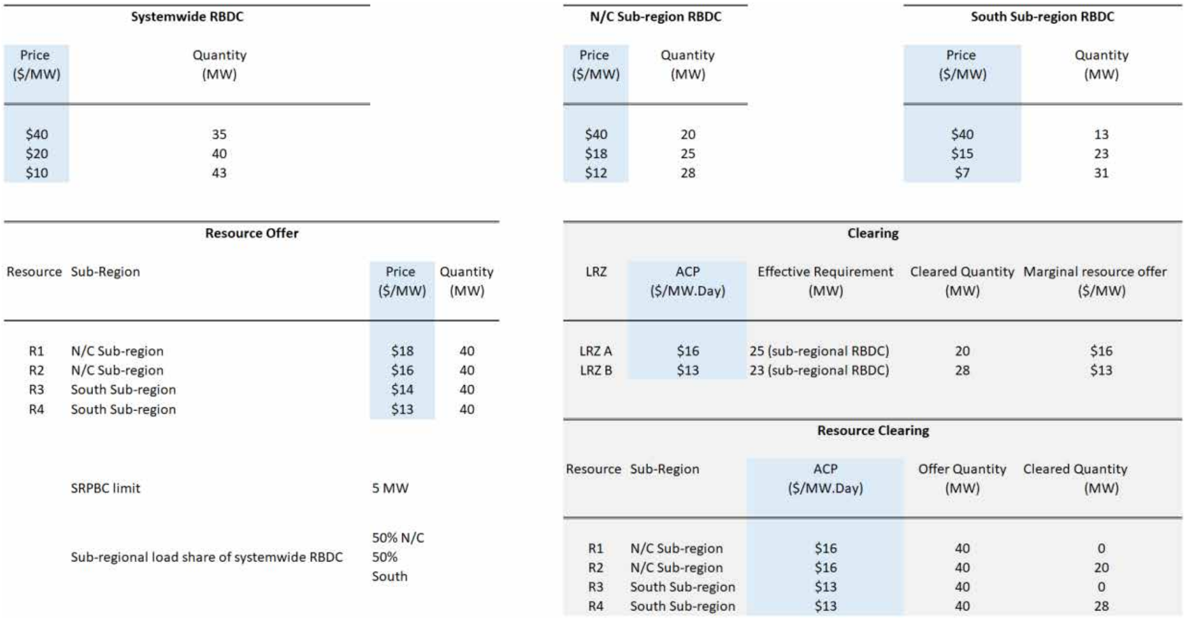
Clearing

LRZ	ACP ($/MW.Day)	Effective Requirement (MW)	Cleared Quantity (MW)	Marginal resource offer ($/MW)
LRZ A	$14	25 (sub-regional RBDC)	0	$14
LRZ B	$14	23 (sub-regional RBDC)	48	$14

Resource Clearing

Resource	Sub-Region	ACP ($/MW.Day)	Offer Quantity (MW)	Cleared Quantity (MW)
R1	N/C Sub-region	$14	40	0
R2	N/C Sub-region	$14	40	0
R3	South Sub-region	$14	40	8
R4	South Sub-region	$14	40	40

Case 2: Regional RBDCs in both subregions are resulting in higher requirements than the share-of-systemwide RBDC, and the subregional import/export constraints are binding. The offer and RBDC information along with the optimal clearing are shown in the following figure.



Systemwide RBDC

Price ($/MW)	Quantity (MW)
$40	35
$20	40
$10	43

N/C Sub-region RBDC

Price ($/MW)	Quantity (MW)
$40	20
$18	25
$12	28

South Sub-region RBDC

Price ($/MW)	Quantity (MW)
$40	13
$15	23
$7	31

Resource Offer

Resource	Sub-Region	Price ($/MW)	Quantity (MW)
R1	N/C Sub-region	$18	40
R2	N/C Sub-region	$16	40
R3	South Sub-region	$14	40
R4	South Sub-region	$13	40

SRPBC limit	5 MW
Sub-regional load share of systemwide RBDC	50% N/C 50% South

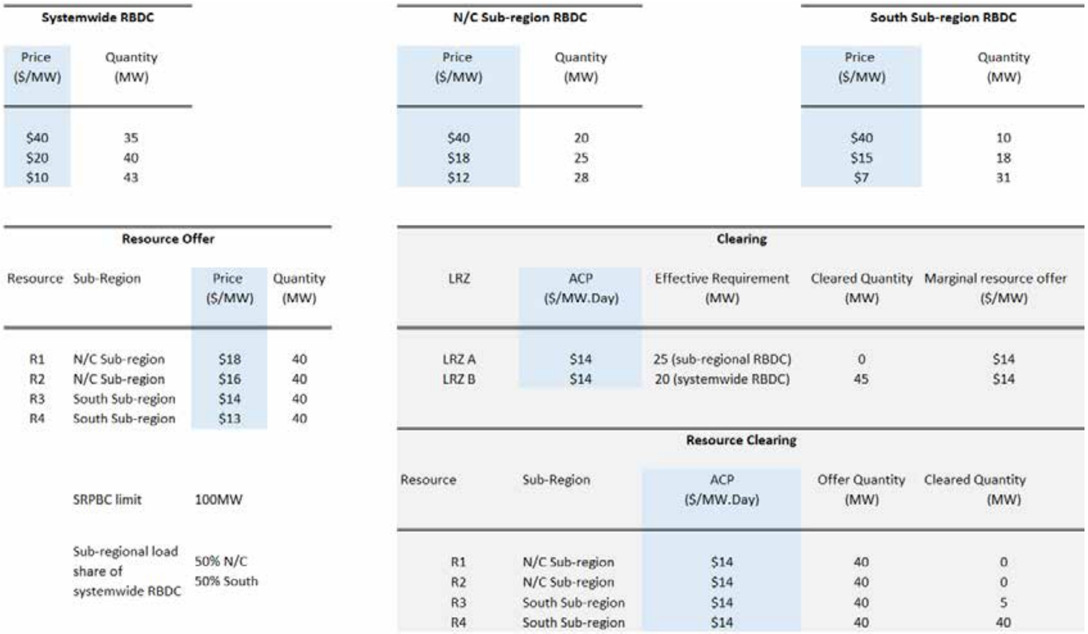
Clearing

LRZ	ACP ($/MW.Day)	Effective Requirement (MW)	Cleared Quantity (MW)	Marginal resource offer ($/MW)
LRZ A	$16	25 (sub-regional RBDC)	20	$16
LRZ B	$13	23 (sub-regional RBDC)	28	$13

Resource Clearing

Resource	Sub-Region	ACP ($/MW.Day)	Offer Quantity (MW)	Cleared Quantity (MW)
R1	N/C Sub-region	$16	40	0
R2	N/C Sub-region	$16	40	20
R3	South Sub-region	$13	40	0
R4	South Sub-region	$13	40	28

Case 3: In one subregion, share-of-systemwide RBDC is resulting in a higher requirement than subregional RBDC, while in the other subregion, the subregional RBDC results in a higher requirement as compared to the share-of-systemwide RBDC. SRIC/SREC are not binding. The offer and RBDC information along with the optimal clearing are shown in the following figure.



Systemwide RBDC

Price ($/MW)	Quantity (MW)
$40	35
$20	40
$10	43

N/C Sub-region RBDC

Price ($/MW)	Quantity (MW)
$40	20
$18	25
$12	28

South Sub-region RBDC

Price ($/MW)	Quantity (MW)
$40	10
$15	18
$7	31

Resource Offer

Resource	Sub-Region	Price ($/MW)	Quantity (MW)
R1	N/C Sub-region	$18	40
R2	N/C Sub-region	$16	40
R3	South Sub-region	$14	40
R4	South Sub-region	$13	40

SRPBC limit	100MW
Sub-regional load share of systemwide RBDC	50% N/C 50% South

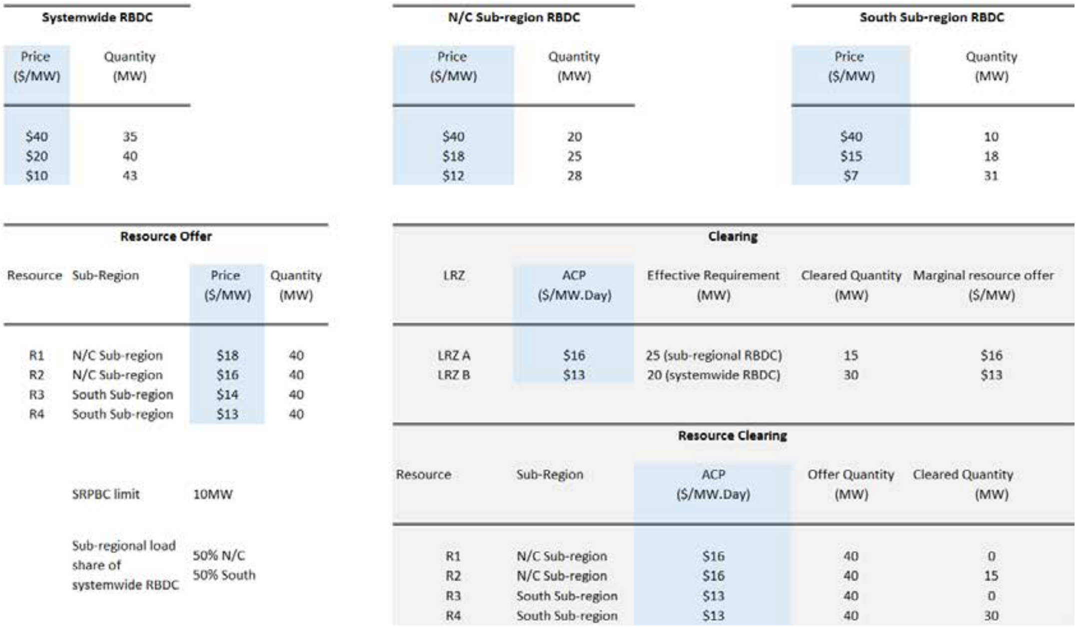
Clearing

LRZ	ACP ($/MW.Day)	Effective Requirement (MW)	Cleared Quantity (MW)	Marginal resource offer ($/MW)
LRZ A	$14	25 (sub-regional RBDC)	0	$14
LRZ B	$14	20 (systemwide RBDC)	45	$14

Resource Clearing

Resource	Sub-Region	ACP ($/MW.Day)	Offer Quantity (MW)	Cleared Quantity (MW)
R1	N/C Sub-region	$14	40	0
R2	N/C Sub-region	$14	40	0
R3	South Sub-region	$14	40	5
R4	South Sub-region	$14	40	40

Case 4: In one subregion, share-of-systemwide RBDC is resulting in a higher requirement than subregional RBDC, while in the other subregion, the subregional RBDC results in a higher requirement as compared to the share-of-systemwide RBDC. SRIC/SREC are binding. The offer and RBDC information along with the optimal clearing are shown in the following figure.



Systemwide RBDC

Price ($/MW)	Quantity (MW)
$40	35
$20	40
$10	43

N/C Sub-region RBDC

Price ($/MW)	Quantity (MW)
$40	20
$18	25
$12	28

South Sub-region RBDC

Price ($/MW)	Quantity (MW)
$40	10
$15	18
$7	31

Resource Offer

Resource	Sub-Region	Price ($/MW)	Quantity (MW)
R1	N/C Sub-region	$18	40
R2	N/C Sub-region	$16	40
R3	South Sub-region	$14	40
R4	South Sub-region	$13	40

SRPBC limit	10MW
Sub-regional load share of systemwide RBDC	50% N/C 50% South

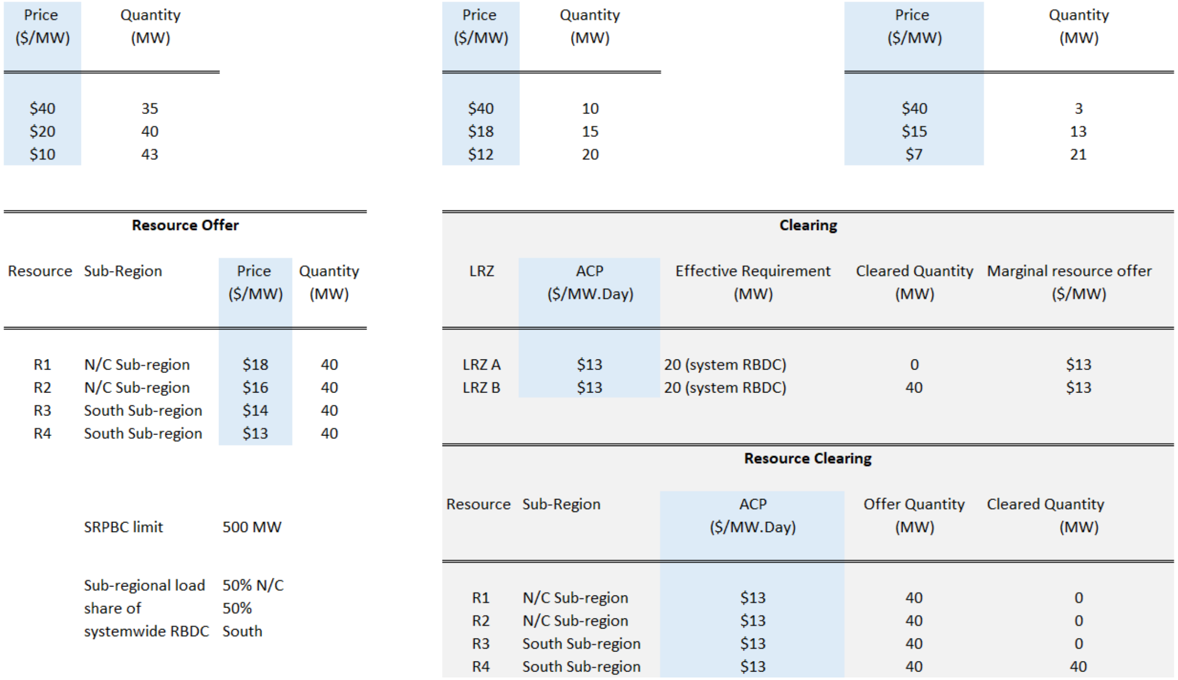
Clearing

LRZ	ACP ($/MW.Day)	Effective Requirement (MW)	Cleared Quantity (MW)	Marginal resource offer ($/MW)
LRZ A	$16	25 (sub-regional RBDC)	15	$16
LRZ B	$13	20 (systemwide RBDC)	30	$13

Resource Clearing

Resource	Sub-Region	ACP ($/MW.Day)	Offer Quantity (MW)	Cleared Quantity (MW)
R1	N/C Sub-region	$16	40	0
R2	N/C Sub-region	$16	40	15
R3	South Sub-region	$13	40	0
R4	South Sub-region	$13	40	30

Case 5: Systemwide RBDC results in a higher requirement in both subregions, and no SRIC/SREC binding. Offer, RBDC, and clearing details are in the following figure.



Price ($/MW)	Quantity (MW)
$40	35
$20	40
$10	43

Price ($/MW)	Quantity (MW)
$40	10
$18	15
$12	20

Price ($/MW)	Quantity (MW)
$40	3
$15	13
$7	21

Resource Offer

Resource	Sub-Region	Price ($/MW)	Quantity (MW)
R1	N/C Sub-region	$18	40
R2	N/C Sub-region	$16	40
R3	South Sub-region	$14	40
R4	South Sub-region	$13	40

SRPBC limit	500 MW
Sub-regional load share of systemwide RBDC	50% N/C 50% South

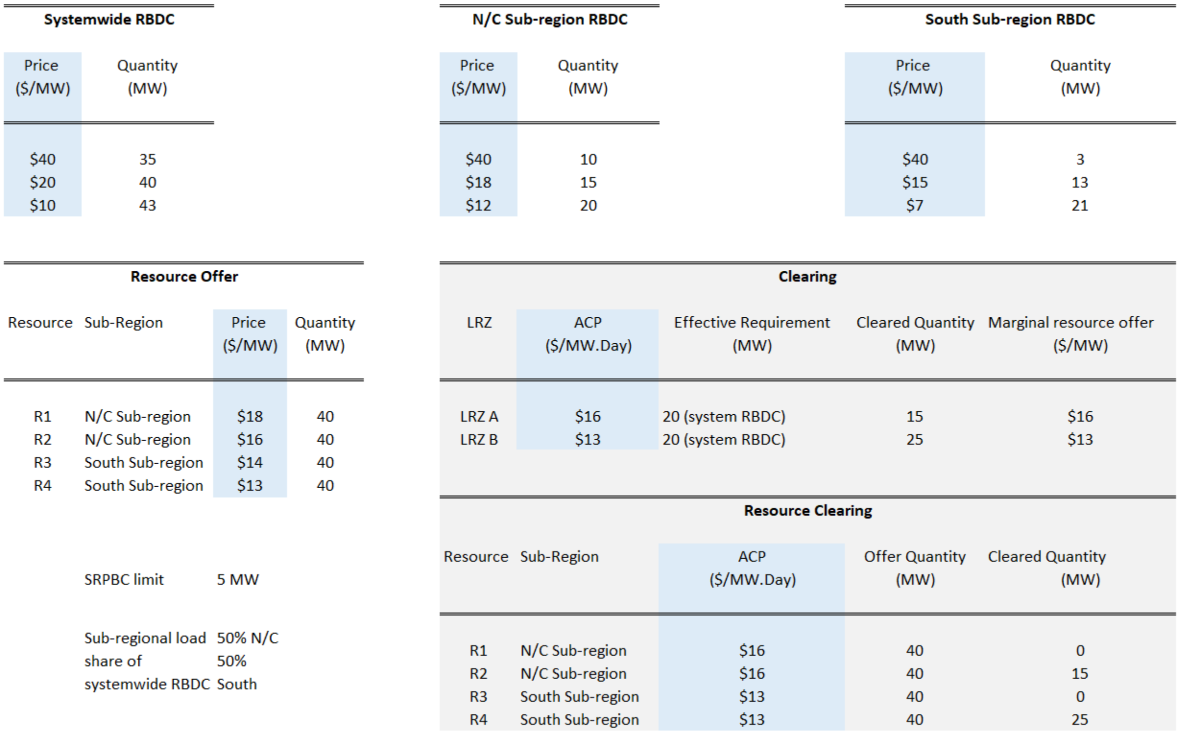
Clearing

LRZ	ACP ($/MW.Day)	Effective Requirement (MW)	Cleared Quantity (MW)	Marginal resource offer ($/MW)
LRZ A	$13	20 (system RBDC)	0	$13
LRZ B	$13	20 (system RBDC)	40	$13

Resource Clearing

Resource	Sub-Region	ACP ($/MW.Day)	Offer Quantity (MW)	Cleared Quantity (MW)
R1	N/C Sub-region	$13	40	0
R2	N/C Sub-region	$13	40	0
R3	South Sub-region	$13	40	0
R4	South Sub-region	$13	40	40

Case 6: Systemwide RBDC results in a higher requirement in both subregions, and SRIC/SREC are binding. Offer, RBDC, and clearing details are in the following figure.



Systemwide RBDC

Price ($/MW)	Quantity (MW)
$40	35
$20	40
$10	43

N/C Sub-region RBDC

Price ($/MW)	Quantity (MW)
$40	10
$18	15
$12	20

South Sub-region RBDC

Price ($/MW)	Quantity (MW)
$40	3
$15	13
$7	21

Resource Offer

Resource	Sub-Region	Price ($/MW)	Quantity (MW)
R1	N/C Sub-region	$18	40
R2	N/C Sub-region	$16	40
R3	South Sub-region	$14	40
R4	South Sub-region	$13	40

SRPBC limit	5 MW
Sub-regional load share of systemwide RBDC	50% N/C 50% South

Clearing

LRZ	ACP ($/MW.Day)	Effective Requirement (MW)	Cleared Quantity (MW)	Marginal resource offer ($/MW)
LRZ A	$16	20 (system RBDC)	15	$16
LRZ B	$13	20 (system RBDC)	25	$13

Resource Clearing

Resource	Sub-Region	ACP ($/MW.Day)	Offer Quantity (MW)	Cleared Quantity (MW)
R1	N/C Sub-region	$16	40	0
R2	N/C Sub-region	$16	40	15
R3	South Sub-region	$13	40	0
R4	South Sub-region	$13	40	25

6.2 PRA Clearing Examples using Indicative RBDCs

This section provides an illustrative graphical representation of the auction clearing with RBDCs: the plots representing the PRA clearing outcomes with indicative RBDCs for PY 24-25 Summer Season are presented in **Error! Reference source not found.**. The indicative RBDCs are d eveloped based on PY 24-25 loss-of-load study and the associated models. Resource offers submitted for the PY 24-25 Summer Season are used for the supply curves. The parameters for the zonal CIL, CEL, and LCR constraints are the same as those used in the PY 2024/25 PRA. The solution to the linear programming-based formulation results in an Auction Clearing Price of about $140/MW-day with no subregional or zonal price separation. The systemwide RBDC is setting up the requirement in both subregions with a total cleared demand of 140.1GW, because the share-of-systemwide RBDCs are to the right of the subregional RBDCs in both subregions.

The SREC limit from the south subregion to the north/central subregion is 1,900 MW; the capacity exports from the south subregion to the north/central subregion are 1,581 MW as reflected in **Error! Reference source not found.**. The RBDCs shown in the dashed lines for t he exporting subregion (south) have been shifted to **the right by the export quantity**, while those for the importing subregion (N/C) have been shifted to **the left by the same quantity**. The original RBDCs are in solid lines.

The horizontal line represents the ACP, which is set at the intersection of the supply curve and import/export-shifted RBDC for each subregion (red dot in the figure). The Final PRMR for an importing subregion (N/C) is to the **right** of the intersection of the supply curve and the import-shifted RBDC by the import quantity (1,581 MW in the figures below). Similarly, for the exporting subregion (south), the final PRMR is to the **left** of the intersection of the supply curve and the export-shifted RBDC by the export quantity of 1,581 MW. The Final PRMR is shown by the dotted dark-gray vertical line passing through the intersection of the horizontal ACP line and the requirement-setting RBDC (share-of-systemwide RBDC for Summer 2024 in both subregions—plots in orange solid lines).

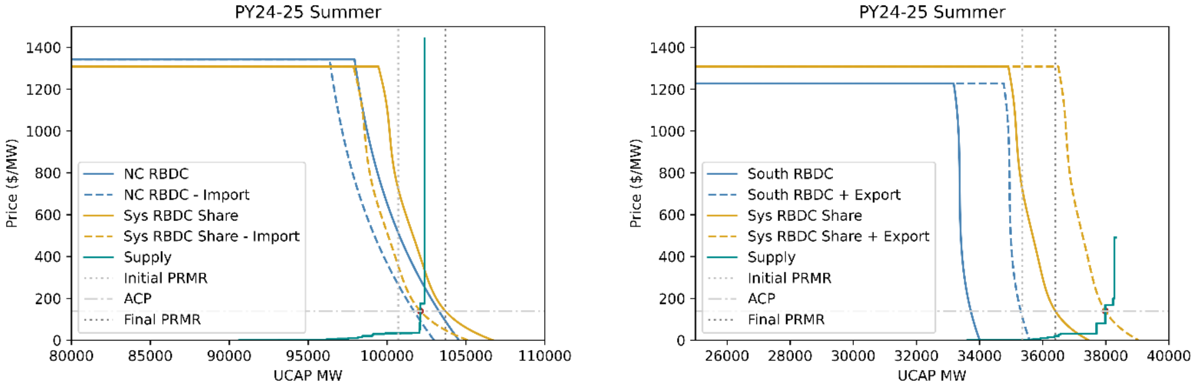


Figure 4. PRA clearing with indicative RBDCs representing PY24-25 Summer season with actual offers submitted for PY24-25 Summer season.

For completeness, the zoomed-in version of PRA clearing presented in **Error! Reference source not found.** is shown below in **Error! Reference source not found.**.

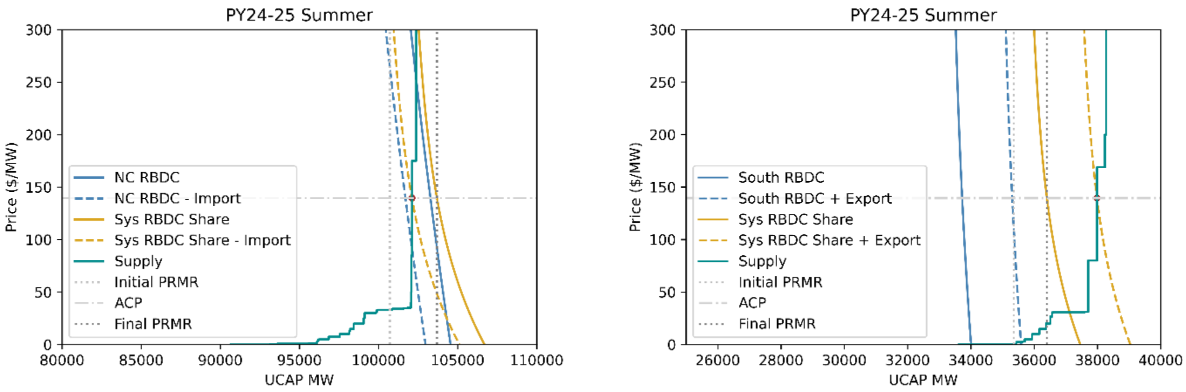


Figure 5. Zoomed in version of illustrative PY 24-25 Summer season PRA clearing

Appendix N – Seasonal Demand and Energy Forecast Characteristics

Forecast Criteria	Coincident Peak Demand and Zonal Coincident Peak Demand Forecasts	Non-Coincident Peak Demand Forecast	Energy for Load Forecast
Includes Demand Served by Energy Efficiency Planning Resources	Yes	Yes	Yes
Includes Demand Served by Energy Efficiency Programs	No	No	No
Includes Demand Served by Demand Resources	Yes	Yes	Yes
Includes Demand Served by BTMG Planning Resources	Yes	Yes	Yes
Includes Demand Served by resources that are not qualified as Planning Resources	Yes	No	No
Includes Demand Pseudo-Tied Out of MISO BA and Included Subject to other RAR	No	Yes	Yes
Includes Transmission Losses	No	No	Yes
Coincident with reporting Load Serving Entities’ system	No	Yes	No
Demand reported at Physical LBA Location	Yes	Yes	Yes
Include Demand from Power Plant Station or Auxiliary Needs	No	No	No

Appendix O – Parties Responsible for Reporting Seasonal Demand and Energy Forecasts

Data	EDC	Retail Choice LSE	Non-Retail Choice LSE
MISO Coincident Peak (Total CPF)	No	No	Yes
MISO Non-Coincident Peak (Total NCPF)	No	No	Yes
Zonal Coincident Peak (Total CPF)	No	No	Yes
RC Coincident Peak (Total CPFEDC Area)	Yes	No	No
RC Coincident Peak (Total NCPF) Load Contribution	Yes	No	No
RC Zonal Coincident Peak (Total CPFEDC Area)	Yes	No	No
Non-Coincident Peak	Yes	No	Yes
RC Non-Coincident Peak	No	Yes	No
Energy for Load	Yes	No	Yes
Retail Choice (MISO Peak)	Yes	No	No
Retail Choice (Zonal Peak)	Yes	No	No

Appendix P – Zonal Deliverability Benefit *Pro Rata* Allocation

This Appendix is an illustrative example of the ZDB *pro rata* allocation methodology in the presence of Historical Unit Considerations (HUC) and Fixed Resource Adequacy Plan (FRAP) or RBDC Opt Out. The results from the Planning Resource Auction for the 2020/2021 Planning Year are used in this example to educate Market Participants. The resulting Auction Clearing Prices illustrated here are different than those settled for the 2020/2021 Planning Year. Starting in Planning Year 2023-2024, the ZDB calculation will be performed separately for each Season in which the ZDB calculation is required.

Step 1Subtract PRMR and ZRCs associated with HUC Hedges to derive an adjusted Final PRMR (Adjusted Final PRMR) and ZRC (Adjusted ZRC). ZRCs are FRAP + RBDC Opt Out + Self-scheduled offers + cleared Non-self-scheduled offers.

RZ	ACP	Final PRMR	ZRC	HUC (MW)	ZDC Hedges (MW)	Adjusted Final PRMR	Adjusted ZRC
Z1	$5.00	18,476.0	18,742.0	191.7	0	18,284.3	18,550.3
Z2	$5.00	13,728.2	13,590.0	0	0	13,728.2	13,590.0
Z3	$5.00	10,129.1	10,551.0	0	0	10,129.1	10,551.0
Z4	$5.00	9,794.6	8,462.1	0	0	9,794.6	8,462.1
Z5	$5.00	8,456.3	7,952.8	0	0	8,456.3	7,952.8
Z6	$5.00	18,720.6	17,054.6	0	0	18,720.6	17,054.6
Z7	$257.53	21,945.3	21,727.5	0	0	21,945.3	21,727.5
Z8	$4.75	7,986.9	10,183.1	0	0	7,986.9	10,183.1
Z9	$6.88	21,711.7	20,893.7	107.3	0	21,604.4	20,786.4
Z10	$4.75	5,030.6	5,244.2	0	0	5,030.6	5,244.2
E20	$4.90	0.0	347.2	0	0	0.0	347.2
E22	$5.00	0.0	633.8	0	0	0.0	633.8
E23	$5.00	0.0	30.1	0	0	0.0	30.1
E24	$5.00	0.0	148.4	0	0	0.0	148.4
E26	$4.92	0.0	24.0	0	0	0.0	24.0
E27	$4.89	0.0	168.3	0	0	0.0	168.3
E28	$4.90	0.0	226.5	0	0	0.0	226.5

Step 2: Create a DBZ for each group of LRZs that have equal ACPs which result from the same auction constraint. In this example, Zone 7 is a DBZ because the PRA bound on its LCR.

RZ	ACP	Adjusted Final PRMR	Adjusted ZRC	**DBZ Grouping**
Z1	$5.00	18,284.3	18,550.3	Zone A
Z2	$5.00	13,728.2	13,590.0	Zone A
Z3	$5.00	10,129.1	10,551.0	Zone A

Z4	$5.00	9,794.6	8,462.1	Zone A
Z5	$5.00	8,456.3	7,952.8	Zone A
Z6	$5.00	18,720.6	17,054.6	Zone A
Z7	$257.53	21,945.3	21,727.5	Zone B
Z8	$4.75	7,986.9	10,183.1	Zone D
Z9	$6.88	21,604.4	20,786.4	Zone C
Z10	$4.75	5,030.6	5,244.2	Zone D
E20	$4.90	0.0	347.2	Zone E
E22	$5.00	0.0	633.8	Zone A
E23	$5.00	0.0	30.1	Zone A
E24	$5.00	0.0	148.4	Zone A
E26	$4.92	0.0	24.0	Zone F
E27	$4.89	0.0	168.3	Zone G
E28	$4.90	0.0	226.5	Zone E

Step 3: For each DBZ, subtract the sum of Adjusted Final PRMR for each LRZ within the DBZ from the sum of Adjusted ZRCs for each LRZ within the DBZ. A DBZ will be considered a net importing DBZ if the sum of Adjusted Final PRMR is greater than the sum of Adjusted ZRCs. A DBZ will be considered a net exporting DBZ if the sum of the Adjusted Final PRMR is less than the sum of Adjusted ZRCs. A net exporting DBZ shall not receive any ZDB credit. A net importing DBZ shall receive a ZDB credit allocation based upon this weighted average approach.

In this example, Zones A, B, and C are net importing DBZ's and Zones D, E, F and G are net exporting DBZs.

DBZ	Adjusted Final PRMR	Adjusted ZRC	**Difference**	**Result**
Zone A	79,113.1	76,973.1	-2140.0	Net Importer
Zone B	21,945.3	21,727.5	-217.8	Net Importer
Zone C	21,711.7	20,893.7	-818.0	Net Importer
Zone D	13,017.5	15,427.3	2,409.8	Net Exporter
Zone E	0.0	573.7	573.7	Net Exporter
Zone F	0.0	24.0	24.0	Net Exporter
Zone G	0.0	168.3	168.3	Net Exporter

Step 4: Calculate the weighted average ACP of all net exporting DBZs (Weighted Average Export ACP) to determine a financial value of export capacity within the Transmission Provider region per the formula below:

$$\text{Weighted Average Export ACP} = \frac{\sum(\text{Net Export}_j \times \text{ACP}_j)}{\sum \text{Net Export}_j}$$

Where j = Each net exporting DBZ

DBZ	Net Export	ACP	Net Export*ACP
D	2409.8	$4.75	$11,446.55
E	573.7	$4.90	$2,811.13
F	24	$4.92	$118.08
G	168.3	$4.89	$822.99
Total of Exporting Zones	3175.8		$15,198.75
Weighted Average Export ACP =(Total Net Export*ACP)/(Total Net Export)			$4.79

Step 5: Calculate the ZDB credit allocation, in dollars, for each net importing DBZ:

$$\text{ZDB Credit}_k = \text{Net Import}_k \times (\text{ACP}_k - \text{Weighted Average Export ACP})$$

Where k = Each net importing DBZs

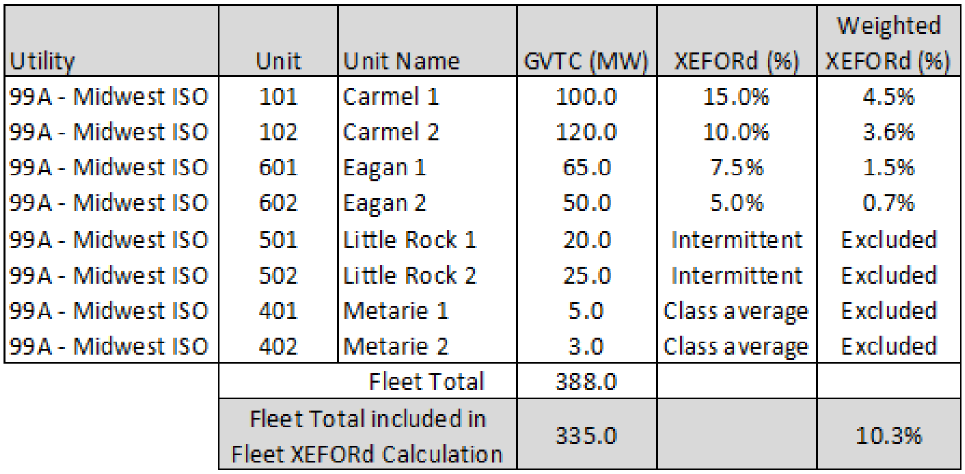
DBZ	Net Import	ACP ($/MW-day)	Weighted Average Export ACP	ZDB Credit ($/day)
A	2140.0	$5.00	$4.79	$458.39
B	217.8	$257.53	$4.79	$55,047.69
C	818.0	$6.88	$4.79	$1,713.05
Total of Importing Zones	3175.8			

Step 6: Distribute the ZDB credit in each DBZk by dividing the ZDB credit by the sum of Adjusted Final PRMR of the LRZs within each DBZk. Subtract this amount from the initial ACP calculated for each LRZ from the PRA.

DBZ	ZDB Credit ($/day)	RZ	Adjusted Final PRMR	ZDB Rate ($/MW-day)	ACP	Net ACP
A	$458.39	1	18,284.3	$0.01	$5.00	$4.99
		2	13,728.2			
		3	10,129.1			
		4	9,794.6			
		5	8,456.3			
		6	18,720.6			
		Total DBZ A	79,113.1			
B	$55,047.69	7	21,945.3	$2.51	$257.53	$255.02
C	$1,713.05	9	21,604.4	$0.08	$6.88	$6.80

Appendix Q – Fleet XEFORd Calculation

This appendix walks through the process for calculating fleet XEFORd. This process is used for External Resources that participate in the PRA as one MECT resource which represents the aggregate of a fleet of units. In order to qualify, resource owners must submit help tickets to help.misoenergy.org to let MISO know which resources to be included in your fleet by November 15, otherwise the resource will not be able to participate in the PRA. For example, an external area might have 100 units in its fleet with a total capacity of 10,000 MW of which it plans to commit 1,000 MW on an installed capacity basis to MISO. MISO will then calculate a seasonal SAC based on a seasonal weighted average forced outage rate of all units in the fleet. Intermittent and class average units are excluded from the fleet XEFORd calculation. This appendix will walk through a weighted average example calculation for a set of fleet units.



Utility	Unit	Unit Name	GVTC (MW)	XEFORd (%)	Weighted XEFORd (%)
99A - Midwest ISO	101	Carmel 1	100.0	15.0%	4.5%
99A - Midwest ISO	102	Carmel 2	120.0	10.0%	3.6%
99A - Midwest ISO	601	Eagan 1	65.0	7.5%	1.5%
99A - Midwest ISO	602	Eagan 2	50.0	5.0%	0.7%
99A - Midwest ISO	501	Little Rock 1	20.0	Intermittent	Excluded
99A - Midwest ISO	502	Little Rock 2	25.0	Intermittent	Excluded
99A - Midwest ISO	401	Metarie 1	5.0	Class average	Excluded
99A - Midwest ISO	402	Metarie 2	3.0	Class average	Excluded
	Fleet Total		388.0		
	Fleet Total included in Fleet XEFORd Calculation		335.0		10.3%

Formulas

- Unit Weighted Average XEFORd = (Unit GVTC (MW)) / (Total GVTC (MW)) * (Unit XEFORd)

  (for Carmel 1 weighted XEFORd is 100.0/335.0*15.0% = 4.5%)

- Fleet Total GVTC (MW) = Sum of GVTC (MW) for all units

  (100.0 + 120.0 + 65.0 + 50.0 + 20.0 + 25.0 + 5.0 +3.0 = 388.0)

- Fleet GVTC w/ XEFORd = Sum of GVTC for all units with an XEFORd value

  (100.0 + 120.0 + 65.0 + 50.0 = 335.0)

- Fleet Weighted XEFORd = Sum of Weighted XEFORd for all units

  (4.5% + 3.6% + 1.5% + 0.7% = 10.3%)

Appendix R – Annual CONE Calculation

MISO calculates gross Cost of New Entry (CONE) values for each LRZ for each Planning Year. This CONE value will be used for all Seasons within the entire Planning Year. MISO calculates CONE for each LRZ based upon the costs associated with an advanced combustion turbine generator (CT). MISO uses the following approach:

1. MISO begins with an estimate of a CONE value not specific to an LRZ,
2. MISO uses “the law of one price” where applicable (e.g., turbines that are sold competitively),
3. MISO develops zonal differences to reflect different locational costs (e.g., labor, technical enhancements and others) using the most recent United States Energy Information Administration (EIA) document, and
4. MISO uses the Net Present Value (NPV) algorithm to calculate CONE values for each LRZ.

MISO allows factors such as the weighted average cost of capital, escalation rates, and other factors where global competition drives prices to have no locational differences to be constant.

In order to determine the appropriate CONE value for each LRZ, MISO relies upon the most recent EIA report on “Capital Cost and Performance Characteristic Estimates for Utility Scale Electric Power Generating Technologies (EIA Report)”. The EIA Report contains detailed specifications for a hypothetical advanced CT, including information regarding the differences in project costs for an advanced CT with a nominal capacity of 237 MW, based upon the state where the facility is constructed. The report is available at: https://www.eia.gov/analysis/studies/powerplants/capitalcost/.

MISO uses an NPV analysis to determine an appropriate CONE value for hypothetical advanced CTs located in each LRZ. In accordance with Section 69A.8.a of Module E-1, MISO considers many factors in its calculation of the CONE value, including the following: (1) physical factors (such as, the type of Generation Resource that could reasonably be constructed to provide Planning Resources, costs associated with locating the Generation Resource within the Transmission Provider Region, the estimated costs of fuel for the Generation Resource); (2) financial factors (such as, the hypothetical debt/equity ratio for the Generation Resource, the cost of capital, a reasonable return on equity, applicable taxes, interest, insurance); and (3) other costs (such as, costs related to permitting, environmental compliance, operating and maintenance expenses). MISO does not consider the anticipated net revenue from the sale of capacity, Energy or Ancillary Services.

CONE values for each Planning Year are based, in part, upon data supplied by the EIA, which are adjusted using the implicit price deflator from the Bureau of Economic analysis in order to convert EIA cost data into present value dollars. In order to produce the annualized CONE value for each LRZ from these cost numbers, for the 2023/2024 Planning Resource Auction MISO assumed: (i) a 55/45 debt to equity ratio; (ii) a 20-year project life and loan term; (iii) a 5.16 percent debt interest rate; (iv) a 2.2 percent Operation and Maintenance escalation factor; (v) a 2.2 percent GDP deflator; (vi) a 25-31 percent combined effective federal and state tax rate; (vii) property tax and insurance costs of 1.5 percent of the capital costs; (viii) a calculated weighted average cost of capital of 7.99 to 8.17 percent; (ix) and a 13.4 percent after tax internal rate of return on equity. None of these factors vary by LRZ to any significant degree that is discernible in available data. MISO will continue to examine these factors in the future to determine if any LRZ specific modifications are indicated. These factors and assumptions are comparable to those used by other RTOs in the development of CONE estimates.

Steps for calculating CONE

1. Obtain latest ‘Base Project Cost $/kW’
   Obtain the latest Energy Information Administration (EIA) report for *EIA,* Capital Cost and Performance Characteristic Estimates for Utility Scale Electric Power Generating Technologies*.* It provides the following data:

   - Plant Capital Cost in $/kW. MISO currently uses the number for advanced CT.
   - Location Based Costs Table: Location Percent Variation, Delta Cost Difference and Total Location Project Cost columns

2. Use Bureau of Economic Analysis (BEA) data to calculate implicit price deflator
   Use Table 1.1.9 - Implicit Price Deflators for Gross Domestic Product from NIPA data. Using the table, calculate the *Escalation Rate* from base year to planning year, based on historical and projected quarterly PCE deflator values. Use this Escalation Rate to calculate “Total Location Project Cost” in current year dollars.

3. Calculate LRZ and Base total capital costs, adjusted by multiplying with the Escalation Rate
   For LRZs - Use averages of adjusted project costs for locations (for which data is available) in each zone.

4. Calculate the after-tax weighted average cost of capital (WACC)

$WACC = (E * R_e) + (D * R_d * (1 – T_c))$.

Where E = Equity Fraction of Project

R_e = Cost of Equity. Assume as the after-tax IRR

D = Debt Fraction of Project

R_d = Cost of Debt (20-year BB corporate bond rate)

T_c = Combined effective federal and state tax rate

5. Calculate estimated annualized costs for each LRZ and also for the Base.

    - Calculate annualized capital costs using total capital costs, after-tax WACC and assuming the project lifespan. (Use PMT function)
    - Calculate the O&M costs based on O&M data, project lifespan, WACC and US GDP Deflator (Use PMT and NPV functions)
        - Assume suitable O&M escalation factor
        - Assume/Update US GDP Deflator
    - Assume insurance and property tax costs.

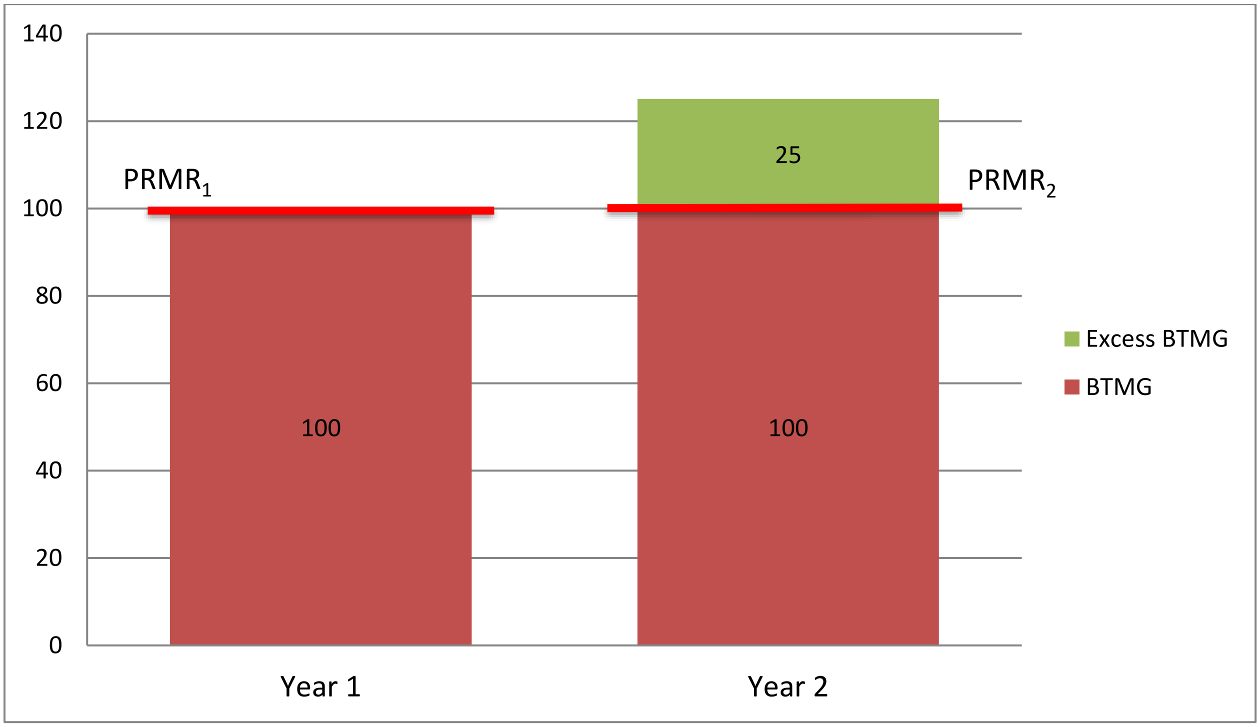
Appendix S – Example Scenarios of "Excess BTMG"

This Appendix shares a few illustrative examples of how BTMG may change to "Excess BTMG" from one year to the next. The examples below show how some specific factors may cause BTMG to be classified as "Excess BTMG" from one year to the next. Below are four examples of "Excess BTMG".

(All PRMR being referred in this appendix are Final PRMR cleared through PRA auction)

1. Increase in BTMG and No Change to Seasonal PRMR

The chart below illustrates the scenario in which a Market Participant experiences an increase in BTMG SAC from one year to the next while PRMR remains unchanged. In Year 1, the chart shows that the BTMG SAC is 100 MW and the seasonal PRMR is 100 MW; therefore, the Market Participant has no "Excess BTMG" in Year 1. Between Year 1 and Year 2, the Market Participant experiences an increase in BTMG of 25 MW—however, seasonal PRMR remains unchanged. In Year 2, the chart shows that BTMG SAC is 125 MW and the seasonal PRMR is 100 MW; therefore, the Market Participant has 25 MW of "Excess BTMG" in Year 2.

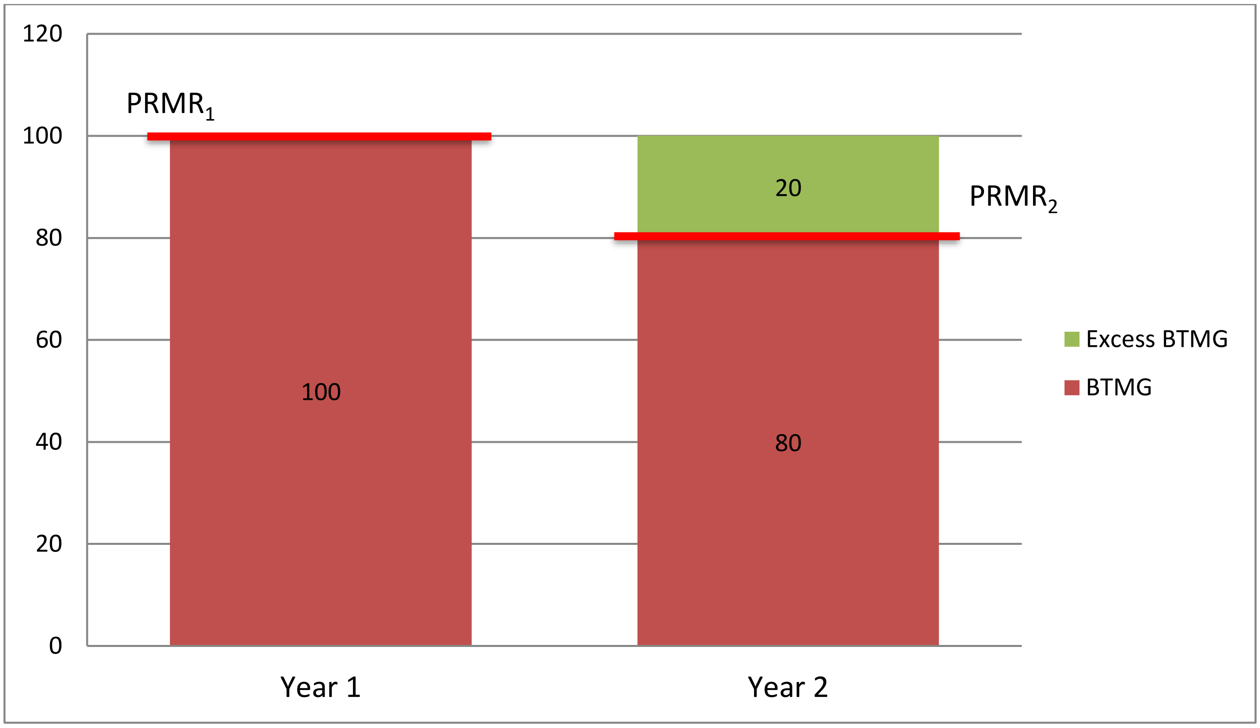


2. Increase in Demand Resources and/or Demand Response Resources and No Change to PRMR

The chart below illustrates the scenario in which a Market Participant experiences an increase in DR / DRR SAC from one year to the next while seasonal PRMR remains unchanged. In Year 1, the chart shows that the BTMG SAC is 100 MW and the seasonal PRMR is 100 MW; therefore, the Market Participant has no “Excess BTMG” in Year 1. Between Year 1 and Year 2, the Market Participant experiences an increase in DR / DRR SAC of 25 MW, however, seasonal PRMR remains unchanged. In Year 2, the chart shows that DR / DRR is 25 MW and BTMG is 100 MW and the seasonal PRMR is 100 MW. Since DR / DRR is netted against seasonal PRMR, the BTMG is stacked on top of the DR / DRR; therefore, the Market Participant has 25 MW of “Excess BTMG” in Year 2.

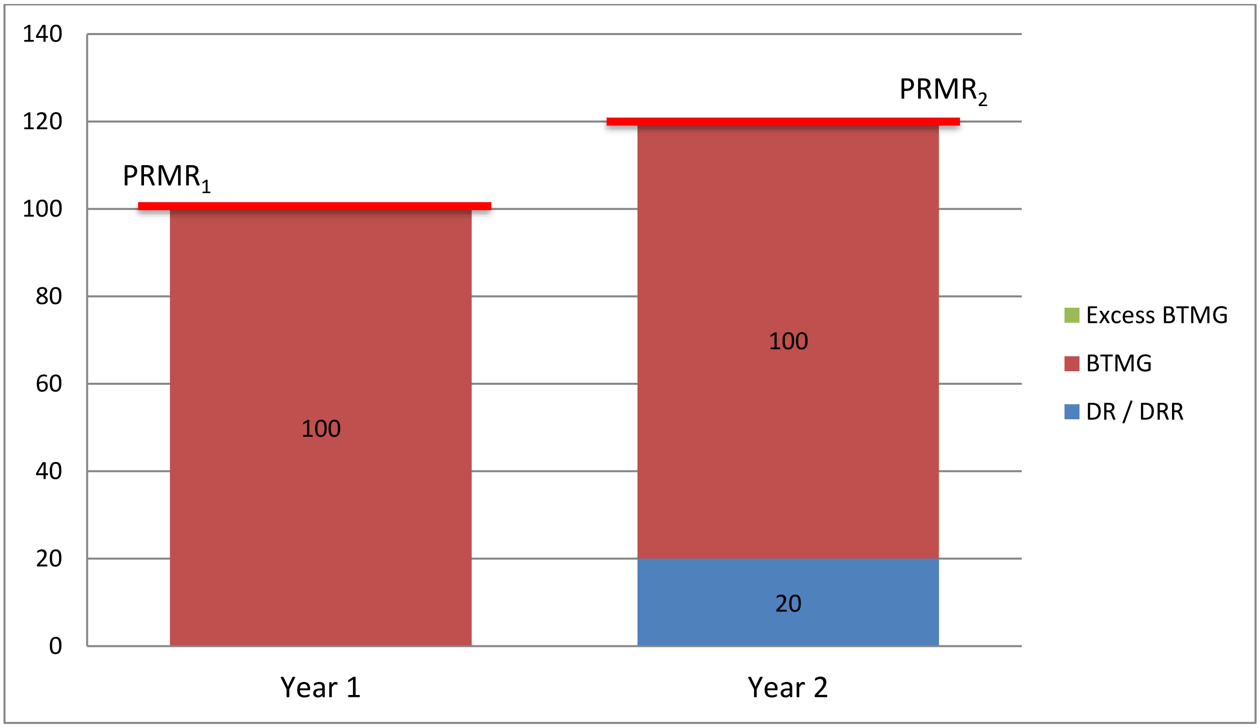
3. No Change to BTMG and Decrease to Seasonal PRMR

The chart below illustrates the scenario in which a Market Participant experiences a decrease in seasonal PRMR from one year to the next while BTMG SAC remains unchanged. In Year 1, the chart shows that the BTMG is 100 MW and the seasonal PRMR is 100 MW; therefore, the Market Participant has no "Excess BTMG" in Year 1. Between Year 1 and Year 2, the Market Participant experiences a decrease in seasonal PRMR of 20 MW, however, BTMG SAC remains unchanged. In Year 2, the chart shows that BTMG is 100 MW the seasonal PRMR is now 80 MW; therefore, the Market Participant has 20 MW of "Excess BTMG" in Year 2.



4. Equal Amount Increase in DR / DRR and Seasonal PRMR

The chart below illustrates the scenario in which a Market Participant experiences an equal increase in DR / DRR SAC and seasonal PRMR from one year to the next while BTMG SAC remains unchanged. In Year 1, the chart shows that the BTMG is 100 MW and the seasonal PRMR is 100 MW; therefore, the Market Participant has no “Excess BTMG” in Year 1. Between Year 1 and Year 2, the Market Participant experiences an equal increase in DR / DRR and seasonal PRMR of 20 MW each, however, BTMG remains unchanged. In Year 2, the chart shows that DR / DRR is 20 MW, BTMG is 100 MW and the seasonal PRMR is 120 MW. Since DR / DRR is netted against seasonal PRMR, the BTMG is stacked on top of the DR / DRR, however, due to the equal increase in DR / DRR and seasonal PRMR there is no “Excess BTMG” in Year 2.



Appendix T – ICAP Deferral Notice

ICAP Deferral Notice
Midcontinent Independent System Operator
720 City Center Drive
Carmel, IN 46032-7574
Attn.: Resource Adequacy
(Delivered via email to help@misoenergy.org)

[Current Date]

[Insert Company Name] ICAP Deferral Notice – [Planning Resource Name/CPNode Name, if applicable]
Select Planning Resource being deferred:
☐Generation Resource – [Insert CPNode Name, Unit Number]
☐Dispatchable Intermittent Resource (DIR) – [Insert Name]
☐Demand Response Resource (DRR) – [Insert Name]
☐External Resource – [Insert Name]
☐Behind the Meter Generation (BTMG) – [Insert Name]

Dear Resource Adequacy,

[Insert Company Name] is providing this written notification in accordance with Section 69A.7.9 of the Midcontinent Independent System Operator (MISO) Tariff, Module E-1 Resource Adequacy regarding an Installed Capacity (ICAP) Deferral for the Planning Resource selected above. [Insert Company Name] intends to increase ICAP between March 1 and the last Business Day of the applicable Season(s) for the [Insert Planning Year] Planning Year.

[Contact Name, Phone Number and Email]	Planning Resource Type
MISO MP ID/NERC ID of Company	
Planning Resource Name	
Local or External Resource Zone (LRZ or ERZ) where located	
Planning Resource Fuel Type	
Estimated ICAP Value (MW) *Note: this is the total ICAP value not the incremental increased value from a prior ICAP*	Summer
	Fall
	Winter
	Spring
Check applicable deferred Season(s)	Summer [ ], Fall [ ], Winter [ ], Spring [ ]
Estimated completion date of ICAP	
Reason for deferring (See Appendix U)	
Please fill out the following that is applicable to the Planning Resource being deferred:	
Generator Interconnection Agreement (GIA) Number and expected contract execution date *Note: only necessary if deferral includes upgrades to Interconnection Service*	

Expected NRIS and ERIS values with Interconnection Service upgrades	
Commercial Operation Date	
TSR Number	

Sincerely,
[Name], [Title – must be an officer], [Company Name], [Contact Information]

Appendix U – ICAP Deferral Examples

- Deliverability

Example 1: Unit is capable of testing at 150 MW, but currently only has 100 MW of NRIS with MISO. The unit is in the queue to have its NRIS increased to 150 MW by the last Business Day prior to the start of a Season in the upcoming Planning Year. Although the difference is 50 MW, the MP would submit an ICAP Deferral Notice for the total ICAP amount of 150 MW. For a Schedule 53 resource, even though the ICAP will increase, SAC will not. For a non-Schedule 53 resource, both ICAP and SAC will increase.

- Increased GVTC and Deliverability

Example 1: Unit currently tested for 100 MW and has 100 MW of NRIS. The unit is in the queue to have NRIS increased to 150 MW and plans to retest after upgrades are in place. Although the difference is 50 MW, the MP would submit an ICAP Deferral Notice for the total ICAP amount of 150 MW. Please note that the current unit should already submit a GVTC test of 100 MW by October 31.

- Commercial Operation

Example 1: The unit currently is subject to an environmental regulation that prevents the unit from operating. The unit is in the process of installing additional equipment to comply with the new environmental regulation. Thus, the unit is deferring GVTC until after all necessary approvals are completed.

Example 2: A resource that is a Dispatchable Intermittent Resource (DIR) would not submit GVTC, but instead receives capacity accreditation based on past historical data. If a DIR is new and is not expected to have Commercial Operation approved until after March 1, then it would be eligible to qualify for capacity credit by submitting an ICAP Deferral for Commercial Operation if Commercial Operation is expected before the last Business Day of prior to the deferred Season.

Example 3: The unit is currently waiting for upgrades to existing Interconnection Service and the upgrades have been completed, however, the unit has yet to be declared Commercial with MISO. The resource owner needs to file an Exhibit E with MISO Resource Integration to finalize the Commercial Operation of the unit. The unit must be in the March Commercial Model prior to the start of the Planning Year. Once this has been done, the Commercial Operation deferral will be considered complete. The resource owner should assist with coordination with MISO Resource Adequacy and MISO Resource Integration throughout the process.

- Suspension of Catastrophic Outage

Example 1: A unit is planning to return from suspension in August and will submit a new GVTC for the upcoming Fall Season prior to the last Business Day of the summer Season. Units returning from suspension are required to retest. The MP may defer the retested value.

- TSR Number

Example 1: A unit is planning to participate in the upcoming Planning Year; however, the unit does not have a Transmission Service Request (TSR) or NITS Scheduling Rights (SR) on the MISO OASIS with a status of “Confirmed” by March 1 to convert the SAC to ZRC to offer into the Auction. The unit expects to have its TSR or SR Confirmed by MISO prior to the last Business Day of prior to the start of the deferred Season. Once the TSR achieves “Confirmed” status on the MISO OASIS, the MP should reach out to help.misoenergy.org. If the TSR or SR status is “Confirmed” prior to June 1, the deferral requirement has been met.

- Additional GVTC Examples

Example 1: The unit defers 100 MW and the test submitted is for 80 MW. The unit is required to replace the UCAP value of 20 ICAP MW. For example, if the XEFORd for the unit is 25%, then the deferred ZRCs is 75 and the submitted test ZRCs is 60. The MP is required to replace the difference of 15 ZRCs through Resource Replacement, Interconnection Service, Cleared Volumes, Bi-lateral ZRC transactions, etc.

Appendix V – Solar and Run-of-River Hydro Accreditation

This appendix walks through examples for calculating solar and run-of-river hydro accreditation. For existing solar resources, the total Seasonal Accredited Capacity (SAC) is determined by the historical average output of the resource during the Summer, Fall, and Spring Seasons for the hours ending 15, 16, and 17 EST and for hours ending 8, 9, 19, and 20 EST for the Winter Season. Existing run-of-river hydro resources can submit up to 15 years of output data over the same hours as for solar resources, with total SAC determined by the median of that data. Market Participants will use the Non-GADS Performance Template found on the MISO website to submit the appropriate historical data for the upcoming Planning Year. The Non-GADS Performance Template can be found on the MISO website under Planning > Resource Adequacy > PRA Documents > PY (Current Plan Year). The populated template should be submitted to MISO by October 31 of each year via the Module E Capacity Tracking (MECT) tool.

For new solar resources, the maximum SAC that can be accredited is 50% for summer, fall, and spring and 5% for winter of the unit's registered maximum output or nameplate capacity. To convert all SAC to seasonal ZRCs, the resource would need to show firm deliverability through NRIS or ERIS with a firm TSR equaling the resource's ICAP value.

For existing solar resources, the historical performance used to calculate the resource's total SAC for a given Season is based on their average output over the defined seasonal peak hours for the last 3 years.

- The amount of total SAC that is convertible into ZRCs is based on the amount of deliverability (NRIS or ERIS with a firm TSR)
- Convertible SAC = total SAC * (deliverability-adjusted capacity factor / peak performance capacity factor)
- Where:
    - Peak performance capacity factor is calculated is calculated by taking an average of the resource's output and then dividing by nameplate capacity.
    - Deliverability-adjusted capacity factor is calculated by adjusting the adjusting output across the seasonal peak hours so that it is capped to the resource's deliverability, taking an average of the resource's output, and then dividing by nameplate capacity.

The examples below show how solar capacity credit is calculated for new resources in the Summer Season only—however, the examples may also be applied to run-of-river hydro resources as well. For the purposes of the examples, the following information will be used in each:

Solar Nameplate = 10 MW
Transmission Losses (vary by LBA) = 5%
Solar Class Average Summer Capacity Credit = 50%
Year 1 Average Historical Summer Output = 6.5 MW (Year 1 data only)
Year 2 Average Historical Summer Output = 7.0 MW (Average of Years 1 and 2 data)

Example 1: New solar (or run-of-river hydro) resources with less than 30 consecutive Summer days or no Summer data

In this example, the new solar resource does not have any historical Summer performance data to submit. Thus, the solar resource will receive the solar class average accreditation for the initial Summer Season in the Planning Year. In Year 2, the resource will use the average (run-of-river hydro resources use a median value) historical Summer performance from Year 1 to determine the accredited amount. In Year 3, the resource will use the average historical Summer performance from Years 1 and 2. In Year 4, the resource will use the average historical Summer performance from Years 1, 2, and 3. In Year 5, the average historical Summer performance from Year 1 will be replaced by Year 4 and the cycle will continue to repeat year-over-year using the 3 most recent years of average historical Summer performance. Below are examples of how both BTMG and CPNode solar resources will be accredited.

BTMG

Year 1 → SAC_{BTMG} = Nameplate capacity * seasonal class credit * (1 + Transmission Losses)
→ SAC_{BTMG} = 10 * 50% * (1 + 5%)
→ SAC_{BTMG} = 5.25

Year 2 → SAC_{BTMG} = 10 * (65%) (1 + 5%)
→ SAC_{BTMG} = 6.8 (rounded to tenth decimal place)

Year 3 → SAC_{BTMG} = 10 * (70%) (1 + 5%)
→ SAC_{BTMG} = 7.4 (rounded to tenth decimal place)

CPNode

Year 1 → Total SAC_{CPNode} = Nameplate capacity * seasonal class credit

→ Total SAC_{CPNode} = 10 * (50%)
→ Total SAC_{CPNode} = 5.0

Year 2 → Total SAC_{CPNode} = 10 * (65%) = 6.5

Year 3 → Total SAC_{CPNode} = 10 * (70%) = 7.0

Example 2: New solar resource with at least 30 consecutive Summer days

In this example, the new solar resource has at least 30 consecutive Summer days of performance. Thus, the solar resource will not receive the solar class average for the initial Planning Year. In Year 1, the average historical Summer performance from Commercial Operation data will be used to determine the accredited amount. In Year 2, the resource will use the average historical Summer performance from Year 1 and 2. In Year 3, the resource will use the average historical Summer performance from Years 1, 2, and 3. In Year 4, the average historical Summer performance from Year 1 will be replaced by Year 4 and the cycle will continue to repeat year-over-year using the 3 most recent years of average historical Summer performance.

BTMG

Year 1 → SAC_{BTMG} = Nameplate capacity * seasonal class credit * (1+ Transmission Losses)
→ SAC_{BTMG} = 10 * (65%) * (1 + 5%)
→ SAC_{BTMG} = 6.8 (rounded to tenth decimal place)

Year 2 → SAC_{BTMG} = 10 * (70%) * (1 + 5%)
→ SAC_{BTMG} = 7.4 (rounded to tenth decimal place)

CPNode

Year 1 → Total SAC_{CPNode} = Nameplate capacity * seasonal class credit
→ Total SAC_{CPNode} = 10 * (65%)
→ Total SAC_{CPNode} = 6.5

Year 2 → Total SAC_{CPNode} = 10 * (70%)
→ Total SAC_{CPNode} = 7.0

Once the total SAC value for a resource has been determined, it is compared with the Interconnection Service assigned to that resource. Resources that are fully deliverable are eligible to convert all of their total SAC to ZRCs with no further action needed.

For resources that are not fully deliverable, having either partial or no deliverability, the following steps would be used:

1) MISO calculates a deliverability-adjusted capacity factor for the resource.

2) For SAC not considered convertible, the Market Participant may choose to obtain firm Transmission service in some level to convert some or all of the undeliverable SAC to Convertible. MISO supplies documentation to the MP on the MECT tool that can be used to determine the level of SAC that can be converted given some level of firm Transmission obtained.

3) Subsequently, the MP uses the Confirm SAC function to move the desired Convertible SAC amount to the Convert SAC MECT page. Once there, the associated firm Transmission information is entered after selecting the ERIS SAC value.

4) After MISO approval of the firm Transmission data that was entered by the MP, the SAC may then be converted to ZRCs for use in the PRA.

SAC is allocated by type of Interconnection Service (NRIS or ERIS with a TSR). SAC associated with ERIS may be converted into Zonal Resource Credits for use in the PRA with an approved Transmission Service Request.

Appendix X – Hybrid and Co-Located Resource Accreditation

This appendix describes the accreditation process for Hybrid Resources and Co-Located Resources. A Hybrid Resource is defined as a resource that is comprised of two or more separate Electric Facilities that share a single Point of Interconnection and that provides a single energy offer in the MISO DA/RT Energy Markets. A Co-Located Resource is defined as a resource that is comprised of two or more separate Electric Facilities that share a single Point of Interconnection where each separate Electric Facility provides separate energy offers in the MISO DA/RT Energy Markets.

Hybrid Resources and Co-Located Resources will be accredited in one of two phases depending on how much operating data is available. The Phase I – Sum of Parts approach will apply default class accreditation values for each separate Electric Facility comprising the Hybrid Resource or Co-Located Resource. The Phase II – Availability-based approach will consist of tracking the historic availability of each separate Electric Facility of the Hybrid Resource or Co-Located Resource. A Hybrid Resource or Co-Located can be Phase I for a Season and then get Phase II for a subsequent Season that it has operational data for. Once a Hybrid Resource begins receiving Phase II availability-based accreditation, the resource will continue to receive Phase II availability-based accreditation.

For Co-Located Resources, allocation of total Interconnection Service at the shared Point of Interconnection among the separate Electric Facilities must be provided to MISO Resource Adequacy staff by the incumbent Asset Owner, or the Market Participant(s) representing the incumbent Asset Owner, prior to conversion of Seasonal Accredited Capacity (SAC) to Zonal Resource Credits (ZRCs).

Phase I – Sum of Parts

Each Hybrid Resource or Co-Located Resource may be operating in very different ways from other Hybrid Resources or Co-Located Resources with a similar configuration depending on the goals of the resource owner and operator. Until historical operating data exists, default class accreditation values for each separate Electric Facility comprising the Hybrid Resource or Co-Located Resource will be applied. Co-Located Resource owners must inform MISO how the total Interconnection Service granted at the shared Point of Interconnection should be allocated among each separate Electric Facility for conversion purposes. Phase I accreditation will apply for each Season until a minimum of 30 consecutive historical days of operation for the corresponding Season have been observed.

For Phase I, Market Participants must submit a populated Non-GADS Performance Template to MISO through the MECT for each separate Electric Facility that includes the nameplate capacity (or registered maximum output from the Commercial Model) and resource type of each Electric Facility, unless the Electric Facility qualifies as a Schedule 53 resource.

Phase II – Availability-based

Phase II accreditation will apply after a Hybrid Resource or Co-Located Resource has sufficient operating history to determine a resource-specific seasonal accreditation value.

Availability is measured as historical net output (exception for ESR below) and will be determined in the following ways:

- For Hybrid Resources, the combined historical net output of each Electric Facility, provided via a single populated Non-GADS Performance Template.
- For Co-Located Resources, the separate historical net output of each Electric Facility, provided via several populated Non-GADS Performance Templates.
- For the ESR component of a Hybrid Resource or Co-Located Resource, availability for a given hour will be measured as the maximum of the net output or the output potential on that hour. Output potential should be determined as the minimum of the Hourly Equivalent Discharge Amount or the state of charge minus the Emergency Minimum Energy Storage Limit for a given hour.

Market Participants must submit Non-GADS Performance Templates to MISO through the MECT. In addition to historical operating performance, populated Non-GADS Performance Templates must include nameplate capacity (or registered maximum output from the Commercial Model) and resource type.

Appendix Y – SAC Calculations for Schedule 53 Resources

This appendix describes the process of calculating Seasonal Accredited Capacity (SAC) for Schedule 53 Resources.

1. Identification of Resource Adequacy Hours

Resource Adequacy (RA) Hours represent the periods of highest risk and greatest need during a Season and throughout the year. They include Emergency Declaration periods and the hours when the operating margin, a measure of available supply capacity above Demand and reserve requirements, is at its lowest. RA Hours are determined seasonally and at a subregional level (North/Central and South) based on emergency events, the tightest operating margin hours (65 hours per Season), and a maximum operating margin threshold established at 25 percent.

RA Hours will be used to determine each resources' availability for calculating its seasonal accreditation. The number of RA Hours in a Season can exceed the target when a high number of hours during declared system or subregional emergencies occurs.

Provisions also ensure Seasons have a minimum target number of RA Hours by supplementing any deficient hours with Annual Average Offered Capacity (AAOC) over all RA hours across the year. The RA Hours used for determining the AAOC (or AAOC Hours) are the hours with emergency events and the tightest 3 percent of operating margin hours below the 25% threshold for each year, up to 260 hours per year. The AAOC Hours are determined on a sub-regional (North/Central and South) basis. Not all AAOC Hours are RA hours.

1.1 **Definition and Identification of RA Hours**

RA Hours are defined over the three most recent historical years from September - August, based on declared MaxGen alert, warning and event hours supplemented by the tightest 3 percent of hours per Season where the realized operating margin for the region is at or below the threshold of 25 percent.

1.1.2 Hourly Operating Margin Calculation

The Operating Margin is determined using historical information to identify RA Hours and AAOC Hours within the three (3) most recent periods beginning September 1 and ending August 31.

We first express the power balance between load and supply, where:

$$Load = Thermal\ Resource\ Energy + Renewable\ Energy + Net\ Scheduled\ Interchange \qquad (1)$$

$$Supply = Thermal\ Resource\ EmergencyMax + Renewable\ Energy + Net\ Scheduled\ Interchange - Operating\ Reserve \qquad \_\_\_\_\_\_\_\_\_\_\_\_\_\_ (2)$$

Substituting (1) into (2), we have

$$\begin{aligned} Margin(MW) = {} & [Thermal\ EmergencyMax + Renewable\ Energy + Net\ Scheduled\ Interchange\ (NSI)] \\ & - [Thermal\ Energy + Renewable\ Energy + Net\ Scheduled\ Interchange] \\ & - Operating\ Reserve \\ & = Thermal\ Resource\ EmergencyMax - Thermal\ Resource\ Energy - Operating\ Reserve \end{aligned}$$

The power balance between equation (1) and (2) suggests the renewable Energy and net-scheduled interchange have been implicitly reflected in the margin calculation but has no impact on the overall margin calculation used for RA hour identification as in the steps below.

By re-arranging the $Margin(MW)$ and broken down to online and offline components, we re-express the Operating Margin Equation as below

$$Operating\ Margin\ (\%)_j = \frac{Online\ margin\ (MW)_j + offline\ margin\ (12\ hour\ leadtime)(MW)_j}{Real\ Time\ (RT)Load\ (MW)_j}$$

Where:

$$\begin{aligned} & Online\ margin\ (MW)_j \\ & = \sum_{unit\ i\ in\ region\ j} (EmergencyMax_i - EnergyMW_i - cleared\ operating\ reserve_i) \end{aligned}$$

for all Resources that are online and under normal dispatch control; and

$$\begin{aligned} & Offline\ margin\ (MW)_j \\ & = \sum_{unit\ i\ in\ region\ j} (EmergencyMax_i - cleared\ offline\ supplement\ reserve_i) \end{aligned}$$

for Resources where all of the following is true: (i) Resource is Offline; (ii) its cold-start lead-time is less than or equal to 12 hours; and (iii) it is not on outage.

Load Modifying Resource (LMR), and Emergency Demand Response (EDR) are excluded in the Online margin (MW) and Offline margin (MW) calculations because they require emergency declarations in order to access.

1.1.2 Selection of RA Hours

Hours during which MaxGen declarations are in effect automatically become RA Hours, including all MaxGen Alert, Warning, or Event hours declared in each Season within each of the three (3) most recent September-August periods.

For non-MaxGen declaration hours in each of the 12 Seasons of the past three-year period, additional RA Hours with the tightest margin will be identified until reaching the (65 hours) for each Season; if a Season already has more than 65 hours because of MaxGen declaration, this step will be skipped.

Finally, a maximum margin threshold is applied to exclude hours with an operating margin greater than 25 percent.

Going through the steps above, some Seasons will have more than 65 hours because of MaxGen declarations, while some other Seasons may have less than 65 hours if there are hours excluded based on the 25 percent maximum margin threshold criterion and a low number of hours with MaxGen declarations, reflecting underlying Demand, supply and weather conditions. The deficiency from the 65 target hours leads to the need for AAOC Hour as described in the next section.

Additionally, each individual resource will have its own set of RA hours that are dependent on outage exemptions and whether it was designated for Resource Adequacy Requirements (RAR) in previous year’s seasonal auctions. Like the system-wide RA hours, if a resource has deficient RA hours in a Season, that resource’s AAOC will be supplemented for the deficient hours.

Non-RAR resources are not subject to SAC calculation using seasonal RA and AAOC hours.

If the unit was designated as RAR within the 3-year lookback period, the following logic will apply.

- When a unit is RAR and has 60 days or more during the 3-year lookback period of that particular Season’s operational data, for that Season SAC will be calculated with that historical operational data. Operating days that a unit was in full outage will be excluded from the statistics.
- If the unit has less than 60 days of data designated as a RAR for that Season over the 3-year lookback period they will receive Schedule 53 seasonal class average SAC accreditation. Operating days that a unit was in full outage will be excluded from the statistics.
- For resources that have a generation capacity change due to upgrades or seasonalization that had a non-zero offer historically, the RT EmerMax will be prorated based on the capacity change/ICAP% of the historical offers, capped at the new GVTC of the resource.
- For resources that have a generation increase due to upgrades or seasonalization, that have zero historical offer information, will receive Schedule 53 seasonal class average SAC accreditation for that Season

- In the case where a schedule 53 generator was derated due to transmission limitations imposed by the incumbent Transmission Operator, the MP can work with MISO to determine if any exemptions for those hours can be granted
- Exemption status for a unit’s outage should be validated and resolved with MISO if needed, per timeline defined in BPM-008 (Business Manual -- Outage Operations)

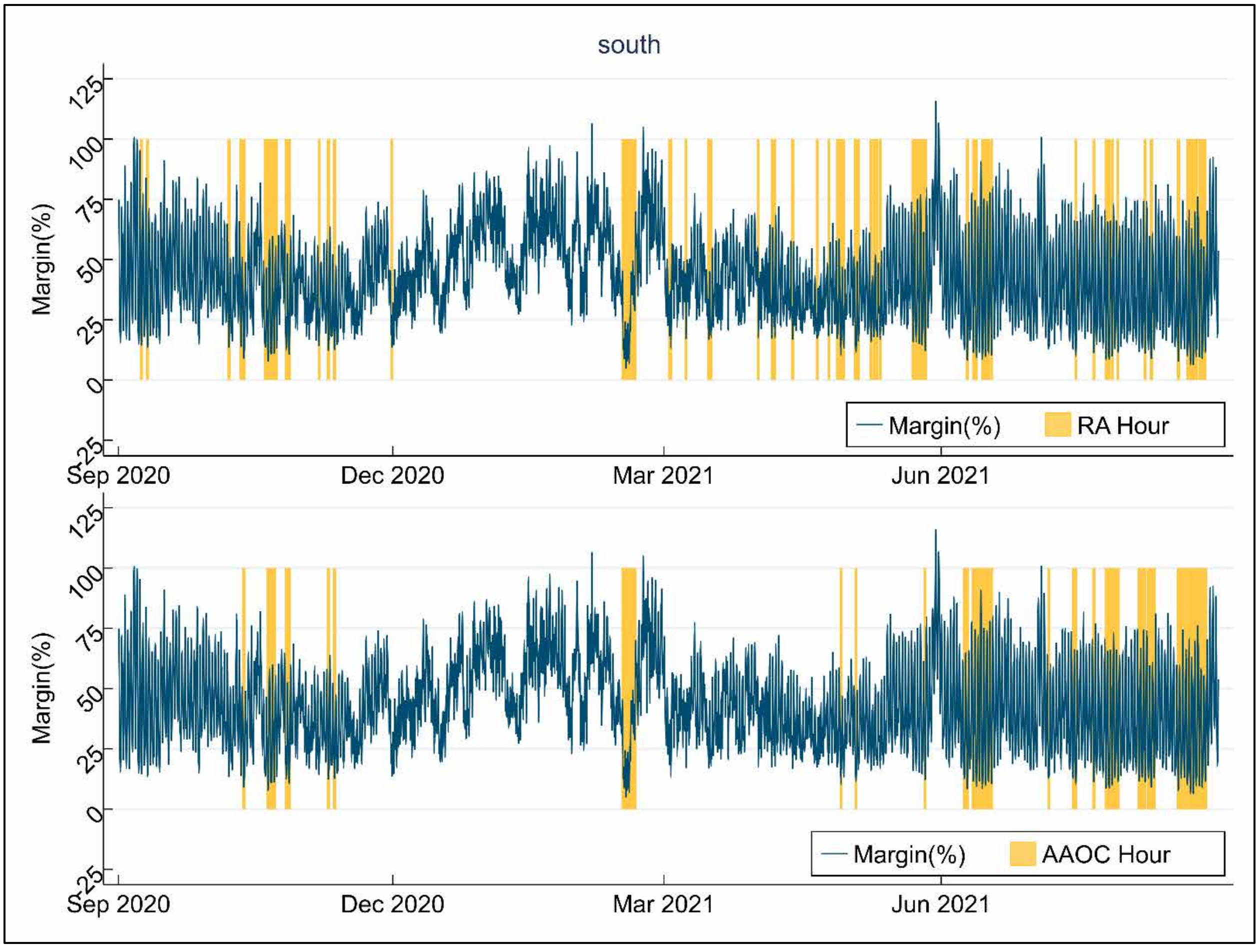
1.1.3 Selection of AAOC RA Hour

Hours where MaxGen declarations are in effect automatically become AAOC RA Hours, including all MaxGen Alert, Warning, or Event hours declared in each Season within the three (3) most recent periods.

For the rest of non-MaxGen declaration hours in each year of the past three-year periods, additional AAOC RA Hours with the tightest margin will be identified until reaching the (260 hours) for each year. For a unit to receive exemption for an AAOC hour they must have Tier 2 exemption during that hour.

1.1.4 Illustration of Selected RA Hour

The figure below, using South region as example, illustrates the variation of hourly Margin (%) between September 1, 2020, and August 31, 2021, and labels the selected RA Hour / AAOC Hour. In this example, there are 65 RA Hours identified in each of the four Seasons, hence the AAOC Hour will not be needed for backfilling any deficiency hour.



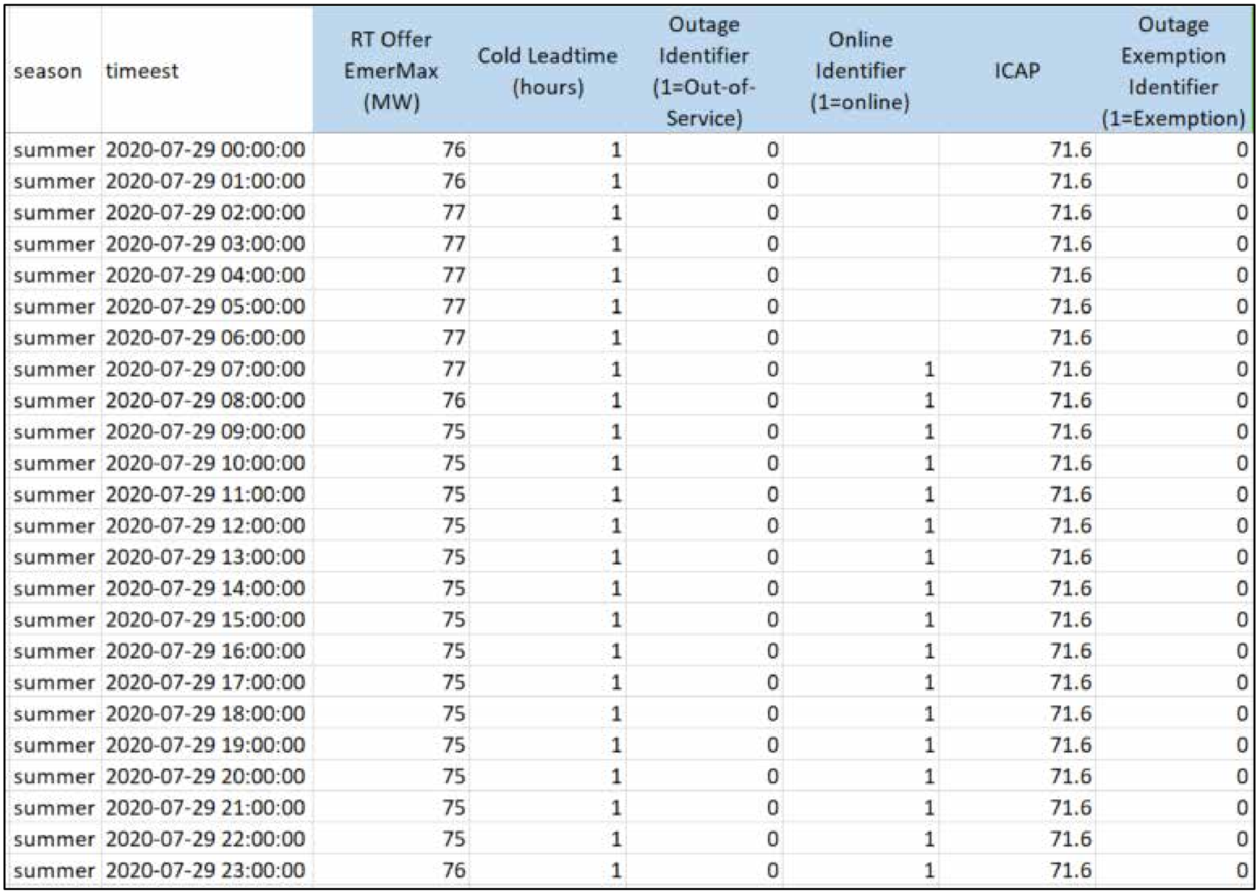
1.2 **Seasonal Accredited Capacity Calculation**

Resource Accreditation should reflect the anticipated capability and availability of Planning Resources during times when they are most needed. The following sections illustrate the two-tiered weighting structure to calculate Intermediate Seasonal Accredited Capacity (ISAC) reflecting general availability while emphasizing availability during times of greatest need. Each Resource will have its ISAC determined based on its Real-Time offered availability (Emergency Maximum Limit) during seasonal RA Hours (Tier 2) as described in Section 1.1 and Non-RA Hours (Tier 1).

1.2.1 Prepare Hourly Real-Time Offered Availability Dataset

The first step is to prepare the hourly Real-Time Offered Availability dataset for a Resource, including (1) hourly timestamp (EST); (2) offered Real-Time availability (EmerMax MW); (3) lead time(Start up time + Start up notification time) (in hours); (4) binary indicator if a resource is in outage from either the commit status or from records in Control Room Operations Window (CROW) Outage Scheduler; (5) binary identifier indicating if a Resource is online.; (6) ICAP (MW); and (7) binary indicator if a resource has received outage exemption.

Figure below provides a sample screenshot of the dataset, using a sample Resource located in Central/North region. If a Resource is in Derated status but not in outage, its offered availability already accounts for the impact of derates.



season	timeest	RT Offer EmerMax (MW)	Cold Leadtime (hours)	Outage Identifier (1=Out-of-Service)	Online Identifier (1=online)	ICAP	Outage Exemption Identifier (1=Exemption)
summer	2020-07-29 00:00:00	76	1	0		71.6	0
summer	2020-07-29 01:00:00	76	1	0		71.6	0
summer	2020-07-29 02:00:00	77	1	0		71.6	0
summer	2020-07-29 03:00:00	77	1	0		71.6	0
summer	2020-07-29 04:00:00	77	1	0		71.6	0
summer	2020-07-29 05:00:00	77	1	0		71.6	0
summer	2020-07-29 06:00:00	77	1	0		71.6	0
summer	2020-07-29 07:00:00	77	1	0	1	71.6	0
summer	2020-07-29 08:00:00	76	1	0	1	71.6	0
summer	2020-07-29 09:00:00	75	1	0	1	71.6	0
summer	2020-07-29 10:00:00	75	1	0	1	71.6	0
summer	2020-07-29 11:00:00	75	1	0	1	71.6	0
summer	2020-07-29 12:00:00	75	1	0	1	71.6	0
summer	2020-07-29 13:00:00	75	1	0	1	71.6	0
summer	2020-07-29 14:00:00	75	1	0	1	71.6	0
summer	2020-07-29 15:00:00	75	1	0	1	71.6	0
summer	2020-07-29 16:00:00	75	1	0	1	71.6	0
summer	2020-07-29 17:00:00	75	1	0	1	71.6	0
summer	2020-07-29 18:00:00	75	1	0	1	71.6	0
summer	2020-07-29 19:00:00	75	1	0	1	71.6	0
summer	2020-07-29 20:00:00	75	1	0	1	71.6	0
summer	2020-07-29 21:00:00	75	1	0	1	71.6	0
summer	2020-07-29 22:00:00	75	1	0	1	71.6	0
summer	2020-07-29 23:00:00	76	1	0	1	71.6	0

In sample data above, the outage indicator is set to 1 (outage) either if there is a valid full outage ticket in CROW or the unit was offered as outaged in real time for the specific hour. The online indicator is based on unit’s control mode from ICCP data as described in 2.4.7 in BPM-031 (ICCP Data Requirement).

1.2.2 Prepare Calculation for Annual Average Offered Capacity (AAOC)

If a Resource does not have 65 RA hours in a Season, AAOC is needed for backfilling the availability during deficiency hours in later steps. To calculate AAOC, the RT Offer EmerMax data is paired with AAOC hours by timestamp. Availability (MW) during AAOC hour is then generated through these following steps:

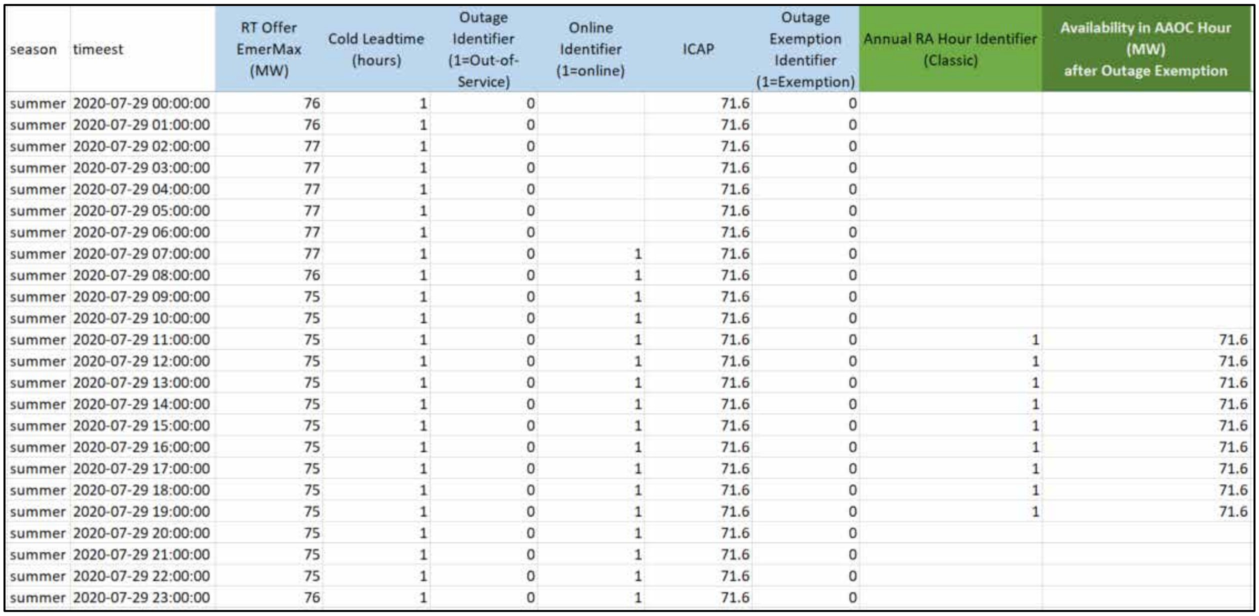
(1) Set availability = Min (ICAP, Real-Time Offer EmerMax) during AAOC hour; this step caps RT Offer EmerMax at ICAP;

(2) Set availability = zero if a Resource is in outage (based on outage identifier) during AAOC Hour;

(3) Set availability = zero if a Resource is not online and not in outage and has lead time (Start up time + Start up notification time) greater than 24 hours during AAOC Hour.

(4) Set availability = NULL if a Resource has been granted outage exemption during AAOC Hour.

Figure below shows the sample dataset fragment after generating the availability (MW) during AAOC hour through the steps described above.



season	timeest	RT Offer EmerMax (MW)	Cold Leadtime (hours)	Outage Identifier (1=Out-of-Service)	Online Identifier (1=online)	ICAP	Outage Exemption Identifier (1=Exemption)	Annual RA Hour Identifier (Classic)	Availability in AAOC Hour (MW) after Outage Exemption
summer	2020-07-29 00:00:00	76	1	0		71.6	0		
summer	2020-07-29 01:00:00	76	1	0		71.6	0		
summer	2020-07-29 02:00:00	77	1	0		71.6	0		
summer	2020-07-29 03:00:00	77	1	0		71.6	0		
summer	2020-07-29 04:00:00	77	1	0		71.6	0		
summer	2020-07-29 05:00:00	77	1	0		71.6	0		
summer	2020-07-29 06:00:00	77	1	0		71.6	0		
summer	2020-07-29 07:00:00	77	1	0	1	71.6	0		
summer	2020-07-29 08:00:00	76	1	0	1	71.6	0		
summer	2020-07-29 09:00:00	75	1	0	1	71.6	0		
summer	2020-07-29 10:00:00	75	1	0	1	71.6	0		
summer	2020-07-29 11:00:00	75	1	0	1	71.6	0	1	71.6
summer	2020-07-29 12:00:00	75	1	0	1	71.6	0	1	71.6
summer	2020-07-29 13:00:00	75	1	0	1	71.6	0	1	71.6
summer	2020-07-29 14:00:00	75	1	0	1	71.6	0	1	71.6
summer	2020-07-29 15:00:00	75	1	0	1	71.6	0	1	71.6
summer	2020-07-29 16:00:00	75	1	0	1	71.6	0	1	71.6
summer	2020-07-29 17:00:00	75	1	0	1	71.6	0	1	71.6
summer	2020-07-29 18:00:00	75	1	0	1	71.6	0	1	71.6
summer	2020-07-29 19:00:00	75	1	0	1	71.6	0	1	71.6
summer	2020-07-29 20:00:00	75	1	0	1	71.6	0		
summer	2020-07-29 21:00:00	75	1	0	1	71.6	0		
summer	2020-07-29 22:00:00	75	1	0	1	71.6	0		
summer	2020-07-29 23:00:00	76	1	0	1	71.6	0		

1.2.3 Prepare Calculation for Intermediate Seasonal Accredited Capacity (ISAC)

To calculate SAC, the RT Offer EmerMax data is paired with RA Hour by timestamp. Availability (MW) during RA Hour is then generated through these following steps:

For availability during Tier 1 Non-RA Hour:

(1) Set availability = Min (ICAP, Real-Time Offer EmerMax) during Tier 1 Non-RA hour; this step caps RT Offer at ICAP;

(2) Set availability = zero if a Resource is in outage (based on outage identifier) during Tier 1 Non-RA Hour;

(3) Set availability = NULL if a Resource has been granted outage exemption during Tier 1 Non-RA Hour.

For availability during Tier 2 RA Hour:

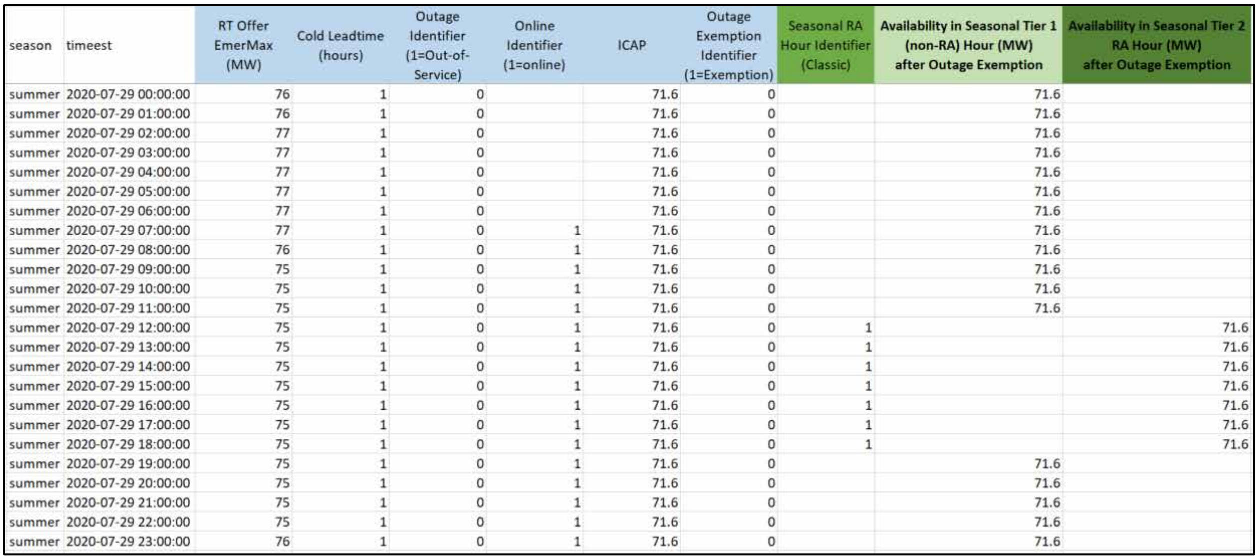
(1) Set availability = Min (ICAP, Real-Time Offer EmerMax) during Tier 2 RA hour; this step caps RT Offer at ICAP;

(2) Set availability = zero if a Resource is in outage (based on outage identifier) during Tier 2 RA Hour;

(3) Set availability = zero if a Resource is not online and not in out-of-service outage and has lead time (start up time + Start up notification time) greater than 24 hours during Tier 2 RA Hour;

(4) Set availability = NULL if a Resource has been granted outage exemption during Tier 2 RA Hour.

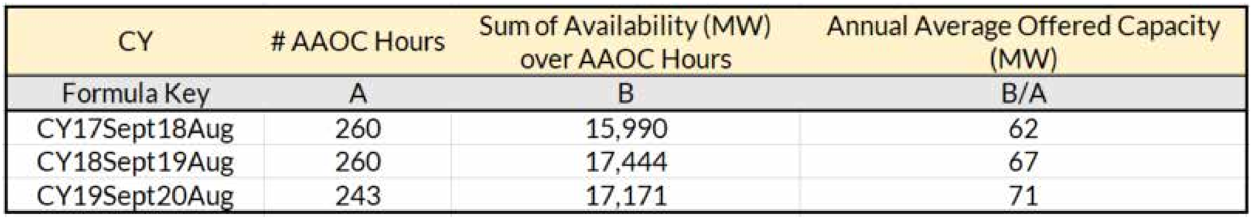
Figure below shows the sample dataset fragment after generating the availability (MW) during seasonal Tier 1 and Tier 2 RA hour through the steps described above.



season	timeest	RT Offer EmerMax (MW)	Cold Leadtime (hours)	Outage Identifier (1=Out-of-Service)	Online Identifier (1=online)	ICAP	Outage Exemption Identifier (1=Exemption)	Seasonal RA Hour Identifier (Classic)	Availability in Seasonal Tier 1 (non-RA) Hour (MW) after Outage Exemption	Availability in Seasonal Tier 2 RA Hour (MW) after Outage Exemption
summer	2020-07-29 00:00:00	76	1	0		71.6	0		71.6	
summer	2020-07-29 01:00:00	76	1	0		71.6	0		71.6	
summer	2020-07-29 02:00:00	77	1	0		71.6	0		71.6	
summer	2020-07-29 03:00:00	77	1	0		71.6	0		71.6	
summer	2020-07-29 04:00:00	77	1	0		71.6	0		71.6	
summer	2020-07-29 05:00:00	77	1	0		71.6	0		71.6	
summer	2020-07-29 06:00:00	77	1	0		71.6	0		71.6	
summer	2020-07-29 07:00:00	77	1	0	1	71.6	0		71.6	
summer	2020-07-29 08:00:00	76	1	0	1	71.6	0		71.6	
summer	2020-07-29 09:00:00	75	1	0	1	71.6	0		71.6	
summer	2020-07-29 10:00:00	75	1	0	1	71.6	0		71.6	
summer	2020-07-29 11:00:00	75	1	0	1	71.6	0		71.6	
summer	2020-07-29 12:00:00	75	1	0	1	71.6	0	1		71.6
summer	2020-07-29 13:00:00	75	1	0	1	71.6	0	1		71.6
summer	2020-07-29 14:00:00	75	1	0	1	71.6	0	1		71.6
summer	2020-07-29 15:00:00	75	1	0	1	71.6	0	1		71.6
summer	2020-07-29 16:00:00	75	1	0	1	71.6	0	1		71.6
summer	2020-07-29 17:00:00	75	1	0	1	71.6	0	1		71.6
summer	2020-07-29 18:00:00	75	1	0	1	71.6	0	1		71.6
summer	2020-07-29 19:00:00	75	1	0	1	71.6	0		71.6	
summer	2020-07-29 20:00:00	75	1	0	1	71.6	0		71.6	
summer	2020-07-29 21:00:00	75	1	0	1	71.6	0		71.6	
summer	2020-07-29 22:00:00	75	1	0	1	71.6	0		71.6	
summer	2020-07-29 23:00:00	76	1	0	1	71.6	0		71.6	

1.2.4 Calculation of Annual Average Offered Capacity (AAOC)

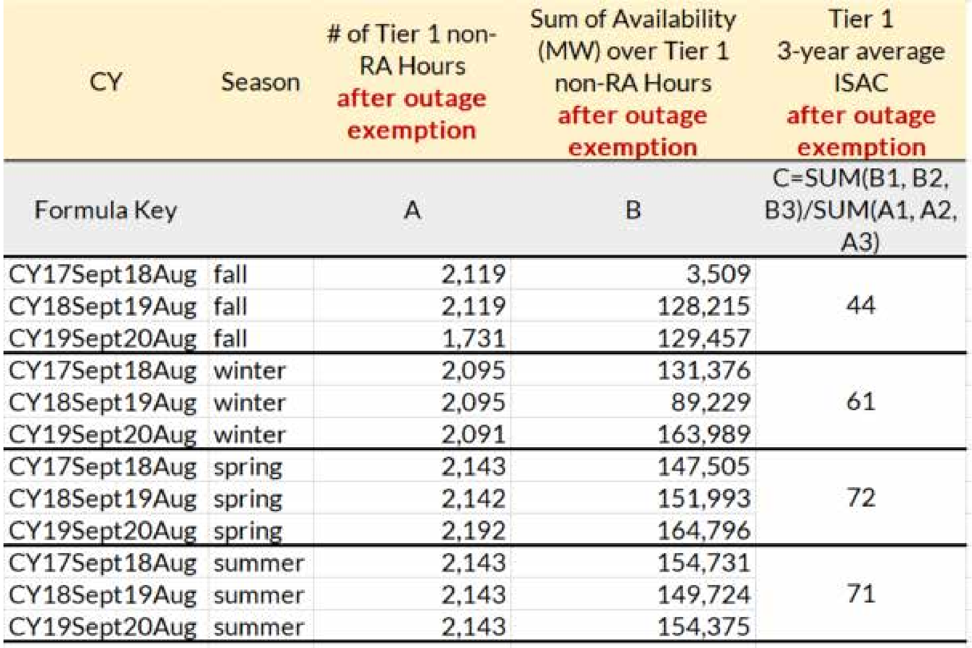
For each of the past three years, the AAOC is calculated as the sum of availability over AAOC hours, divided by the total number of AAOC hours (excluding outage exemption hours) in each year, as shown in the table below for a sample resource.



CY	# AAOC Hours	Sum of Availability (MW) over AAOC Hours	Annual Average Offered Capacity (MW)
Formula Key	A	B	B/A
CY17Sept18Aug	260	15,990	62
CY18Sept19Aug	260	17,444	67
CY19Sept20Aug	243	17,171	71

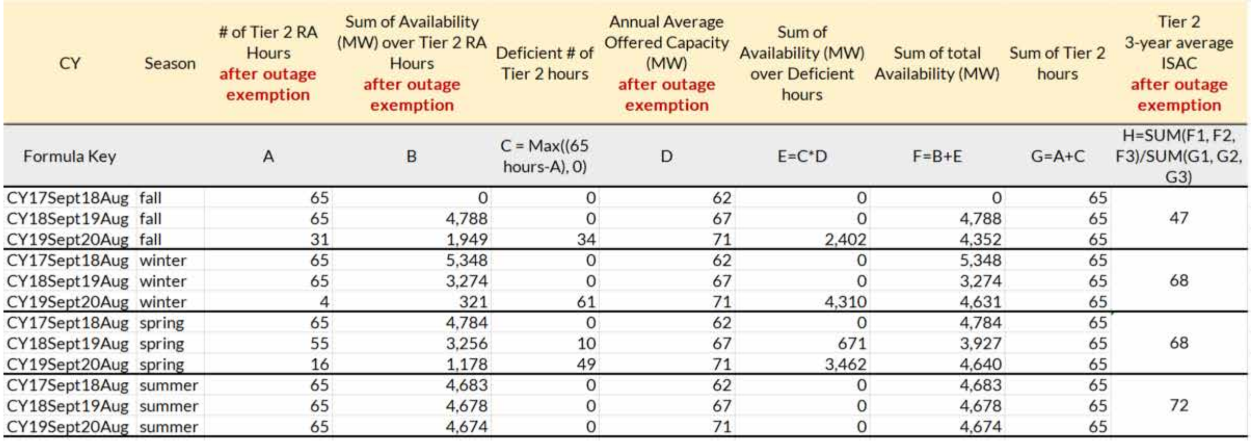
1.2.5 Calculation of Intermediate Seasonal Accredited Capacity (ISAC)

For Non-RA Hours (Tier 1), Intermediate Seasonal Accredited Capacity is calculated as the sum of availability over seasonal Tier 1 Non-RA hours, divided by the total number of seasonal Tier 1 Non-RA hours across the past three years.



CY	Season	# of Tier 1 non-RA Hours after outage exemption	Sum of Availability (MW) over Tier 1 non-RA Hours after outage exemption	Tier 1 3-year average ISAC after outage exemption
Formula Key		A	B	C=SUM(B1, B2, B3)/SUM(A1, A2, A3)
CY17Sept18Aug	fall	2,119	3,509	44
CY18Sept19Aug	fall	2,119	128,215	
CY19Sept20Aug	fall	1,731	129,457	
CY17Sept18Aug	winter	2,095	131,376	61
CY18Sept19Aug	winter	2,095	89,229	
CY19Sept20Aug	winter	2,091	163,989	
CY17Sept18Aug	spring	2,143	147,505	72
CY18Sept19Aug	spring	2,142	151,993	
CY19Sept20Aug	spring	2,192	164,796	
CY17Sept18Aug	summer	2,143	154,731	71
CY18Sept19Aug	summer	2,143	149,724	
CY19Sept20Aug	summer	2,143	154,375	

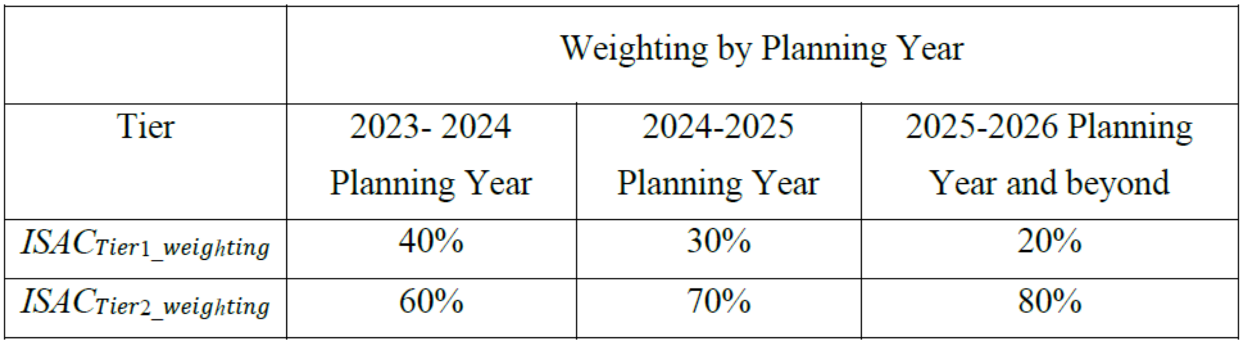
For RA Hour (Tier 2), its Intermediate Seasonal Accredited Capacity is calculated as the sum of availability over seasonal RA hours and AAOC multiplied by the deficient RA hours, then averaged over total number of Tier 2 RA hours across the past three years. A particular Season will be excluded from a unit's tier 1 and tier 2 ISAC calculation if either condition is met: 1) a unit has not been designated as RAR for the Season or 2) it has not been offering into Real-Time market due to an exempt outage for the whole Season.



CY	Season	# of Tier 2 RA Hours after outage exemption	Sum of Availability (MW) over Tier 2 RA Hours after outage exemption	Deficient # of Tier 2 hours	Annual Average Offered Capacity (MW) after outage exemption	Sum of Availability (MW) over Deficient hours	Sum of total Availability (MW)	Sum of Tier 2 hours	Tier 2 3-year average ISAC after outage exemption
Formula Key		A	B	C = Max((65 hours-A), 0)	D	E=C*D	F=B+E	G=A+C	H=SUM(F1, F2, F3)/SUM(G1, G2, G3)
CY17Sept18Aug	fall	65	0	0	62	0	0	65	47
CY18Sept19Aug	fall	65	4,788	0	67	0	4,788	65	
CY19Sept20Aug	fall	31	1,949	34	71	2,402	4,352	65	
CY17Sept18Aug	winter	65	5,348	0	62	0	5,348	65	68
CY18Sept19Aug	winter	65	3,274	0	67	0	3,274	65	
CY19Sept20Aug	winter	4	321	61	71	4,310	4,631	65	
CY17Sept18Aug	spring	65	4,784	0	62	0	4,784	65	68
CY18Sept19Aug	spring	55	3,256	10	67	671	3,927	65	
CY19Sept20Aug	spring	16	1,178	49	71	3,462	4,640	65	
CY17Sept18Aug	summer	65	4,683	0	62	0	4,683	65	72
CY18Sept19Aug	summer	65	4,678	0	67	0	4,678	65	
CY19Sept20Aug	summer	65	4,674	0	71	0	4,674	65	

1.2.6 Tier Weighting of ISAC

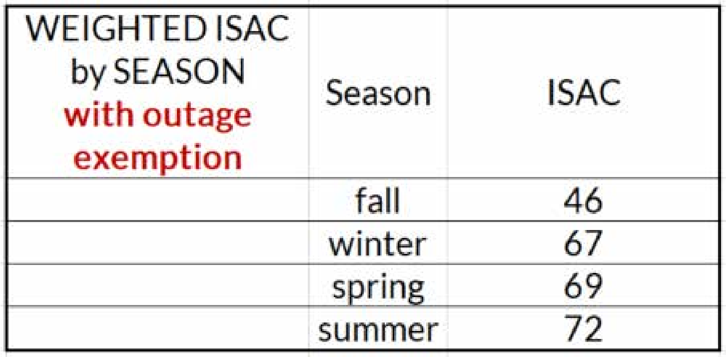
The final Intermediate Seasonal Accredited Capacity (ISAC) value is the weighted averaged over its values from two tiers as calculated from steps above. The corresponding tier weightings are:



	Weighting by Planning Year		
Tier	2023- 2024 Planning Year	2024-2025 Planning Year	2025-2026 Planning Year and beyond
$ISAC_{Tier1\_weighting}$	40%	30%	20%
$ISAC_{Tier2\_weighting}$	60%	70%	80%

$$ISAC = ISAC_{Tier\ 1\ MW} \times ISAC_{Tier\ 1\ weighting} + ISAC_{Tier\ 2\ MW} \times ISAC_{Tier\ 2\ weighting}$$

The table below illustrates the ISAC of a sample resource.

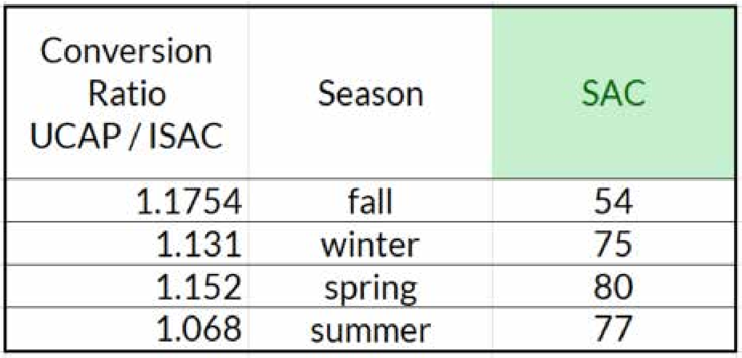


WEIGHTED ISAC by SEASON with outage exemption	Season	ISAC
	fall	46
	winter	67
	spring	69
	summer	72

1.2.7 Final conversion to SAC

Lastly, the ISAC is converted back to SAC in UCAP term using the formula and as illustrated in the sample table below. The Conversion Ratio is calculated for each Season on a system-wide basis for all Schedule 53 resources.

$$SAC = ISAC \times Conversion\ Ratio_{UCAP/ISAC}$$



Conversion Ratio UCAP / ISAC	Season	SAC
1.1754	fall	54
1.131	winter	75
1.152	spring	80
1.068	summer	77

The following rules are applied for determining units to be included/excluded in ratio calculations.

1. Only resources are included in both LOLE study and SAC calculations for the same Season of planning year are included in the UCAP/ISAC ratio calculation.2. Resources that are granted with a class average for one or multiple Seasons, are not included in ratio calculation for the Season(s)

1.2.8 SAC calculation for Combined Cycle (CC)units

Due to complicated nature of modeling and market participation options for combined cycle units, MISO will calculate their ISAC/SAC values based on how they are modeled and historically been offered into the Real-Time market, and how the combined cycle units submit their test capacity (GVTC) data in MISO GADS data:

1. If the owner of combined cycle unit submits GVTC data on the parent CP node only, MISO will calculate the SAC value on the parent node, by combining the Real-Time children's offer data if needed and capped at the latest GVTC. MISO will only provide planned outage exemptions for the SAC calculation, if all of the children units are fully outaged with valid exempt outage requests.

2.If the owner of combined cycle unit submits GVTC data on the children's CP nodes, or submits GVTC data on the parent node, but with specified % split of each children node, MISO will calculate SAC values for each children CP node. MISO may need to split the Real-Time offer (Emergency Max) based on the % ratios of all the children's GVTC data, if needed. In this scenario, each children's exempt outage will be reflected in their own SAC calculations.

1.2.9 SAC calculation for Jointly Owned Units (JOU)

Jointly Owned Units (JOUs) SAC values will be calculated the same way as regular units as long as the owners submit their separate GVTC data in the MISO GADS system. For units that have experienced ownership and/or share percentage changes within the last 3 years where Real-Time offer data is used, MISO may need to combine all the owner's Real-Time offers, capped by their total GVTC and then split again based on the latest GVTC ratios among ownerships before calculating each owner's SAC values.

1.3 **Class Average based SAC calculation**

New Schedule 53 Resources or existing Resources that do not have at least 60 days of Real-Time offered availability when designated for RAR over the last three (3) years for each Season (Summer, Fall, Winter, Spring) will have a SAC based on the class average SAC to ICAP Ratio for its Resource type. MISO will calculate Schedule 53 class averages based on existing GADS fuel type categories from the existing MISO Schedule 53 fleet.

Per MISO's discretion and agreement with the resource owner, MISO may grant the unit class average, if a unit's operation and offer history no longer represents its future economical and physical characteristics.

Class averages (% values) are calculated based on units with sufficient Real-Time offer in each resource type by dividing their total seasonal ISAC values divided by total effective ICAP (lesser of GVTC or interconnection service):

$$Class\ Average\ \%_{type\ of\ resource} = {\sum_{type\ of\ resource} ISAC} \Big/ {\sum_{type\ of\ resource} Effective\ ICAP}$$

For units whose SAC is calculated based on a class average, their class average % is applied to the unit's ICAP (lesser of GVTC or Interconnection Service) to determine the ISAC. The UCAP/ISAC ratio per Season will then be applied to identify the final SAC for the Season

1.4 SAC conversion to ZRC

1.4.1 Allocate Total SAC into NRIS SAC and ERIS SAC based on Interconnection Service:

Schedule 53 Resource's Total SAC is allocated into NRIS SAC and ERIS SAC based upon its type of Interconnection Service.

$$Total\ SAC = NRIS\ SAC + ERIS\ SAC$$

To the extent the Planning Resource has Network Resource Interconnection Service (NRIS) or was determined to be aggregate deliverable through the market transition deliverability test, then that quantity will be allocated first to calculate the NRIS SAC as defined in Module E 69A.4.5

$$NRIS\ SAC = \min(NRIS, ICAP) \times \frac{Total\ SAC}{ICAP}$$

The remaining balance of Total SAC is allocated to ERIS SAC with following formula:

$$ERIS\ SAC = \max\big(0, (ICAP - NRIS)\big) \times \frac{Total\ SAC}{ICAP}$$

1.4.2 Eligibility of NRIS SAC and ERIS SAC Conversion into seasonal Zonal Resource Credits

The NRIS SAC represents capacity in MW that is eligible to be converted into seasonal Zonal Resource Credits.

In determining the amount of ERIS SAC eligible for conversion into seasonal ZRCs, the deliverability of any ERIS must be determined prior to ERIS SAC conversion. ERIS must be paired with firm Transmission Service that covers the entire Season to be considered deliverable. NRIS is automatically considered deliverable and does not require an additional Transmission Service Request. The full amount of ERIS SAC can be converted to ZRCs if the resource is fully deliverable to its ICAP amount.

Total SAC which can be converted into seasonal ZRCs are the summation of the Planning Resource's NRIS SAC plus the lesser of the resource's ERIS with firm Transmission Service. .

Attachment LL

2025-08-21 Modified Attachment Y Notice

Consumers Energy
Count on Us

VIA EMAIL

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

August 21, 2025

Re: Modified Suspension Date for Campbell Units 1, 2, & 3

Mr. Witmeier:

On December 14, 2021, Consumers Energy Company ("Consumers Energy") submitted an Attachment Y Notice to the Midcontinent Independent System Operating, Inc. ("MISO") for the suspension of Units 1, 2, and 3 at the J.H. Campbell Generation Complex ("Campbell Plant"), effective June 1, 2025. After reviewing 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"), MISO determined the suspension of Campbell Plant Units 1, 2, and 3, would not result in violations of applicable reliability criteria, as outlined in the Tariff. On March 11, 2022, MISO approved the suspension of Campbell Plant Units 1, 2, and 3 without the need for the generators to be designated as System Support Resource units as defined in the Tariff.

On May 23, 2025, the U.S. Department of Energy ("DOE") issued Order No. 202-25-3 (the "Order"), requiring the Campbell Plant to be available to MISO through August 20, 2025. On May 28, 2025, consistent with Section 38.2.7(d)(ii)(1) of the Tariff, Consumers Energy notified MISO of its intent to modify the Attachment Y Notice suspension date from June 1, 2025, to August 21, 2025.

On August 20, 2025, the DOE renewed the Order, requiring the Campbell Plant to be available to MISO through November 19, 2025. In order to comply with the Order, Consumers Energy hereby provides notice to MISO, consistent with Section 38.2.7(d)(ii)(1) of the Tariff, of its intent to modify the current Attachment Y Notice such that the Campbell Plant will now suspend on December 3, 2025, to account for the DOE Order period plus a reasonable ramp down period at the close of the DOE Order.

As noted in Consumers Energy's original Attachment Y Notice, Campbell Unit 3 is jointly owned by Consumers Energy (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 it has notified all Campbell Unit 3 owners of this submittal.

In the event you have any questions regarding this matter, please contact Derek Anspaugh at (517) 788-1869.

Regards,

Sri M.

Sri Maddipati
VP Electric Supply
1945 W. Parnell Rd
Jackson, MI 49901

Attachment M

MPSC Case No. U-21775, Capacity Demonstration
Results Report, May 12, 2025

Capacity Demonstration Results

Planning Year 2028/29

Case No. U-21775

May 12, 2025

MPSC Staff

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%

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[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.

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[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

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[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

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[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.

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[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).

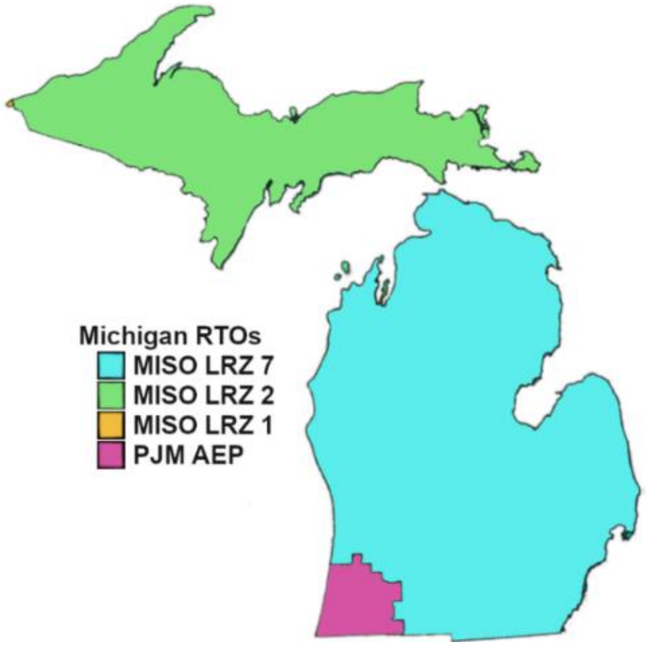
[10] See January 23, 2025 Order in Case No. U-21571

[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

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[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

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[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.

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[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

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[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

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[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]

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[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

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[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

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[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.

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[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

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[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%

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[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.

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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.

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Attachment MM

2025 NERC Winter Reliability Assessment

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

2025–2026 Winter Reliability Assessment

November 2025

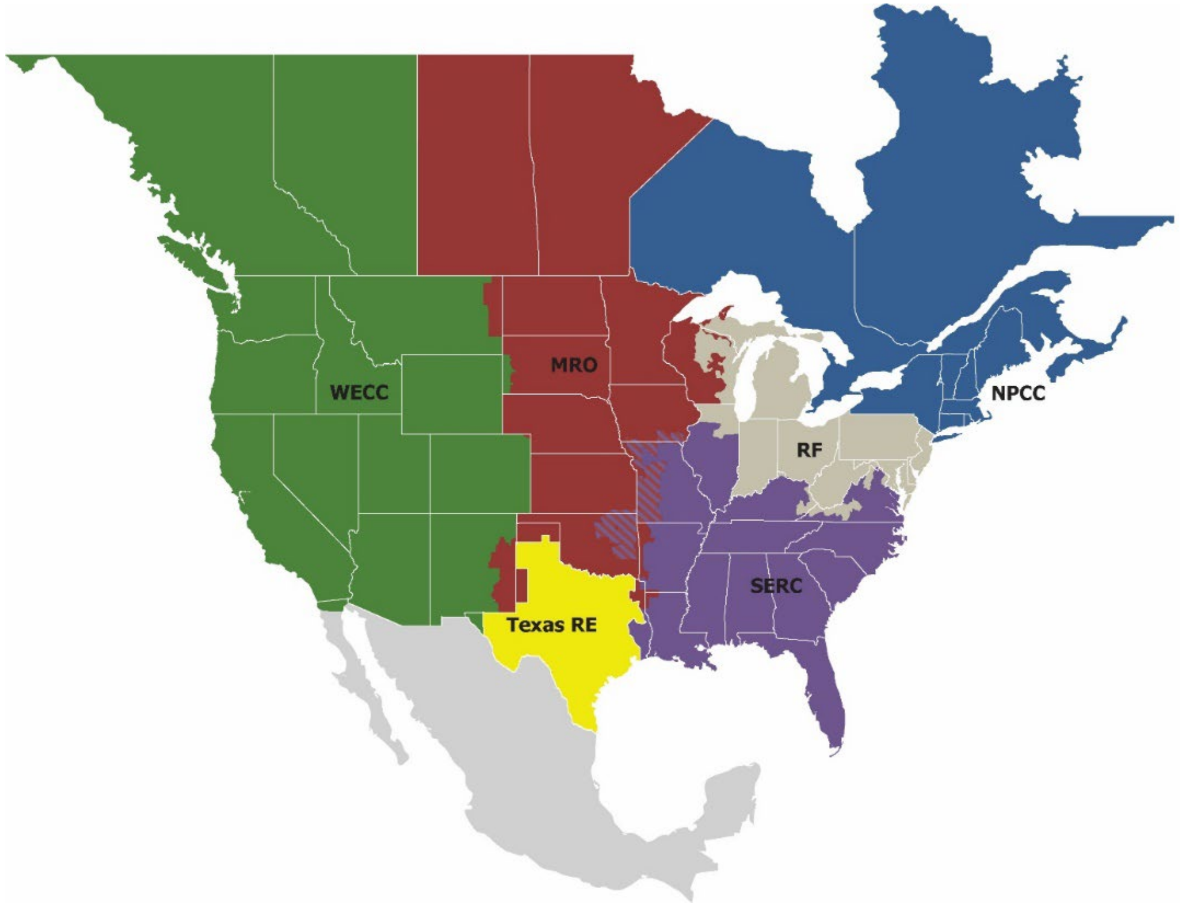
Table of Contents

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 made up of six Regional Entities as shown in the map and corresponding table below. The multicolored area denotes overlap as some load-serving entities participate in one Regional Entity while associated Transmission Owners/Operators participate in another.



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

About this Assessment

NERC's *2025–2026 Winter Reliability Assessment* (WRA) identifies, assesses, and reports on areas of concern regarding the reliability of the North American BPS for the upcoming winter season. In addition, the WRA 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 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 the ERO Enterprise (i.e., NERC and the six Regional Entities) and is intended to inform industry leaders, planners, operators, and regulatory bodies so that they are better prepared to ensure BPS reliability. This report also provides an opportunity for industry to discuss plans and preparations to ensure reliability for the upcoming winter period.

Key Findings

This WRA covers the upcoming three-month (December–February) winter period, providing an evaluation of the generation resource and transmission system adequacy necessary to meet projected winter peak demands and operating reserves. This assessment identifies potential reliability issues of interest and regional risks. The following findings are the ERO Enterprise's independent evaluation of electricity generation and transmission capacity as well as the potential operational concerns that may need to be addressed for the upcoming winter.

Two trends affecting resource adequacy across the BPS for the upcoming winter are rising electricity demand forecasts and a continued shift in the resource mix characterized by the retirement of thermal generators and growth in battery resources. After years of flat or low (~1%) peak demand growth, the aggregate peak demand for all NERC assessment areas has risen by 20 GW (2.5%) since the previous winter. Nearly all assessment areas are reporting year-on-year demand growth; some are forecasting increases near 10%. Total BPS resources have also increased since last winter, but by a smaller amount of 9.4 GW. This number includes the net change in generating capacity as well as additional demand response. These demand and resource changes are described in **Escalating Winter Demand** and **Resource Trends** sections.

The following findings are derived from NERC and the ERO Enterprise's independent evaluation of electricity generation and transmission capacity as well as potential operating concerns that should receive attention for Winter 2025–2026:

1. **All areas are assessed as having adequate resources for normal winter peak-load conditions (i.e., the area's 50-50 peak forecast). However, more extreme winter conditions extending over a wide area could result in electricity supply shortfalls.** Prolonged, wide-area cold snaps can drive sharp increases in electricity demand and threaten reliable BPS generation and the availability of fuel supplies for natural-gas-fired generation. Four severe arctic storms have descended to cover much of North America since 2021, causing regional demand for electricity and heating fuel to soar and exposing generation and fuel infrastructure in temperate areas to freezing conditions.[1] The following areas face risks of electricity supply shortfalls during periods of more extreme conditions this winter (see **Figure 1**):
    - **NPCC-Maritimes**: The peak demand forecast has fallen slightly (-1.6%) in the NPCC-Maritimes assessment area, contributing to higher reserves compared to the 2024–2025 winter. Maritimes is projected to have an Anticipated Reserve Margin (ARM) of 16.9%, which is 270 MW below the area's Reference Margin Level of 20% . New Brunswick has long-term energy contracts that can be used to mitigate resource adequacy challenges through the purchase of energy on a day-ahead basis. NPCC's all-hours probabilistic assessment for the NPCC Region included the simulation of both a base case (i.e., normal 50/50 demand) and highest peak load scenario (having an approximate 7% chance of occurring), for both an expected and a low-likelihood, reduced-resource condition. The preliminary results of this assessment indicate that operators in Maritimes are likely to require emergency operating mitigations and/or energy emergency alerts (EEA) during above-normal demand or low-resource output conditions.
    - **NPCC-New England**: A lower peak demand forecast and additional resources from demand response and firm imports offset recent generator retirements, resulting in little change to the NPCC-New England ARM for this winter. New England continues to closely monitor regional energy adequacy, particularly during extended cold snaps where constrained natural gas pipelines contribute to rapid depletion of stored fuel supplies. ISO-NE's deterministic winter scenario analysis shows limited exposure to energy shortfalls this winter. In New England, winter energy concerns are highest in scenarios when stored fuels are rapidly depleted; during these periods, timely replenishment is critical to minimizing the potential for energy shortfalls.
    - **SERC-East**: The winter peak demand forecast has increased by 700 MW (1.6%) since last winter, while winter firm capacity has declined, resulting in lower reserves. SERC-East has changed from a summer-peaking area to potentially peaking during both summer and winter. This is due to the continued addition of solar photovoltaic (PV) generation that shaves off summer peak demand and a trend toward electrification of heating that drives up winter peak demand. All-hours probabilistic analysis from SERC found some load-loss hours (<0.1 hrs) and small amounts of expected unserved energy, with the highest risk occurring during above-normal peak demand and early morning hours when solar output is absent.
    - **SERC-Central:** Additional demand response and flat load growth since last winter is offsetting declining resource capacity (down 1,120 MW), resulting in little change to the ARM at 30.5%. There are adequate resources for normal winter peak demand; however, higher levels of demand that can occur during extreme cold temperatures can result in insufficient reserves that operators would need to manage with non-firm imports and potential energy emergencies.
    - **Texas RE-ERCOT:** Strong load growth from new data centers and other large industrial end users is driving higher winter electricity demand forecasts and contributing to continued risk of supply shortfalls. For the upcoming winter season, Texas RE-ERCOT is expected to continue facing reserve shortage risks during the peak load hour and high-

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[1] See detailed reports on the January 2024 and January 2025 Arctic Storms, Winter Storm Elliott, and Winter Storm Uri.

net-load hours, particularly under extreme load conditions that accompany freezing temperatures. Elevated forced outage of thermal resources and reduced output from intermittent resources during these conditions exacerbates the risk of supply shortfalls. In winter, peak demands typically occur before sunrise and after sunset coinciding with the unavailability of solar generation making the system dependent on wind generation and dispatchable resources. Data centers are altering the daily load shape due to their round-the-clock operating pattern, lengthening peak demand periods. Additional battery storage and demand-response resources since last winter help mitigate shortfall risks. However, with the continued flattening of the load curve, maintaining sufficient battery state of charge will become increasingly challenging for extended periods of high loads, such as a severe multi-day storm like Winter Storm Uri.

- **WECC-Basin**: There is sufficient capacity in the area for expected peak conditions; however, Balancing Authorities (BA) are likely to require external assistance during extreme winter weather that causes thermal plant outages, adverse wind turbine conditions, and natural gas fuel supply issues for area internal resources. External assistance may not be available during region-wide extreme winter conditions. With an expected winter peak demand of 11.1 GW, under an extreme combination of generator derates and outages, the region could be short 1.6 GW before imports. Forecasted net internal demand has increased 1% since last year, with little change in winter capacity. Note that the WECC-Basin assessment area includes Utah, southern Idaho, and a portion of western Wyoming. In prior WRA reports, this part of the BPS was included as part of the WECC-NW assessment area. The *2025–2026 WRA* 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.
- **WECC-NW**: Like WECC-Basin, there is sufficient capacity in the area for expected peak conditions; however, BAs are likely to require external assistance during extreme winter weather that causes thermal plant outages and adverse wind turbine conditions for area internal resources. External assistance may not be available during region-wide extreme winter conditions. Winter peak demand for the area is forecast to be 2.9 GW higher (9.3%) compared to last year. Over 3 GW of new resources have been in development for the assessment area this year, primarily battery storage, solar PV, and wind resources. Delays that threaten timely completion of these resource additions will make the area more reliant on imports to meet peak demand.

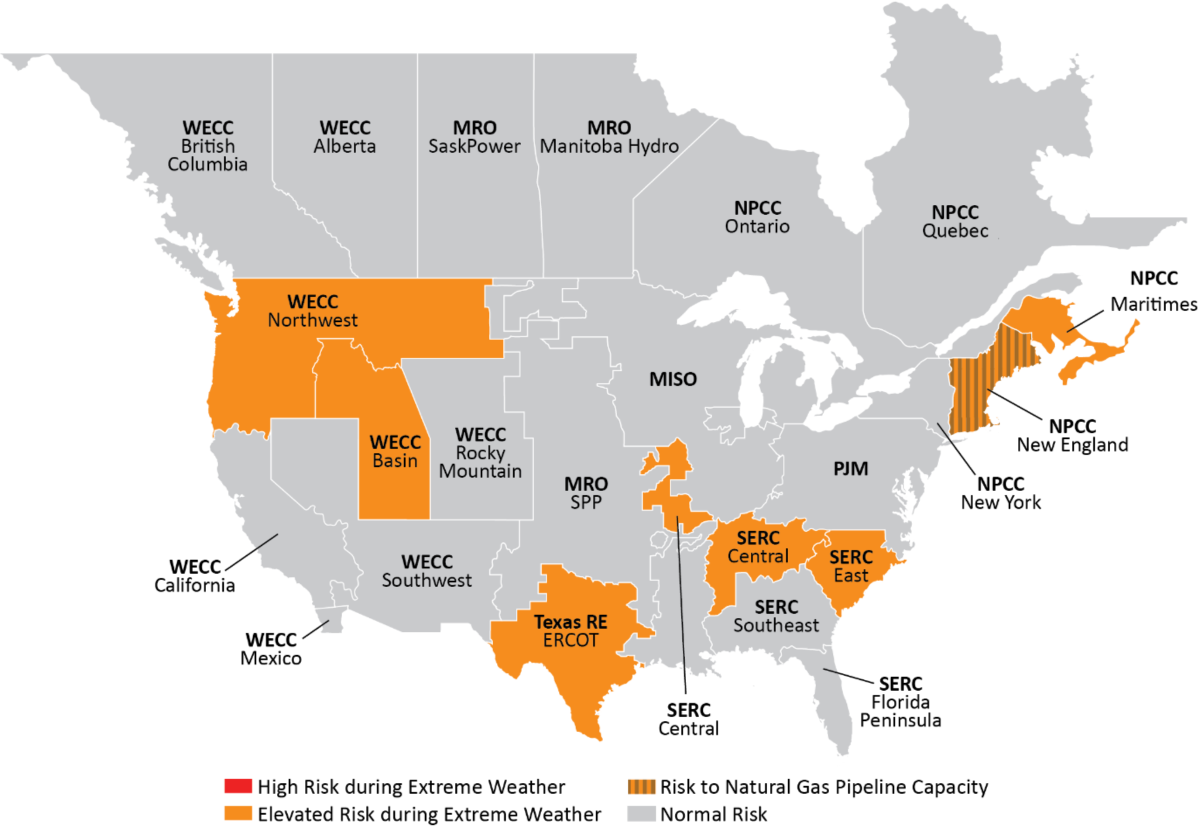

Figure 1: Winter Reliability Risk Area Summary

2. **The performance of natural gas production and supply infrastructure during peak winter conditions will again have a significant effect on BPS reliability.** Natural gas is an essential fuel for electricity generation in winter. Winter fuel supplies for thermal generators must be readily available during the periods of high electricity and natural gas demand that accompany extreme cold weather. Yet these periods are the most challenging for natural-gas-fired Generator Operators to obtain sufficient fuel and delivery. Natural gas production often falls off in extreme winter temperatures as supply infrastructure is affected by freezing issues, and Generator Operators that fail to secure firm fuel delivery are frequently unable to access fully subscribed pipelines. Evidence from the past two winters indicates notable improvement in the delivery of natural gas to BPS generators since winter storms Elliott and Uri with overall less natural gas production decline during cold weather and fewer natural gas infrastructure

force majeures.[2] Still, natural gas infrastructure freeze protection mitigations are voluntary for the natural gas industry in most of North America, resulting in uneven application of protections and continued supply risks during extreme conditions. Furthermore, timing misalignments between the natural gas and electric markets continue to challenge generator fuel procurement in advance of severe winter conditions that occur over winter holiday weekends. As winter approaches, NERC encourages all entities across the gas-electric value chain—from production to the burner tip—to take all necessary preparations for extreme cold and keep natural gas flowing and the lights on.

3. **Cold weather Reliability Standards first introduced in 2023 have been improved prior to the upcoming winter and address recommendations from winter storms Elliott and Uri.** In September 2025, the Federal Energy Regulatory Commission (FERC) approved EOP-012-3 with an effective date of October 1, 2025, concluding the development of Reliability Standards for generator cold weather preparedness.[3] The EOP-012 Reliability Standard contains requirements for generator freeze protection measures, cold weather preparedness plans, and operator training. Among the improvements in the new version are enhanced and expanded requirements to ensure that Generator Owners (GO) are implementing corrective actions to address known issues affecting their ability to operate in cold weather in a timely manner. NERC collects data on the winterization of generating units, which, in conjunction with NERC's monitoring of BPS performance and analysis of cold weather events, helps determine the effectiveness of Reliability Standards. NERC submitted to FERC its first annual *Cold Weather Data and Analysis* informational filing in October 2025.[4] Based on the data reported this year, 96% of the total net winter capacity reported extreme cold weather temperatures (ECWT) at or below 32 degrees Fahrenheit, triggering winter preparedness measures under the Cold Weather Preparedness Standard, and 99% of total net winter capacity in the continental US reporting the ability to operate at the calculated ECWT. As the first such report, this *Cold Weather Data and Analysis* filing provides a benchmark for future analysis.

Recommendations

To reduce the risks of energy shortfalls on the BPS this winter, NERC recommends the following:

- Reliability Coordinators (RC), BAs, and Transmission Operators (TOP) in the elevated risk areas identified in the key findings should review seasonal operating plans and the protocols for communicating and resolving potential supply shortfalls in anticipation of potentially high generator outages and extreme demand levels. Operators should review NERC's Resources on Cold Weather Preparations.
- GOs should complete winter readiness plans and checklists prior to December, deploy weatherization packages well in advance of approaching winter storms, and frequently check and maintain cold weather mitigations while conditions persist.
- BAs should be cognizant of the potential for short-term load forecasts to underestimate load in extreme cold weather events and be prepared to take early action to implement protocols and procedures for managing potential reserve deficiencies. Proactive issuance of winter advisories and other steps directed at generator availability contributed to improved reliability during cold weather events of the past two winters.
- RCs and BAs should implement generator fuel surveys to monitor the adequacy of fuel supplies. They should prepare their operating plans to manage potential supply shortfalls and take proactive steps for generator readiness, fuel availability, load curtailment, and sustained operations in extreme conditions.
- Generator Owners/Operators of natural-gas-fired units should maintain awareness of potential extreme cold weather developing over holiday weekends and the implications for fuel planning and procurement that may result given the natural gas purchase close dates that precede long holiday weekends.
- State and provincial regulators can assist grid owners and operators in advance of and during extreme cold weather by maintaining awareness of BA, natural gas pipeline, and gas local distribution company (LDC) operational public announcements and notices, amplifying public appeals for electricity and natural gas conservation, and supporting requested environmental and transportation waivers.

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[2] See *January 2025 Arctic Events | A System Performance Review*, April 2025

[3] See NERC's Statement on FERC September Open Meeting for summary and link to FERC's order.

[4] See 2025 Cold Weather Data Collection and Analysis Informational Filing

Risk Highlights

Escalating Winter Demand

Winter electricity demand is rising at the fastest rate in recent years, particularly in areas where data center development is occurring. After several years of low (~1%) growth, total internal demand for the BPS is forecast to increase by 20.2 GW (2.5%) over last winter's forecast. The changes in forecasted net internal demand for each assessment area are shown in **Figure 2** below.[5] Assessment areas develop these forecasts based on historical load and weather information as well as future projections. Most assessment areas are projecting an increase in peak demand. SaskPower, PJM, the U.S. Southeast, and parts of the U.S. West have the largest increase in peak demand forecasts.

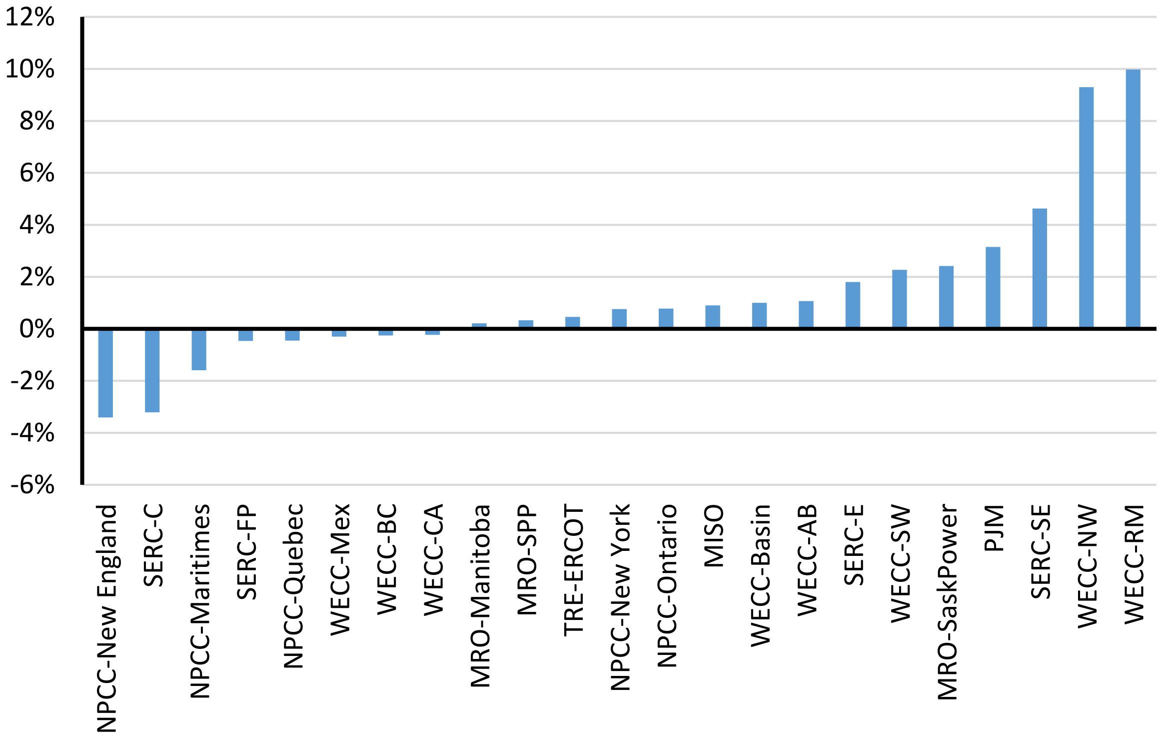

Figure 2: Change in Net Internal Demand—Winter 2025–2026 Forecast Compared to Winter 2024–2025 Forecast

Resource Trends

BPS resources are growing, but at a slower rate than demand is rising. Battery and solar facilities were the leading resource types added to the BPS since last winter. Solar resources, however, often do not supply output during hours of peak winter demand. Growth in demand response is also contributing to BPS resources for the upcoming winter. **Table 1** shows the total change in BPS resources since last winter. For battery, solar, and wind resources, the table includes change in both nameplate (installed) capacity as well as the change in on-peak demand capacity, which is the capacity that resources are expected to provide in their area during the time of peak demand. For assessment-area specific information see **Variable Energy Resource Contributions** section.

Table 1: BPS Resource Change from Winter 2024–2025 to Winter 2025–2026

Resource	Net Change Nameplate Capacity (MW)	Net Change Peak Demand Capacity (MW)
Total Generator Capacity		1,335
Battery	19,659	11,121
Solar	11,097	1,176
Wind	-562	-14,238
Thermal and Hydro		3,276
Demand Response		8,112
Total Resources		9,447

Total BPS resources for serving winter peak demand, including generating capacity and demand response, have increased since last winter by 9,447 MW. Sizeable additions in battery resources and some new natural gas-fired generators contribute to the increase in resource capacity. However, the increase is offset by lower on-peak capacity values for wind resources, which are the result of revised valuations of wind resource capability at peak demand hours in some areas.[6] As a result, BPS generator capacity for winter peak demand makes up only a small portion of the total BPS increase. Generation accounts for 1,335 MW of the total 9,445 MW increase, while the larger share comes from demand response programs. Area specific information on demand response is provided in the **Demand and Resource Tables**.

The recent trend in resource additions is contributing to higher risk of electricity supply shortfalls in winter. BA operators are likely to face higher winter demand without a comparable increase in supply resources. Furthermore, the types of resources that are growing the most-- battery resources and

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[5] See **Data Concepts and Assumptions** section for demand definitions.

[6] Since last winter, ERCOT and MISO have implemented new methods for determining capacity contributions that result in lower wind and solar resources contributions at peak demand. See ERCOT's Resource Adequacy page and MISO's *Planning Year 2025-2026 Wind and Solar Capacity Credit Report*.

demand response—have unique characteristics that operators will need to account for and could limit the use of these resources in extreme winter conditions. Battery energy is reliable when it can be dispatched and has sufficient charge for the period it is needed, yet little time to recharge can be expected during extreme winter weather. System operators will need good visibility on battery state of charge and should anticipate that some extreme winter events will cause these resources to become depleted when needed. Demand response is limited by contract terms, which typically specify how often and for how long the resource may be used. Other resource types are also challenged in winter (see **Thermal Generator Fuel Adequacy and Security**). As BAs grapple with higher demand in most parts of the BPS, they will do so with resources that are becoming increasingly complex to dispatch especially in winter.

Thermal Generator Fuel Adequacy and Security

The performance of the thermal generator fleet remains critical to winter BPS operations. Winter fuel supplies for thermal generators must be readily available during periods of high demand and extreme cold weather. Generally, fuel adequacy for the thermal generating fleet is bolstered through strategic infrastructure investments and fuel stockpiling that increases the certainty of having fuel on hand that can be converted to electricity when needed. Because of this, winter performance of thermal generators is inextricably linked to extraction, processing, storage, and delivery infrastructure for a variety of fuels. Fuel supply risks have been noted in recent years' WRAs related to coal and natural gas availability and illustrate the interconnected nature of these critical energy infrastructure systems.

BPS stakeholders across North America note multiple fuel-related issues that are being monitored entering the winter season. For example, while coal represents a waning share of the overall resource mix, it continues to play an important role in meeting demand during extreme winter weather events, and oil inventories at dual-fuel gas-oil generators lessen risks related to natural gas deliverability in infrastructure-constrained regions, especially during the winter. Notably, it is infeasible or prohibitively costly to stockpile natural gas locally at power plants, and this exposes the BPS to the risk profile of the constituent systems that comprise the supply and delivery of this just-in-time fuel.

Natural Gas Generator Fuel Supplies

Natural gas generators remain a crucial part of on-peak resources meant to meet winter electricity demand across much of North America. While many Generator Owners and Operators secure backup fuel supplies at critical gas-fired generators, particularly in the northeastern United States and Florida, large contributions to the on-peak winter resource mix by single-fuel natural-gas-fired generators remain across North America (see **Figure 3**).

Natural gas generator performance can be threatened when natural gas supplies are insufficient or when natural gas infrastructure is unable to maintain the flow of fuel to critical generators. Grid operators continue to acknowledge and enhance their winter planning processes to firm up their fuel supplies and guard against natural gas disruptions, but winter storms Uri and Elliott demonstrated that combinations of natural gas flow restrictions and supply insufficiency can occur regardless of whether cold temperatures are common or uncommon in the region and can affect more than one BA area concurrently.

Many BPS areas that regularly experience cold weather events, like New England, have adopted mitigating technologies to lessen the impact of natural gas shortages through generator dual-fuel capability and stored backup fuel. In those areas, prolonged cold weather events present a risk of rapid depletion of stored backup fuel. Robust regional and distributed storage investments and winter planning for timely fuel replenishment are critical to minimizing potential energy shortfalls in the operational time frame in these areas.

Natural gas and electricity infrastructures have the added complexity of interdependence. Electricity is used to power some facilities, such as compressor stations and processing plants that make up natural gas infrastructure. These interdependencies mean that reliability events that originate on one system have the potential to affect the other and worsen the overall event magnitude or duration.

Natural gas infrastructure freeze protection mitigations are voluntary for the natural gas industry in most of North America. Texas is an exception, where the Railroad Commission of Texas adopted rules to require critical natural gas facilities to implement weather-related emergency preparation measures.[7] Lack of consistent standards for natural gas infrastructure protections will result in uneven application of freeze protections and continued supply risks during extreme conditions in many areas.

These considerations have driven higher levels of coordination to ensure sustained reliable operation of the natural gas and electricity systems. While a FERC and ERO staff review of system performance during the January 2025 arctic events[8] details improvements in electric and natural gas coordination since winter storms Uri and Elliott, the review also identifies continuing gaps between the electricity and natural gas industries that remain entering the 2025–2026 Winter season. These include natural gas scheduling challenges during winter holiday weekends, market time frame and process incompatibility, and electric power entities' lack of visibility into operational impact data from natural gas producers and suppliers.

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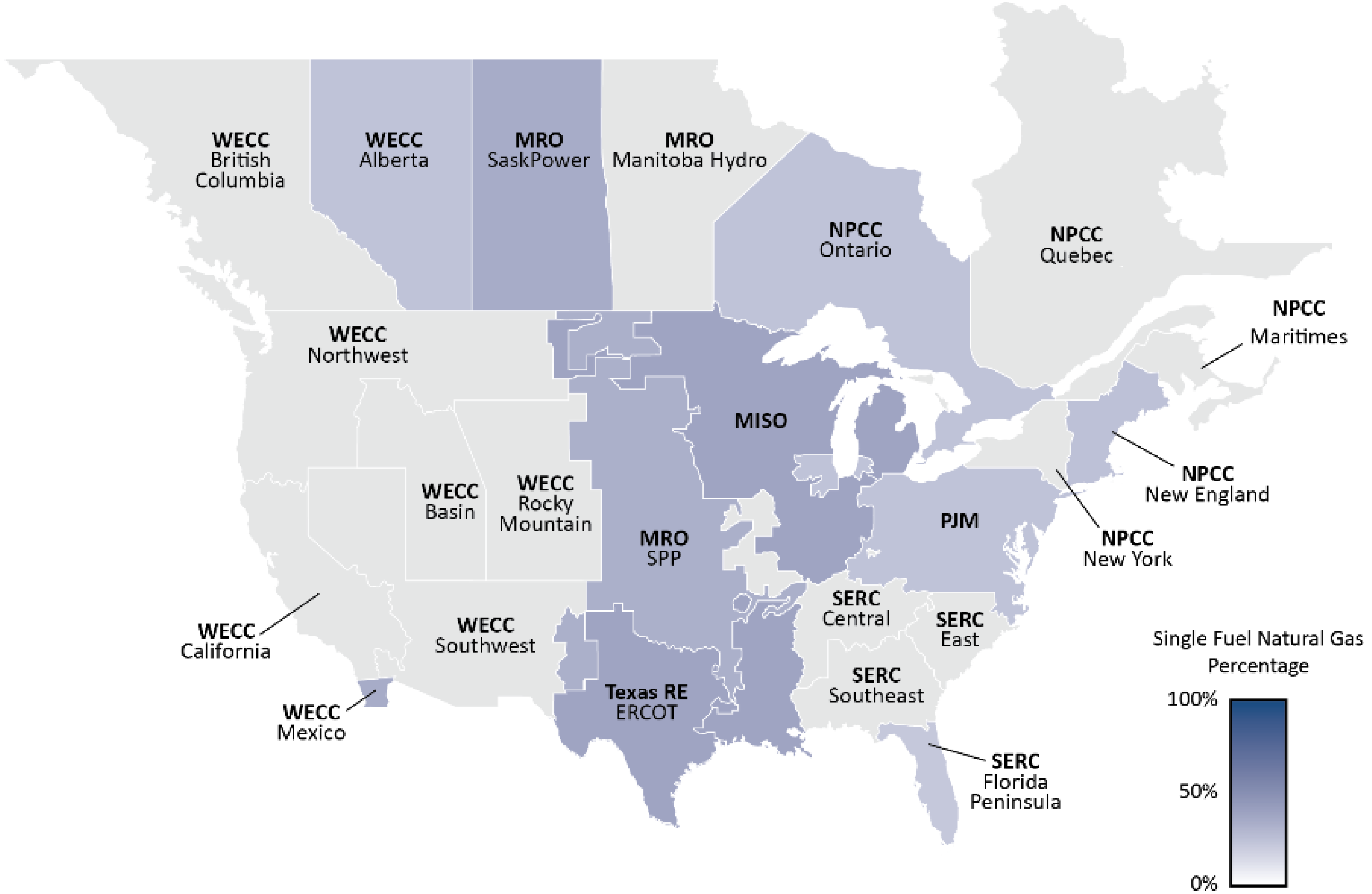
[7] See Railroad Commission of Texas weatherization rule.

[8] FERC, NERC Issue Report on System Performance During the January 2025 Arctic Weather | Federal Energy Regulatory Commission

The U.S. Energy Information Administration (EIA)[9] anticipates a slightly milder winter than last year across much of the United States, especially in the Northeast, leading to a projection that households will consume approximately 2% less natural gas than last winter. Working natural gas storage inventories are about 5% above the previous five-year average in the United States heading into the winter season. The EIA attributes this relative surplus in part to robust production this summer and lower-than-expected natural gas consumption by power generators.



Note: Areas with less than 20% natural gas are shown in light gray.

Single-Fuel Natural-Gas-Fired Generation

	Winter Capacity (GW)	Contribution to Total Winter Resource Mix
MISO	63.9	38%
TRE-ERCOT	53.0	38%
WECC-MX	2.2	34%
MRO-SaskPower	2.5	34%
SPP	33.4	32%
NPCC-New England	12.1	24%
PJM	60.9	23%
WECC-AB	13.9	23%
NPCC-Ontario	8.0	23%
SERC-FP	45.6	21%
WECC-CA	35.9	18%
WECC-SW	21.5	17%
WECC-Basin	4.9	16%
WECC-RM	6.2	14%
SERC-C	17.0	13%
SERC-SE	21.5	13%
WECC-NW	8.7	12%
SERC-E	11.3	9%
NPCC-New York	5.0	8%
NPCC-Maritimes	0.5	7%
MRO-Manitoba	0.3	4%
WECC-BC	0.1	1%
NPCC-Quebec	0.0	0%

Figure 3: Single-Fuel Natural-Gas-Fired Generation Capacity Contribution to the 2025–2026 Winter Generation Mix

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[9] See the U.S. Energy Information Administration's Winter Fuels Outlook 2025–26

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 2.

Table 2: 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 (RML); or • Probabilistic indices exceed benchmarks, e.g., loss of load hours (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 (ARM), which provide the Planning Reserve Margins for normal peak conditions, as well as reserve margins with typical forced outage levels and for the most extreme seasonal risk scenarios are provided in Table 3.

Table 3: Seasonal Risk Scenario On-Peak Reserve Margins

Assessment Area	Anticipated Reserve Margin	Reserve Margin with Typical Outages	Reserve Margin with Higher Demand, Outages, Derates in Extreme Conditions
MISO	49.5%	22.3%	3.7%
MRO-Manitoba	13.7%	11.4%	6.1%
MRO-SaskPower	35.1%	29.0%	16.1%
MRO-SPP	56.5%	29.4%	16.9%
NPCC-Maritimes	16.9%	12.5%	-4.7%
NPCC-New England	58.9%	45.4%	8.7%
NPCC-New York	78.2%	52.4%	16.2%
NPCC-Ontario	28.6%	21.8%	13.2%
NPCC-Québec	15.2%	15.1%	5.0%
PJM	35.6%	24.8%	15.6%
SERC-C	30.5%	22.4%	-0.9%
SERC-E	21.9%	17.5%	3.0%
SERC-FP	41.7%	28.3%	25.6%
SERC-SE	39.7%	24.7%	17.7%
TRE-ERCOT	36.0%	25.2%	-20.0%
WECC-AB	35.2%	32.4%	10.0%
WECC-Basin	29.6%	19.7%	-21.1%
WECC-BC	25.9%	25.8%	15.4%
WECC-CA	82.3%	73.7%	57.9%
WECC-Mex	83.1%	79.4%	52.9%
WECC-NW	30.9%	29.5%	-8.5%
WECC-RM	61.7%	53.2%	10.0%
WECC-SW	104.4%	90.1%	50.1%

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 winter 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 3**, each assessment area's ARMs 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.

Areas highlighted in orange in **Figure 1** above have been identified as having resource adequacy or energy risks for the winter and are included in the **Key Findings** section's discussion that follows. 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 ARM, 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 winter season. Results are summarized in **Table 5**. 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 loss of load expectation (LOLE), loss of load hours (LOLH), expected unserved energy (EUE), and the probabilities of energy emergency alert (EEA) declarations (see **Table 4** for a description of EEA levels).

Table 4: 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 operating 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 operating reserve requirements.
EEA 3	Firm load interruption is imminent or in progress	• The energy-deficient BA is unable to meet minimum operating reserve requirements.

Energy Emergency Alerts

The combination of above-normal generation outages, low resource output, and peak loads as occurred during the extreme cold weather events of Winter Storm Uri in 2021 and Winter Storm Elliott in 2022 are ongoing winter reliability risks. When supply resources in an area fall below expected demand and operating reserve requirements, BAs may need to employ EEAs to maintain balance between available capacity and energy and real-time demand. A description of each EEA level is provided above.

Table 5: Probability-Based Risk Assessment		
Area	**Type of Assessment**	**Results and Insight from Assessment**
MISO	Deterministic	MISO does not provide a probabilistic assessment for the WRA. MISO applies a deterministic look at expected system conditions, looking at generation availability under typical and extreme outages and looking at a typical 50/50 load forecast and an extreme 90/10 load forecast. For the upcoming winter season, under an extreme outage and extreme 90/10 load forecast, this is the riskiest scenario for the MISO footprint. This scenario produces the shortest actual reserve margin for January.
MRO-Manitoba	Probabilistic study for the NERC Probabilistic Assessment (ProbA)	Probabilistic analysis for the 2024 ProbA summarized in NERC's 2024 *Long-Term Reliability Assessment* (LTRA) found no load-loss or unserved energy hours for 2026.
MRO-SaskPower	Probability-based capacity adequacy assessment	SaskPower's probabilistic assessment for the 2025–2026 Winter indicates that risk of shortfalls is lower than the previous winter. LOLH for an elevated risk scenario for the 2025–2026 Winter season is 0.08 hours. The month with the highest LOLH is December (0.05 hours).
MRO-SPP	NERC 2024 ProbA	Probabilistic analysis for the 2024 ProbA summarized in NERC's 2024 LTRA found no load-loss or unserved energy hours for 2026.
NPCC	NPCC conducted an all-hour probabilistic reliability assessment that included detailed neighbor modeling and consisted of a base case and severe case examining low resources, reduced imports, and higher loads. The assessment evaluates the probabilistic indices of LOLE, LOLH, and EUE. The highest peak load scenario has an approximately 7% probability of occurring.	
NPCC-Maritimes	The Maritimes Area low-likelihood resource case assumed: wind derated by 50% for every hour in December through February and a 50% natural gas capacity curtailment for December through February (dual-fuel units assumed reverting to oil) and reduced transfer capabilities.	The preliminary assessment indicates that established operating procedures are not sufficient to maintain a balance between electricity supply and demand. Under highest peak load levels, the Maritimes Area shows a notable likelihood of utilizing its operating procedures such as reducing 30-minute reserves, initiating interruptible loads, and reducing 10-minute reserves to maintain system reliability during the upcoming winter period.
NPCC-New England	The New England Area low-likelihood resource case assumed: 500 MW of additional maintenance outages, ~4,513 MW of gas-fired generation unavailable due to fuel supply constraints, and 50% reduced import capabilities of external ties.	The preliminary results of this assessment indicate that operating procedures were not needed to maintain a balance between electricity supply and demand
NPCC-New York	The New York Area low-likelihood resource case assumed: ~500 MW of extended maintenance in southeastern New York, 600 MW of cable transmission reduction across HVdc facilities, and ~5,000 MW of generation unavailable due to fuel delivery issues.	The preliminary results of this assessment indicate that operating procedures were not needed to maintain a balance between electricity supply and demand. No cumulative LOLE, LOLH or EUE risks were indicated over the December–February winter period, for all the scenarios modeled.
NPCC-Ontario	An energy assessment for the Ontario Assessment Area was conducted for two scenarios: firm resources and firm demand with expected weather, and planned resources with planned demand with expected weather.	No cumulative LOLH or EUE risks were identified over the entire November-to-April winter season for both scenarios modeled.

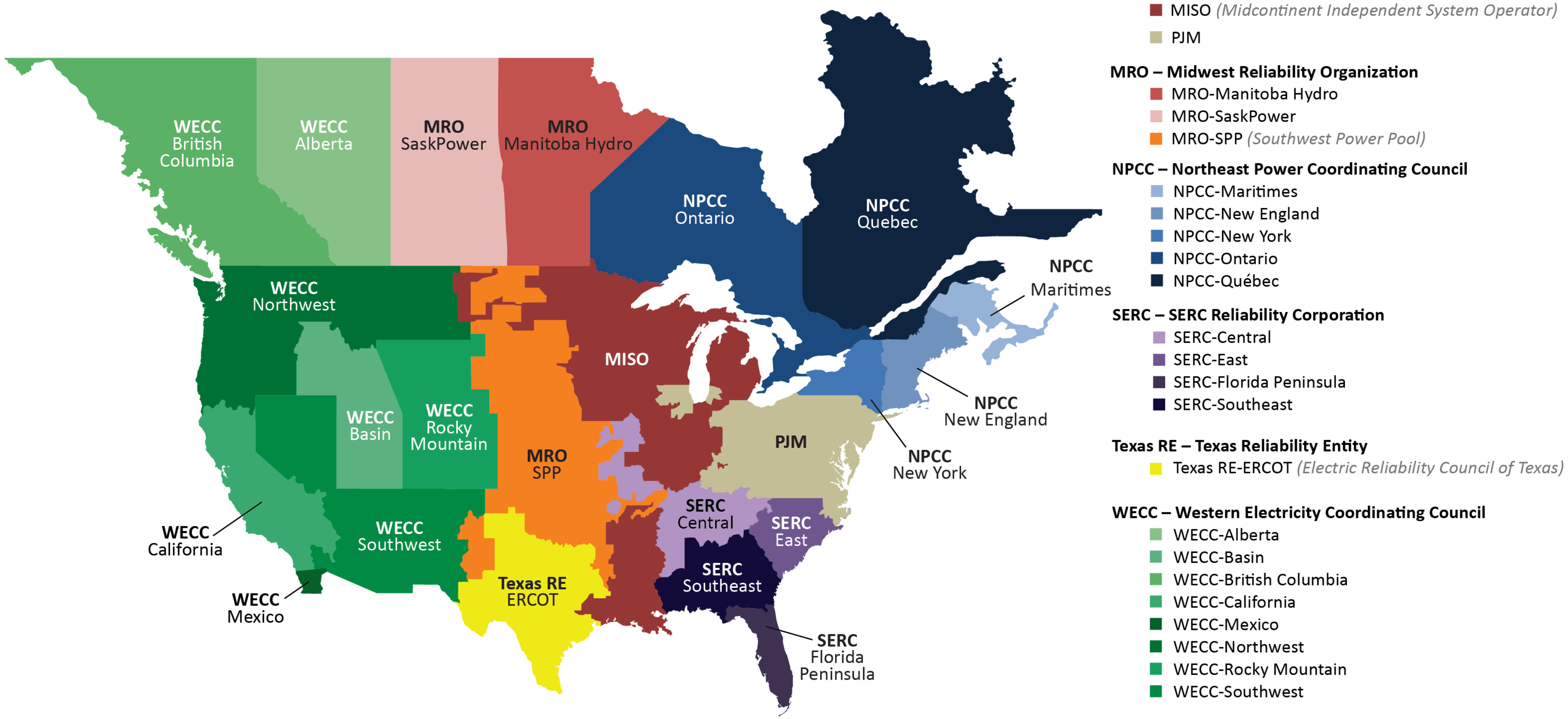
Table 5: Probability-Based Risk Assessment

Area	Type of Assessment	Results and Insight from Assessment
NPCC-Québec	The Québec Area low-likelihood resource case assumed 1,000 MW of generation reductions.	The preliminary results of this assessment indicate that established operating procedures are sufficient to maintain a balance between electricity supply and demand if needed. No cumulative LOLE, LOLH or EUE risks were indicated over the December–February winter period for all the scenarios modeled
PJM	Probabilistic study for the NERC Probabilistic Assessment (ProbA)	Probabilistic study for 2025–2026 Winter is not provided for the WRA. PJM performed probabilistic analysis for 2026-2027 winter as part of the 2024 ProbA summarized in NERC's 2024 LTRA. The results of this study indicate risk of load loss (<0.1 hours) and unserved energy during winter months. For the upcoming winter, load-loss hours are expected to be less than this value because forecasted load is lower and anticipated resource capacity is higher than the case studied for the 2024 ProbA.
SERC	Based on the 2024 NERC Probabilistic Assessment (ProbA) base-case result. SERC's assessment used 38 years of historical load shapes to assess the resource adequacy of years 2026 and 2028, primarily based on data from the 2024 Long Term Reliability Assessment (LTRA).	
SERC-Central		Probabilistic analysis for the 2024 ProbA summarized in NERC's 2024 LTRA found no load-loss or unserved energy hours for 2026.
SERC-East		Probabilistic analysis for the 2024 ProbA summarized in NERC's 2024 LTRA found a small number of load-loss hours (<0.1) and EUE (61 MWh / 1 ppm) for 2026.
SERC-Florida Peninsula		Probabilistic analysis for the 2024 ProbA summarized in NERC's 2024 LTRA found negligible load-loss hours and EUE.
SERC-Southeast		Probabilistic analysis for the 2024 ProbA summarized in NERC's 2024 LTRA found no load-loss or unserved energy hours for 2026.
Texas RE-ERCOT	ERCOT Probabilistic Reserve Risk Model	ERCOT's probabilistic risk assessment indicates a 2% probability of having to declare EEAs during the January forecasted winter peak day (which coincides with the highest reserve shortage risk) and a controlled load shed probability of 1.8%. ERCOT defines low-risk hours as when the probability of an EEA is less than 10%.
WECC	The resource adequacy work performed at WECC used the Multi-Area Variable Resource Integration Convolution (MAVRIC) model for the 2025 LTRA. The MAVRIC model is a convolution-based probabilistic model and is WECC's chosen method for developing probability metrics used for assessing demand and variable resource availability in every hour. In the resource adequacy environment, the reports produced support NERC's seasonal assessments, LTRA, and ProbA.	
WECC-AB		The results of the probabilistic assessment reveal no EUE or LOLH for Winter 2025–2026.
WECC-Basin		The results of the probabilistic assessment reveal no EUE or LOLH for Winter 2025–2026.
WECC-BC		The results of the probabilistic assessment reveal no EUE or LOLH for Winter 2025–2026.

Table 5: Probability-Based Risk Assessment		
Area	**Type of Assessment**	**Results and Insight from Assessment**
WECC-CA		The results of the probabilistic assessment reveal no EUE or LOLH for Winter 2025–2026.
WECC-Mexico		The results of the probabilistic assessment reveal no EUE or LOLH for Winter 2025–2026.
WECC-Rocky Mountain		The results of the probabilistic assessment reveal no EUE or LOLH for Winter 2025–2026.
WECC-NW		The results of the probabilistic assessment reveal no EUE or LOLH for Winter 2025–2026. Results for a case where new resource additions are not completed for the upcoming winter found some EUE and LOLH.
WECC-SW		The results of the probabilistic assessment reveal no EUE or LOLH for Winter 2025–2026.

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 ARM compared to a reference margin level (RML) that is established for each area 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 winter 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 WRA 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 vary by assessment area and provide further insights into the risk conditions forecasted for this upcoming winter period.

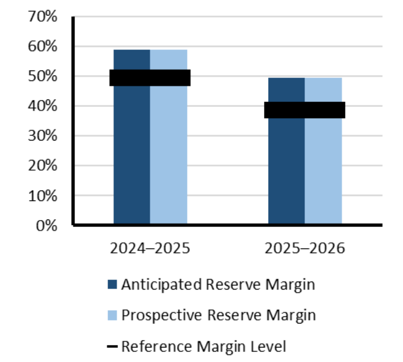


MISO

The Midcontinent Independent System Operator, Inc. (MISO) is an independent, not-for-profit organization responsible for operating the bulk electric power system and administering wholesale electricity markets across 15 U.S. states and the Canadian province of Manitoba. MISO ensures the reliable delivery of electricity to approximately 45 million people by managing regional transmission operations as well as energy and ancillary services markets and advising on long-term resource planning. The MISO footprint includes 39 Local BAs and more than 550 market participants. MISO operates one of the world's largest organized electricity markets, with its members operating a system that consists of over 77,000 miles of transmission lines and approximately 1,888 generating units. The peak electricity demand on the MISO system currently occurs during the summer season. MISO's footprint lies across three regional entities (MRO, RF, and SERC), but MRO is responsible for coordinating data and information submitted for NERC's reliability assessments.

- MISO expects limited risk in the 2025–26 Winter season as MISO was able to procure 6.1% more resources through the annual planning reserve auction than required by its minimum resource adequacy target. A further 3.3 GW of resources were available but not chosen to be committed for the winter season.
- Some risk has been identified for this upcoming winter season. In a high generation outage and high winter load scenario reliability is expected to be maintained by reliance upon operational mitigations that include non-firm energy transfers into the system, energy-only resources not subject to a must-offer requirement that may still offer into the energy markets, load-modifying resources, and internal transfers that exceed the Sub-Regional Import/Export Constraint (SRIC/SREC) between the MISO North/Central and South areas.
- MISO continues to coordinate with neighboring RCs and BAs to improve situational awareness and vet any needs for energy transfers to address extreme system conditions.
- MISO continues to survey and coordinate with its members on winter preparedness and fuel sufficiency.
- MISO has implemented a seasonal resource adequacy construct and seasonal unit accreditation to better affirm adequate supply in all seasons.

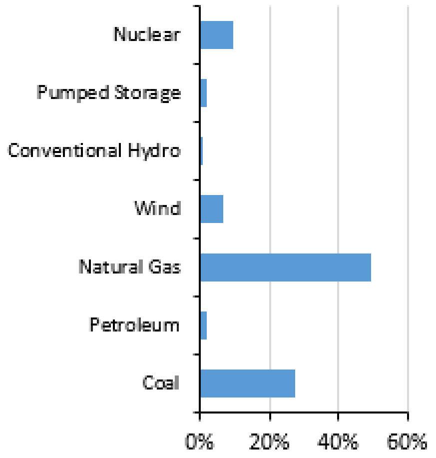
On-Peak Reserve Margin[10]



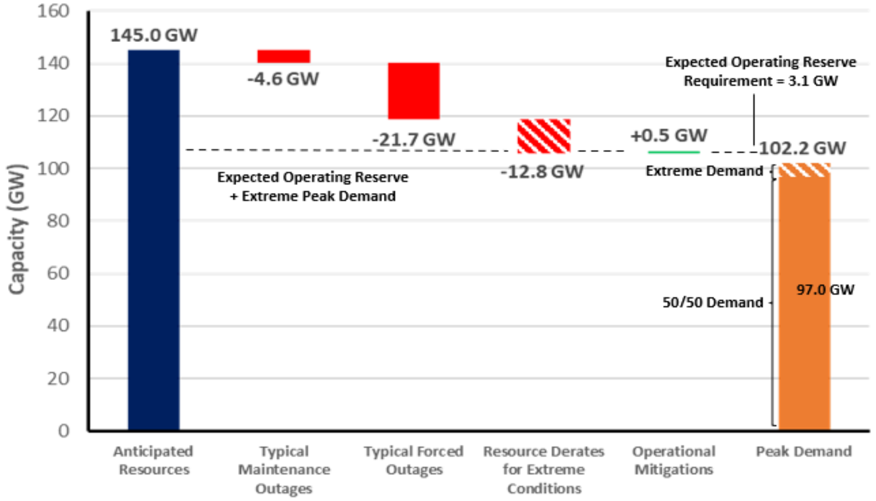
Risk Scenario Summary

Expected resources meet operating reserve requirements under assessed demand scenarios. Above-normal winter peak load combined with generator outages from freezing or fuel supply issues and low wind output result in the need to employ operating mitigations (i.e., demand response and transfers).

On-Peak Resource Mix



2025–2026 Winter 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 net internal demand and additional demand during extreme weather conditions (e.g., Winter Storm Enzo) using member submitted data and historical load data

Typical Maintenance Outages: Rolling three-year winter average of peak-day maintenance and planned outages

Typical Forced Outages: Three-year average of all peak-day outages that were not planned

Resource Derates for Extreme Conditions: Represents derates aligning with the most extreme hour of each of the past 3 years,

Operational Mitigations: Non-firm energy transfers into the system, energy-only resources that do not have a must-offer requirement, or internal transfers that exceed the SRIC/SREC between the MISO North/Central and South regions

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[10] The MISO Risk Scenario Assessment for the 2025-26 Winter Season is not directly comparable to that for the 2024-25 Winter Season as methodology improvements have been implemented.

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 Balancing Authority (BA). Manitoba Hydro is a coordinating member of MISO, which is the RC for Manitoba Hydro.

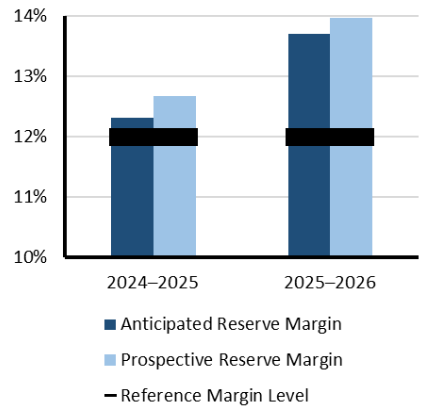
Highlights

- Manitoba Hydro is not anticipating any operational challenges and/or emerging reliability issues in its assessment area for Winter 2025–2026.
- Manitoba Hydro expects to reliably supply its internal demand and export obligations even under continued drought conditions.
- Manitoba Hydro is experiencing well below-average water supply conditions; however, the Manitoba Hydro system is designed and operated such that reliable operations can be maintained under extreme drought.
- The ARM for Winter 2025–26 exceeds the 12% RML.

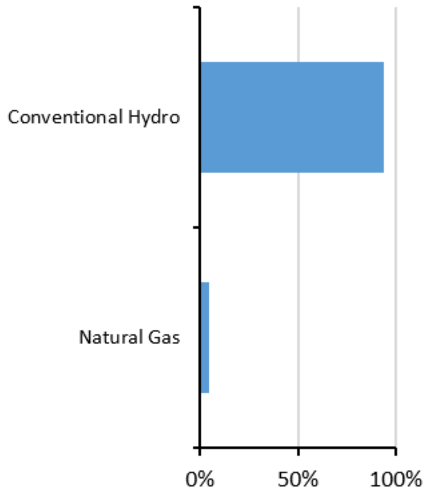
Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed scenarios.

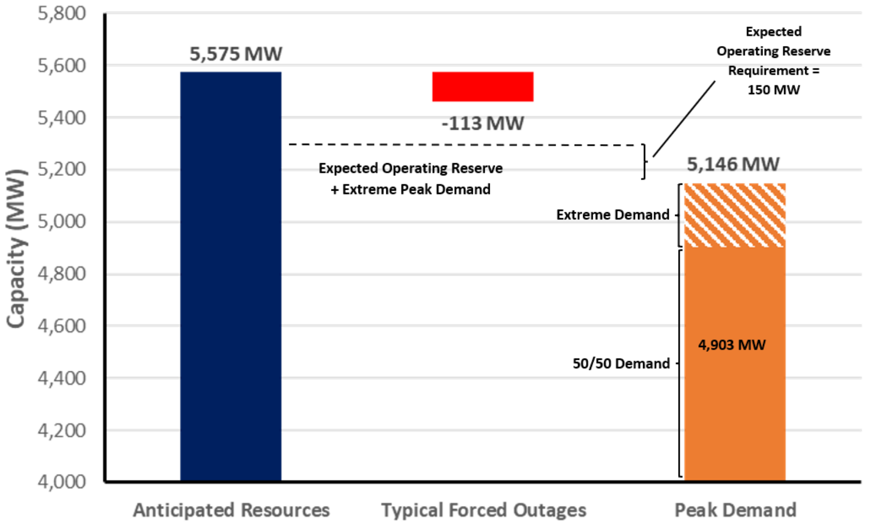
On-Peak Reserve Margin



On-Peak Resource Mix



2025–2026 Winter 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 weather data

Typical Forced Outages: Accounts for average forced outages

MRO-SaskPower

MRO-SaskPower is an assessment area that covers the Canadian province of Saskatchewan. The province has a geographic area of 651,900 square kilometers (251,700 square miles) and a population of just over 1.1 million people. 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 Bulk Electric System (BES) and its interconnections. Overall, SaskPower operates nearly 14,816 circuit-km of transmission lines, 65 high-voltage switching stations, and 191 distribution substations. Peak electricity demand on the SaskPower system currently occurs during the winter season.

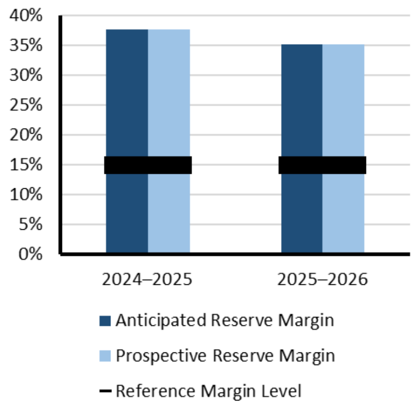
Highlights

- Saskatchewan experiences its peak load during the winter months due to extreme cold weather.
- Based on the planned maintenance, typical forced outages from historical data, and expected renewable generation under the normal and extreme demand conditions, SaskPower does not anticipate any reliability issues during the 2025–2026 Winter.
- During extreme winter conditions, SaskPower would utilize available demand-response programs, short-term power transfers from neighboring utilities, maintenance rescheduling, and/or short-term load interruptions to manage the situation.

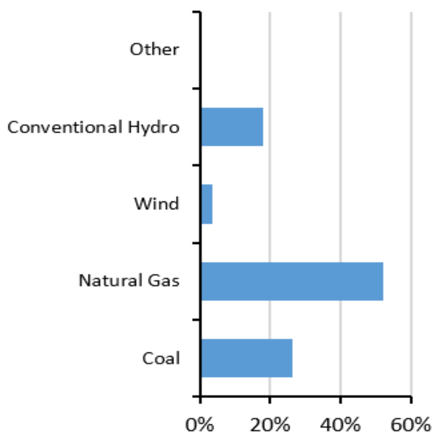
Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed scenarios.

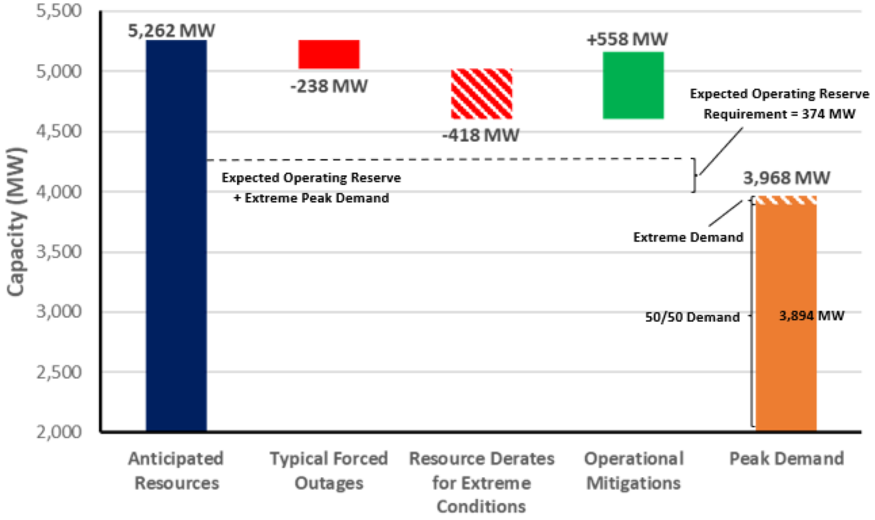
On-Peak Reserve Margin



On-Peak Resource Mix



2025–2026 Winter Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: Based on the historical load variability, SaskPower calculates a probability density function for load to simulate various scenarios that include extreme conditions.

Typical Forced Outages: Estimated using SaskPower forced outage model

Resource Derates for Extreme Conditions: Wind capacity is derated by 96% due to the cut-out of most wind farms below -30°C. Solar generation is expected to be fully unavailable under extreme conditions.

Operational Mitigations: Includes the non-firm import capability (360 MW) and generators in layup status (167 MW) that can be brought online with one to five days' notice; additional demand-side resources are estimated based on other demand response programs and non-firm loads that require 15 minutes to 2 hours of notification

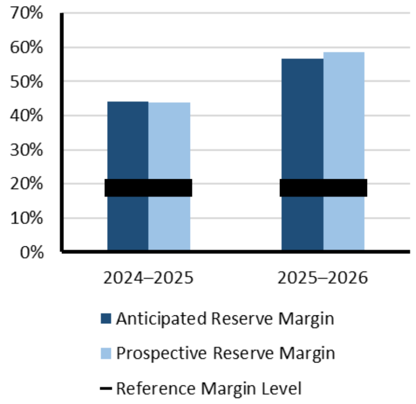
MRO-SPP

SPP’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 anticipates that planning reserves are adequate for the upcoming winter season even as SPP continues to set new winter season load records.
- SPP does not anticipate any emerging reliability issues impacting the area for the 2025–2026 Winter season but realizes that interruptions to fuel supply combined with higher penetration of variable energy resources could create unique operation challenges.
- SPP continues to work at enhancing communications and operator preparedness with neighboring regions to address potential electric deliverability issues associated with extreme weather events.
- To minimize conservative operations, EEAs, and mid-range forecast error uncertainty response in wind forecasts, SPP implemented several new operational mitigation processes and procedures to deal with high-impact real-time areas of reliability concern.
- SPP has proposed numerous resource adequacy initiatives, including addressing EUE standards, fuel assurance, winter planning reserve margins, outage policies, demand response, and accreditation; all were recently approved by FERC.

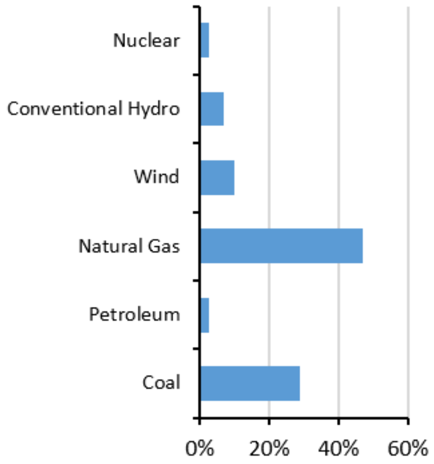
On-Peak Reserve Margin



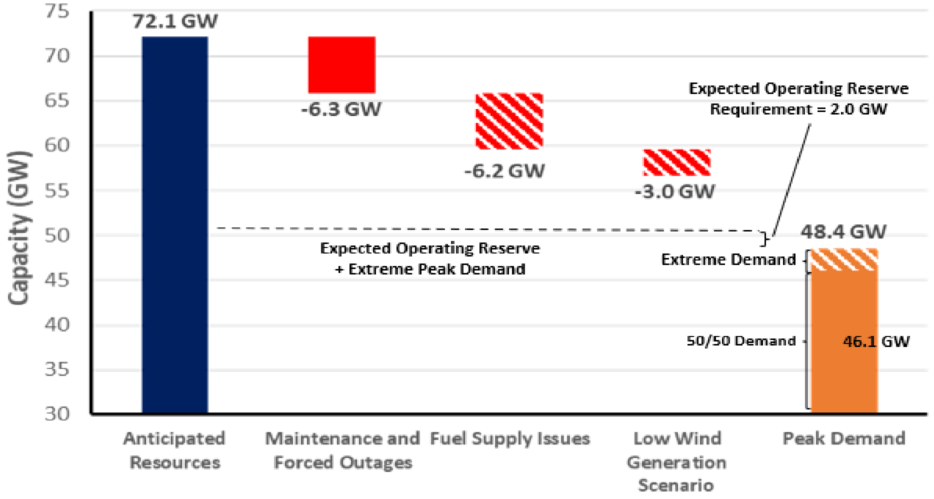
Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed scenarios.

On-Peak Resource Mix



2025–2026 Winter 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 using historical data

Maintenance and Forced Outages: A capacity derate of 6.3 GW for maintenance outages, forced outages, and performance in extreme weather based on historical data

Fuel Supply Issues: BA derate of 6.2 GW based on MW capacity of gas-fired generators experiencing fuel supply issues in winter storm Elliott.

Low Wind Generation Scenario: 3 GW of wind potentially off-line when temperatures fall below their cold weather performance packages

NPCC-Maritimes

NPCC-Maritimes is an assessment area that covers the Canadian Maritime provinces—New Brunswick, Nova Scotia, and Prince Edward Island—and the northernmost portion of the U.S. state of Maine. The area covers approximately 150,000 square kilometers (58,000 square miles) and has a total population of nearly 1.9 million people. The New Brunswick Power Corporation (NB Power) is the balancing authority for New Brunswick, Prince Edward Island, and the northern portion of Maine. Nova Scotia Power Inc. (NSPI) is the balancing authority for Nova Scotia. NB Power's system is electrically interconnected with NPCC-Québec and NPCC-New England, and the electric systems in the provinces of Nova Scotia and Prince Edward Island have ties with New Brunswick but no direct ties with other assessment areas. Peak electricity demand in NPCC-Maritimes occurs during the winter season.

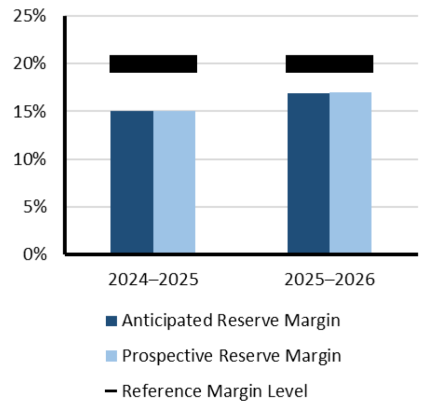
Highlights

- The Maritimes has a diversified mix of capacity resources fueled by oil, coal, hydro, nuclear, natural gas, wind, dual-fuel oil/gas, tie benefits, and biomass with no one type making up more than about 27% of the total capacity in the area.
- The Maritimes has long-term energy contracts in place for its winter supply and can purchase additional energy in the day-ahead and in real time as required.
- As part of the winter planning and preparation process, dual-fueled units will have sufficient supplies of heavy fuel oil stored on site to enable sustained operation in the event of natural gas supply interruptions.

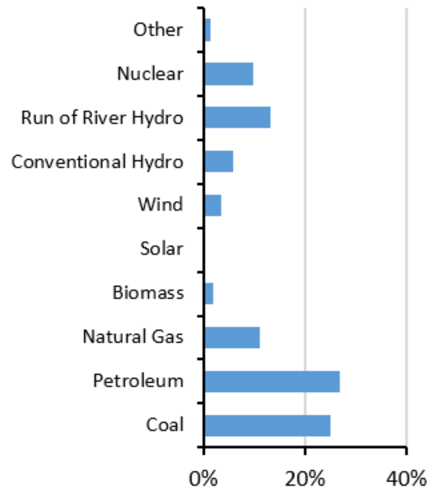
Risk Scenario Summary

Expected resources do not meet operating reserve requirements under normal peak-demand scenarios. Normal winter peak load and outage conditions could result in the need for operating mitigations (i.e., demand response, transfers, appeals) and EEAs. NPCC probabilistic analysis indicates some risk of unserved energy and LOLH under high demand or low resource scenarios.

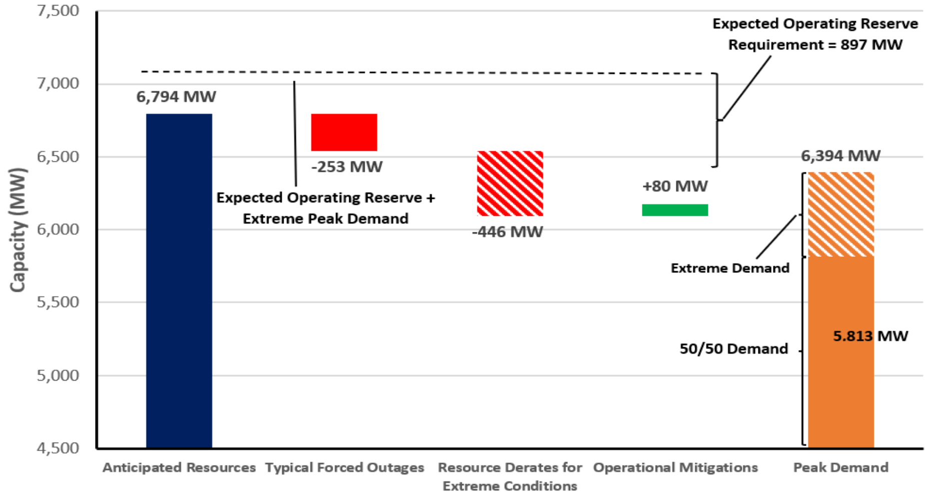
On-Peak Reserve Margin



On-Peak Resource Mix



2025–2026 Winter Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: Scenario peak load with adjustment calculated by adding a 10% margin of error to the peak internal demand forecast taken from the *Long-Term Reliability Assessment* (LTRA) for the 2025–2026 Winter period (aligns with the all-time winter peak, which occurred on February 4, 2024)

Typical Forced Outages: Based on historical operating experience

Resource Derates for Extreme Conditions: Based on ambient temperature thermal derates, wind derated to zero, as well as natural gas capacity derated by 50% due to supply issues

Operational Mitigations: Based on emergency operations and planning procedures in place including fuel switching

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.

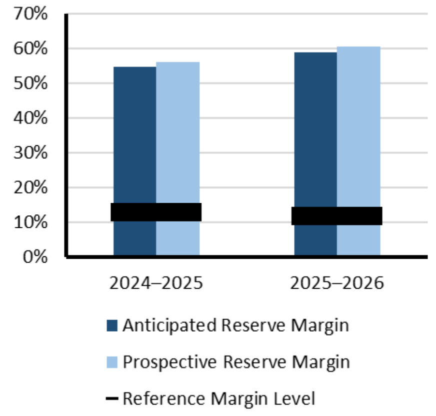
Highlights

- ISO-NE expects to meet its regional resource adequacy requirements this 2025–2026 Winter operating period without calling upon operating procedures to maintain a balance between electricity supply and demand.
- A standing concern is whether there will be sufficient energy available to satisfy electricity demand during an extended cold spell given the existing resource mix, fuel delivery infrastructure, and expected fuel arrangements without considerable effort to replenish stored fuels (i.e., fuel oil and liquefied natural gas (LNG)).
- ISO-NE expects to have sufficient capacity resources to meet the 2025–2026 50/50 and 90/10 winter peak demand forecast of 19,616 MW and 21,125 MW, respectively, for the weeks beginning January 10, January 17, and January 24.
- ISO-NE has recently developed the Regional Energy Shortfall Threshold (REST) as an effort to quantify the tolerable risk of energy shortfall during extreme events. Within the 0.25% highest-risk scenarios, the REST thresholds are 3.0% normalized EUE over 72-hour periods and 18.0 hours over 21-day periods.
    - ISO-NE does not anticipate exceeding the REST criteria for Winter 2025–2026.

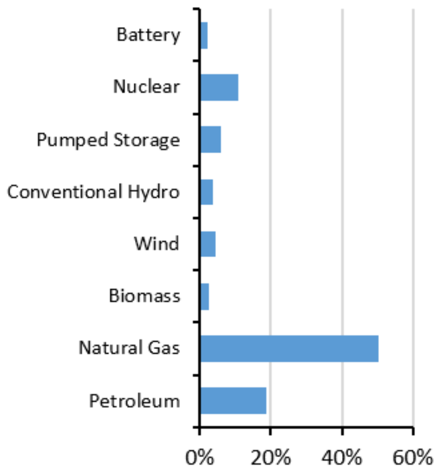
Risk Scenario Summary

Expected resources meet operating reserve requirements under assessed demand scenarios. Above-normal winter peak load combined with high generator outages could result in the need for operating mitigations (i.e., demand response and transfers). Prolonged extreme cold weather events that result in depletion of stored fuels can lead to resource shortfalls.

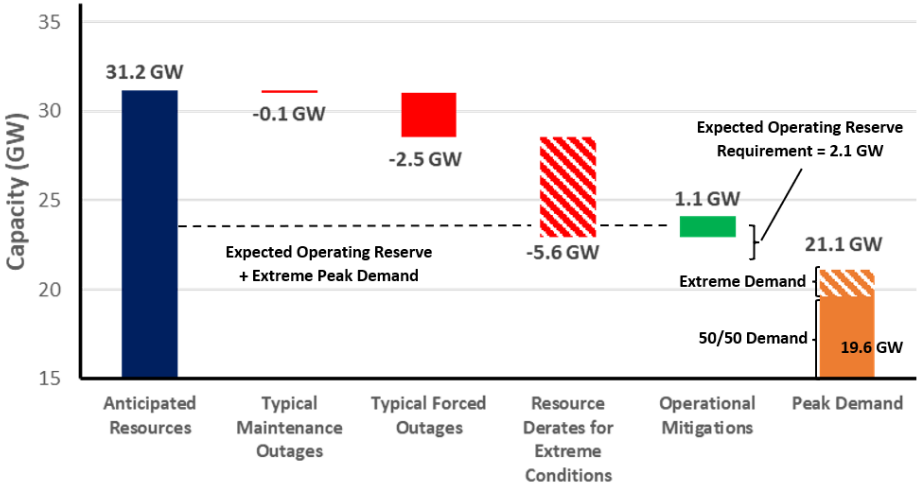
On-Peak Reserve Margin



On-Peak Resource Mix



2025–2026 Winter 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 capturing the region’s coldest day in the last 30 years using current and future load models

Typical Maintenance Outages: Based on historical weekly averages

Typical Forced Outages: Based on seasonal capacity of each resource as determined by ISO-NE

Resource Derates for Extreme Conditions: Represent a case that is beyond the (90/10) conditions based on historical observation of force outages and additional reductions for generation at risk due to natural gas supply and cold weather-related outages

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 WRA, 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 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%.

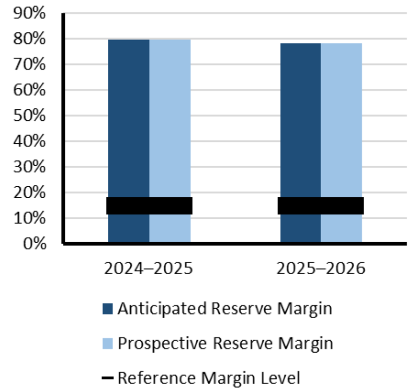
Highlights

- New York is presently a summer-peaking area, and no emerging reliability issues are anticipated during the 2025–26 Winter assessment period.
- Expected resources meet operating reserve requirements under the assessed demand and resource scenarios. A scenario involving an extended cold snap that causes above-normal demand and diminished natural gas supplies would result in low but sufficient reserves.
- The preliminary results of the NPPCC winter probabilistic assessment indicate that operating procedures are not needed to maintain a balance between electricity supply and demand. No cumulative LOLE, LOL,H or EUE risks were indicated over the December–February winter period for all the scenarios modeled.

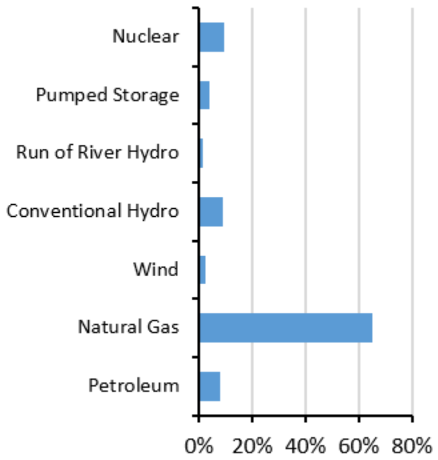
Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed demand and resource scenarios.

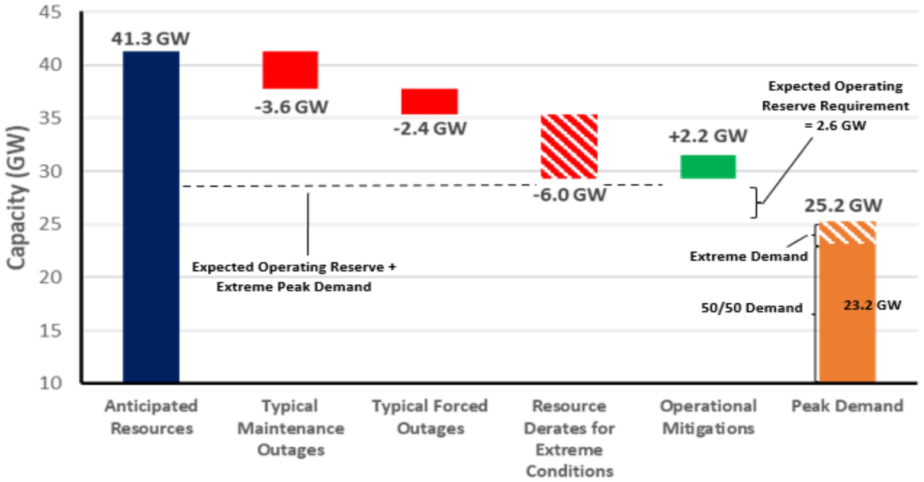
On-Peak Reserve Margin



On-Peak Resource Mix



2025–2026 Winter 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 Maintenance Outages: Based on planned scheduled maintenance

Typical Forced Outages: Based on 5–year averages from GADS data.

Resource Derates for Extreme Conditions: Potential natural gas generation at risk if non-firm supply is unavailable in a period of extended cold weather. Based on a 2025 analysis, approximately 6,307 MW of gas generation with non-firm fuel supplies could be unavailable.

Operational Mitigations: Based on NYISO operating procedures

NPCC-Ontario

NPCC-Ontario is an assessment area that covers the Canadian province of Ontario. The province of Ontario covers more than 1 million square kilometers (415,000 square miles) and has a population of almost 16 million people. The Independent Electricity System Operator (IESO) is the balancing authority for the province of Ontario. NPCC-Ontario is electrically interconnected with NPCC-Québec, MRO-Manitoba, MISO, and NPCC-New York. Peak electricity demand in NPCC-Ontario occurs during the summer season.

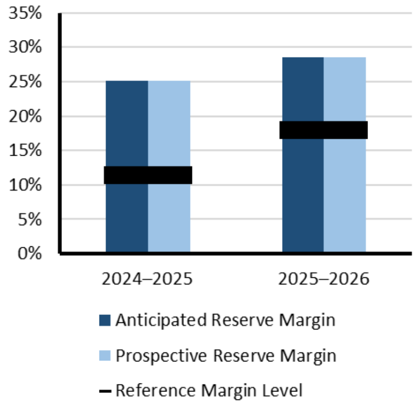
Highlights

- As Ontario is a summer-peaking province, there is typically a lower risk of reliability issues during the winter than the summer. However, Ontario regularly experiences extreme cold weather in the winter.
- NPCC-Ontario is well prepared for Winter 2025–2026, and IESO expects that the electric system will remain reliable with reserve margins well above required levels.
- Operators and forecasters in Ontario work closely with neighboring jurisdictions to manage extreme weather events.
- Natural-gas-fired generators in Ontario are supplied by pipelines with access to the Enbridge Gas Dawn Hub and its associated storage facilities, which significantly reduces natural gas deliverability and reliability concerns by connecting those systems to several major gas transportation corridors, enabling access to multiple supply basins.

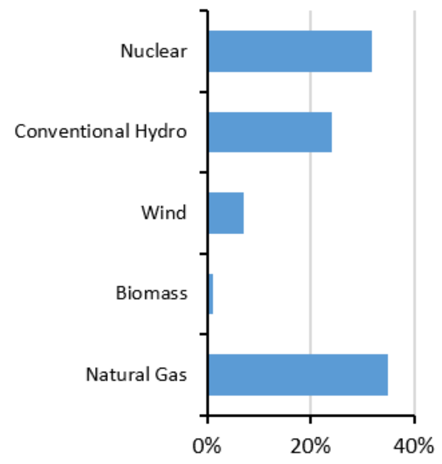
Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed scenarios.

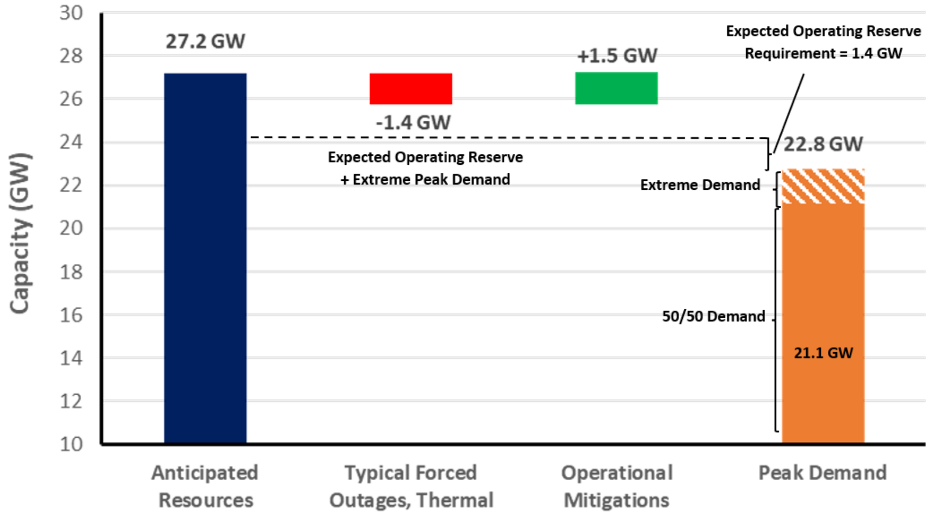
On-Peak Reserve Margin



On-Peak Resource Mix



2025–2026 Winter 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 from 31 years of winter demand history

Typical Forced Outages, Thermal: Based on analysis of a rolling five-year history of actual forced outage data.

Operational Mitigations: Imports anticipated from **neighbors** during emergencies

NPCC-Québec

NPCC-Québec is an assessment area that covers the Canadian province of Québec. The province of Québec covers over 1.5 million square kilometers (nearly 600,000 square miles) and has a population of 9 million people. Hydro-Québec is the BA for the province of Québec. The Québec BPS is one of the four electric Interconnections in North America. It is a predominately hydroelectric-generation-based system that is electrically interconnected with NPCC-Ontario, NPCC-New York, NPCC-New England, and NPCC-Maritimes. Peak electricity demand in NPCC-Québec occurs during the winter season.

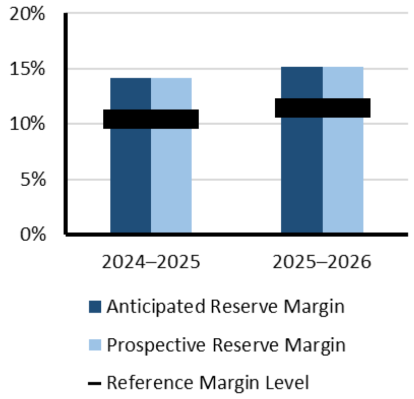
Highlights

- NPCC-Québec projects adequate capacity margins above its reference reserve requirements and that system resource adequacy will be maintained for the province for the 2025–26 Winter assessment period.
- No hydropower performance issues are expected during extreme cold because of design criteria for cold weather.
- No fuel supply or transportation issues are anticipated for the upcoming winter season.
- While a slight decrease in net firm transfers has occurred since last winter (-89 MW), significant increases in demand-side management programs (+450 MW year-over-year) have been realized over the same period and are expected to compensate for this winter’s modest expected load growth.

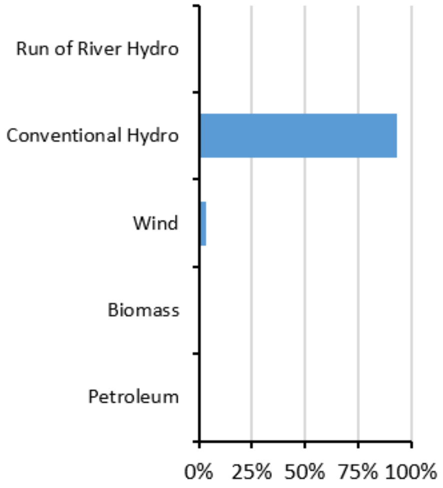
Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed scenarios.

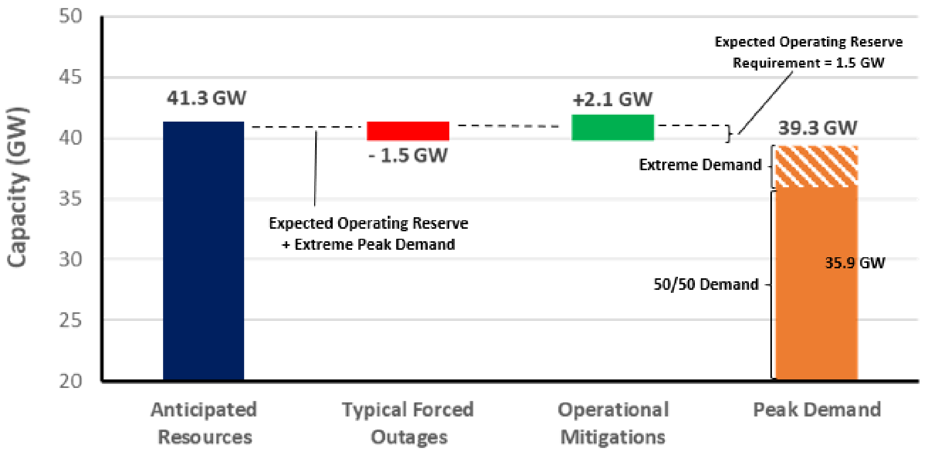
On-Peak Reserve Margin



On-Peak Resource Mix



2025–2026 Winter Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at hour ending 8:00 a.m.

Demand Scenarios: Demand forecasts include demand-side resources. The demand side resources are the same for the 50/50 and extreme demand scenarios. The extreme load forecast is determined at two standard deviations higher than the mean, which has a 6.06% probability of occurrence.

Extreme Derates: Maintenance outages and other deratings are already included in existing-certain capacity calculation. Wind capacity is 64% derated

Typical Forced Outages: Unplanned outages are 1,500 MW.

Operational Mitigations: Operational mitigations include imports from neighboring areas and reduction of reserves

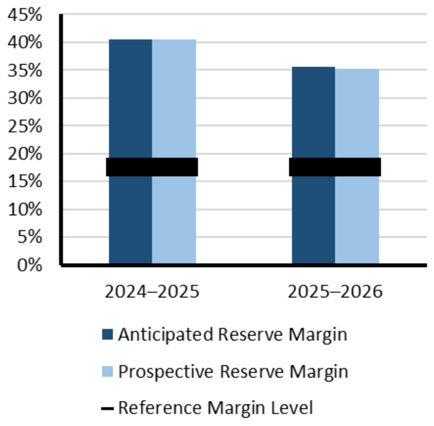
PJM

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's footprint covers approximately 369,054 square miles and with an approximate population of 67 million people. PJM is the area's BA, Transmission and Resource Planner, interchange authority, TOP, transmission service provider, and RC. PJM is electrically interconnected with MISO, NPCC-New York, SERC-Central, and SERC-East. Peak electricity demand in PJM occurs during the summer season.

Highlights

- Due to the low penetration of limited and variable resources in PJM relative to PJM's peak load, the hour with highest loss-of-load risk remains the hour with highest forecasted demand.
- PJM is expecting little capacity adequacy risk during Winter 2025–2026 and expects around 35% installed reserves, which is above the target IRM of 17.7% necessary to meet the 1-day-in-10-years LOLE criterion.
- Last winter, PJM hit a new all-time winter peak, but generator preparations anticipating congestion and tight capacity projections led to sufficient reserves throughout the demand event and PJM's transmission system performed well.
- The decrease in reserves from Winter 2024–2025 is due to load increases and retirement of generation without like (non-solar dispatchable) replacement generation.

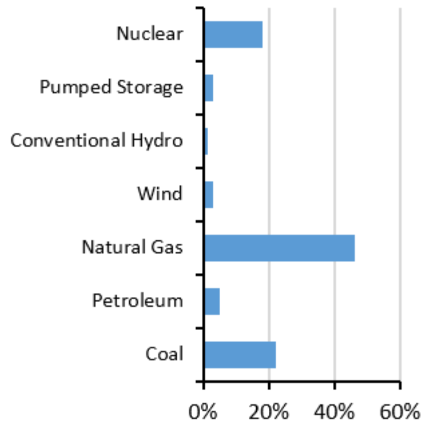
On-Peak Reserve Margin



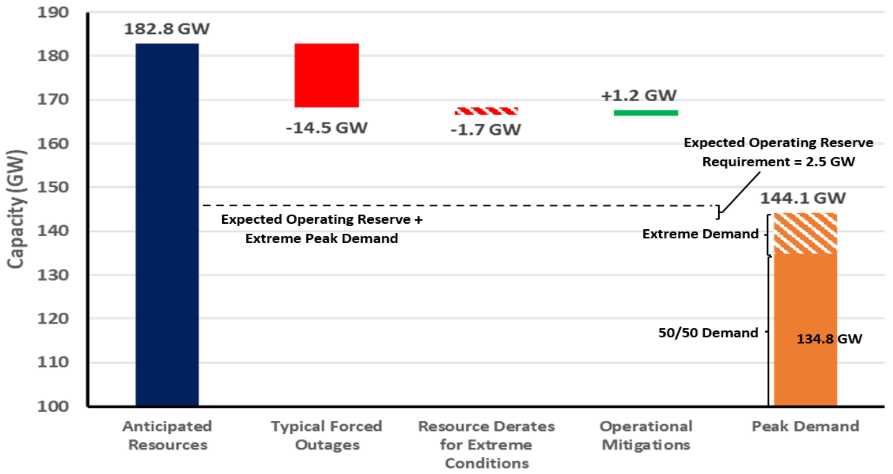
Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed scenarios.

On-Peak Resource Mix



2025–2026 Winter 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: Based on historical data and trending

Resource Derates for Extreme Conditions: Reduced thermal capacity contributions due to performance in extreme conditions

Operational Mitigations: accounts for an estimated value 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 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.

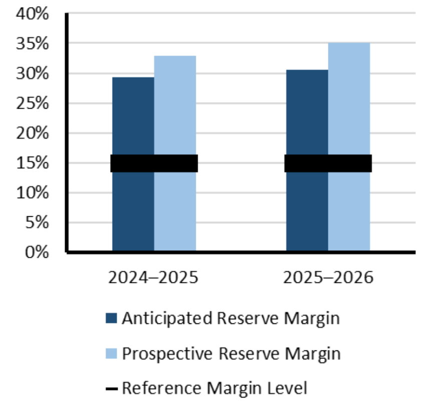
Highlights

- SERC-Central is transitioning from a summer-peaking area to a dual-peaking system.
- For the 2025–2026 Winter, SERC-Central projects a sufficient level of resources to serve the expected load under median weather and typical system operating conditions, based on the 2024 NERC ProbA base-case results.
- Most entities across SERC-Central report that fuel security is strong since it is supported by firm natural gas contracts, storage resources, and reliable pipeline capacity. Coal inventories are projected to remain within operational ranges necessary to meet winter demand.
- Following lessons from Winter Storm Elliott, one SERC-Central entity raised its winter Planning Reserve Margin target to 26% and updated preparedness programs with improved heat trace capabilities.

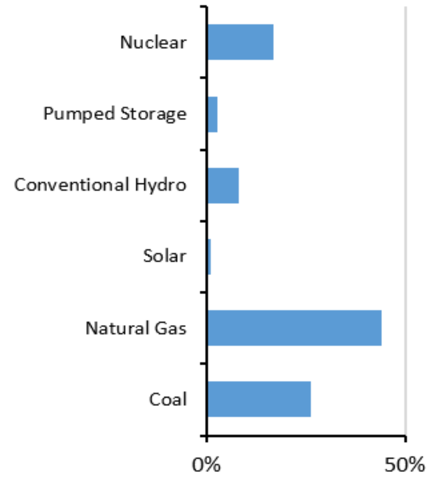
Risk Scenario Summary

Expected resources meet operating reserve requirements under normal peak demand. A severe cold weather event that extends to the south could lead to energy emergencies as operators face sharp increases in generator forced outages and electricity demand. Above-normal winter peak load and outage conditions could result in the need for operating mitigations (i.e., demand response and transfers) and EEAs. Load shedding is unlikely but may be needed under wide-area cold weather events.

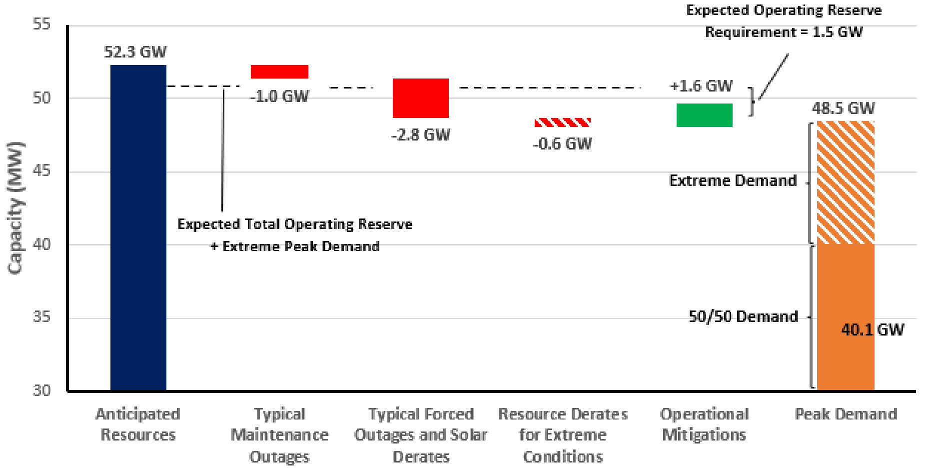
On-Peak Reserve Margin



On-Peak Resource Mix



2025–2026 Winter 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

Typical Maintenance Outages: Data collected through a survey of members for expected outages during December through February

Typical Forced Outages and Solar Derate: Includes any weighted average forced-outage rates on-peak that are not factored into the anticipated resources calculation . Also, solar resources are derated to account for peak demand occurrence during darkness.

Resource Derates for Extreme Conditions: Entity-provided values for low likelihood extreme conditions

Operational Mitigations: A total of over 1.6 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 Regional Entities 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 United States. The SERC Regional Entity covers approximately 630,000 square miles with a population of more than 91 million. The SERC Regional Entity includes 36 BAs, 28 Planning Authorities (PA), and 6 RCs.

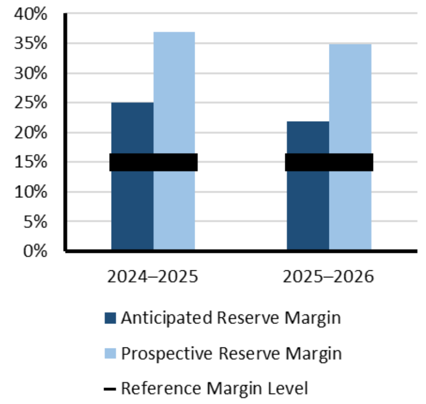
Highlights

- SERC-East is transitioning from a summer-peaking area to potentially peaking during both summer and winter. This shift is attributed to the continued addition of solar PV generation, which reduces summer peak demand, and a trend toward electrification of heating, which drives up winter peak demand.
- For the 2025–2026 Winter, the SERC-East region projects a sufficient level of resources to serve the expected load under median weather and typical system operating conditions, based on the 2024 NERC ProbA base-case results.
- Fuel supplies and transportation remain stable, and entities anticipate maintaining adequate coal and oil inventories with no reported changes to fuel procurement or operator plans for the upcoming winter.
- Probabilistic Base Case Results (Median Weather): EUE is 61.95 MWh and LOLH is 0.06 hours/year. EUE values are likely due to higher winter peaks and/or lower supply of capacity that can meet early winter morning demand.
- Mitigation measures for extreme conditions include voltage reduction (25–50 MW) and load-shedding programs that cover up to 30% of system load.

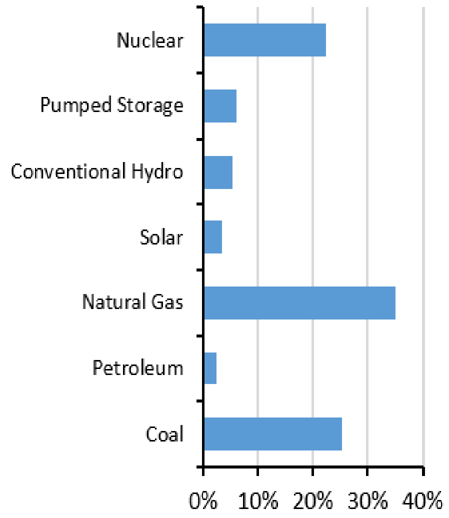
Risk Scenario Summary

Expected resources meet operating reserve requirements under normal demand scenarios. A severe cold weather event extending to the south could lead to energy emergencies as operators face sharp increases in generator forced outages and electricity demand. Above-normal winter peak load and outage conditions could result in the need for operating mitigations (i.e., demand response and transfers) and EEAs. Load shedding is unlikely but may be needed under wide-area cold weather events.

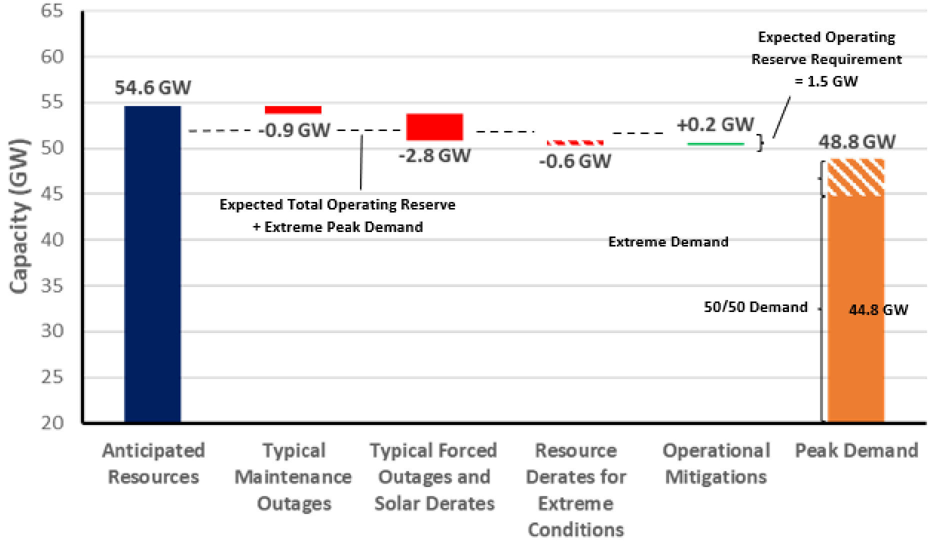
On-Peak Reserve Margin



On-Peak Resource Mix



2025–2026 Winter 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 Maintenance Outages: Data collected through a survey of members for outages during December through February

Typical Forced Outages and Solar Derate: Weighted average forced-outage rates on-peak are factored into the anticipated resources calculation. Also, solar resources are derated to account for peak demand occurrence during darkness.

Resource Derates for Extreme Conditions: Maximum historical generation outages (excluding 2022–2025)

Operational Mitigations: A total of 0.2 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 Regional Entities across North America that is 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 United States. The SERC Regional Entity area covers approximately 630,000 square miles with a population of more than 91 million. The SERC Regional Entity includes 36 BAs, 28 PAs, and 6 RCs.

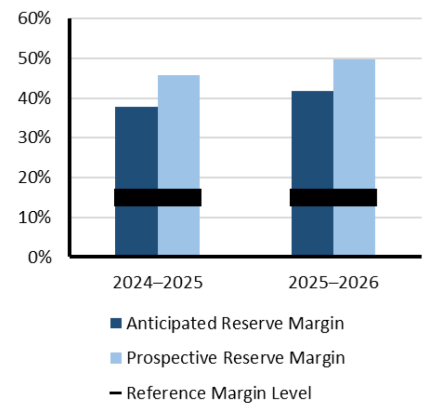
Highlights

- SERC-Florida Peninsula is a summer-peaking assessment area.
- Florida Peninsula entities have not identified any emerging reliability issues for the upcoming 2025–26 Winter season with an ARM projected at 39%, well above the RML, while the 2024 NERC ProbA base-case results project a sufficient level of resources to serve the expected load under median weather and typical system operating conditions (EUE is 1.09 MWh and LOLH is 0.00 hours/year).
- Many entities report strong fuel security, supported by firm natural gas contracts, storage resources, reliable pipeline capacity, and actively managed coal and oil inventories, which are projected to remain within operational ranges to meet winter demand.
- Florida Peninsula entities do not assume non-firm external assistance from neighboring areas during extreme conditions.

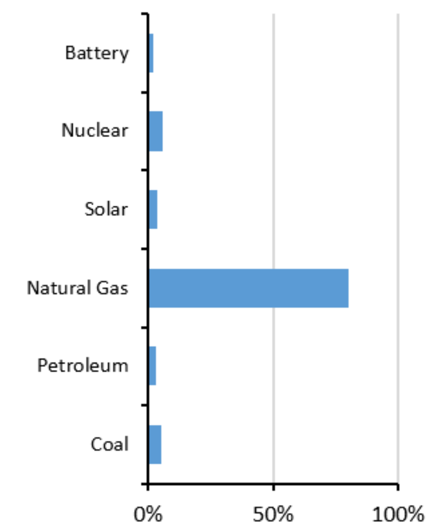
Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed scenarios.

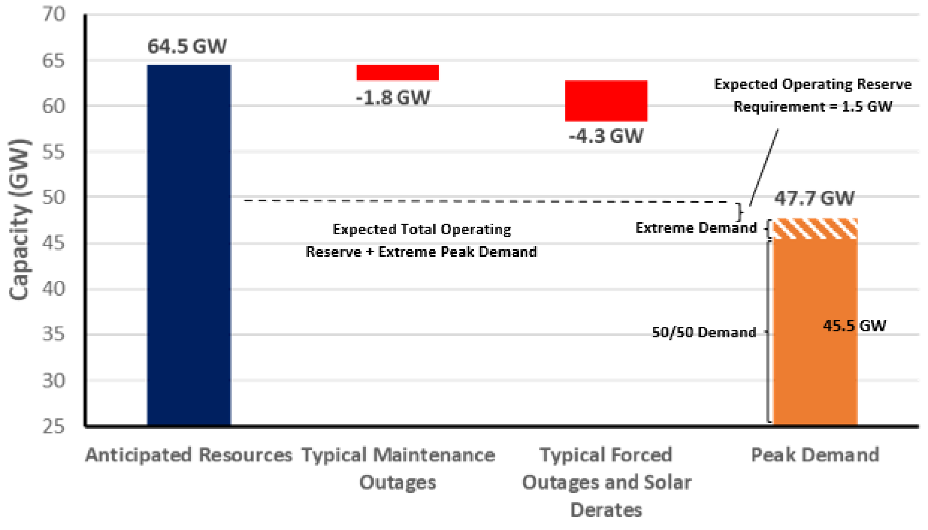
On-Peak Reserve Margin



On-Peak Resource Mix



2025–2026 Winter 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

Typical Maintenance Outages: Data collected through a survey of members for outages during December through February

Typical Forced Outages and Solar Derate: Weighted average forced-outage rates on-peak are factored into the anticipated resources calculation. Also, solar resources are derated to account for peak demand occurrence during darkness.

Resource Derates for Extreme Conditions: Entity-provided values for low likelihood 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 Regional Entities across North America that is 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 United States. The SERC Regional Entity covers approximately 630,000 square miles with a population of more than 91 million. The SERC Regional Entity includes 36 BAs, 28 PAs, and 6 RCs.

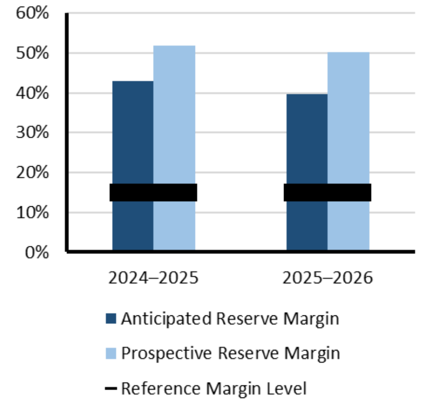
Highlights

- SERC-Southeast is trending towards becoming slightly winter-peaking.
- For the 2025–2026 Winter, SERC-Southeast entities report no emerging reliability concerns and expect to have adequate resources, supported by firm natural gas transportation contracts, diverse fuel portfolios, and sufficient on-site coal inventories to serve the expected load under typical system operating conditions. The 2024 NERC ProbA base-case results in EUE and LOLH are both 0.00.
- While most SERC-Southeast BAs expect to have adequate resources, supported by firm natural gas transportation contracts, diverse fuel portfolios, and sufficient on-site coal inventories, one BA highlights potential risks related to natural gas transportation capacity, citing high pipeline utilization, competition for delivered gas, and ratable flow requirements. Mitigation strategies include securing third-party gas supply, adding dual-fuel capability, and implementing coal inventory management.
- Entities have made refinements such as replacing specific 230 kV circuit breakers and increasing monitoring frequencies for critical plant systems after January 2025 winter events.

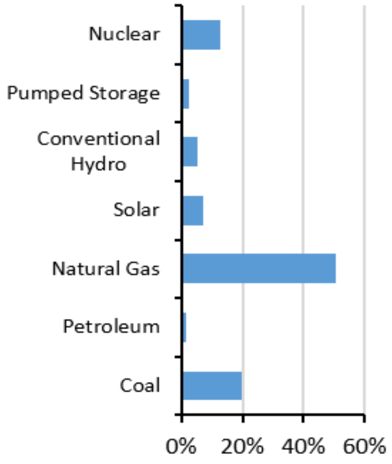
Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed scenarios.

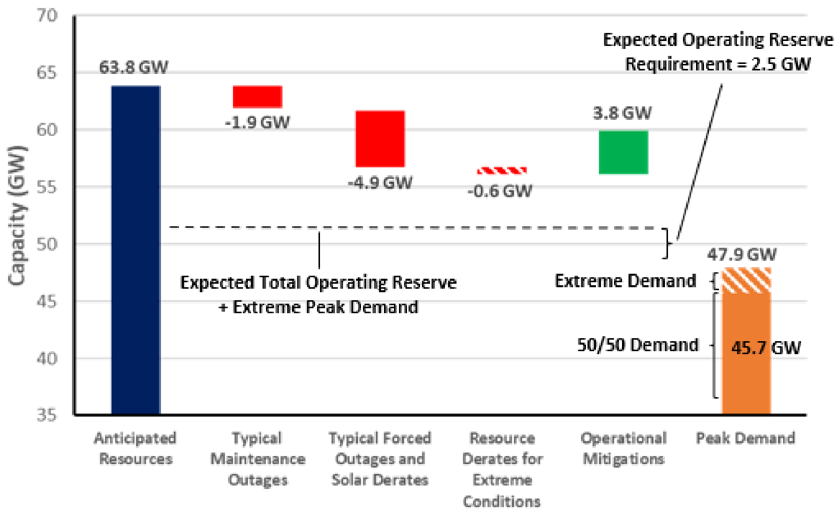
On-Peak Reserve Margin



On-Peak Resource Mix



2025–2026 Winter 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

Typical Maintenance Outages: Data collected through a survey of members for outages during December through February

Typical Forced Outages and Solar Derate: Weighted average forced-outage rates on-peak are factored into the anticipated resources calculation. Also, solar resources are derated to account for peak demand occurrence during darkness.

Resource Derates for Extreme Conditions: Maximum historical generation outages

Operational Mitigations: A total of 3.8 GW based on operational/emergency procedures

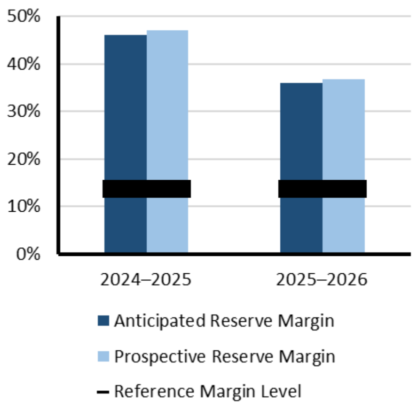
Texas RE-ERCOT

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 and covers approximately 200,000 square miles, connects over 54,100 miles of transmission lines, has over 1,250 generation units, and serves more than 27 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 power grid.

Highlights

- Given expected system conditions, an ARM of 36% and RML of 13.75%, ERCOT expects to have sufficient operating reserves for the peak hour ending 8:00 a.m.
- ERCOT does not expect any significant fuel supply issues for the winter.
- ERCOT has conducted 2,028 generation resource and transmission service provider (TSP) winter weatherization inspections since Winter 2021–2022.
- Winter peak demands typically occur before sunrise and after sunset when solar generation is not available. Significant battery storage mitigates these risks.
- ERCOT's probabilistic risk assessment indicates a 2% probability of having to declare EEAs during the January forecasted winter peak day (which coincides with the highest reserve shortage risk) and a controlled load shed probability of 1.8%. ERCOT defines low-risk hours as when the probability of an EEA is less than 10%.
- Increased load growth in west Texas combined with "no solar" and low wind conditions can cause transmission lines into this area to become heavily loaded. ERCOT has introduced improved dynamic line ratings that allow for greater transfers at colder temperatures and periods of low irradiance.

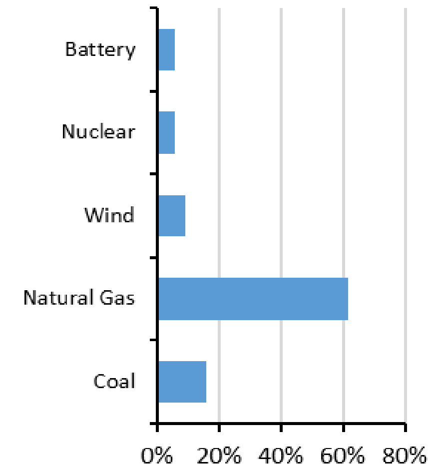
On-Peak Reserve Margin



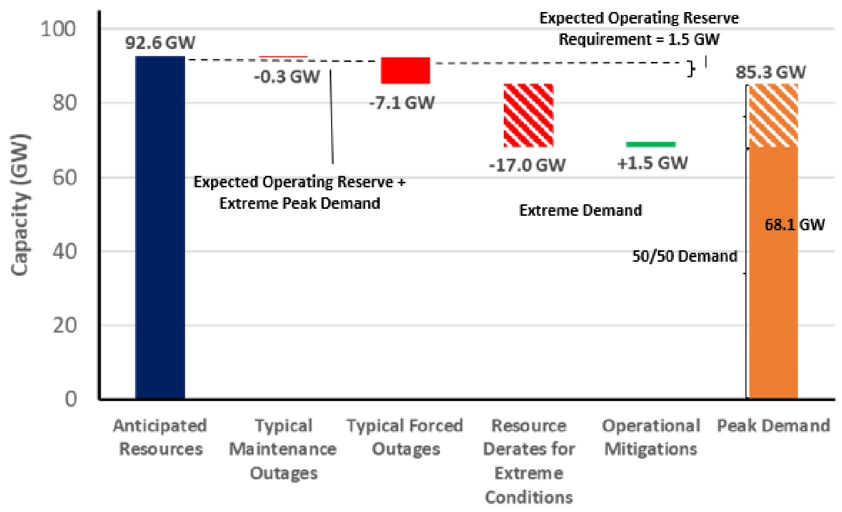
Risk Scenario Summary

Expected resources meet operating reserve requirements under normal peak-demand scenarios. Above-normal winter peak load and outage conditions could result in the need for operating mitigations (i.e., demand response and transfers) and EEAs. Load shedding is unlikely but may be needed under wide-area cold weather events.

On-Peak Resource Mix



2025–2026 Winter Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: Presumes weather conditions comparable to Winter Storm Uri. The adjustment is calculated as the difference between the 100th percentile and 50th percentile values from ERCOT's Probabilistic Reserve Risk Model (PRRM) simulated load outcome distribution for hour ending 8:00 a.m.

Typical Maintenance Outages: Based on historical winter data and consideration of ERCOT's allowed maximum system daily planned outage capacity

Typical Forced Outages: Based on a probability distribution created using historical ERCOT Outage Scheduler data for the last three Januarys.

Resource Derates for Extreme Conditions: Weather-related thermal and wind outages based on Winter Storm Uri levels, adjusted for reductions due to weatherization standards. Also includes high non-weather-related outages.

Operational Mitigations: Additional potential capacity from switchable generation and imports

WECC-Alberta

WECC-Alberta is an assessment area that covers the Canadian province of Alberta. The province has a geographic area of 661,848 square kilometers (255,541 square miles) and a population of almost 5 million people. The Alberta Electric System Operator (AESO) is the province's Planning Entity and RC responsible for safe, reliable, and economic operation of the Alberta Interconnected Electric System. AESO is a non-profit corporation that operates a system that includes approximately 26,000 kilometers of transmission lines and connects approximately 426 qualified generating units and nearly 250 market participants through a wholesale market. Alberta's transmission system has three interties with neighboring areas: Saskatchewan (see MRO-SaskPower), British Columbia (see WECC-British Columbia), and Montana (see WECC-Northwest). Peak electricity demand on the AESO system currently occurs during the winter season.

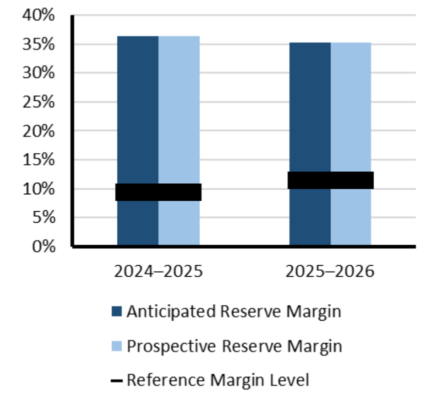
Highlights

- At an extreme winter peak of 12,982 MW, with extreme forced outages at 530 MW and derates for extreme conditions bringing wind energy availability down by 1,800 MW and hydroelectricity by 88 MW, the required reserves are 759 MW and are sufficiently met, even with low availability.
- Demand is expected to increase 1.1% from last winter with the existing-certain installed capacity having increased 23%.
- Solar availability is down because 1,000 MW of PV moved from originally expecting to come on-line in 2024 as Tier 1 resources to Tier 2s mostly anticipated to come on-line in 2025, but with less certainty.

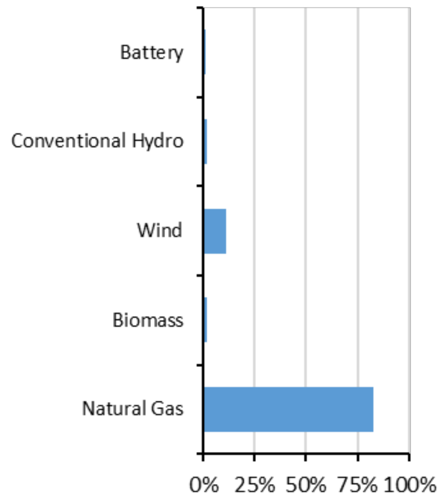
Risk Scenario Summary

Expected resources meet operating reserve requirements under assessed scenarios.

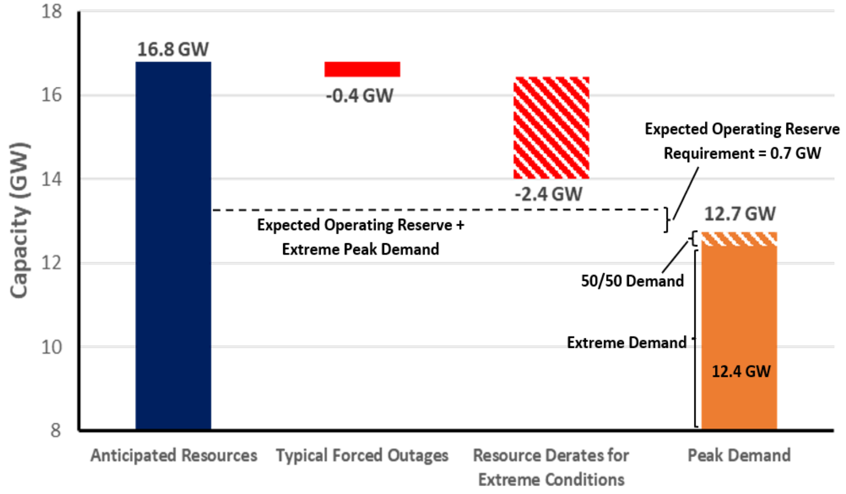
On-Peak Reserve Margin



On-Peak Resource Mix



2025–2026 Winter Risk Period Scenario



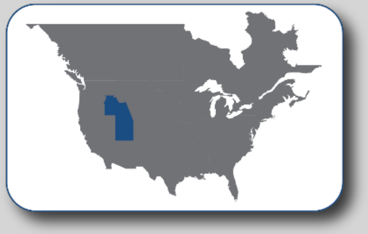
Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy is on the peak demand hour

Demand Scenarios: Net internal demand is the expected (50th percentile) peak and the 90th percentile of peak demand is the extreme forecast

Typical Forced Outages: Calculated using historical GADS data

Resource Derates for Extreme Conditions: Thermal, wind, and solar are based on the hourly energy availability curves' probability distributions' 10th percentiles for the risk period



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 BA 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 2025-26 WRA 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 2024–25 WRA.*

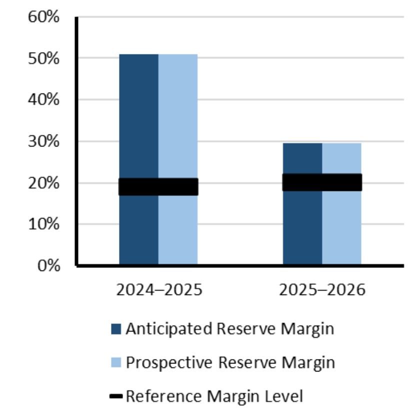
Highlights

- At an extreme winter peak of 11.1 GW under an extreme combination of derates and outages, the region could be short 1.0 GW before imports and is expected to need to rely on transfers.
- Net internal demand is expected to increase 1% since last year, with total internal demand up 1.8% being offset by a doubling of controllable and dispatchable demand response.
- Tier 1 resources have declined and do not appear to be offset by increases in existing-certain generation resource capacity. Nameplate wind has increased by almost 18% and solar by almost 30%. Hydro is also up over 7% in total installed capacity.
- Reliance on imports is expected to be required to maintain resource adequacy during extreme peak demand and extreme derate conditions.

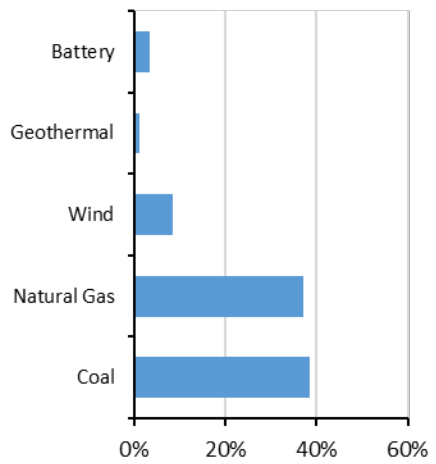
Risk Scenario Summary

Expected resources meet operating reserve requirements under normal peak demand scenarios. Above-normal peak demand combined with high generator outages in extreme conditions results in the need for external assistance to maintain reserves.

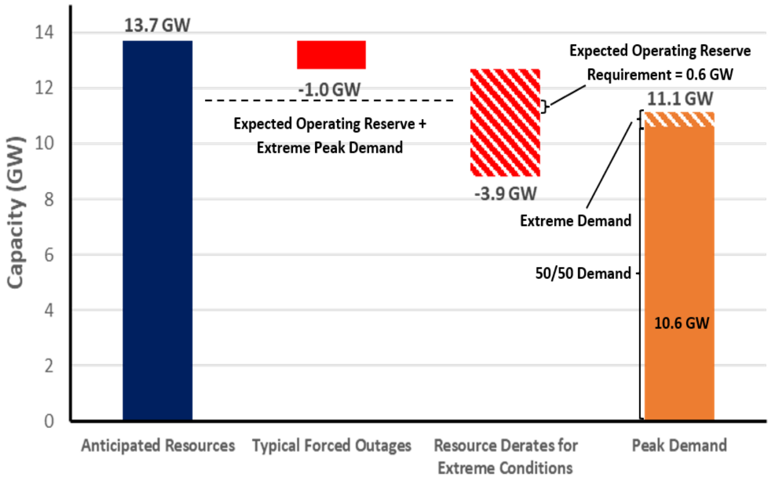
On-Peak Reserve Margin



On-Peak Resource Mix



2025–2026 Winter Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy is on the peak demand hour

Demand Scenarios: Net internal demand is the expected (50th percentile) peak and the 90th percentile of peak demand is the extreme forecast

Typical Forced Outages: Calculated using historical GADS

Extreme Derates: Thermal, wind, and solar are based on the hourly energy availability curves' probability distributions' 10th percentiles for the risk period

WECC-British Columbia

WECC-British Columbia is an assessment area that covers the Canadian province of British Columbia. The province has a geographic area of 944,735 square kilometers (364,764 square miles) and a population of just over 5 million people. BC Hydro is the Planning Entity and RC for the province of British Columbia and is the principal supplier of electricity for the province. BC Hydro is a provincial Crown corporation and, under provincial legislation, is responsible for the oversight of the British Columbia BES and its interconnections. BC Hydro operates an integrated system supported by 30 hydroelectric plants, approximately 80,000 kilometers of transmission and distribution lines, and 125 contracts with independent power producers. BC Hydro's transmission system has two interties with neighboring areas: the U.S. state of Washington (see WECC-Northwest) and Alberta (see WECC-Alberta). Peak electricity demand on the BC Hydro system currently occurs during winter.

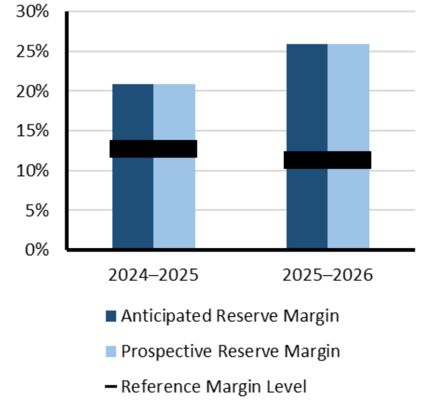
Highlights

- Peak demand is expected to remain about the same as last winter.
- There are about 200 MW more (47%) planned Tier 1 resources for this winter than last.
- Solar nameplate capacity has increased from 2 MW to 17 MW since last winter and hydroelectric nameplate capacity is up more than 5%, or 1,366 MW.

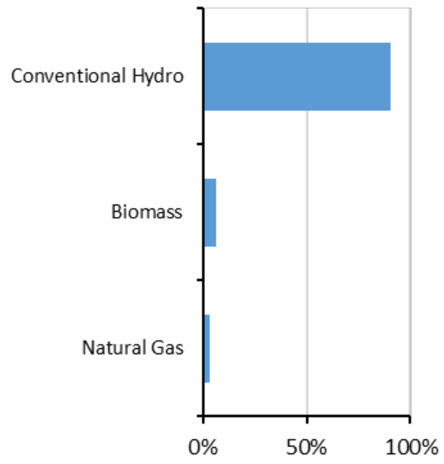
Risk Scenario Summary

Expected resources meet operating reserve requirements under normal and extreme demand scenarios.

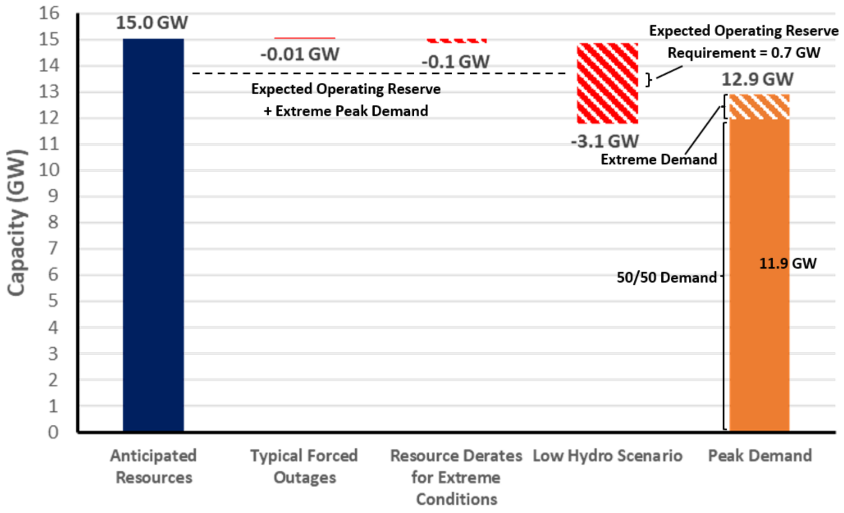
On-Peak Reserve Margin



On-Peak Resource Mix



2025–2026 Winter Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy is on the peak demand hour

Demand Scenarios: Net internal demand is the expected (50th percentile) peak and the 90th percentile of peak demand is the extreme forecast

Typical Forced Outages: Calculated using historical GADS

Resource Derates for Extreme Conditions: Thermal, wind, and solar are based on the hourly energy availability curves' probability distributions' 10th percentiles for the risk period

Low Hydro Scenario: Estimated derate for lower hydro output

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, the Los Angeles Department of Water and Power, the 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 2025–26 WRA 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 2024–25 WRA.*

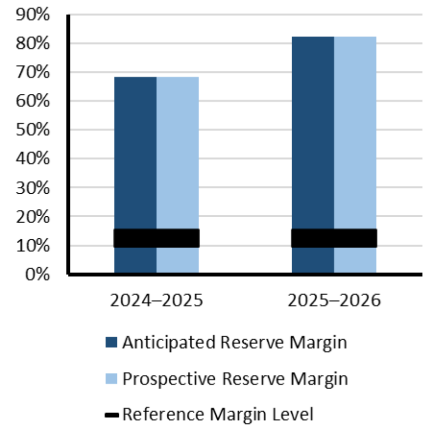
Highlights

- Operating reserve margins are met before imports in all winter resource availability scenarios.
- On-peak demand is expected to remain about the same as last winter. Demand-side management is down about 10%.
- Existing-certain capacity is up almost 5%, while planned Tier 1 resources are up more than 2 GW. The total wind nameplate capacity is up almost 27% and solar almost 13%. Hydro is down 4%.
- No reliance on imports is expected to be required to maintain resource adequacy for Winter 2025–2026.

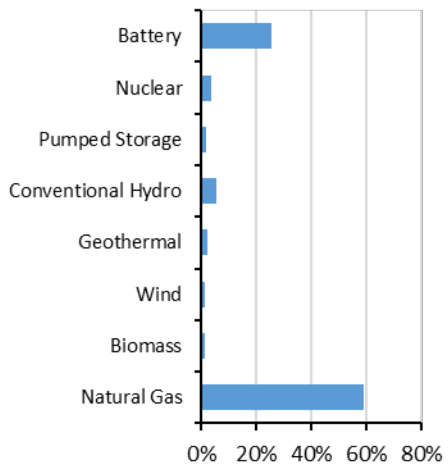
Risk Scenario Summary

Expected resources meet operating reserve requirements under assessed scenarios.

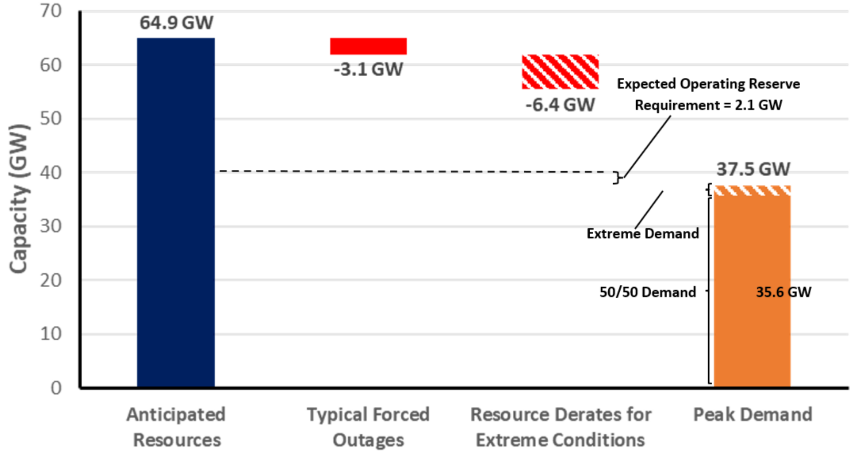
On-Peak Reserve Margin



On-Peak Resource Mix



2025–2026 Winter Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy is on the peak demand hour

Demand Scenarios: Net internal demand is the expected (50th percentile) peak and the 90th percentile of peak demand is the extreme forecast

Typical Forced Outages: Calculated using historical GADS

Resource Derates for Extreme Conditions: Thermal, wind, and solar are based on the hourly energy availability curves' probability distributions' 10th percentiles for the risk period

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 2025–26 WRA 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 2024–25 WRA.*

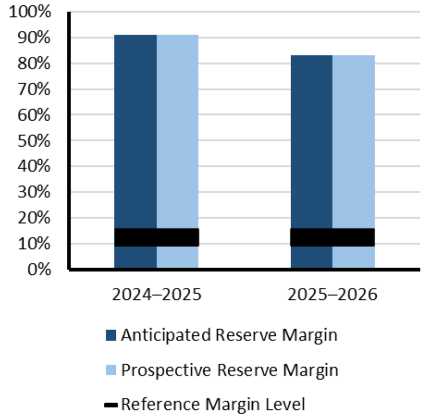
Highlights

- As a summer-peaking region, operating reserve margins are met before imports in all scenarios.
- Planned Tier 1 resources are down 100% to zero as expected resources have either been brought on-line to move into existing or, in the case of some natural gas, have been delayed until 2026 and moved into Tier 2.
- The existing-certain on peak reserve margin is down by 5.2%, and the anticipated and prospective reserve margins are down by 7.8%; however, since Mexico is heavily summer-peaking, the 83% reserve margin still exceeds the RML of 12.5%, which remains unchanged.

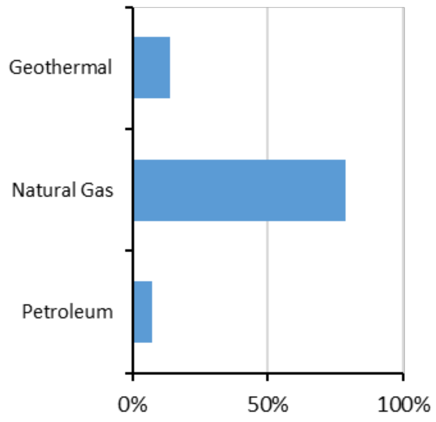
Risk Scenario Summary

Expected resources meet operating reserve requirements under assessed scenarios.

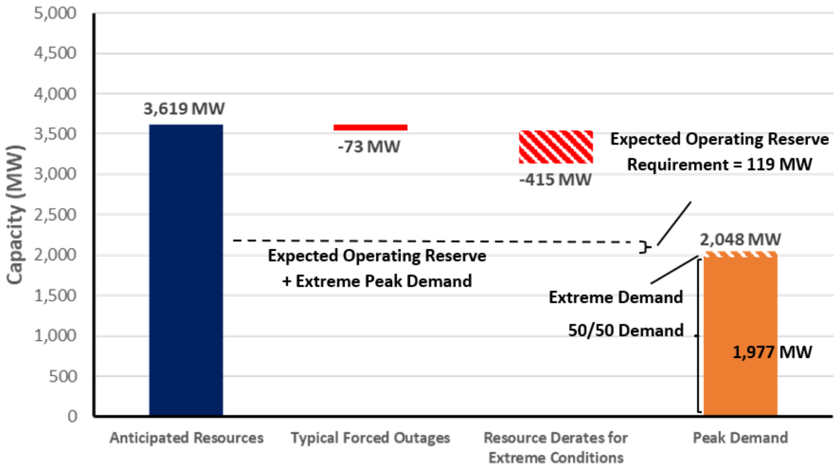
On-Peak Reserve Margin



On-Peak Resource Mix



2025–2026 Winter Risk Period Scenario



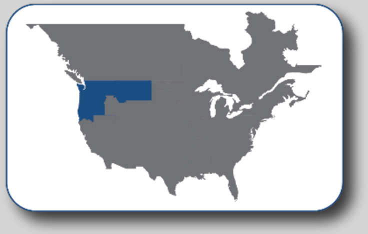
Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy is on the peak demand hour

Demand Scenarios: Net internal demand is the expected (50th percentile) peak and the 90th percentile of peak demand is the extreme forecast

Typical Forced Outages: Calculated using historical GADS

Resource Derates for Extreme Conditions: Thermal, wind, and solar are based on the hourly energy availability curves' probability distributions' 10th percentiles for the risk period



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 2025–26 WRA 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 2024–25 WRA.*

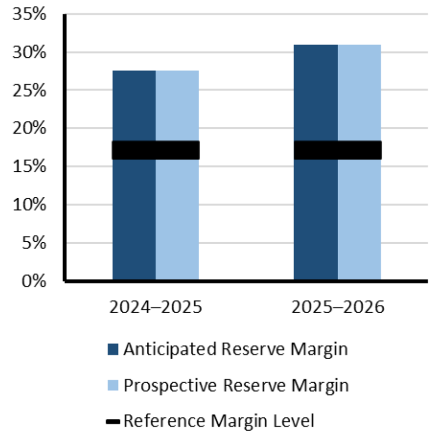
Highlights

- The Northwest has historically been a mixed season-peaking region.
- Operating reserve margins are expected to be met after imports in all winter scenarios.
- Total and net internal demand are up 9.3% with the primary drivers being data centers, residential electrification, transportation electrification, and semiconductor manufacturing.
- Large coal unit retirements and conventional hydro unit retirements are attributable to the reduction in existing certain capacity of 10.5%; however, planned Tier 1 resources have soared over 580%, from 463 MW to over 3 GW.
- Nameplate wind capacity is up over 3 GW (26%) and solar nameplate capacity is up nearly 2,690 MW (134%), which has also increased the solar availability on the peak hour.
- An increase in firm imports is seen in the model, 6.1 GW, absorbing the reduction in existing certain capacity of 4 GW.

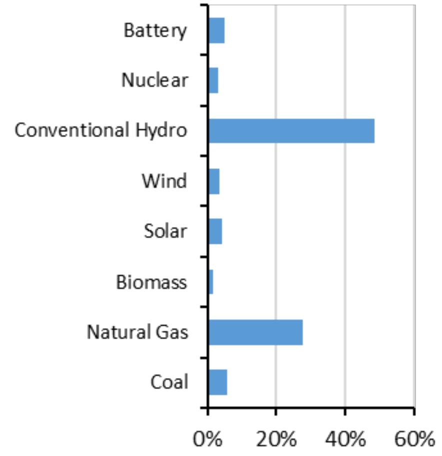
Risk Scenario Summary

Expected resources meet operating reserve requirements under normal peak demand scenarios. Above-normal peak demand combined with high generator outages in extreme conditions results in the need for external assistance to maintain reserves.

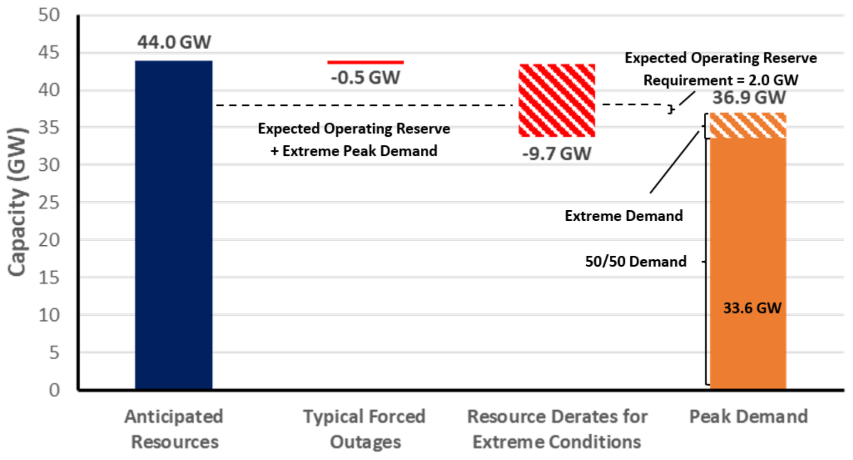
On-Peak Reserve Margin



On-Peak Resource Mix



2025–2026 Winter Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy is on the peak demand hour

Demand Scenarios: Net internal demand is the expected (50th percentile) peak and the 90th percentile of peak demand is the extreme forecast

Typical Forced Outages: Calculated using historical GADS

Resource Derates for Extreme Conditions: Thermal, wind, and solar are based on the hourly energy availability curves' probability distributions' 10th percentiles for the risk period. This value includes 6.8 GW of hydro derates.

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 2025–26 WRA 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 2024–25 WRA.*

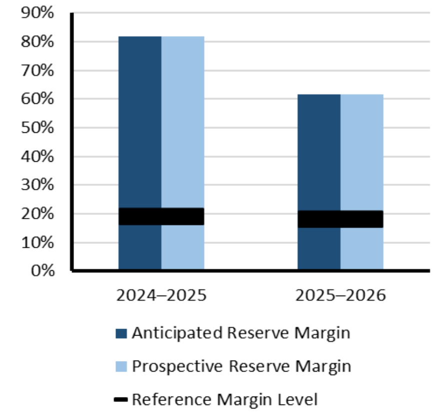
Highlights

- In Rocky Mountain, operating reserve margins are expected to be met before imports in all winter scenarios.
- Total and net internal demand are up almost 1%. The primary drivers are data centers and commercial and industrial customer growth.
- Planned Tier 1 resources are up over 84%, from almost 200 MW to over 365 MW. Solar nameplate capacity is up 27%; however, on-peak solar energy availability is down 100% due to the shift to after sunset. Expected hydro on peak energy availability is also down by around a quarter on the peak hour. Existing-Certain, Anticipated, and Prospective Reserve Margins are all down by over 20% on the peak hour; however, the region still maintains resource adequacy with margins hovering around 60% compared to the RML of 18%.
- No reliance on imports is expected to be required to maintain resource adequacy under combined extreme peak and extreme derated conditions.

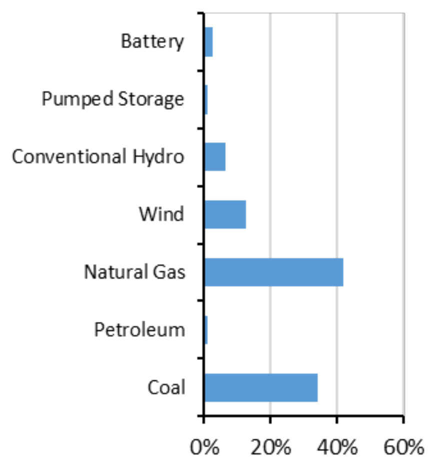
Risk Scenario Summary

Expected resources meet operating reserve requirements under assessed scenarios.

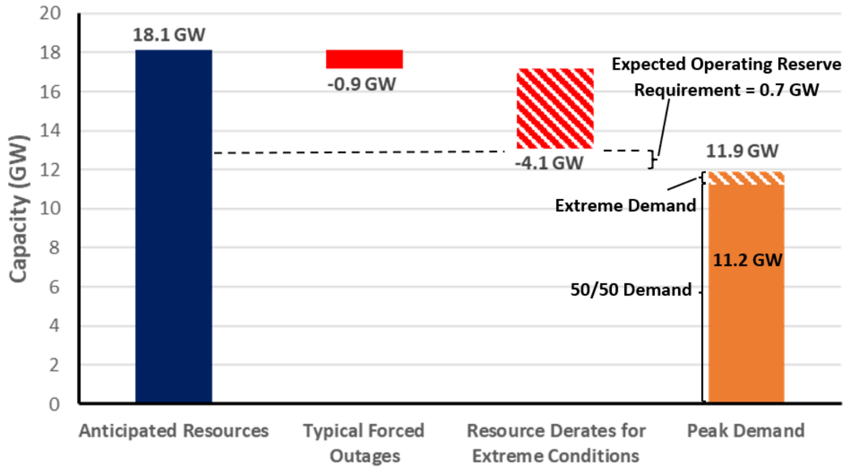
On-Peak Reserve Margin



On-Peak Resource Mix



2025–2026 Winter Risk Period Scenario



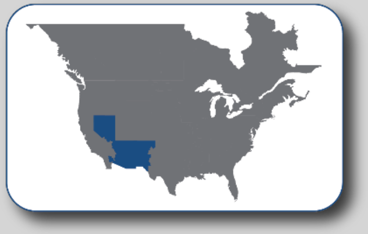
Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy is on the peak demand hour

Demand Scenarios: Net internal demand is the expected (50th percentile) peak and the 90th percentile of peak demand is the extreme forecast

Typical Forced Outages: Calculated using historical GADS

Resource Derates for Extreme Conditions: Thermal, wind, and solar are based on the hourly energy availability curves' probability distributions' 10th percentiles for the risk period



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 2025–26 WRA 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 2024–25 WRA.*

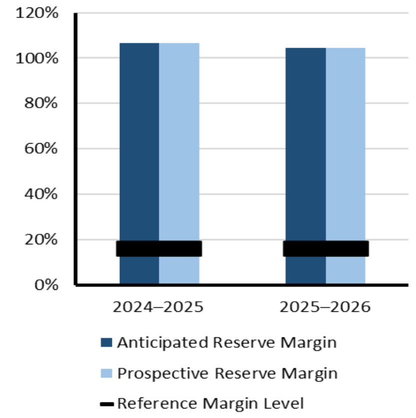
Highlights

- The Southwest is anticipated to be resource adequate under all winter expected and extreme energy availability and demand scenarios before imports.
- Total internal demand is expected to be up 1.5% and net internal demand up 2.3% since last winter. The primary drivers for load growth are data centers and industrial and residential electrification. Controllable and dispatchable demand response is down nearly half, by 163 MW.
- Planned Tier 1 resources are down over 19% as some have moved into existing certain, which is up almost 3%, over 1 GW, and other projects have experienced delays.
- Wind nameplate is up 12%, 470 MW, correlating to on-peak energy availability from wind increasing almost 11%, by 114 MW, while solar nameplate is up 27% or over 2.5 GW.

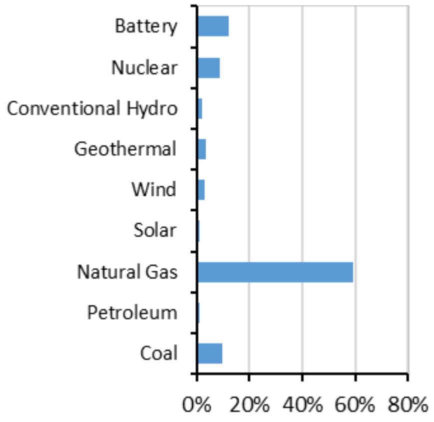
Risk Scenario Summary

Expected resources meet operating reserve requirements under assessed scenarios.

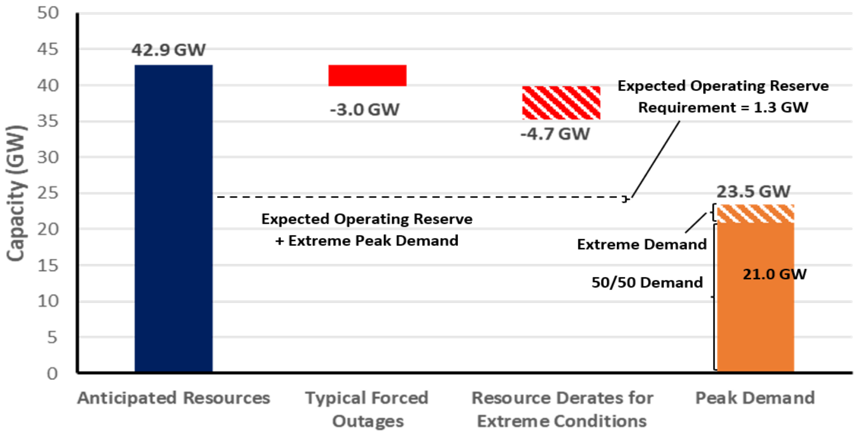
On-Peak Reserve Margin



On-Peak Resource Mix



2025–2026 Winter Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy is on the peak demand hour

Demand Scenarios: Net internal demand is the expected (50th percentile) peak and the 90th percentile of peak demand is the extreme forecast

Typical Forced Outages: Calculated using historical GADS

Resource Derates for Extreme Conditions: Thermal, wind, and solar are based on the hourly energy availability curves' probability distributions' 10th percentiles for the risk period

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[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. Because the electrical output of variable energy resources (VER) (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.

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[11] https://www.nerc.com/pa/Stand/Glossary%20of%20Terms/Glossary_of_Terms.pdf 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 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 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.[15] Large year-to-year changes in anticipated resources or forecast peak demand (net internal demand) can greatly impact Planning Reserve Margin calculations. NPCC-Maritimes marginally does not meet its RML for the upcoming winter. Other than NPCC-Maritimes, all assessment areas have sufficient ARMs to meet or exceed their RML for the 2025 winter as shown in **Figure 4**.

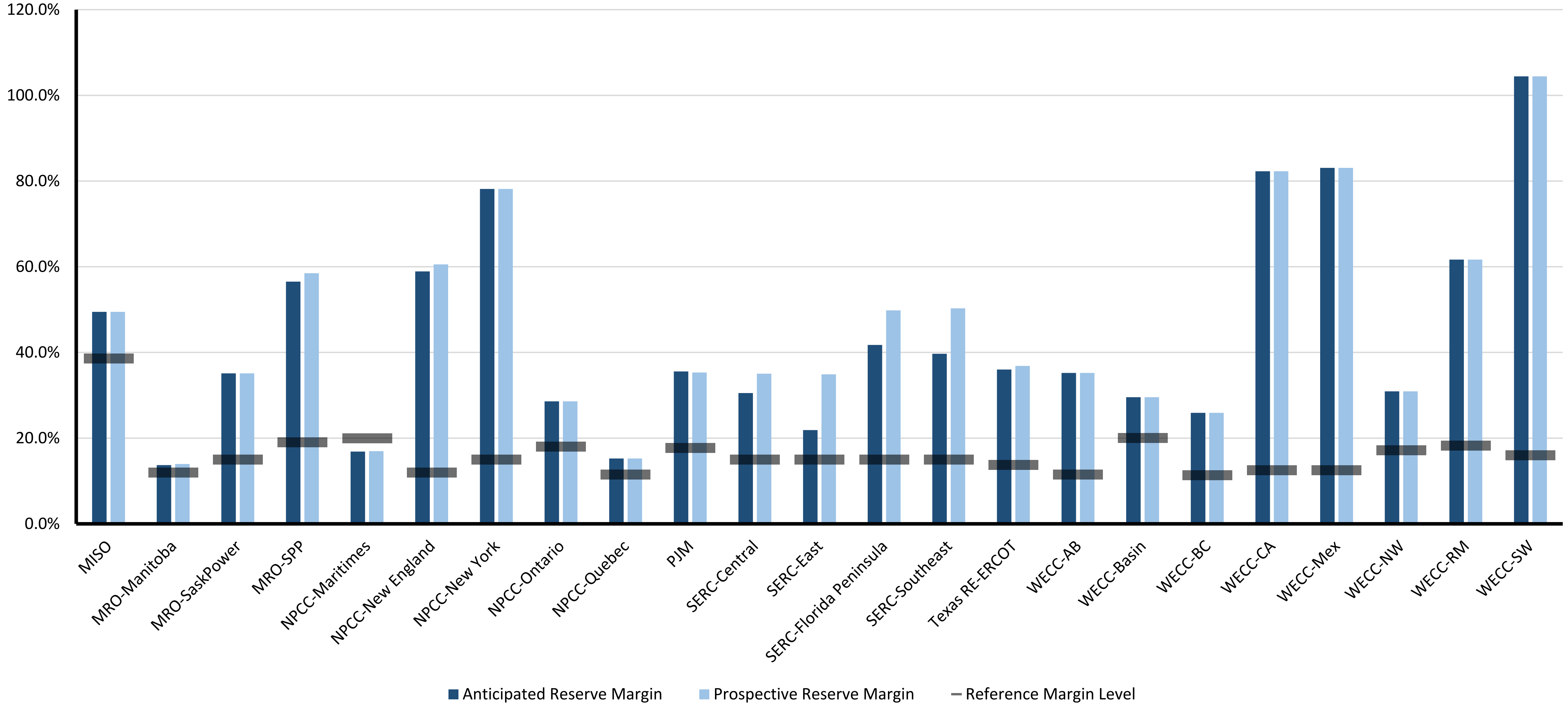

Figure 4: Winter 2025–2026 Anticipated/Prospective Reserve Margins Compared to Reference Margin Level

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[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 RMLs.

Changes from Year-to-Year

Figure 5 provides the relative change in the forecast ARMs from the 2024–2025 Winter to the 2025–2026 Winter. All areas except NPCC-Maritimes remain above their RMLs for 2025–2026 Winter. The Canadian winter-peaking systems, which include MRO-Manitoba, MRO-SaskPower, NPCC-Maritimes, NPCC-Québec, WECC-Alberta, and WECC-British Columbia, may have reserve margins that are near RMLs but are unlikely to experience high outage rates from their winterized generators. Additional details are provided in the Data Concepts and Assumptions section.

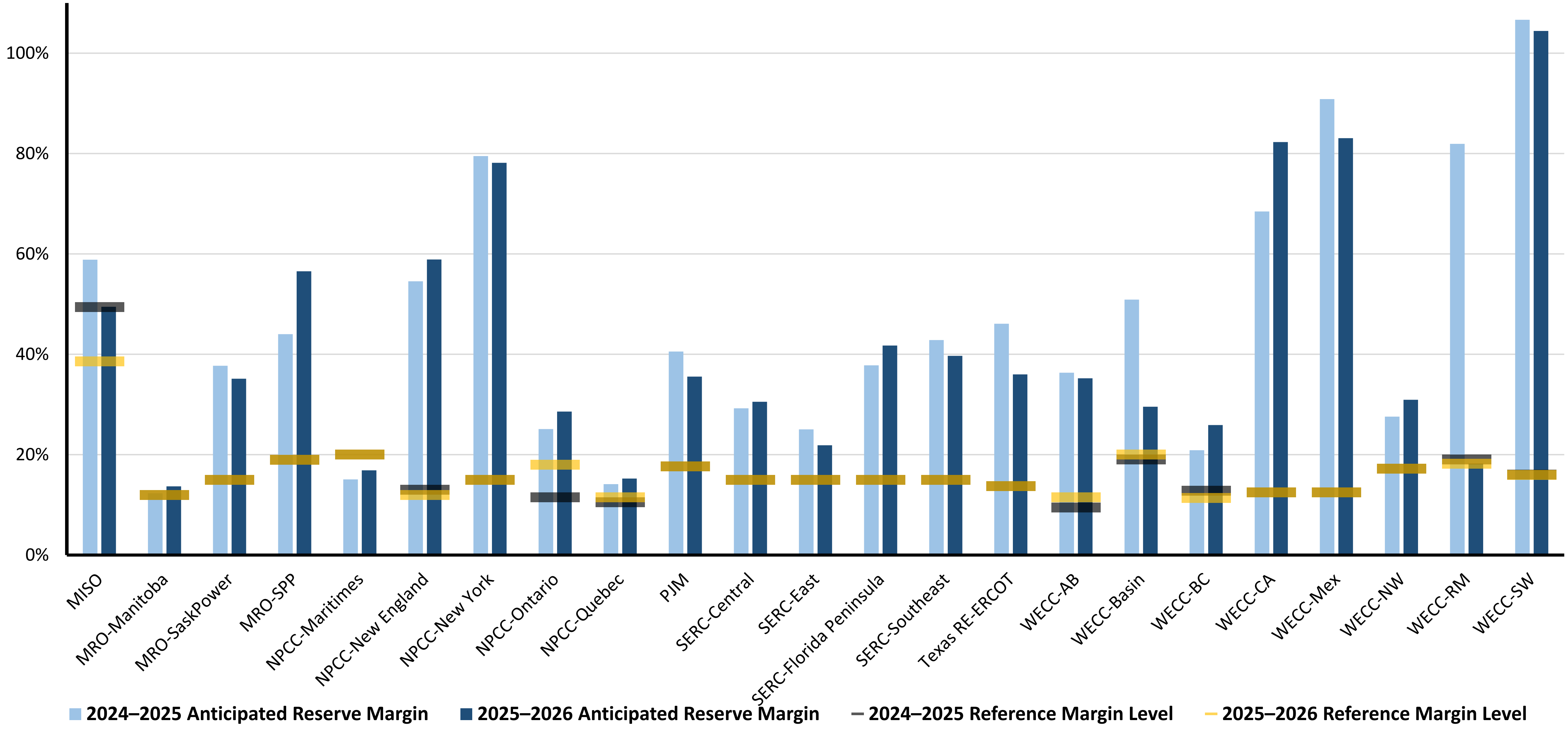

Figure 5: Winter 2024–2025 and Winter 2025–2026 Anticipated Reserve Margins Year-to-Year Change

Demand and Resource Tables

Peak demand and supply capacity data (i.e., resource adequacy data) for each assessment area are as follows in each table.

MISO

Demand, Resource, and Reserve Margins	2024–2025 WRA[16]	2025–2026 WRA	2024–2025 vs. 2025–2026
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	102,353	105,249	2.8%
Demand Response: Available	6,219	8,250	32.7%
Net Internal Demand	96,134	96,999	0.9%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	150,407	142,880	-5.0%
Tier 1 Planned Capacity	122	0	0.0%
Net Firm Capacity Transfers	2,310	2,113	-8.5%
Anticipated Resources	152,717	144,993	-5.1%
Existing-Other Capacity	0	0	0.0%
Prospective Resources	152,839	144,993	-5.1%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	58.9%	49.5%	-9.4
Prospective Reserve Margin	59.0%	49.5%	-9.5
Reference Margin Level	49.4%	38.6%	-10.8

MRO-SPP

Demand, Resource, and Reserve Margins	2024–2025 WRA	2025–2026 WRA	2024–2025 vs. 2025–2026
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	45,788	47,168	3.0%
Demand Response: Available	1,128	1,091	-3.3%
Net Internal Demand	45,926	46,077	0.3%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	67,252	71,074	5.7%
Tier 1 Planned Capacity	0	1087	0.0%
Net Firm Capacity Transfers	-1,116	-32	-97.1%
Anticipated Resources	66,136	72,129	9.1%
Existing-Other Capacity	0	0	0.0%
Prospective Resources	66,090	73,029	10.5%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	44.0%	56.5%	12.5
Prospective Reserve Margin	43.9%	58.5%	14.6
Reference Margin Level	19.0%	19.0%	0.0

MRO-SaskPower

Demand, Resource, and Reserve Margins	2024–2025 WRA	2025–2026 WRA	2024–2025 vs. 2025–2026
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	3,852	3,944	2.4%
Demand Response: Available	50	50	0.0%
Net Internal Demand	3,802	3,894	2.4%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	4,946	4,972	0.5%
Tier 1 Planned Capacity	0	0	0.0%
Net Firm Capacity Transfers	290	290	0.0%
Anticipated Resources	5,236	5,262	0.5%
Existing-Other Capacity	0	0	0.0%
Prospective Resources	5,236	5,262	0.5%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	37.7%	35.1%	-2.6
Prospective Reserve Margin	37.7%	35.1%	-2.6
Reference Margin Level	15.0%	15.0%	0.0

MRO-Manitoba Hydro

Demand, Resource, and Reserve Margins	2024–2025 WRA	2025–2026 WRA	2024–2025 vs. 2025–2026
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	4,814	4,903	1.8%
Demand Response: Available	0	0	0.0%
Net Internal Demand	4,814	4,903	1.8%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	5,924	5,688	-4.0%
Tier 1 Planned Capacity	10	0	-100.0%
Net Firm Capacity Transfers	-527	-113	-78.5%
Anticipated Resources	5,407	5,575	3.1%
Existing-Other Capacity	18	13	-26.8%
Prospective Resources	5,425	5,588	3.0%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	12.3%	13.7%	1.4
Prospective Reserve Margin	12.7%	14.0%	1.3
Reference Margin Level	12.0%	12.0%	0.0

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[16] MISO-provided updated data post 2024-25 WRA publication.

NPCC-Maritimes

Demand, Resource, and Reserve Margins	2024–2025 WRA	2025–2026 WRA	2024–2025 vs. 2025–2026
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	6,167	6,061	-1.7%
Demand Response: Available	259	248	-4.4%
Net Internal Demand	5,907	5,813	-1.6%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	6,647	6,704	0.9%
Tier 1 Planned Capacity	6	88	0.0%
Net Firm Capacity Transfers	145	1	-99.0%
Anticipated Resources	6,798	6,794	-0.1%
Existing-Other Capacity	0	0	0.0%
Prospective Resources	6,798	6,800	0.0%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	15.1%	16.9%	1.8
Prospective Reserve Margin	15.1%	17.0%	1.9
Reference Margin Level	20.0%	20.0%	0.0

NPCC-New York

Demand, Resource, and Reserve Margins	2024–2025 WRA	2025–2026 WRA	2024–2025 vs. 2025–2026
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	23,800	24,200	1.7%
Demand Response: Available	802	1,027	28.1%
Net Internal Demand	22,998	23,173	0.8%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	40,522	40,080	-1.1%
Tier 1 Planned Capacity	0	0	0.0%
Net Firm Capacity Transfers	759	1,203	58.5%
Anticipated Resources	41,281	41,283	0.0%
Existing-Other Capacity	0	0	0.0%
Prospective Resources	41,281	41,283	0.0%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	79.5%	78.2%	-1.3
Prospective Reserve Margin	79.5%	78.2%	-1.3
Reference Margin Level	15.0%	15.0%	0.0

NPCC-New England

Demand, Resource, and Reserve Margins	2024–2025 WRA	2025–2026 WRA	2024–2025 vs. 2025–2026
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	20,651	20,056	-2.9%
Demand Response: Available	343	440	28.2%
Net Internal Demand	20,308	19,616	-3.4%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	30,030	29,935	-0.3%
Tier 1 Planned Capacity	194	0	-100.0%
Net Firm Capacity Transfers	1,161	1,235	6.4%
Anticipated Resources	31,385	31,170	-0.7%
Existing-Other Capacity	306	322	5.2%
Prospective Resources	31,691	31,492	-0.6%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	54.5%	58.9%	4.4
Prospective Reserve Margin	56.1%	60.5%	4.5
Reference Margin Level	13.0%	12.0%	-1.0

NPCC-Ontario

Demand, Resource, and Reserve Margins	2024–2025 WRA	2025–2026 WRA	2024–2025 vs. 2025–2026
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	21,898	22,013	0.7%
Demand Response: Available	915	868	-5.2%
Net Internal Demand	20,982	21,146	0.9%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	26,652	27,319	2.5%
Tier 1 Planned Capacity	0	294	#DIV/0!
Net Firm Capacity Transfers	-450	-420	-6.7%
Anticipated Resources	26,202	27,193	3.8%
Existing-Other Capacity	0	0	0.0%
Prospective Resources	26,202	27,193	3.8%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	25.1%	28.6%	3.5
Prospective Reserve Margin	25.1%	28.6%	3.5
Reference Margin Level	11.5%	18.0%	6.5

NPCC-Québec

Demand, Resource, and Reserve Margins	2024–2025 WRA	2025–2026 WRA	2024–2025 vs. 2025–2026
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	40,512	40,799	0.8%
Demand Response: Available	4,451	4,902	10.9%
Net Internal Demand	36,061	35,897	-0.4%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	41,560	41,698	0.3%
Tier 1 Planned Capacity	73	61	0.0%
Net Firm Capacity Transfers	-479	-390	-18.6%
Anticipated Resources	41,154	41,368	0.5%
Existing-Other Capacity	-479	0	0.0%
Prospective Resources	41,154	41,368	0.5%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	14.1%	15.2%	1.1
Prospective Reserve Margin	14.1%	15.2%	1.1
Reference Margin Level	10.5%	11.5%	1.0

PJM

Demand, Resource, and Reserve Margins	2024–2025 WRA	2025–2026 WRA	2024–2025 vs. 2025–2026
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	136,328	140,827	3.3%
Demand Response: Available	5,616	5,998	6.8%
Net Internal Demand	130,712	134,829	3.1%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	179,216	178,335	-0.5%
Tier 1 Planned Capacity	0	0	0.0%
Net Firm Capacity Transfers	4,502	4,448	-1.2%
Anticipated Resources	183,718	182,783	-0.5%
Existing-Other Capacity	0	0	0.0%
Prospective Resources	183,718	182,452	-0.7%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	40.6%	35.6%	-5.0
Prospective Reserve Margin	40.6%	35.3%	-5.2
Reference Margin Level	17.7%	17.7%	-12.3

SERC-Central

Demand, Resource, and Reserve Margins	2024–2025 WRA	2025–2026 WRA	2024–2025 vs. 2025–2026
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	42,895	42,875	0.0%
Demand Response: Available	1,497	2,809	87.6%
Net Internal Demand	41,397	40,067	-3.2%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	51,578	50,454	-2.2%
Tier 1 Planned Capacity	0	0	0%
Net Firm Capacity Transfers	1,922	1,847	-3.9%
Anticipated Resources	53,500	52,301	-2.2%
Existing-Other Capacity	1,498	1,810	20.8%
Prospective Resources	54,998	54,111	-1.6%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	29.2%	30.5%	1.3
Prospective Reserve Margin	32.9%	35.1%	2.2
Reference Margin Level	15.0%	15.0%	0.0

SERC-East

Demand, Resource, and Reserve Margins	2024–2025 WRA	2025–2026 WRA	2024–2025 vs. 2025–2026
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	45,005	45,703	1.6%
Demand Response: Available	982	888	-9.6%
Net Internal Demand	44,023	44,815	1.8%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	54,379	54,460	0.1%
Tier 1 Planned Capacity	72	11	-84.3%
Net Firm Capacity Transfers	593	150	-74.7%
Anticipated Resources	55,045	54,622	-0.8%
Existing-Other Capacity	5,209	5,832	12.0%
Prospective Resources	60,254	60,453	0.3%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	25.0%	21.9%	-3.2
Prospective Reserve Margin	36.9%	34.9%	-2.0
Reference Margin Level	15.0%	15.0%	0.0

SERC-Florida Peninsula

Demand, Resource, and Reserve Margins	2024–2025 WRA	2025–2026 WRA	2024–2025 vs. 2025–2026
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	48,494	48,628	0.3%
Demand Response: Available	2,780	3,127	12.5%
Net Internal Demand	45,714	45,501	-0.5%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	62,579	63,502	1.5%
Tier 1 Planned Capacity	15	692	4510.0%
Net Firm Capacity Transfers	400	300	-25.0%
Anticipated Resources	62,994	64,494	2.4%
Existing-Other Capacity	3,673	3,671	0.0%
Prospective Resources	66,667	68,165	2.2%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	37.8%	41.7%	3.9
Prospective Reserve Margin	45.8%	49.8%	4.0
Reference Margin Level	15.0%	15.0%	0.0

SERC-Southeast

Demand, Resource, and Reserve Margins	2024–2025 WRA	2025–2026 WRA	2024–2025 vs. 2025–2026
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	45,308	47,056	3.9%
Demand Response: Available	1,638	1,365	-16.7%
Net Internal Demand	43,670	45,691	4.6%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	62,805	63,339	0.9%
Tier 1 Planned Capacity	765	0	-100.0%
Net Firm Capacity Transfers	-1,192	489	-141.0%
Anticipated Resources	62,378	63,828	2.3%
Existing-Other Capacity	3,920	4,847	23.7%
Prospective Resources	66,298	68,675	3.6%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	42.8%	39.7%	-3.1
Prospective Reserve Margin	51.8%	50.3%	-1.5
Reference Margin Level	15.0%	15.0%	0.0

Texas RE-ERCOT

Demand, Resource, and Reserve Margins	2024–2025 WRA	2025–2026 WRA	2024–2025 vs. 2025–2026
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	73,193	77,387	5.7%
Demand Response: Available	5,447	9,330	71.3%
Net Internal Demand	67,746	68,057	0.5%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	98,712	89,977	-8.8%
Tier 1 Planned Capacity	239	1351	464.9%
Net Firm Capacity Transfers	20	1,235	6075.0%
Anticipated Resources	98,971	92,562	-6.5%
Existing-Other Capacity	0	0	0.0%
Prospective Resources	99,691	93,137	-6.6%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	46.1%	36.0%	-10.1
Prospective Reserve Margin	47.2%	36.9%	-10.3
Reference Margin Level	13.75%	13.8%	0.0

WECC-AB

Demand, Resource, and Reserve Margins	2024–2025 WRA	2025–2026 WRA	2024–2025 vs. 2025–2026
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	12,280	12,411	1.1%
Demand Response: Available	0	0	0.0%
Net Internal Demand	12,280	12,411	1.1%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	13,535	16,658	23.1%
Tier 1 Planned Capacity	3206	124	-96.1%
Net Firm Capacity Transfers	0	0	0.0%
Anticipated Resources	16,740	16,782	0.3%
Existing-Other Capacity	0	0	0.0%
Prospective Resources	16,740	16,782	0.3%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	36.3%	35.2%	-1.1
Prospective Reserve Margin	36.3%	35.2%	-1.1
Reference Margin Level	9.5%	11.5%	2.0

WECC-Basin

Demand, Resource, and Reserve Margins	2024–2025 WRA	2025–2026 WRA	2024–2025 vs. 2025–2026
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	10,568	10,758	1.8%
Demand Response: Available	85	170	100.0%
Net Internal Demand	10,483	10,588	1.0%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	13,213	13,183	-0.2%
Tier 1 Planned Capacity	2,605	533	-79.5%
Net Firm Capacity Transfers	0	0	0%
Anticipated Resources	15,817	13,717	-13.3%
Existing-Other Capacity	0	0	0.0%
Prospective Resources	15,817	13,717	-13.3%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	50.9%	29.6%	-21.3
Prospective Reserve Margin	50.9%	29.6%	-21.3
Reference Margin Level	19.0%	20.0%	1.0

WECC-CA

Demand, Resource, and Reserve Margins	2024–2025 WRA	2025–2026 WRA	2024–2025 vs. 2025–2026
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	36,441	36,281	-0.4%
Demand Response: Available	743	666	-10.4%
Net Internal Demand	35,698	35,615	-0.2%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	55,380	57,923	4.6%
Tier 1 Planned Capacity	4,757	6,997	47.1%
Net Firm Capacity Transfers	0	0	0.0%
Anticipated Resources	60,138	64,920	8.0%
Existing-Other Capacity	0	0	0.0%
Prospective Resources	60,138	65,920	8.0%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	68.5%	82.3%	13.8
Prospective Reserve Margin	68.5%	82.3%	13.8
Reference Margin Level	12.5%	12.5%	0.0

WECC-BC

Demand, Resource, and Reserve Margins	2024–2025 WRA	2025–2026 WRA	2024–2025 vs. 2025–2026
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	11,966	11,936	-0.3%
Demand Response: Available	0	0	0.0%
Net Internal Demand	11,966	11,936	-0.3%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	13,870	14,389	3.7%
Tier 1 Planned Capacity	433	637	47.0%
Net Firm Capacity Transfers	164	0	-100.0%
Anticipated Resources	14,467	15,026	3.9%
Existing-Other Capacity	0	0	0.0%
Prospective Resources	14,467	15,026	3.9%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	20.9%	25.9%	5.0
Prospective Reserve Margin	20.9%	25.9%	5.0
Reference Margin Level	12.8%	11.4%	-1.5

WECC-Mexico

Demand, Resource, and Reserve Margins	2024–2025 WRA	2025–2026 WRA	2024–2025 vs. 2025–2026
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	1,983	1,977	-0.3%
Demand Response: Available	0	0	0%
Net Internal Demand	1,983	1,977	-0.3%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	3,733	3,619	-3.0%
Tier 1 Planned Capacity	52	0	-100.0%
Net Firm Capacity Transfers	0	0	0%!
Anticipated Resources	3,784	3,619	-4.4%
Existing-Other Capacity	0	0	0.0%
Prospective Resources	3,784	3,619	-4.4%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	90.8%	83.1%	-7.8
Prospective Reserve Margin	90.8%	83.1%	-7.8
Reference Margin Level	12.5%	12.5%	0

WECC-Northwest

Demand, Resource, and Reserve Margins	2024–2025 WRA	2025–2026 WRA	2024–25 vs. 2025–26
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	30,748	33,604	9.3%
Demand Response: Available	30	30	0.0%
Net Internal Demand	30,718	33,574	9.3%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	38,729	34,671	-10.5%
Tier 1 Planned Capacity	463	3,152	581.5%
Net Firm Capacity Transfers	0	6,136	100%!
Anticipated Resources	39,192	43,959	12.2%
Existing-Other Capacity	0	0	0.0%
Prospective Resources	39,192	43,959	12.2%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	27.6%	30.9%	3.3
Prospective Reserve Margin	27.6%	30.9%	3.3
Reference Margin Level	17.2%	17.2%	0.0

WECC-Rocky Mountain

Demand, Resource, and Reserve Margins	2024–2025 WRA	2025–2026 WRA	2024–25 vs. 2025–26
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	10,481	11,501	9.7%
Demand Response: Available	282	285	1.1%
Net Internal Demand	10,199	11,216	10.0%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	18,356	17,768	-3.2%
Tier 1 Planned Capacity	199	366	84.3%
Net Firm Capacity Transfers	0	0	0%
Anticipated Resources	18,555	18,134	-2.3%
Existing-Other Capacity	0	0	0.0%
Prospective Resources	18,555	18,134	-2.3%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	81.9%	61.7%	-20.3
Prospective Reserve Margin	81.9%	61.7%	-20.3
Reference Margin Level	19.0%	18.2%	-0.8

WECC-Southwest

Demand, Resource, and Reserve Margins	2024–2025 WRA	2025–2026 WRA	2024–25 vs. 2025–26
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	20,844	21,147	1.5%
Demand Response: Available	340	177	-47.9%
Net Internal Demand	20,504	20,970	2.3%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	38,991	40,135	2.9%
Tier 1 Planned Capacity	3,381	2,733	-19.2%
Net Firm Capacity Transfers	0	0	0.0%
Anticipated Resources	42,372	42,868	1.2%
Existing-Other Capacity	0	0	0.0%
Prospective Resources	42,372	42,868	1.2%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	106.6%	104.4%	-2.2
Prospective Reserve Margin	106.6%	104.4%	-2.2
Reference Margin Level	16.0%	16.0%	0.0

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 and may vary widely year to year based on the identified risk hour. In many areas, winter demand peaks in the early morning hours or early evening resulting in little or no electrical resource output from solar PV resources and wide variability in wind availability. The following table shows the capacity contribution of existing wind and solar PV resources at the identified risk hour for each assessment area. Resource contributions are also aggregated by Interconnection and across the entire BPS.

BPS Variable Energy Resources On-Peak Capacity Contributions by Assessment Area

	Wind			Solar			Hydro		
Assessment Area/Interconnection	**Nameplate Wind (MW)**	**Expected Wind (MW)**	**Expected Share of Nameplate (%)**	**Nameplate Solar PV (MW)**	**Expected Solar (MW)**	**Expected Share of Nameplate (%)**	**Nameplate Hydro (MW)**	**Expected Hydro (MW)**	**Expected Share of Nameplate (%)**
MISO	30,247	8,772	29%	13,726	686	5%	9,103	5,354	59%
MRO-Manitoba Hydro	259	52	20%	0	0	0%	6,288	5,676	90%
MRO-SaskPower	816	433	53%	30	0	13%	884	703	80%
MRO-SPP	35,714	7,198	20%	1,197	457	38%	5,602	5,521	99%
NPCC-Maritimes	1,635	241	15%	155	10	6%	1,357	1,283	0%
NPCC-New England	2,675	455	17%	3,620	0	0%	3,742	1,453	39%
NPCC-New York	2,586	737	29%	627	0	0%	6,357	5,283	83%
NPCC-Ontario	4,943	1,971	40%	478	0	0%	8,763	6,824	78%
NPCC-Québec	4,024	1,426	35%	10	0	0%	41,014	39,501	96%
PJM	13,318	5,463	41%	15,732	1	0%	8,134	7,900	97%
SERC-Central	1,324	370	28%	1,576	455	29%	4,991	4,027	81%
SERC-East	0	0	0%	7,068	1,792	25%	3,010	2,951	98%
SERC-Florida Peninsula	0	0	0%	12,058	2,151	18%	0	0	0%
SERC-Southeast	0	0	0%	8,670	4,461	51%	3,258	3,258	100%
Texas RE-ERCOT	40,629	7,833	19%	35,609	660	2%	579	566	98%
WECC-AB	5,712	1,919	34%	2,206	0	0%	1,788	570	32%
WECC-Basin	5,932	1,148	19%	3,853	62	2%	5,334	2,946	55%
WECC-BC	747	85	11%	17	0	0%	35,504	27,119	76%
WECC-CA	9,382	682	7%	28,328	0	0%	31,479	9,143	29%
WECC-Mex	40	4	11%	350	0	0%	0	0	0%
WECC-NW	14,744	1,319	9%	4,695	1,556	33%	65,830	37,005	56%
WECC-RM	5,681	2,265	40%	3,521	0	0%	6,502	2,654	41%
WECC-SW	4,303	1,182	27%	12,139	391	3%	6,234	1,896	30%
EASTERN INTERCONNECTION	93,517	25,692	27%	64,937	10,013	15%	61,489	50,233	82%
QUÉBEC INTERCONNECTION	4,024	1,426	35%	10	0	0%	41,014	39,501	96%
TEXAS INTERCONNECTION	40,629	7,833	19%	35,609	660	0%	579	566	98%
WECC INTERCONNECTION	46,541	8,605	19%	55,108	2,008	4%	152,671	81,333	53%
INTERCONNECTION TOTAL:	**184,711**	**43,556**	**23%**	**155,664**	**12,685**	**8%**	**255,753**	**171,633**	**67%**

Review of Winter 2024–2025 Capacity and Energy Performance

The meteorological winter across the contiguous United States had an average temperature of 34.1 degrees F—1.9 degrees above average—ranking in the warmest third of NOAA's historical record. Total winter precipitation in the US was 5.87 inches, 0.92 of an inch below average, ranking in the driest third of the December–February climate record.[17] Most of Canada experienced temperatures at least 2°C above the baseline average with the Maritime provinces, southern Ontario, and the Canadian west coast recording temperature departures nearer the baseline average while a small region in southern Saskatchewan recorded temperatures just slightly below the baseline average.[18]

In February 2025, FERC and NERC and its Regional Entities launched a joint review of the BPS' performance during the January 2025 arctic events, which comprised Winter Storms Blair, Cora, Demi, and Enzo.[19] The week of January 19–25, 2025 was the third coldest winter week (spanning Sunday through Saturday) across the United States since 2000. Between January 21 and 22, 2025, natural gas demand peaked at 150 Bcf/day, electric demand peaked at 683 GW, and unplanned outages peaked at 71,022 MW. Nevertheless, during the January 2025 arctic events, manual load shed was not required. The January 2025 arctic events had lower observed hourly wind chill temperatures in pockets of the Northeast, the Louisiana Gulf, California, and the Southwest compared to Winter Storms Uri, Elliott, Gerri, and Heather. During the January 2025 arctic events, the most extreme storm relative to typical weather was Winter Storm Enzo—a Gulf and Southern storm. On January 20, 2025, a burst of snow, sleet, and freezing rain developed across Texas and Louisiana late in the day. A mixture of sleet and freezing rain fell from Austin to San Antonio and to the southernmost point of Texas. By the early morning hours of January 21, 2025, for the first time in history, a blizzard warning was issued for southwest Louisiana and the southeastern-most point of Texas. Snow fell in Gulf cities in Texas, southern Mississippi, southern Alabama, and western Florida. On January 21, 2025, Baton Rouge recorded 7.6 inches of snowfall, making it the city's snowiest day since recordkeeping began in 1892, while New Orleans saw its snowiest day on record, with a total of 8.0 inches. Temperatures plunged to single digits in Louisiana. Temperatures in some parts of the state fell to levels not seen in more than 125 years.

The review team engaged with 10 electric entities across the Eastern and Texas Interconnections to gather the information necessary to provide a high-level overview of the BPS' performance during the cold weather events. Based on the data and interviews that the team reviewed, electric generators appear to have performed better during the January 2025 arctic events because of additional generator commitments, improved preparedness, increased situational awareness, and the implementation of lessons learned from previous extreme cold weather events and prior report recommendations. The natural gas system also performed better overall, serving record levels of natural gas demand and experiencing only minor production declines and short-duration force majeure events.

On October 1, 2025, NERC submitted to the Federal Energy Regulatory Commission its first *Cold Weather Data Annual Report*. This report includes a review of forced outage data from GADS for the winter 2024–2025 period indicating performance consistent with historical performance as reported in NERC's annual *State of Reliability* report. This is within the normal range of capacity that occurs across the fleet. During the Winter 2024–2025 period, the highest amount of capacity in a forced outage state for all reasons occurred on January 20, 2025, with 68,519 MW across all regions. The outages occurring over January 20, 2025, were analyzed as part of the joint FERC, NERC, and Regional Entity *2025 System Performance Review*. The joint FERC, NERC, and Regional Entity *2025 System Performance Review* found a reduction in peak coincident unplanned generator outages for the four 2025 winter storms reviewed compared to past winter storms; however, this review also noted that it was not an exact comparison due to prior winter storms having different characteristics.

Eastern Interconnection–Canada and Québec Interconnection

No EEAs were needed during the previous winter season. One entity plans to make a slight increase to the demand-response program based on last winter's operations.

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[17] Despite Arctic air outbreaks, U.S. had warm, dry winter on average | National Oceanic and Atmospheric Administration

[18] Climate Trends and Variations Bulletin – Winter 2024/2025 - Canada.ca

[19] https://www.ferc.gov/media/report-january-2025-arctic-events-system-performance-review-ferc-nerc-and-its-regional

Eastern Interconnection–United States

Several entities indicated that generators performed better during the January 2025 arctic events than in previous winter storms. For example, TVA stated that generator performance within its footprint was stable, with minimal natural gas delivery issues. Southeastern RC detailed that no major fuel-related outages occurred. FRCC noted that generator performance was strong during this period. The significant characteristics of Winter Storm Enzo in the Southern and Gulf states were freezing precipitation and snow accumulation, especially in regions where those conditions rarely occur. In FRCC, only the northern portion of Florida experienced severe arctic weather including freezing precipitation and snowfall (record-setting, in some cities) that were abnormal for the region even though certain northern cities have faced cold temperatures in the past. In Florida, entities experienced energy emergencies caused by extended generation outages from hurricanes Milton and Helene, compounded by unusually high loads from cold weather. Entities were able to serve native load and firm delivery obligations, though non-firm sales were curtailed during certain events. ISO-NE, NYISO, and PJM all generally described the January 2025 arctic events as having cold temperatures but overall weather conditions that were similar to a winter without a major storm.

MISO emerged from Winter 2024–2025 without turning to emergency procedures despite the wide-ranging winter storms from January 6 to 9 and again from January 20 to 22. Generators continue to prioritize scheduling planned or maintenance outages to the shoulder seasons of fall and spring to maximize unit availability for the winter season. Also, extreme cold weather outage adders were added to the LOLE model to make sure that winter storm risks are included in planning. In PJM, demand reached a new all-time winter peak on January 22, 2025, of 143,714 MW with sufficient reserves. PJM did call an EEA1 on January 22, 2025, however reserves remained adequate. PJM had less than 3% load forecast error over the peak days of the January cold weather events. Reliability cases were conducted, and units with extended start times were evaluated and started early to ensure units were on-line before extreme cold weather settled in. PJM had a 9.24% forced outage rate on the peak day, a relatively low forced outage rate for the weather experienced. There were also very few gas production problems; however, market issues prevented proper scheduling because of the four-day holiday weekend.

In SERC-Central, entities reported only limited impacts from Winter 2024–2025 coldest weather and made minor adjustments. One entity declared conservative operations ahead of peak conditions but experienced no emergencies. One entity raised its winter Planning Reserve Margin target to 26% following lessons learned from Winter Storm Elliott. Corrective actions were implemented due to isolated equipment issues, including improved heat trace capabilities and adding heat trace equipment to the cold weather critical component list. During the previous winter season, some SERC-Florida Peninsula entities experienced energy emergencies caused by extended generation outages from hurricanes Milton and Helene, compounded by unusually high loads from cold weather. Despite these challenges, entities were able to serve native load and firm delivery obligations, though non-firm sales were curtailed during certain events.

Texas Interconnection–ERCOT

There were no energy emergencies for the Texas RE-ERCOT region last winter and no conditions that prompted changes in operating procedures. Winter Storm Kingston, which occurred in February 2025, was the only storm where ERCOT utilized firm fuel supply service resources (FFSS), a firm-fuel product that provides additional grid reliability and resiliency during extreme cold weather and compensates generation resources that meet a higher resiliency standard. A maximum FFSS deployment of 470 MW occurred on February 19 between the hours 13:10 and 17:02. Two other storms, Enzo and Cora, impacted ERCOT in January 2025, but these storms did not cause any system reliability issues.

Western Interconnection

Between January 11 and 17, 2024, a prolonged Arctic outbreak impacted British Columbia, Alberta, and the U.S. Pacific Northwest, driving record electricity demand and widespread reliability challenges. Four U.S. Northwest BAs and one Canadian BA declared energy emergencies, underscoring two core vulnerabilities: Inadequate capacity during evening peak hours (4 to 8 p.m.) and Insufficient fuel supply (limited hydro availability) across multiple days.

Although temperatures were comparable to the December 2022 cold snap, WECC-Northwest peak demand rose two percentage points to 6% over then, with BC Hydro and AESO both setting new all-time records. The U.S. Northwest relied heavily on imports—averaging 4,745 MW during peaks and 5,241 MW across all hours, mostly from the Southwest and Rockies. California remained a net importer, providing little relief. Market prices in the Northwest reached or neared caps across most hours, indicating persistent scarcity rather than short-term peaks. Overall, the January 2024 event illustrated capacity alone does not ensure resilience. Sustained energy availability with interregional flexibility (both physical and market-based) will be key to maintaining reliability through the 2025–2026 and future winter seasons.

2024–2025 Winter Demand and Generation Summary at Peak Demand

Assessment Area	Peak Demand Date	Peak Demand Hour	Demand[1] (MW)	WRA Peak Demand Scenarios[2] (MW)	Generation[1] (MWh)	Transfers[1] (MW)	Wind – Actual[1] (MWh)	Wind – Expected[3] (MW)	Solar – Actual[1] (MWh)	Solar – Expected[3] (MW)	Forced Outages Summary[4] (MW)
MISO	Jan. 21	18:00	108,888*	96,134 100,395	101,655	-977	18,468	16,761	0	519	17,010
MRO-Manitoba Hydro	Jan. 20	08:00	5.132	4,814 5,060	5,292	-277	142	52	N/A	0	146
MRO-SaskPower	Dec. 18	18:00	3,785	3,802 3,897	3,641	-231	664	368	0	3	0
MRO-SPP	Feb. 20	08:00	47,981	45,926 47,054	40,898	-1,424	4,886	4,783	255	36	9,272
NPCC-Maritimes	Jan. 22	07:00	5,810	5,907 6,498	4,266	-1,174	368	261	3	5	*
NPCC-New England	Jan. 21	18:00	19,607	20,308 21,814	17,686	-1,896	285	329	4	23	624
NPCC-New York	Jan. 22	19:00	23,521	22,998 24,023	18,932	-4,589	654	728	0	0	4,835

2024–2025 Winter Demand and Generation Summary at Peak Demand											
Assessment Area	Peak Demand Date	Peak Demand Hour	Demand[1] (MW)	WRA Peak Demand Scenarios[2] (MW)	Generation[1] (MWh)	Transfers[1] (MW)	Wind – Actual[1] (MWh)	Wind – Expected[3] (MW)	Solar – Actual[1] (MWh)	Solar – Expected[3] (MW)	Forced Outages Summary[4] (MW)
NPCC-Ontario	Jan. 22	18:00	21,940	20,951 22,179	24,250	2,990	3,693	1,914	0	0	*
NPCC-Québec	Jan. 22	08:00	37,178	36,061 39,545	39,514	-766	1,463	1,449	0	0	*
PJM	Jan. 22	09:00	144,420	130,712 144,939	152,142	7,731	3,704	3,620	3,076	1	8,663
SERC-C	Jan. 22	08:00	47,815	41,397 47,062	40,898	-6,921	563	176	214	455	1,538
SERC-E	Jan. 23	08:00	47,130	44,023 47,662	41,810	-5,323	0	0	145	2,526	1,830
SERC-FP	Jan. 25	08:00	43,974	45,714 54,239	41,702	-557	0	0	362	1,684	2,824
SERC-SE	Jan. 22	08:00	46,490	43,670 45,116	48,227	1,741	0	0	592	3,861	2,210

2024–2025 Winter Demand and Generation Summary at Peak Demand

Assessment Area	Peak Demand Date	Peak Demand Hour	Demand[1] (MW)	WRA Peak Demand Scenarios[2] (MW)	Generation[1] (MWh)	Transfers[1] (MW)	Wind – Actual[1] (MWh)	Wind – Expected[3] (MW)	Solar – Actual[1] (MWh)	Solar – Expected[3] (MW)	Forced Outages Summary[4] (MW)
TRE-ERCOT	Feb. 20	08:00	80,560	73,193[5] 90,405[5]	79,960	-191	9,397	15,697	1,586	15	5,742
WECC-AB	Dec. 18	17:00	12,241	12,280 12,635	12,711	-470	3,175	1,867	4	0	*
WECC-BC	Feb 3	18:00	11,359	11,996 12,749	11,415	44	70	279	0	0	839
WECC-CA/MX	Dec. 12	15:00	35,555	35,359 36,823	31,925	-4,669	4,021	569	11,547	0	1,627
WECC-NW	Feb. 12	08:00	54,278	58,001 62,230	48,437	-920	2,607	7,876	1,494	2,198	3,281
WECC-SW	Feb. 13	16:00	22,969	16,177 17,777	25,087	2,117	2,741	1,065	1,599	182	1,496
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

2024–2025 Winter Demand and Generation Summary at Peak Demand

Assessment Area	Peak Demand Date	Peak Demand Hour	Demand[1] (MW)	WRA Peak Demand Scenarios[2] (MW)	Generation[1] (MWh)	Transfers[1] (MW)	Wind – Actual[1] (MWh)	Wind – Expected[3] (MW)	Solar – Actual[1] (MWh)	Solar – Expected[3] (MW)	Forced Outages Summary[4] (MW)

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 *2024–2025* WRA demand scenarios for each assessment area. Values are the normal winter 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 *2024–2025 WRA*.

[4] Values from NERC Generator Availability Data System for the 2024–2025 winter 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 2024–2025 winter risk period scenarios in the *2024–2025 WRA*.

[5] Texas RE-ERCOT peak demand scenarios are obtained by adding expected demand response (5.4 GW for winter 2024-2025) to the demand scenarios found on p. 29 of the 2024-2025 WRA.

*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.

Attachment N

NERC Probabilistic Assessment Technical Guideline,
August 2016

NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Probabilistic Assessment

Technical Guideline Document

August 2016

RELIABILITY | ACCOUNTABILITY

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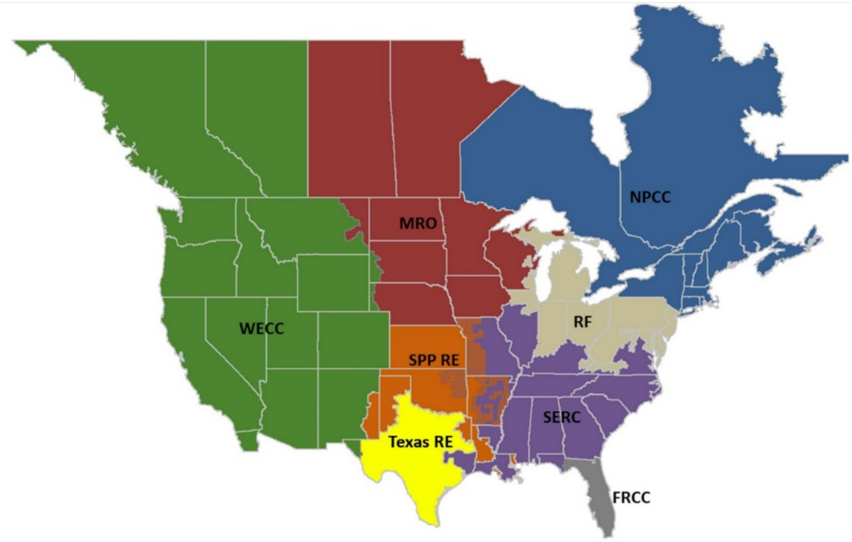
Table of Contents

Preface

The North American Electric Reliability Corporation (NERC) is a not-for-profit international regulatory authority whose mission is to assure the reliability of the bulk power system (BPS) in North America. NERC develops and enforces Reliability Standards; annually assesses seasonal and long-term reliability; monitors the BPS through system awareness; and educates, trains, and certifies industry personnel. NERC's area of responsibility spans the continental United States, Canada, and the northern portion of Baja California in Mexico. NERC is the electric reliability organization (ERO) for North America, subject to oversight by the Federal Energy Regulatory Commission (FERC) and governmental authorities in Canada. NERC's jurisdiction includes users, owners, and operators of the BPS, which serves more than 334 million people.

The North American BPS is divided into eight Regional Entity (RE) boundaries as shown in the map and corresponding table below.



The Regional boundaries in this map are approximate. The highlighted area between SPP and SERC denotes overlap as some load-serving entities participate in one Region while associated transmission owners/operators participate in another.

FRCC	Florida Reliability Coordinating Council
MRO	Midwest Reliability Organization
NPCC	Northeast Power Coordinating Council
RF	ReliabilityFirst
SERC	SERC Reliability Corporation
SPP RE	Southwest Power Pool Regional Entity
Texas RE	Texas Reliability Entity
WECC	Western Electricity Coordinating Council

Executive Summary

In an effort to improve NERC's continuing probabilistic assessments, the NERC Planning Committee (PC) tasked the Probabilistic Assessment Improvement Task Force (PAITF) with seeking enhancements to the existing Probabilistic Assessment (ProbA). The intent of the ProbA is to probabilistically evaluate resource adequacy based upon current reserve margin projections and emerging risks that have been identified in the Long-Term Reliability Assessment (LTRA).

This Probabilistic Technical Guideline Document serves as a platform for detailing probabilistic analytical enhancements that apply to resource adequacy. It provides guidance for NERC and its Regions and Assessment Areas to improve consistency in conducting probabilistic studies for Assessment Areas, and to establish consistent measures and metrics for monitoring potential resource adequacy trends. In addition, the Probabilistic Assessment Technical Guideline Document outlines suggestions for performing probabilistic analyses and common methods used by different entities while incorporating PAITF's recommendations for enhancing NERC Regions and Assessment Areas' modeling approaches at the time of publication. The Probabilistic Technical Guideline Document may be updated as deemed necessary, per a recommendation by the PC or its subgroups to reflect current modeling practices. The Probabilistic Assessment Technical Guideline Document is not applicable to individual entities or the resource planning activities they conduct for their specific jurisdictional authorities.

Primary Objectives

Under the guidance of the NERC Reliability Assessment Subcommittee (RAS), PAITF has created this Technical Guideline Document to identify and document enhancement opportunities for NERC's Regions and Assessment Areas.

The enhancements put forth by this Probabilistic Technical Guideline Document seek to:

- Identify practices, requirements, and recommendations needed to perform high-quality probabilistic resource adequacy assessments
- Complement reserve margin analyses in NERC's Long-Term Reliability Assessment by producing enhanced resource adequacy metrics and modeling approaches
- Provide NERC and policy makers with greater insight, understanding, and perspective on BPS reliability
- Support regional scenarios to study resource adequacy issues identified in the Long-Term Reliability Assessment

Enhancement Recommendations

The following section highlights major recommendations for enhancement of the ProbA Furthermore, Appendix C of this document provides a full list of recommendations.

- **NERC to develop and maintain documentation describing the establishment of Assessment Areas.** Assessment Areas are established through the NERC Reliability Assessment process. These areas are used for reporting probabilistic metrics. The ERO-RAPA, with input from RAS is to develop and maintain documentation describing the establishment of Assessment Areas. The ERO-RAPA, with input from NERC RAS annually to assess the need to revise the Assessment Areas based on boundary changes as market participation and planning responsibilities change over time. NERC staff, with input from NERC RAS, to provide a supplemental mapping document of changes to Assessment Areas over time.
- **Regions and Assessment Areas need to estimate or calculate monthly resource adequacy metrics.** As resource and demand characteristics change over time, annual loss of load may start accruing during historically off-peak months. Therefore, the monthly aggregation of these metrics [Loss of Load Hours

(LOLH) and Expected Unserved Energy (EUE)] will better inform industry of potential resource adequacy risks throughout the year.

- **Regions and Assessment Areas need to model seasonal load forecast uncertainty.** Current models incorporate some level of load forecast uncertainty, primarily around the annual peak; however, this recommendation seeks incremental improvements in load modeling to capture a reasonable expectation of seasonal load variability around the load forecast. Each Assessment Area is to incorporate both annual and seasonal peak uncertainty influenced by weather, economic, and other drivers in their load modeling.
- **Regions and Assessment Areas need to incorporate seasonal variations in their modeling of resource outages.** Current models incorporate some level of seasonal variation of resource outages through annual average forced outage rates; however, this recommendation seeks incremental improvements in outage modeling to capture a reasonable expectation of seasonal outages for the study years. Each Assessment Area to incorporate seasonal forced outage impacts by utilizing forced-outage rates, deration with load or temperature, varying transition rates, etc. Model modifications may be needed to accommodate this improvement.
- **Assessment Areas need to coordinate with neighboring areas and document coordination and modeling activities.** Each Assessment Area to provide and document further detail probabilistic modeling and coordination efforts with their neighboring entities. This is an incremental improvement to the narratives for increased awareness of Assessment Areas' methods. In addition, Assessment Areas to coordinate and document modeling differences and similarities from the LTRA data in terms of on-peak capacity transfer obligations and seasonal, weekly, or daily variations in the probabilistic model.
- **Assessment Areas to perform the sensitivity modeling within the Core Probabilistic Assessment framework**. NERC RAS identifies the variable data elements relevant to each sensitivity modeling.
- **Assessment Areas to address the reliability issues identified within the LTRA that impact resource adequacy, within the Special-Coordinated Probabilistic Assessment framework**. NERC ERO-RAPA and the PC identify reliability risk issues for scenario analysis, and NERC RAS evaluates input parameters relevant to each candidate scenario.

Introduction

Probabilistic analysis describes events in terms of how probable they are, and requires knowledge of the performance characteristics of bulk power system (BPS) components. These performance characteristics may include but not limited to generator outage rates, resource realizations in terms of energy produced, load characteristics, transmission congestions and constrains, etc.,. Measurement of past performance of the BPS can be expressed precisely in terms of frequency, duration, and the number of elements affected in past events. Prediction of future reliability must be expressed in terms of the expected performance of the system components, and of the uncertainty in those expectations. These characteristics can be brought together to derive various measures of the reliability of the BPS. Probabilistic methods typically rely on either statistical analysis of historical performance or enumeration techniques which are capable of simulating large numbers of contingencies. However, the choice of methods and selection of acceptable reliability levels are still matters of judgment and differ from Region to Region (and from utility to utility in some cases).

Probabilistic Modeling Overview

In addition to defining various technical considerations for probabilistic modeling, the PC PAITF Technical Guideline report identifies potential practices, requirements, and recommendations needed to ensure BPS reliability.

The PAITF 2015 ProbA Improvement Plan—Summary and Recommendations report reviewed recent key findings in the 2015 LTRA and ProbA reports resulting in the following conclusions:[1]

- The PAITF to prepare a Probabilistic Assessment Technical Guideline document to address consistency issues by recommending specific modeling guidelines to be used by the individual Assessment Areas.
- NERC and the Regions to take the lead in developing and evaluating additional scenarios to study resource adequacy issues related to resource risk areas identified in LTRAs.
- There are additional reliability issues, not directly related to resource adequacy, to be addressed using different probability analysis techniques. The review of methods and techniques for these non-resource adequacy issues should be identified in a separate report.

The Improvement Plan outlined two approaches that will increase NERC's ability to identify reliability trends as well as assess and evaluate resource adequacy concerns:

- **Core Probabilistic Assessment:** this approach is a continuation of the individual area probability assessments that will be an enhanced version of the current ProbA. Modeling consistency will be improved by following a Probabilistic Assessment Technical Guideline document.
- **NERC-Regional Coordinated Special Assessment:** this approach will expand the probabilistic study efforts through NERC and the Regions taking the lead in developing and evaluating additional scenario studies on resource adequacy concerns related to the BPS identified in LTRAs.

Guidelines for these approaches are demonstrated in this document, and highlight possible enhancements recommended by the PAITF. Each probabilistic enhancement or recommendation in this Technical Guideline Document is tied to one of four improvement areas: 1) process and coordination, 2) data needs and data collection, 3) assumptions criteria and modeling requirements, and 4) modeling software requirements.

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[1] NERC Probabilistic Assessment Improvement Plan – Summary and recommendations Report, December 2015, http://www.nerc.com/comm/PC/Reliability%20Assessment%20Subcommittee%20RAS%202013/ProbA%20%20Summary%20and%20Recommendations%20final%20Dec%2017.pdf

Core Probabilistic Assessment

Metric Reporting Areas

The term “metric reporting area” (MRA) is synonymous with the areas of the BPS which report resource adequacy metrics, such as loss-of-load hours (LOLH). MRAs are meant to be flexible in order to address individual assessment objectives. For the purpose of the Core Probabilistic Assessment, MRAs are synonymous with the reporting Assessment Areas of LTRA.

One key to delivering credible and meaningful Core Probabilistic Assessments is the establishment of Assessment Areas that accurately represent the current and future operations of the system. The intent of establishing these Assessment Areas is to report on the same basis as entities plan and operate their respective system(s).

Assessment Areas are established through the NERC Reliability Assessment processes, and these areas will be used for reporting probabilistic metrics for the Core Probabilistic Assessment under this PAITF recommendation, provided the following:

1. The ERO RAPA, with input from NERC RAS, develops documentation describing the establishment of Assessment Areas.
2. The ERO RAPA, with input from NERC RAS, maintains this documentation and annually assesses the need to revise the Assessment Areas based on boundary changes over time as market participation and planning responsibilities change.
3. NERC staff, with input from NERC RAS, provides a supplemental mapping document of Assessment Areas boundary changes over time.

Metrics Description

Resource adequacy metrics describe the occurrence, frequency, and duration of risk throughout the planning year for an Assessment Area. The LTRA is a peak-driven deterministic approach to gage resource adequacy. However, a compliment to the LTRA’s reported reserve margins is the associated probability of loss of load hours and/or unserved energy at the respective reserve margins. Even if from a deterministic view an hour’s demand is below the expected peak demand, other factors may drive that hour to be more at risk for loss of load than the peak hour due to scheduled and forced outages, transmission constraints, etc. Previous LTRAs have highlighted the need to evaluate more granular metric reporting in order to provide better risk-informed recommendations and leading edge indicators—given an evolving BPS. Probabilistic Assessment indicates trends in risks for any hour of the year, and it provides a trigger for further investigation that may be needed. The monthly aggregation of risk across 8,760 hours of the year may be more suitable to indicate the duration or occurrence of resource adequacy risks in some areas of the BPS.

Historically, the focus of the Core Probabilistic Assessment has been around annual indicators of risk to resource adequacy.

The following and other probabilistic metrics may be produced for different time intervals:

- Loss of Load Probability (LOLP)
- Expected Unserved Energy (EUE)
- Loss of Load Hours (LOLH)
- Loss of Load Expectation (LOLE)
- Loss of Load Event (LOLEV)

Although classic reliability metrics such as LOLE, LOLP and LOLEV have been used for a long time, they are not metrics used in the Core Probabilistic Assessment to avoid potential conflicts with regional practices based on different methods.

Loss-of-Load Probability (LOLP)

This is defined as the probability of system daily peak or hourly demand exceeding the available generating capacity during a given period. The probability can be calculated either using only the daily peak loads (or daily peak variation curve) or all the hourly loads (or the load duration curve) in a given study period.

Expected Unserved Energy (EUE)

This is defined as a measure of the resource availability to continuously serve all loads at all delivery points while satisfying all planning criteria. The EUE is energy-centric and analyzes all hours of a particular year. Results are calculated in megawatt hours (MWh). The EUE is the summation of the expected number of megawatt hours of load that will not be served in a given year as a result of demand exceeding the available capacity across all hours. Additionally, this measure can be normalized based on various components of an Assessment Area (i.e., total of peak demand, Net Energy for Load, etc.). Normalizing the EUE provides a measure relative to the size of a given Assessment Area. One example of calculating a Normalized EUE is defined as [(Expected Unserved Energy) / (Net Energy for Load)] x 1,000,000 with the measure of per unit parts per million.

Loss-of-Load Hours (LOLH)

This is generally defined as the expected number of hours per year when a system's hourly demand is projected to exceed the generating capacity. This metric is calculated using each hourly load in the given period (or the load duration curve) instead of using only the daily peak in the classic LOLE calculation. To distinguish this expected value from the classic calculation, the hourly LOLE is often called LOLH. It must be noted that the classic LOLE in days per year is not interchangeable with the LOLH in hours per year (i.e., LOLE of 0.1 days per year is not equivalent to a LOLH of 2.4 hours per year.) Unlike the classic LOLE metric, there is currently no generally acceptable LOLH criterion.

Loss-of-Load Expectation (LOLE)

This is generally defined as the expected number of days per year for which the available generation capacity is insufficient to serve the daily peak demand. This is the original classic metric that is calculated using only the peak load of the day (or the daily peak variation curve). However, this metric is not being reported as part of this assessment. Currently some Assessment Areas also calculate the LOLE as the expected number of days per year when the available generation capacity is insufficient to serve the daily load demand (instead of the daily peak load) at least once during that day.

Loss-of-Load Events (LOLEV)

This is defined as the number of events in which some system load is not served in a given year. A LOLEV can last for one hour or for several continuous hours and can involve the loss of one or several hundred megawatts of load. Note that this is not a probability index, but a frequency of occurrence index.

Metric Calculations

The PAITF recommends calculations of the following metrics for each Assessment Area and study period evaluated for all hours per year:

- Annual LOLH
- Monthly LOLH
- Annual EUE—both actual and normalized

- Monthly EUE—both actual and normalized

Probabilistic Study Reporting

Assessment Areas will perform a probabilistic assessment and report the results to NERC on a biennial basis for study years two and four of the LTRA. The purpose of the duplicate study year from assessment-to-assessment is to track and trend resource adequacy in the near term for each Assessment Area.

Simulation Software

A common software requirement is not necessary. Different models may be used at the discretion of the Assessment Areas. However, these models must be capable of performing the computations required as delineated in the Probabilistic Resource Adequacy Metrics Computations section of this document.

It is recommended that these models utilize a load-generation-transmission simulation software or another type that is appropriate for the Assessment Area for computing the forward-looking probabilistic metrics. The PAITF does not propose a common simulation software requirement in order to allow flexibility at the Assessment Area level. However, the PAITF does recommend that the G&T RPMTF's Assessment Area Simulation Software requirement be adhered to, which states "Each Assessment Area will utilize a load-generation-transmission simulation software for computing forward-looking probabilistic metrics."

It is at the discretion of each Assessment Area to select their solution tool, provided that metrics are calculated through simulation (e.g., Monte Carlo or convolution), while also adhering to all load, generation, and transmission modeling requirements/criteria/guidelines.

Specific Modeling Requirements for Core ProbA

Included Generation Categories

Existing generating resources

Existing generation is all generating resources that are capable of supplying BPS demand. This resource must be in commercial service or be expected to be in commercial service by the end of the current calendar year This includes steam generators, combustion turbine generators, combined cycle generators, wind turbine generators, hydro generators, and generation from various types of energy storage facilities. The characteristics of these resources align with the LTRA Data Form Instructions for existing resources. [2]

Load as a Capacity Resource: Demand that can be curtailed or interrupted under a contractual arrangement can be included as an existing resource from the perspective of capacity modeling. Since these resources are predetermined reductions in demand, they must also satisfy the applicable modeling rules for Demand Side management (DSM).

Future generating resources

For any scenario that includes future time periods, additional capacity is included that meets the requirements as identified in the 2016 LTRA Data Instructions to be a LTRA Tier 1 designated unit.

Excluded Generation Categories

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[2] NERC 2016 LTRA Data Form Instructions http://www.nerc.com/comm/PC/Reliability%20Assessment%20Subcommittee%20RAS%202013/2016LTRA_Data_Instructions.pdf

Any existing generating resource that supplies non-BPS demand is excluded. Any generating resource that is backup or standby generation that is not obligated to supply BPS demand as instructed by the BPS system operator (direct or indirect instruction) is also excluded.

Scheduled generator retirement: An existing generator with a known retirement date should be removed from the existing resources in applicable study years.

Future generating resources

The Core Probabilistic Assessment determines the amount of additional capacity needed to supply future demand forecasts. Excluded future capacity falls under Tier 2 and Tier 3 generation units' categories identified in the LTRA Data From Instructions.

General Modeling Assumptions

Load Modeling

Load modeling to include the following: 1) Peak load projection and forecast uncertainty, 2) A total of 8,760 hourly annual load profile(s) and their associated probabilistic weightings, 3) Load correlation within each Assessment Area incorporating weather and economic parameters.

In the most generic terms, an hourly (usually an 8,760 hourly annual load shape) load model that includes load forecast uncertainty (LFU) to be used for probabilistic assessments. Fundamentally, the load used in the analysis should describe a reasonable expectation of variability of the load forecast for the study year. It is important to represent the correlation across Assessment Area of load and weather parameters.

LFU models the forecast peak load differently from the actual load to provide uncertainty bands around load shapes. Weather, economic variability and forecast modeling errors are key components in establishing these acceptable bands around the 50/50 load shape projections. Each Assessment Area's narrative should address how the load shape is expected to change prospectively.

The general principles for both single and multi-area analysis are described in NERC's Reliability Assessment Guidebook.[3]

PAITF recommends the following for Assessment Areas with respect to load modeling:

- Each Assessment Area should incorporate both annual peak uncertainty and seasonal variation in their load modeling.
- Each Assessment Area should submit a narrative describing their load modeling assumptions.
- Narratives should also include assumptions made on Demand-Side Management (DSM) modeling within the load shapes and forecasts. The DSM section highlights requirements and DSM modeling improvements.
- Load Forecast Uncertainty (LFU) must be incorporated into the ProbA models at a minimum. The industry standard for LFU modeling is to calculate the probability of load exceeding or falling below the forecast. LFU application can be conducted as a multiplier to the load shape(s), captured in multiple weather years modeling, or a combination thereof.
- This LFU should capture the uncertainty due to weather and economics.
- Weather, economic and forecast trend uncertainty include:
    - Conservation and energy efficiency
    - Historic and future embedded variable generation (wind and solar mainly)
    - Controllable or dispatchable demand response
    - Other load shapes within the Assessment Area (among internal transmission zones)
    - Load shapes of outside areas (external Assessment Areas)
- What is included or excluded from the 50/50 base forecast should be detailed in each Assessment Area's narrative. This narrative should also include the methodology to calculate the 50/50 forecasted load for the study years and how that applies to the load shapes within the model.

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[3] NERC Reliability Assessment Guidebook http://www.nerc.com/files/Reliability%20Assessment%20Guidebook%203%201%20Final.pdf

Demand-Side Management

The general issues related to the DSM description, data and modeling are extensively discussed in Chapter 3 of the NERC Reliability Assessment Guideline. In this section of this Technical Guideline Document we will concentrate specifically on the modeling of DSM in probabilistic assessments.

As with any analysis the first concern is to ensure that the DSM is being counted exactly once. If the DSM is modeled as an Emergency Operating Procedure (EOP) or as a dispatchable resource, it must be assured that the load shape and load forecast were constructed to include the demand from the loads that the DSM act on. This often means actively adjusting historic information to add the effect of the DSM back in because historic metered load is often load after the impact of the DSM.

The DSM contains all activities or programs undertaken by an entity to achieve a reduction in Demand. The DSM is often understood to include three components: 1) conservation, 2) energy efficiency (EE), and 3) controllable and dispatchable demand response (DR).[4]

EE resources may be classified into two groups: permanent and user controlled.

Permanent EE is the installations and process improvements that lead to the permanent efficiency of devices, buildings, etc.

User Controlled EE is the implementation of end use customer controlled devices and choices that may shift energy usage at the discretion of the end use customer (i.e., thermostat controls). User controlled EE to be implicitly modeled in the ProbA through load shape(s) and LFU, since one factor in the variability from the 50/50 demand is end-use customer activities. However, permanent EE to be modeled explicitly in the ProbA, at least to the extent that its impacts are known.

The PAITF recommends the following requirements for Assessment Areas with respect to permanent EE modeling:

- Assessment Areas should provide a narrative on their methodology to determine the impact of permanent EE on the historical demand series used for the ProbA model.
- Assessment Area's should provide a narrative on their methodology to determine the impact of permanent EE on the load growth rate(s) used in the ProbA model.
- If an Assessment Area utilizes permanent EE within an organized market, the Assessment Area must ensure that its impact is removed from the historical demand series and also ensure that the future impact on load is explicitly modeled as either a load modifier or as a resource with some defined level of uncertainty applied to its load reduction capability.

DR resources may be classified into two categories: controllable (or dispatchable) and non-controllable (or non-dispatchable).

- Controllable DR is any DSM activities or programs that are directly controlled or dispatched by the System Operator or Load-Serving Entity to influence the amount of electricity used.

- Non-controllable DR is not controlled or dispatched by the System Operator or Load-Serving Entity (such as Time-of-Use, Critical Peak Pricing, Real Time Pricing and System Peak Response Transmission Tariffs). Much like user controlled EE, non-controlled DR should be modeled implicitly in the ProbA through load shape(s) and LFU. However, controllable DR should be modeled both explicitly.

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[4] 2016 Long Term Reliability Assessment –Data Form Instructions
http://www.nerc.com/comm/PC/Reliability%20Assessment%20Subcommittee%20RAS%202013/2016LTRA_Data_Instructions.pdf

Only controllable DR shall be modeled explicitly in the ProbA. To further expound upon the definition of controllable DR given above, It is useful to consider three different types of DR differentiated by who controls it—customer, distributor/micro-grid, or grid/market authority/system operator.

- **Customer controlled DR** includes such things as price response (especially to real time rates) and building automation. They are considered to be DSM because they respond to lower demand when price is high which may be triggered by a high expectation or actual loss of load. This DSM is not activated because load is high, but rather is price driven. These tend to be correlated but loss of load does not only occur at high loads especially if it is triggered by generator outages or transmission limitations. The big problem with this type of DSM is lack of available data which lead to incomplete models. This is similar to user controlled EE, and for purposes of the ProbA falls outside the scope of controllable DR.
- **Dispatchable** DSM is fairly simple to directly model either as an EOP or as a grid controlled resource. The data is usually readily available and it is, in practice, directly dispatched as needed by the system operator. It has unique features of weather and time-of-day correlations, often a maximum number of occurrences limit and there may be a maximum period over which it may be used. These may need some special treatment in the modeling but they can usually be approximated by utilizing some of the model features designed for thermal or hydro-electric generation is necessary. For the purposes of the ProbA this type of DSM is considered controllable DR.
- **Distributor/Micro-Grid controlled DSM** falls between customer controlled and grid controlled DSM. It is similar to grid controlled but is dispatched based on local needs and system signals such as price. This hybrid DSM is fairly rare so far and specific system characteristics will dictate whether it should be modeled similarly to grid controlled DSM or customer controlled DSM.

Controllable DR, like any other resource should have its intrinsic uncertainty modeled. It has an uncertain capacity impact similar to the uncertainty introduced by thermal generation forced outages. Controllable DR has a much more muted effect typically however as it acts like an aggregation of a large number of small units. Its expected available capacity would exhibit a low variability. This variability is usually much less than the uncertainty in estimating the overall impact. Modeling controllable DR as a deterministic resource may be quite acceptable.

Whether controllable DR is modeled as an EOP or a dispatchable resource doesn't directly impact a probabilistic resource adequacy assessment. However, controllable DR and its intrinsic uncertainty should be modeled explicitly in the ProbA.

PAITF recommends the following requirements Assessment Areas with respect to controllable DR modeling:

- Assessment Area's must provide a narrative on their modeling methodology.
- Assessment Area's must model the limitations associated with controllable DR through one of the following approaches.
    - Assessment areas must model the limitations based on program performance and/or contractual obligations as a load modifier or energy limited resource.
    - If the probabilistic approach is not available, use a net value of MW reduction impact into the model. Include a detailed narrative of how the net value is calculated.

Capacity Modeling

Accurate capacity modeling is important in order to correctly produce probabilistic analysis. Generation resources can be of many forms including, but not limited to, combustion turbine, steam turbine, and pumped storage, utilizing numerous types of fuels such as nuclear, fossil, solar, wind, and hydro. Some entities also consider certain DSM programs as generation resources.

In probabilistic capacity modeling, if the primary energy supply (energy to be converted to electricity) is limited or cannot be controlled by the generator operator, the probability consideration for that capacity will be consistent with the Variable Energy Resources (VER) capacity modeling guidelines in this section. When the primary energy supply (energy to be converted to electricity) is controllable by the generator operator, the probability consideration for that capacity will be based on the equipment outage performance.

Thermal Generation

Combinations of capacity ratings, outage rates, and other thermal parameters such as duration curves and ramp rates can be used to model the variability of thermal generation resources. Below are minimum requirements and PAITF recommendations for thermal generation modeling.

Ratings

The PAITF recommends for Assessment Areas that:

- Thermal generation resources in each Assessment Area should be modeled capturing seasonal capacity ratings. Since the goal of monthly indices such as the LOLH is to identify whether risks are greater in different times of the year, appropriate modeling of seasonal ratings is essential to evaluate risk throughout the calendar year.
- Assessment Area’s narratives shall include how seasonal ratings are derived.
- Thermal generation capacity ratings should be consistent with the LTRA data collection process as indicated in recent LTRA report instructions.

Outage Rates

Forced Outages: Forced-outage rates (FOR) vary between resource types and areas. Most Assessment Areas are using FOR based on annual or seasonal averages. Generator performance is evaluated over long time periods generally 3–5 years and across various seasons. This allows for creating generator performance averages that may include seasonal variations.

PAITF recommends the following for Assessment Areas:

- Incorporating seasonal forced outage factor by either changing forced-outage rates with load or temperature or by derating generation specifically to account for this effect could improve the realism of the ProbA simulations. Model modifications may be needed to accommodate this improvement.
- Unit deratings should be reflected in the FOR, the unit transition states, and/or energy profiles with respect to unit’s historical performances and unit’s data availability.
- Assessment Area’s narratives should include but not be limited to:
    - How forced outage ratings and derates are derived for each unit or by resource fuel type.
    - Ambient and seasonal conditions impacts such as temperature and heat indices.
    - How maintenance and reserve shut down hours are incorporated.
    - What type of FOR is utilized based on units’ loading characteristics (e.g., EFOR or EFORd).

Scheduled Outages:
Scheduled outages should be considered within the probabilistic model. These outages may be categorized into the following groups: 1) Planned Outages—scheduled well in advance, and 2) Maintenance Outages—delayed maintenance in response to unforeseen events. Two approaches may be employed to account for scheduled outages model—random events or fixed schedules.

PAITF recommends with respect to modeling scheduled outages that each Assessment Area document its approach, either as a random schedule or a fixed schedule approach.

Variable Energy Resources

Wind and Solar Energy Resources

Wind and solar resources which are serving the BPS demand are required to be modeled. For instance, the impact of distributed solar should be reflected in load shapes and load forecast uncertainty models. Currently there is no standard method for modeling Variable Energy Resources (VER) in probabilistic assessment of power systems within the industry; however, a range of approaches have been proposed and implemented in academia and industry, each with their own inherent limitations. Given the intermittent nature of VER, these pose challenges in modeling and reliability analyses. It is recommended that a time series model be used in the probabilistic assessment of VER as time series models provide accurate predictions of the behavior of stochastic processes such as the variations in wind speed or solar radiation. The industry has not, however, been ready for using such time series model in probabilistic assessment of power systems containing VER yet. VER should be modeled as a stochastic parameter in the probabilistic assessment in which a key determinant of reliability is the ability of other resources to support the reliability index during periods of low availability of intermittent resources. This means that there needs to be information regarding the uncertainty distribution of the parameter, expressed either as mean and standard deviation in the case of a normal distribution, a more sophisticated non-normal statistical distribution, or as distribution of discrete samplings such as a number of years of historical resource availability (e.g., wind production or hydro production and/or reservoir information). As an interim solution, the following approach may be used:

- VER may be modeled assuming a certain probability distribution. The probability distribution function can be developed with reference to actual historical data. The models should be able to capture the uncertainty distribution of the parameter, expressed either as mean and standard deviation in the case of a normal distribution, a more sophisticated non-normal statistical distribution, or as a distribution of discrete variables such as a number of years of historical resource availability.
- Alternatively, seasonal accredited Capacity Contribution or some time referred to as the Effective Load Carrying Capability (ELCC) for variable resources should be used in the model. At least two values, one for the defined summer period and one for the defined winter period, can be used in the probabilistic assessment.

Each Assessment Area should document how each of these resources are modeled and what data is used. PAITF recommends that each Assessment Area:

- Describe how the ELCC or Capacity Contribution calculation is modeled across the year. If available, monthly or seasonal ELCCs, Capacity Contribution Calculations, or per-unit wind and/or solar generation profiles, based on history, for each significantly different wind or solar patterned zone in each Region/Assessment Area should be modeled.
- Provide the justification and methodology for the determination of the probability distribution function and seasonal accredited values for VER.

- Categorize the existing and annual future installed capacity of all wind resources and solar resources by each significantly different wind or solar patterned zone in your Region/Assessment Area. If available, provide these annual quantities on a monthly or seasonal basis.

Energy limited Resources

Energy limited generation such as hydro generation is an important source for electricity in North America. In some of the jurisdictions (e.g., Manitoba Hydro) energy limited generation comprises up to 90 percent of their total resources.

Typically there are three types of hydro resources including pumped storage, storage capable, and run of river. Currently these resources are primarily modeled either as thermal units or as deterministic load modifiers in probabilistic assessment of power systems in the industry. Modeling energy limited hydro unit as a thermal unit using the average FOR may produce performance results that are too optimistic. Modeling hydro units as simple deterministic load modifiers may not accurately incorporate the uncertainties associated with the primary resource of water; therefore, energy limited resources to be modeled probabilistically to recognize and reflect the variability in the primary source of water.

The PAITF recommends the following for Assessment Areas with respect to energy limited resources' modeling:

- Each Assessment Area should document how each of the energy limited resources are modeled and what data is used:
  - The type of hydro modeling approach currently used.
  - The capacity amount that can be reliably maintained for at least one full hour—designate number of hours if stated capacity amount can be sustained longer than one hour.
  - The annual forced outage rates, based on history, incorporating units impound times.
  - Storage maximum capacity in MWh values incorporating impound and discharging times.
  - The operating procedures for units' charging.
- For probabilistic assessment, water flows developed using historical data. The water flow can be treated as a random variable with a certain distribution and can be treated either as a continuous random variable using probability distribution function (PDF) or as a discrete random variable using probability mass function (PMF). The PDF and the PMF can be developed with reference to the historical water flows.
- Each Assessment Area should document in detail the justifications and methodologies for the development of the PDF/PMF, determination of the probabilities of different water conditions, and the modeling of hydro unit as an equivalent thermal unit
- Once the primary source of energy is modeled, the available capacity and energy can be determined considering the forced unavailability of the generating units and the associated storage capability.
- Alternatively Assessment Areas can model hydro units using the following approximate methods:
  - Deterministic load modifiers considering different water conditions (dry, wet, seasonal) with certain probabilities and calculate the weighted average indices
  - Analytical thermal equivalent approach modifying by either the capacity or the forced outage rate

Behind the Meter Generation

Behind the Meter Generation is a generating unit or multiple generating units on the customer's side of the retail meter that serve all or part of the retail load with electric energy[5]. There is a wide array of methodologies on how the BTMGs are incorporated in each Assessment Area.

PAITF recommends the following for Assessment Areas with regards to the BTMG resources*:*

- Each Assessment Area includes in their narrative if BTMGs are modeled and if so how within their respective areas.
- The narrative needs to detail how each Assessment Area treats the BTMGs, either as a resource or a load modifier, etc. and how they insure that the BTMGs are not double counted.
- For the BTMGs modeled as a resource category, they should follow capacity modeling recommendations.

Capacity Transfers: Imports and Exports

Imports and exports across areas of the BPS are generally categorized as two types: "firm" or "non-firm" transactions. Firm transactions are set in advance with firm scheduled transmission from the seller (source) to the purchaser (sink). Non-firm transactions occur from area-to-area as needed to assist to meet load and reliability obligations and are dependent upon the availability of resources and the transmission system after taking scheduled transactions into account.

Modeling approach for both types of imports and exports to capture: a) the variability in availability of the resources and transmission paths associated with the transactions, and b) the priority of firm transactions over non-firm transactions. However, given the complexity of this modeling approach and software limitations, the following is a list of acceptable modeling approaches from the PAITF for Assessment Areas:

- Firm Imports[6]
    - Net capacity transfers based on historical schedules and/or actual flows
    - Net capacity transfers based on contract amount
    - Internal thermal generation with forced outage rates and a commensurate reduction in the interface limits
- Non-Firm Imports
    - No reliance on non-firm support
    - A function of remaining capacity and interface limits. The interface limits should be adjusted to reflect the firm purchases/sales. Resource allocation should attempt to represent established markets and/or reserve sharing groups as much as possible within the model. See Transmission Modeling section recommendations on establishing interfaces and limitations.
- Firm Exports: Similar to either "Firm Imports" net capacity approaches.
- Non-Firm Exports: Similar to "Non-Firm Imports"

Along with adhering to the recommended approaches to modeling imports and exports, PAITF recommends the following requirements with respect to modeling capacity transactions:

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[5] 2015 LTRA Data Instructions

[6] All approaches should consider firm transmission service and deliverability limitations

- Assessment Areas should coordinate with neighboring areas to determine the appropriate amount of import/export contractual obligations for probabilistic modeling and shall provide documentation of this coordination effort (including impact of imports/exports on the neighboring area's reliability).
- Assessment Areas should coordinate with neighboring areas to determine reasonable assumptions regarding external resources and load modeling that impact non-firm support.
- Assessment Areas should document their modeling methodology and assumptions.
- Assessment Areas should understand and document modeling similarities and differences from the LTRA in terms of peak MW amounts and seasonal/weekly/or daily variations of modeled flows in the probabilistic model.

Emergency Operating Procedures (EOP)

Emergency operating procedures (EOP) provide a plan for system operators when responding to capacity and energy emergencies on their respective systems. These procedures generally include alerts, warnings, as well as event levels to mitigate capacity and energy deficiencies in real-time.

EOP resources are the last line of defense prior to loss of firm load. Each assessment area decides whether or not to include the use of EOP in the planning criteria that determines the minimum amount of planning reserves for its area. Including or excluding the use of EOP in the Core Probabilistic Assessment should be consistent with the planning criteria for the assessment area.

When modeling EOP, Assessment Areas should consider the variability in the amount of relief obtainable and how it is prioritized with respect to other resources in the model. The key modeling assumptions of any EOP action are the priority level assigned to the resource whether capacity or load modifying, the variability of the amount of load and capacity relief, and the relationship these actions have with respect to neighboring modeled systems, particularly with respect to emergency capacity imports and exports.

The PAITF recommends the following for Assessment Areas with respect to EOP modeling:

- Assessment Areas should provide a narrative describing their methodology in determining the amount of EOP benefits for each EOP step. Specifically addressing at a minimum the following:
  - The amount counted for voltage reduction, and how the amount obtainable is determined.
  - The amount counted for public notice, and how the amount obtainable is determined.
  - Summarize all other EOP types, the amount of relief, and how the amount obtainable is determined.
- EOP should be modeled adhering to the guidelines in previous sections (i.e., Thermal, Imports, DR, etc.)
- EOP should be last available action modeled to serve load, and each step of the EOP should be explicitly modeled.
- Seasonal variability of EOP should be included when appropriate (e.g., DR, Capacity Resources, etc.)

If it is not modeled, PAITF recommends that each Assessment Area supplies thorough documentation explaining why they have decided not to model EOP, and summarize the impact this decision has on the probabilistic assessment results.

Transmission Modeling

Internal and external Transmission modeling and deliverability assumptions are key components in producing probabilistic analysis. Often, transmission is modeled deterministically into the probabilistic model, but it can be modeled probabilistically. Flexibility should be maintained to allow Assessment Areas to define their modeling and deliverability requirements.

Transmission systems are typically modeled on a nodal (power flow) or zonal (pipe and bubble) basis. The determination on which method used is dependent on model simulation software capabilities and system characteristics. The amount of transmission zones and interface limits are dependent on the Assessment Areas' topology.

With respect to transmission modeling, PAITF recommends for Assessment Areas the following:

- Internal and external modeling constraints need to be addressed.
- Flexibility should be maintained to allow Assessment Areas to define their modeling and deliverability requirements.
- Each Assessment Area i*nclude*s in their narrative how transmission is *modeled within their respective areas*
- Specify how the transmission limits are determined and the approach(s) being used.
- Document transmission additions and retirements for years two and four that are included in the modeling: explain any differences between the modeled transmission additions and retirements, and explain the differences between the transmission addition and retirement data provided for the LTRA.
- Describe the Assessment Areas' transmission modeling approach: how that approach takes into account transmission constraints and outages within and outside of the Assessment Area, and how it developed the data needed for modeling that is consistent with its planning processes. If transmission constraints (e.g., thermal, voltage, stability, or interface limits) are used in the Assessment Areas' process, the methodology should be described. The Assessment Areas should also describe how deliverability of internal and external resources as well as access to external supplemental resources are addressed.

Sensitivity and Scenario Modeling

Sensitivity Modeling: Sensitivity analyses are run to assess the impact of a change in an input (either load, transmission or resource-related) on resource adequacy metrics. The runs are performed by changing one input at-a-time in order to isolate the potential impact of each input. Ideally, the change in each input should be accompanied by an associated probability.

Scenario Modeling: In its most general form, a scenario analysis is performed to assess the impact of changes in multiples inputs (either load, transmission or resource-related) on resource adequacy metrics. The runs are performed by changing multiple inputs at the same time. Ideally, each scenario should have an associated probability calculated based on the changes in inputs included within the scenario. Scenarios are likely to be identified in the LTRA or by sensitivity analysis results. In some cases, scenario analysis may require additional inputs (not included in the Core Probabilistic Assessment) relevant to address a specific reliability concern.

PAITF recommends the following for Assessment Areas:

- The sensitivity modeling should be addressed within the Core Probabilistic Assessment framework. NERC RAS identifies the variable data elements relevant to each sensitivity modeling.
- The scenario modeling should address the reliability issues identified within the LTRA that impact resource adequacy, within the Special-Coordinated Probabilistic Assessment framework. NERC ERO-RAPA and the PC identify reliability risk issues for scenario analysis, and NERC RAS evaluates input parameters relevant to each candidate scenario.

Coordinated NERC Regional Special Assessments

This approach is a coordinated effort between NERC and the Regions to utilize a common assessment method to evaluate and report on various resource adequacy issues. The purpose of this approach is to address potential resource adequacy concerns. The approach will identify uncertainties and trends using a uniform NERC probabilistic analysis. NERC will work closely with the Regions and Assessment Areas to conduct complimentary analyses to assess potential risks to reliability.

Special Assessment Determination

Driving factors are key findings from NERC's LTRA and core probabilistic assessments. If there is no existing study effort or market rules to address the issues, NERC (with inputs from RAS, PC, and ERO-RAPA as well as the Assessment Areas) will develop the risk analysis framework to identify the need to perform this assessment. NERC, the Regions, and representatives from each Assessment Area will work closely together to sufficiently conduct the analysis.

Roles and Responsibilities

A Coordinated NERC-Regional Special Assessment encompasses the deployment of a coordinated effort between NERC and the Regions to evaluate, assess, and report developing reliability concerns on Assessment Area resource adequacy using a common assessment method as shown below:

- **Coordination**: NERC will work closely with the Region(s) and Assessment Areas to develop a complementary study scope. Study results developed throughout the study will be shared with NERC and the Regions.
- **Data Collection**: The Region(s) will be responsible for collecting the required data to run the probabilistic study.
- **Modeling**: NERC has in-house probabilistic modeling capabilities to run a special assessment and responsibilities of running the model will be determined through a scope of work document.
- **Reviewing**: Overall peer review process is determined in the scope of work through NERC RAS. Inputs and feedback from the PC and ERO-RAPA are key elements in the development. Endorsements and approval process are topic dependent.

Modeling Requirements and Scope of Work

The special assessment should follow the general methods and assumptions of this Technical Guideline Document; however, deviations from general methods and assumptions may be required to support the scope of the special assessment work. This special assessment occurs at the request of NERC's PC and ERO-RAPA focusing on specific systems and areas of concern. Detailed milestones are left for NERC and Region(s) to assign.

Appendix A: Definitions

Backup/standby generators: These are customer owned generators that may be used to supply emergency power or other short term power needs. If this generation is obligated to operate at the instruction of a system operator, and will supply BPS demand, it can be included as a capacity resource. If operation is at the discretion of the backup/standby generator owner, this generator must be excluded.

BPS demand: This is the aggregated customer demand that the BPS is responsible for supplying from the BPS facilities.

Capable of supplying: These are resources that are connected to the BPS or are resources that reduce the BPS demand when generating.

Directly or indirectly supplied BPS demand: Direct supply is generation controlled by a BPS operator. Indirect supply is BTM generation that reduces BPS demand.

Direct or indirect instruction: Dispatch instructions provided to the generator operator via phone call or EMS signal (direct) or instructions provided to a third party that contacts the operator (indirect).

Future generating resource: A generator facility, planned or under construction, but not expected to be in commercial service by the end of the current calendar year.

Non-BPS demand: This is demand that is not included in any aggregation of BPS demand. This is customer demand supplied solely by customer owned generation.

NSC—Net seasonal capability: The maximum MW output of the generator given the expected ambient conditions of the season.

Primary energy supply: The energy (coal, wind, sunlight, water in a reservoir, etc.) delivered to the generating resource that is converted to electricity.

Appendix B: Contacts

The North American Electric Reliability Corporation

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3353 Peachtree Road NE, Suite 600 – North Tower
Atlanta, GA 30326
404-446-2560

Washington, D.C.
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Washington, DC 20005
202-400-3000

NERC Staff

Name	Position
Mark Lauby	Senior Vice President and Chief Reliability Officer
John N. Moura	Director, Reliability Assessment and System Analysis
Thomas Coleman	Director, Reliability Assessment
Noha Abdel-Karim	Senior Engineer, Reliability Assessment
David Calderon	Engineer, Reliability Assessment
Elliott Nethercutt	Senior Technical Advisor, Reliability Assessment
Michelle Marx	Executive Assistant, Reliability Assessment and System Analysis

NERC Probabilistic Assessment Improvement Task Force Roster[7]

Name	Region/Organization
Josh Collins (Chairman)	SERC
Layne Brown	WECC
Matthew Elkins	WECC
Vince Ordax	FRCC
Richard Becker	FRCC
Philip A. Fedora	NPCC
Ryan Westphal	MISO
Jordan Cole	MISO
Chris Haley	SPP
Alex Crawford	SPP
Paul Kure	RF
Patricio Garrido	PJM
Lewis De La Rosa	TEXAS-RE
Brad Wood	TEXAS-RE
Kevan Jefferies	Ontario Power Generation
David Jacobson	Manitoba Hydro
Bagen Bagen	Manitoba Hydro
Dange Huang	Manitoba Hydro
Joel Dison	Southern Company
Dale Burmester	American Transmission Company
Russell Schussler	Georgia Transmission Corporation
Anish Gaikwad	Electric Power Research Institute
Mark Walling	GE Energy Management
Chi Hung Kelvin Chu	GE Energy Management
Salva Andiappan (Observer)	MRO
Alan Phung (Observer)	FERC
Richard Sobonya (Observer)	FERC

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[7] Probabilistic Assessment Improvement Task Force (PAITF) is a task force from the PC members, members from the RAS and selected observers from the industry. PAITF was formed in May 2015, following the March 2015 release of the 2014 Probabilistic Assessment report with a main mission to identify improvement opportunities by developing an improvement plan and a Probabilistic Technical Guideline Document with recommendations to enhance NERC's future probabilistic assessments.

Appendix C: Full List of Recommendations

- NERC to develop and maintain documentation describing the establishment of Assessment Areas.
- Core ProbA to remain biennial work product.
- It is at the discretion of each Assessment Area to select their solution tool, provided that metrics are calculated through simulation (e.g., Monte Carlo or convolution), while also adhering to all load, generation, and transmission modeling requirements/criteria/guidelines.
- In general resources modeled in Core ProbA to align with the LTRA Data Form Instructions with some exclusions of future generating resources based on confidence factor of resource being built.

Load Modeling

- **Each Assessment Area should incorporate both annual peak uncertainty and seasonal variation** in their load modeling.
- Each Assessment Area should submit a narrative describing their load modeling assumptions.
- Narratives should also include assumptions made on Demand-Side Management (DSM) modeling within the load shapes and forecasts. The DSM section highlights requirements and DSM modeling improvements.
- Load Forecast Uncertainty (LFU) must be incorporated into the ProbA models at a minimum. The industry standard for LFU modeling is to calculate the probability of load exceeding or falling below the forecast. LFU application can be conducted as a multiplier to the load shape(s), captured in multiple weather years modeling, or a combination thereof.
    - This LFU should capture the uncertainty due to weather and economics.
- Weather, economic and forecast trend uncertainty include:
    - Conservation and energy efficiency
    - Historic and future embedded variable generation (wind and solar mainly)
    - Controllable or dispatchable demand response
    - Other load shapes within the Assessment Area (among internal transmission zones)
    - Load shapes of outside areas (external Assessment Areas)
- What is included or excluded from the 50/50 base forecast should be detailed in each Assessment Area's narrative. This narrative should also include the methodology to calculate the 50/50 forecasted load for the study years and how that applies to the load shapes within the model.

Permanent Energy Efficiency Modeling (DSM)

- Assessment Areas should provide a narrative on their methodology to determine the impact of permanent EE on the historical demand series used for the ProbA model.
- Assessment Area's should provide a narrative on their methodology to determine the impact of permanent EE on the load growth rate(s) used in the ProbA model.
- If an Assessment Area utilizes permanent EE within an organized market, the Assessment Area must ensure that its impact is removed from the historical demand series and also ensure that the future impact on load is explicitly modeled as either a load modifier or as a resource with some defined level of uncertainty applied to its load reduction capability.

Controllable Demand Response Modeling (DSM)

- Assessment Area's must provide a narrative on their modeling methodology.
- Assessment Area's must model the limitations associated with controllable DR through one of the following approaches.
- Assessment areas must model the limitations based on program performance and/or contractual obligations as a load modifier or energy limited resource.
- If the probabilistic approach is not available, use a net value of MW reduction impact into the model. Include a detailed narrative of how the net value is calculated

Capacity Ratings

- Thermal generation resources in each Assessment Area should be modeled capturing seasonal capacity ratings. Since the goal of monthly indices such as the LOLH is to identify whether risks are greater in different times of the year, appropriate modeling of seasonal ratings is essential to evaluate risk throughout the calendar year.
- Assessment Area's narratives shall include how seasonal ratings are derived.
- Thermal generation capacity ratings should be consistent with the LTRA data collection process as indicated in recent LTRA report instructions.

Forced Outages

- Incorporating seasonal forced outage factor by either changing forced-outage rates with load or temperature or by derating generation specifically to account for this effect could improve the realism of the ProbA simulations. Model modifications may be needed to accommodate this improvement.
- Unit deratings should be reflected in the FOR, the unit transition states, and/or energy profiles with respect to unit's historical performances and unit's data availability.
- Assessment Area's narratives should include but not be limited to:
    - How forced outage ratings and derates are derived for each unit or by resource fuel type.
    - Ambient and seasonal conditions impacts such as temperature and heat indices.
    - How maintenance and reserve shut down hours are incorporated.
    - What type of FOR is utilized based on units' loading characteristics (e.g., EFOR or EFORd).

Scheduled Outages

- PAITF recommends with respect to modeling scheduled outages that each Assessment Area document its approach, either as a random schedule or a fixed schedule approach.

Variable Energy Resource (VER) Modeling

- VER may be modeled assuming a certain probability distribution. The probability distribution function can be developed with reference to actual historical data. The models should be able to capture the uncertainty distribution of the parameter, expressed either as mean and standard deviation in the case of a normal distribution, a more sophisticated non-normal statistical distribution, or as a distribution of discrete variables such as a number of years of historical resource availability.
- Alternatively, seasonal accredited Capacity Contribution or some time referred to as the Effective Load Carrying Capability (ELCC) for variable resources should be used in the model. At least two values, one for the defined summer period and one for the defined winter period, can be used in the probabilistic assessment.
- Each Assessment Area should document how each of these resources are modeled and what data is used. PAITF recommends that each Assessment Area:
    - Describe how the ELCC or Capacity Contribution calculation is modeled across the year. If available, monthly or seasonal ELCCs, Capacity Contribution Calculations, or per-unit wind and/or solar generation profiles, based on history, for each significantly different wind or solar patterned zone in each Region/Assessment Area should be modeled.
    - Provide the justification and methodology for the determination of the probability distribution function and seasonal accredited values for VER.

Energy-Limited Resource Modeling

- Each Assessment Area should document how each of the energy limited resources are modeled and what data is used:
    - The type of hydro modeling approach currently used.
    - The capacity amount that can be reliably maintained for at least one full hour—designate number of hours if stated capacity amount can be sustained longer than one hour.
    - The annual forced outage rates, based on history, incorporating units impound times.
    - Storage maximum capacity in MWh values incorporating impound and discharging times.
    - The operating procedures for units' charging.

- For probabilistic assessment, water flows developed using historical data. The water flow can be treated as a random variable with a certain distribution and can be treated either as a continuous random variable using probability distribution function (PDF) or as a discrete random variable using probability mass function (PMF). The PDF and the PMF can be developed with reference to the historical water flows.
- Each Assessment Area should document in detail the justifications and methodologies for the development of the PDF/PMF, determination of the probabilities of different water conditions, and the modeling of hydro unit as an equivalent thermal unit
- Once the primary source of energy is modeled, the available capacity and energy can be determined considering the forced unavailability of the generating units and the associated storage capability.
- Alternatively Assessment Areas can model hydro units using the following approximate methods:
    - Deterministic load modifiers considering different water conditions (dry, wet, seasonal) with certain probabilities and calculate the weighted average indices
    - Analytical thermal equivalent approach modifying by either the capacity or the forced outage rate

Behind-the-meter Generation (BTMG)

- Each Assessment Area includes in their narrative if BTMGs are modeled and if so how within their respective areas.
- The narrative needs to detail how each Assessment Area treats the BTMGs, either as a resource or a load modifier, etc. and how they insure that the BTMGs are not double counted.
- For the BTMGs modeled as a resource category, they should follow capacity modeling recommendations.

Emergency Operating Procedures (EOP)

- Assessment Areas should provide a narrative describing their methodology in determining the amount of EOP benefits for each EOP step. Specifically addressing at a minimum the following:
    - The amount counted for voltage reduction, and how the amount obtainable is determined.
    - The amount counted for public notice, and how the amount obtainable is determined.
    - Summarize all other EOP types, the amount of relief, and how the amount obtainable is determined.
- EOP should be modeled adhering to the guidelines in previous sections (i.e., Thermal, Imports, DR, etc.)
- EOP should be last available action modeled to serve load, and each step of the EOP should be explicitly modeled.
- Seasonal variability of EOP should be included when appropriate (e.g., DR, Capacity Resources, etc.)
- If it is not modeled, PAITF recommends that each Assessment Area supplies thorough documentation explaining why they have decided not to model EOP, and summarize the impact this decision has on the probabilistic assessment results.

Transmission Modeling

- Internal and external modeling constraints need to be addressed.
- Flexibility should be maintained to allow Assessment Areas to define their modeling and deliverability requirements.
- Each Assessment Area includes in their narrative how transmission is modeled within their respective areas
- Specify how the transmission limits are determined and the approach(s) being used.
- Document transmission additions and retirements for years two and four that are included in the modeling: explain any differences between the modeled transmission additions and retirements, and explain the differences between the transmission addition and retirement data provided for the LTRA.
- Describe the Assessment Areas' transmission modeling approach: how that approach takes into account transmission constraints and outages within and outside of the Assessment Area, and how it developed the data needed for modeling that is consistent with its planning processes. If transmission constraints (e.g., thermal, voltage, stability, or interface limits) are used in the Assessment Areas' process, the methodology should be described. The Assessment Areas should also describe how deliverability of internal and external resources as well as access to external supplemental resources are addressed.

Sensitivity & Scenario Modeling

- The sensitivity modeling should be addressed within the Core Probabilistic Assessment framework. NERC RAS identifies the variable data elements relevant to each sensitivity modeling.
- The scenario modeling should address the reliability issues identified within the LTRA that impact resource adequacy, within the Special-Coordinated Probabilistic Assessment framework. NERC ERO-RAPA and the PC identify reliability risk issues for scenario analysis, and NERC RAS evaluates input parameters relevant to each candidate scenario.

Attachment O

FERC Docket No. EL25-90, submission of MPSC, June 20, 2025, p. 2.

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Consumers Energy Company **v.** **Midcontinent Independent System Operator, Inc.**	)))))))	**Docket No. EL25-90-000**

COMMENTS OF MICHIGAN PUBLIC POWER AGENCY IN SUPPORT OF COMPLAINT

Pursuant to Rule 213 of the Rules of Practice and Procedure of the Federal Energy Regulatory Commission ("FERC" or the "Commission"),[1] Michigan Public Power Agency ("MPPA") respectfully submits these comments in support of the June 6, 2025, complaint of Consumers Energy Company ("Consumers Energy" or "Consumers") against Midcontinent Independent System Operator, Inc. ("MISO") (the "Complaint").[2] For the reasons set forth below, the Commission should grant the Complaint and the relief requested therein.

I. COMMENTS

MPPA owns a 4.80% interest in Unit No. 3 of the Campbell Plant and supports the Complaint.[3] MPPA purchased its ownership interest through the 1979 Campbell Unit No. 3 Ownership and Operating Agreement ("O&O Agreement"). Article 7 of the O&O Agreement provides that MPPA and Consumers Energy shall share all operating costs of Unit No. 3 in proportion to their ownership interests in the unit.[4] Operating costs include operation and

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[1] 18 C.F.R. § 385.213.

[2] *Consumers Energy Company v. Midcontinent Independent System Operator, Inc.*, Complaint, Docket No. EL25-90-000 (filed June 6, 2025) ("Complaint"). MPPA filed a (doc-less) motion to intervene in this proceeding on June 13, 2025.

[3] *Id.* at n.12.

[4] 1979 Campbell Unit No. 3 Ownership and Operating Agreement, § 7.2.

maintenance expenses and the portion of administrative and general expenses of Consumers Energy's system-wide electric operations which is attributable to Unit No. 3.[5]

Consumers Energy planned to retire the Campbell Plant on or about May 31, 2025. However, on May 23, 2025, the Department of Energy ("DOE") ordered Consumers Energy to continue to operate the plant at least until August 21, 2025.[6] Consumers Energy's Complaint explains that, as a result of the DOE Order, the owners may incur costs (net of any market revenues) related to the extended operation of the Campbell Plant past its planned retirement date of May 31, 2025.[7] Currently, no mechanism in the MISO Open Access Transmission, Energy and Operating Reserve Markets Tariff ("Tariff") enables the owners of the Campbell Plant to recover their costs (net of any market revenues) associated with the plant's continued operations. The DOE Order directed Consumers to file tariff revisions or waivers necessary to effectuate the DOE Order, stating that rate recovery is available pursuant to 16 U.S.C. § 824a(c).[8] The Complaint requests that the Commission direct MISO to revise its Tariff pursuant to sections 202(c)[9] and 309 of the Federal Power Act ("FPA"), or in the alternative grant relief pursuant to section 206, to add a new rate schedule pursuant to which a later filing may be made to recover costs incurred to comply with the DOE Order to the extent not recovered through market revenues.[10]

Consumers Energy's proposed cost recovery mechanism is just and reasonable. The only costs that the Complaint seeks to recover through the proposed cost recovery mechanism are those net of market revenues, which appropriately limits the recovery of the costs of the Campbell Plant from MISO customers in the central and north regions to those costs the owners were unable to

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[5] *Id.* § 7.1.

[6] U.S. Department of Energy, Order No. 202-25-3 (May 23, 2025) ("DOE Order").

[7] Complaint at 3-4.

[8] DOE Order at F.

[9] Section 202(c) provides that the Commission may prescribe just and reasonable terms, "including the compensation or reimbursement which should be paid to or by any such party." *See* 16 U.S.C. § 824a(c)(1).

[10] 16 U.S.C. §§ 824a(c), 825h, 824e.

recover in the market and avoids over recovery of such costs. Likewise, the proposal to recover such costs only from MISO Zones 1 through 7 represents a just and reasonable approach.[11] The Commission's beneficiary pays/cost causation principles provide that costs should be allocated to those who caused the costs and benefit from the costs. The central and north regions of MISO will benefit from the Campbell Plant's continued operation, as reflected by the discussion in the DOE Order.[12]

Because the Campbell Plant is in MISO and will be participating in MISO's markets, Consumers Energy's proposal for MISO to revise its Tariff to provide for the recovery of those costs is reasonable. It would not be feasible for Consumers Energy or the Commission to try to create a framework outside of MISO that would allocate the costs to those who benefited from the plant's operation.[13]

As a co-owner of the Campbell Plant, Unit No. 3, MPPA will be required to pay its share of costs related to its continued operations. MPPA has a right to recover its costs for the same reasons Consumers Energy has a right to recover its costs.[14] MPPA appreciates that Consumers Energy has recognized that right and has committed to coordinating with MPPA on its cost recovery.[15] Thus, MPPA agrees that for Consumers Energy and MPPA "to have a means of recovering the costs that [they] [have] a right to recover, the MISO Tariff must be amended to include an appropriate [cost] recovery mechanism."[16]

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[11] Complaint at 17-18.
[12] DOE Order at 2.
[13] *See* Complaint at 4, 18.
[14] *Id.* at 11-13.
[15] *Id.* at n.12; *see also id.* at Attachment A ("Consumers Energy (on its own behalf and, as necessary, on behalf of the minority interest owners in Campbell Unit 3, Wolverine Power Supply Cooperative, Inc. and the Michigan Public Power Agency) shall petition FERC to approve recovery of Order Costs, net of market revenues, that FERC determines are recoverable pursuant to section 202(c)….").
[16] *Id.* at 18.

II. CONCLUSION

WHEREFORE, for the foregoing reasons, MPPA respectfully requests that the Commission grant the Complaint so that the owners of the Campbell Plant may recover the costs they incur, net of market revenues, to comply with the DOE Order.

Respectfully submitted,

//s// Alan I. Robbins
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Counsel to Michigan Public Power Agency

Dated: June 20, 2025.

CERTIFICATE OF SERVICE

I hereby certify that I have this day served the foregoing document upon each person designated on the official service list compiled by the Secretary of the Federal Energy Regulatory Commission in this proceeding.

Dated at Washington, D.C. this 20th day of June, 2025.

//s// Jessika Dziechciowska
Jessika Dziechciowska
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Attachment P

Michigan AG Request for Rehearing of Order No. 202-25-3

UNITED STATES OF AMERICA
BEFORE THE
UNITED STATES DEPARTMENT OF ENERGY

Order No. 202-25-3

REQUEST FOR REHEARING BY MICHIGAN ATTORNEY GENERAL DANA NESSEL

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Michigan Attorney General

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Special Assistant Attorney General
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Dated: June 18, 2025

Pursuant to section 313*l* of the Federal Power Act ("the Act"), 16 U.S.C. § 825*l*, Michigan Attorney General Dana Nessel, on behalf of the people of the State of Michigan, requests that the Department of Energy (Department or DOE) grant rehearing of Order No. 202-25-3 (May 23, 2025) ("Order"). The Order invoked the Department's emergency authority under section 202(c) of the Act to prevent the scheduled retirement of the J.H. Campbell power plant (J.H. Campbell) in West Olive, Michigan.

The Order is an unlawful abuse of the Department's emergency authority. Until now, the Department has reserved section 202(c) for real emergencies like natural disasters and extreme weather and has typically acted at the behest of grid operators or governmental bodies. In the Order, acting on its own motion and without notice, the Department declares that the retirement of J.H. Campbell presents an emergency. But the Order's emergency determination cannot bear even the mildest scrutiny.

The scheduled retirement of J.H. Campbell was the culmination of a carefully planned process that unfolded over four years. Under the oversight of the Michigan Public Service Commission (MPSC), Consumers Energy (Consumers) executed a plan to retire an old and inefficient facility, J.H. Campbell, and replace it largely with newer resources that would both increase Consumers' available generation capacity and save its ratepayers money. J.H. Campbell's proposed retirement was also studied carefully by the Midcontinent Independent System Operator (MISO), the regional grid operator, which determined that the facility could retire without causing reliability issues.

In the Order, the Department uses its authority under section 202(c) in a manner untethered from the need to identify a real emergency and unhindered by the statutory requirement that the actions it orders go no further than necessary to address the emergency. The result of this overreach will be unnecessary costs imposed on already-overburdened ratepayers, needless pollution emitted into Michigan and its neighboring states, and an unprecedented intrusion into the authority of states and the Federal Energy Regulatory Commission to regulate the resource adequacy of our electric grid.

I. MOTION TO INTERVENE

The Michigan Attorney General,[1] on behalf of the people of the State of Michigan, moves to intervene in this proceeding and thereby to become a party for purposes of Section 313*l* of the Act, 16 U.S.C. § 825*l*. The People of the State of Michigan have an interest in and are aggrieved by the Order in several ways. First, households and businesses in Michigan will pay higher electricity bills as a result of the Order. The retirement of J.H. Campbell and its replacement with more cost-effective resources were elements of a careful plan expected to save Michigan

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[1] *See* MCL 14.28 ("The attorney general . . . may, when in [her] own judgment the interests of the state require it, intervene in and appear for the people of this state in any other court or tribunal, in any cause or matter, civil or criminal, in which the people of this state may be a party or interested."). *See also In re Certified Question*, 465 Mich 537, 543-545; 638 NW2d 409 (2002), *Gremore v Peoples Community Hospital Authority*, 8 Mich App 56; 153 NW2d 377 (1967), and *People v O'Hara*, 278 Mich 281; 270 NW2d 298 (1936).

ratepayers nearly $600 million.[2] By ordering the continued operation of J.H. Campbell, the Order ensures that Michigan ratepayers will pay higher costs. Although the precise amounts of costs are not yet known, it is certain that Michigan ratepayers will be stuck with substantial new costs in excess of what they would have paid absent the Order.

Second, the People of the State of Michigan will suffer environmental harms as a result of the Order. J.H. Campbell is a significant source of particulate matter, nitrogen oxides, sulfur oxides, and carbon dioxide,[3] among other pollutants. By prolonging the operations of J.H. Campbell beyond its planned retirement date, the Order will increase the amount of pollution emitted in the state of Michigan, causing harms to the public health and welfare.

Third, the retirement of J.H. Campbell on May 31, 2025, was a provision agreed to as part of a settlement agreement in Michigan Public Service Commission Case (MPSC) No. U-21090, to which the Michigan Attorney General was a party. Because the Order deprives the Michigan Attorney General of the benefit of her bargain under the settlement agreement, the Michigan Attorney General will suffer a discrete and separate harm as a result of the Order.

II. BACKGROUND

A. DOE's Historical Use of Section 202(c).

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[2] *See* Michigan Public Service Commission Case No. U-21090-0867, Reply Brief of Consumers at 1 – 2, available at https://mi-psc.my.site.com/sfc/servlet.shepherd/version/download/0688y0000032ZSXAA2.

[3] *See In the Matter of the Application of Consumers Energy Co. for Approval of Its Integrated Res. Plan Pursuant to Mcl 460.6t & for Other Relief.*, No. U-21090, 2022 WL 2915368, at *73 (June 23, 2022).

In the past, the Department has used section 202(c) sparingly. The Department has used this authority only in response to concrete, particularized emergencies, and subject to limitations to ensure that the Department's reach extends no further than necessary to address the emergency at hand.

Between enactment of the Department of Energy Organization Act in 1977, Pub. L. No. 95-91, and the end of last year, the Department appears to have used section 202(c) nineteen times, not counting amendments and extension orders. DOE's first usage of section 202(c) came in response to the California Energy Crisis in 2000.[4] That order was followed by two others directing the operation of the Cross-Sound Cable, a submarine transmission line connecting New York and Connecticut that was complete but that had been delayed from entering service due to environmental permitting issues.[5] But by far the most common usage – comprising 13 of 19 instances – has been in response to extreme weather events such as hurricanes,[6] extreme cold,[7] and extreme heat.[8] In each of these weather-driven cases, the exercise of emergency power was requested by the relevant system operator or responsible utility, or both.

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[4] DOE, *Order Pursuant to Section 202(c) of the Federal Power Act* (Dec. 14, 2000). Section 202(c) was used by the Federal Power Commission prior to the Department of Energy Organization Act's creation of DOE. Those uses were generally limited to orders directing interconnection as a result of discrete and sudden emergencies or war. *See* Benjamin Rolsma, *The New Reliability Override*, 57 U. Conn. L. Rev. 789, 822 (2025).

[5] *See* DOE Order No. 202-02-1 (Aug. 16, 2002); DOE Order No. 202-03-01 (Aug. 14, 2003).

[6] *See* DOE Order Nos. 202-05-1 & -2 (Sept. 28, 2005) (response to Hurricane Rita); DOE Order No. 202-08-1 (Sept. 14, 2008) (Hurricane Ike); DOE Order No. 202-20-1 (Aug. 27, 2020) (Hurricane Laura); DOE Order No. 202-24-1 (Oct. 9, 2024) (Hurricane Milton).

[7] *See* DOE Order No. 202-21-1 (Feb. 14, 2021); DOE Order No. 202-22-3 (Dec. 23, 2022); DOE Order No. 202-22-4 (Dec. 24, 2022).

[8] *See* DOE Order No. 202-20-2 (Sept. 6, 2020) (responding to extreme heat in California); DOE Order No. 202-21-2 (responding to extreme heat, wildfires and drought in California); DOE Order Nos. 202-22-1 & 2 and amendments (same).

And in each, DOE carefully limited its remedy to ensure that generation facilities were only ordered to run in circumstances necessary to address the emergency and in a manner so as to minimize any conflict with environmental requirements.[9] DOE also limited the duration of those orders to the minimum period necessary to address the emergency, often shorter than 10 days.[10]

Prior to the Order, DOE had used section 202(c) on three occasions to delay the retirement of generation facilities.[11] These cases had key features in common. In each: (i) the order was requested by a system operator or governmental body; (ii) the generation facility had ceased or would soon cease operation due to an inability to comply with environmental laws; (iii) the request aimed to address a concrete and particularized emergency threatening an imminent loss of load; and, (iv) DOE tailored its order to go no further than necessary to address the emergency.

The first such instance came in 2004, when the District of Columbia's Public Service Commission requested an order directing the continued operation of a power plant located in Alexandria, Virginia, owned by the Mirant Corporation (Mirant). After its state regulator found the plant to be out of compliance with its air permit, Mirant abruptly announced that the plant would close.[12] The D.C. Public Service Commission, supported by the local utility, PEPCO, explained that the Mirant facility

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[9] *See supra* notes 3 – 5.
[10] *Id.*
[11] Nor did the DOE's predecessor agency, the Federal Power Commission, use section 202(c) to delay retirement of any generation units between the section's enactment in 1935 and the formation of DOE in 1977. *See* Rolsma, 57 U. Conn. L. Rev. at 843-46.
[12] DOE Order No. 202-05-3 (Dec. 20, 2005) at 1 (explaining that Mirant provided emissions information to its state regulator on August 19, 2005, the regulator demanded immediate action that same day, and Mirant decided to cease operations on August 24).

directly powered downtown D.C. and that, without it, critical federal infrastructure faced an unacceptable risk of blackout.[13] Before acting on the request, the Department commissioned an analysis from the Oak Ridge National Laboratory that confirmed the threat that the plant's closure would pose to reliability in D.C.[14] Based on that study, and based on the severity of the harm that could result from a prolonged power outage to downtown D.C., the Department issued an order directing the continued operation of the Mirant facility.[15] The Department took pains, however, to limit its order to go no further than necessary to address the emergency. The Department directed Mirant to maintain the facility's capacity to respond when needed, but only ordered it to run when one or both of the 230 kV transmission lines serving downtown D.C. were out of service.[16]

Twelve years later, in 2017, the Department received a request from the Grand River Dam Authority (GRDA), an Oklahoma state agency, to direct the continued operation of Unit No. 1 at the Grand River Energy Center. GRDA explained that the Grand River Energy Center was needed to provide dynamic reactive power support to the local grid, a fact confirmed by the region's Reliability Coordinator, the Southwest Power Pool (SPP). GRDA explained, however, that it would be unable to provide reactive power without action from DOE. Unit No.1, the subject of the request, had been ordered to close by an Administrative Order of the Environmental Protection Agency. Unit No. 2 had been struck by lightning and was under repair.

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[13] *Id*. at 2.

[14] *Id*. at 3 – 4.

[15] *Id*. at 5 – 8.

[16] *Id*. at 10 – 11.

And, construction of the new Unit No. 3 had been delayed because flooding in Louisiana interfered with the fabrication of essential project materials.[17] The Department granted GRDA's request, ordering Unit No. 1 to remain in operation for 90 days or until Unit No. 2 or Unit No. 3 were brought online, whichever came first.[18] The Department strictly limited its remedy, directing GRDA only to provide "dynamic reactive power support and not real power generation, and only when called upon by SPP for reliability purposes."[19]

Later that year, the Department received a pair of requests from PJM and Dominion Virginia (Dominion) to direct the continued operation of Units 1 and 2 of the Yorktown Power Station. PJM and Dominion explained that, based on PJM load flow studies, these units were necessary to prevent uncontrolled power disruptions and shedding of critical loads in the North Hampton Roads area east of Richmond.[20] DOE issued an order directing Dominion to maintain operation at the two units, but to dispatch those units "only when called upon by PJM for reliability purposes."[21] DOE later extended the order several times due to the delayed completion of the transmission line needed to resolve the reliability issue. In doing so, DOE cited the "imminent" risk of load-shedding in the North Hampton Roads area absent extension of the order.[22] In its extension order, the Department continued to limit dispatch of

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[17] Letter Request of Grand River Dam Authority, April 11, 2017. Available at https://www.energy.gov/sites/default/files/2017/05/f34/GRDA%20public%20202%28c%29%20letter.pdf.

[18] DOE Order No. 202-17-1 at 2.

[19] *Id.*

[20] DOE Order No. 202-17-2, at 1.

[21] *Id.* at 2.

[22] DOE Order No. 202-17-4, Summary of Findings, Sept. 14, 2017.

the units only when called upon by PJM for reliability purposes and, further, directed PJM and Dominion to exhaust available resources, including demand response and behind-the-meter generation resources, prior to operating the units.[23]

B. Executive Order 14262 and the White House Strategy to Prop Up the Coal Industry.

Over the past several months, the White House and the Department have sought to radically transform how section 202(c) of the Federal Power Act is applied, departing in almost every material respect from the longstanding approach described above. As shown below, the Order cannot be understood intelligibly as a response to a discrete event or emergency akin to past orders under section 202(c). Rather, it can only be understood as part of a long-term and multi-part strategy to preserve coal and other fossil fuel generation under the guise of grid reliability concerns.

On April 8, 2025, President Trump issued Executive Order 14262, *Strengthening the Reliability and Security of the United States Electric Grid*.[24] The Executive Order was issued concurrently with three other executive actions aimed at supporting the coal industry that were announced at a White House political event explicitly focused on that objective.[25] This event, and the related Executive Order, are one of several in a series of public actions by the Administration aimed at reversing coal plant retirements and promoting fossil fuel generation.

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[23] DOE Order No. 202-17-4 at 2.

[24] Executive Order 14262, 90 Fed. Reg. 15521 (April 14, 2025).

[25] New York Times, *Trump Signs Orders Aimed at Reviving a Struggling Coal Industry* (April 8, 2025); Executive Order 14261, *Reinvigorating Americans Beautiful Clean Coal Industry and Amending Executive Order 14241*, 90 Fed. Reg. 15517 (April 14, 2025); Executive Order 14260, *Protecting American Energy from State Overreach*, 90 Fed. Reg. 15513 (April 14, 2025); *Regulatory Relief for Certain Stationary Sources To Promote American Energy*, 90 Fed. Reg. 16777 (April 21, 2025).

Executive Order 14262 directs DOE to, among other things, streamline and expedite the issuance of emergency orders under section 202(c), specifically in order to "safeguard the reliability and security of the United States' electric grid during periods when the relevant grid operator forecasts a temporary interruption of electricity supply [that] is necessary to prevent a complete grid failure."[26] It also directs DOE to take a subsequent series of actions related to national resource adequacy, including mandating:

- the development of a uniform methodology for assessing reserve margins and identifying "at-risk" regions;
- establishment of a process by which the developed methodology and any analysis results are regularly assessed; and,
- establishment of a protocol to identify generation resources within a region that are critical to system reliability, a mechanism under section 202(c) to ensure such generation resources are appropriately retained and, for resources over 50MW, are prevented from leaving the bulk-power system or converting their source of fuel.[27]

DOE has not yet published the analysis or protocols—the deadline provided in Executive Order 14262 is July 7.

Executive Order 14262 states that it is intended to help address the national energy emergency declared in the earlier-issued Executive Order 14,156, *Declaring a National Energy Emergency*.[28] In fact, this order is part of a broader pattern in which the Administration has expansively invoked emergency powers to achieve long-standing political objectives, rather than respond to genuine, unforeseen crises. The

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[26] Executive Order 14262 section 3(a).
[27] Executive Order 14262 section 3(b), (c).
[28] Executive Order 14262, section 2.

President has declared eight national emergencies in 2025 alone—more than any other President in the first 100 days of an administration.[29]

C. The Planned Retirement of JH Campbell.

i. Description of J.H. Campbell

J.H. Campbell is a three-unit coal-fired power plant with a total rated net generating capability of approximately 1,450 megawatts (MW).[30] (The Order incorrectly states that J.H. Campbell has a capacity of 1,560 MW). In its current degraded condition, however, J.H. Campbell has a maximum capacity of 920 MW.[31] Part of that difference comes from the fact that Unit 2 is not operational, nor was it operational when the Order was issued. When Unit 2 comes back on-line later this month, the maximum capacity of the facility will be 1,180 MW. J.H. Campbell Unit 1 is 63-years-old and has a rated net generating capability of 261 MW, but now has an effective maximum output of 220 MW.[32] Unit 2 is 58-years-old and has a rated net generating capability of 356 MW. Currently out of service, when Unit 2 comes back online it will have a maximum capacity of 260 MW.[33] Unit 3 is 45 years old and has a rated net generating capability of 843 MW. The current maximum capacity of Unit 3 is 700 MW.[34] Consumers operates the entire J.H. Campbell plant and is the sole

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[29] *See* https://www.brennancenter.org/our-work/research-reports/declared-national-emergencies-under-national-emergencies-act.

[30] Michigan Public Service Commission (MPSC) Case No. U-21585, Direct Testimony of Richard Blumenstock, p. 7, Table 1 (5 Tr 1394-95); see also, https://www.consumersenergy.com/about-us/electric-generation/campbell-complex-retirement, last checked June 11, 2025 (reporting 1,450 MW of capacity).

[31] Conversation between representatives of Consumers and the undersigned counsel, June 12, 2025.

[32] *Id.*

[33] *Id.*

[34] *Id.*

owner of Units 1 and 2. Consumers owns about 93% of Unit 3, the Michigan Public Power Agency owns 4.8% of Unit 3, and Wolverine Power Supply Cooperative owns less than 2% of Unit 3.[35]

J.H. Campbell and Consumers' service territory are located within MISO Local Resource Zone 7. Most of the lower peninsula of Michigan is in MISO Zone 7, except for a small area in the southwest portion of the State, which is in PJM.

ii. State proceeding approving the retirement of J.H. Campbell

In 2021, Consumers proposed to retire J.H. Campbell in 2025 for economic reasons. The MPSC thoroughly reviewed the proposed retirement for a year in an integrated resource plan (IRP) proceeding governed by Michigan statute.[36] No party in the case opposed the retirement of Units 1 and 2; and only a few opposed the retirement of Unit 3.[37] The MPSC ultimately approved Consumers' proposed retirement of J.H. Campbell in a settlement joined by most of the parties to the case. A single party appealed the MPSC's decision to approve the retirement of Unit 3, but the Michigan Court of Appeals affirmed that decision in 2023.[38] Both the MPSC and the appeals court found that Michigan would still have more than enough generating capacity to serve demand after J.H. Campbell retired.[39]

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[35] MPSC Case No. U-21090 (Kapala Direct, 7 Tr 1739); Ex. WPSC-1, p. 19 (Agreement, p. 11), section 2.1, available at https://mi-psc.my.site.com/sfc/servlet.shepherd/version/download/0688y000001QqldAAC.

[36] MCL 460.6t.

[37] MPSC Case No. U-21090, Order approving contested settlement, June 23, 2022, p. 8.

[38] *Wolverine Power Supply Coop., Inc. v Michigan Public Service Commission (In re Consumers Energy)*, 2023 Mich. App. LEXIS 2045; 2023 WL 2620437 (March 23, 2023).

[39] *Id.*

Michigan's IRP statute requires electric utilities whose rates are regulated by the MPSC to periodically file an integrated resource plan. The IRP is a projection of the utility's load obligations and a plan to meet those obligations.[40] The IRP statute directs the MPSC to approve a plan if the MPSC determines that it "represents the most reasonable and prudent means of meeting the electric utility's energy and capacity needs."[41] To make that decision, the statute instructs the MPSC to consider whether the IRP appropriately balances seven statutory factors: (i) resource adequacy and capacity to serve anticipated peak electric load, applicable planning reserve margin, and local clearing requirement; (ii) compliance with applicable state and federal environmental regulations; (iii) competitive pricing; (iv) reliability; (v) commodity price risks; (vi) diversity of generation supply; and (vii) whether proposed levels of peak load reduction and energy waste reduction are reasonable and cost effective.[42]

The IRP statute also directs the MPSC to establish – among other things – computer modeling scenarios that must be used to analyze the costs of possible plans in an IRP, including costs associated with plant retirement dates.[43] In the modeling used to prepare its 2021 IRP, Consumers determined that it would be most cost-effective to retire the entire J.H. Campbell plant in 2025.[44] Later in the proceeding, Consumers conducted more modeling that compared other possible retirement dates

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[40] MCL 460.6t(3).

[41] MCL 460.6t(8)(a).

[42] *Id.*

[43] MCL 460.6t(1).

[44] MPSC Case No. U-21090 (Blumenstock Direct, 3 Tr 99 and 147-49), available at https://mi-psc.my.site.com/sfc/servlet.shepherd/version/download/0688y000001OEXnAAO.

to a 2025 retirement and again concluded that the most cost-effective retirement date was 2025.[45] Among other things, parties to the IRP case noted that the 2025 retirement of J.H. Campbell would save ratepayers $150 million in avoidable capital expenditures.[46]

After months of litigation, most of the parties reached a settlement agreement, which Consumers filed with the MPSC on April 20, 2022.[47] The settlement agreement approved the retirement of J.H. Campbell – but it also approved the construction, procurement, and extension of other major generating resources. The net effect of these changes was to substantially increase the total generating resources available to MISO Zone 7.

iii. Effect of Consumers' overall plan on resource adequacy

MISO measures capacity for resource adequacy purposes in zonal resource credits (ZRCs). One ZRC is equal to one MW of deliverable seasonal accredited capacity, which is the net amount of capacity MISO calculates it can reasonably expect from a resource.[48]

Consumers' IRP projected that the entire J.H. Campbell plant would provide 1,346 ZRCs in 2024, its last full year of planned operation.[49] In recognition of the

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[45] *Id.* (Walz Rebuttal, 3 Tr 364-73 & Ex A-123; Blumenstock Rebuttal, 3 Tr 178-79).

[46] MPSC Case No. U-21090, Order approving contested settlement, June 23, 2022, pp. 48, 55.

[47] MPSC Case No. U-21090-0777 (Settlement Agreement), available at https://mi-psc.my.site.com/sfc/servlet.shepherd/version/download/0688y000002gLkGAAU.

[48] MISO Knowledge Base, KA-01402, available at https://help.misoenergy.org/knowledgebase/article/KA-01402/en-us#:~:text=Zonal%20Resource%20Credits%20(ZRC)%20are,Seasonal%20Accredited%20Capacity%20(SAC); MISO, Resource Adequacy, available at https://www.misoenergy.org/planning/resource-adequacy2/resource-adequacy/#t=10&p=0&s=FileName&sd=desc.

[49] MPSC Case No. U-21090, Order approving contested settlement, June 23, 2022, p. 33.

reduced capacity that would result from the retirement of J.H. Campbell, the settlement authorized Consumers to acquire the Covert gas plant, which Consumers has done.[50] At the time, the Covert plant was in the PJM regional transmission organization – but after acquiring it, Consumers redesignated the Covert plant as part of MISO Zone 7.[51] This action added 1,114 ZRCs to Zone 7 – almost enough by itself to offset the ZRCs removed by the Campbell retirement.[52]

The settlement also authorized Consumers to continue operating Units 3 and 4 of the Karn plant – peaking units that burn natural gas and oil – until 2031, rather than retire them in 2023 as originally planned.[53] This action maintained another 784 ZRCs in Zone 7 beyond what was in Consumers' original plan.[54] The settlement agreement also authorized Consumers to develop or acquire 250 ZRCs of new solar generation by mid-2025, increasing to 852 ZRCs by mid-2028; added 94 ZRCs of demand response and energy waste reduction by mid-2025; and added 71 ZRCs of new battery storage in 2024-2027.[55] The settlement also provided that Consumers would issue a solicitation for power purchase agreements (PPAs) that would provide capacity beginning in 2025/2026, right after J.H. Campbell's retirement.[56] The PPA solicitation would seek up to 500 MW of dispatchable generation, and up to 200 MW of clean energy resources.[57]

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[50] *Id.* at 5.
[51] *Id.* at 91.
[52] *Id.* at 50.
[53] *Id.* at 11.
[54] *Id.*
[55] *Id.* at 23.
[56] *Id.* at 6 – 7. In MISO, the planning year runs from June 1 through May 31.
[57] *Id.*

Overall, the plan approved in the settlement was projected to increase Zone 7's capacity by at least 127 ZRCs by June 2025 – an increase that will grow to at least 923 ZRCs by 2028, not including the 700 MW of additional capacity sought in the PPA solicitations.[58]

iv. MPSC approval of the settlement and affirmance on appeal

Consumers' IRP settlement agreement was supported by most parties in the case, including Consumers, Staff, the Attorney General, consumer advocates, a transmission company, commercial and industrial customers, businesses in the advanced energy sector, environmental groups, and third-party energy developers.[59] The MPSC approved the Settlement Agreement on June 23, 2022.[60] The state commission found that the plan embodied in the settlement "is the most reasonable and prudent means of meeting Consumers' energy and capacity needs."[61]

In reaching these conclusions, the MPSC specifically addressed resource adequacy.[62] After discussing the record evidence regarding the Covert plant, Karn units 3 and 4, new battery storage, and ongoing investments in solar, energy waste reduction, and demand response,[63] the MPSC concluded that "the approval of the settlement agreement will enhance resource adequacy in Zone 7 in both the near-term and long-term."[64] One party, Wolverine Power Supply Cooperative, appealed

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[58] *Id*. at 24.

[59] *Id*. at 30 – 31.

[60] *Id*. at 87-93.

[61] *Id*. at 95.

[62] *Id*. at 90-93.

[63] *Id*.

[64] *Id*. at 92.

the MPSC's decision to approve the Campbell plant retirement. The Michigan Court of Appeals affirmed the MPSC. The court specifically addressed resource adequacy, quoted the MPSC's findings about the generating resource additions, and found that the state commission's decision was based on substantial evidence.[65]

v. Subsequent proceedings before the MPSC show that both Consumers' service territory and Michigan as a whole will have sufficient capacity this summer and for years to come

Filings in MPSC proceedings regarding capacity supply and resource adequacy demonstrate that there is no capacity shortfall. To the contrary, the most current available information is that both Consumers and MISO Zone 7 will have sufficient capacity this summer and for years to come. On June 10, 2025, Consumers reported that it now has a surplus of 273 ZRCs for this summer.[66] Consumers further reported that it expects J.H. Campbell will not contribute any ZRCs to the Company's summer position.[67]

Consumers' ZRC projections compare Consumers' available resources not just to projected actual demand but to the planning reserve margin requirement (PRMR). MISO establishes the PRMR as the amount of reserve margin target necessary to meet NERC's Loss of Load Expectation (LOLE) standard of 1 day in 10 years.[68] NERC

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[65] *Wolverine Power Supply Coop., Inc. v Michigan Public Service Commission (In re Consumers Energy)*, 2023 Mich. App. LEXIS 2045; 2023 WL 2620437 (March 23, 2023).

[66] *See* Attachment D, Consumers' Responses from June 10, 2025.

[67] *Id.*

[68] MISO Resource Adequacy Business Practices Manual, BPM-011-r31, p. 27, Section 3.4.2 LOLE Analysis; MPSC Case No. U-21775, Capacity Demonstration Results Report, May 12, 2025, p. 9.

defines the LOLE as "the expected number of days per year for which the available generation capacity is insufficient to serve the daily peak demand."[69]

For Michigan as a whole, the MPSC Staff finds in its annual capacity demonstration report that – except for one small municipal utility – all Michigan load serving entities "were able to procure the necessary capacity to demonstrate compliance for the current planning year in all four seasons" in Planning Year 2025-26.[70] The Staff Report also finds that there are more than enough resources in Zone 7 to meet the MISO Local Clearing Requirement (LCR) – which is the minimum amount of resources that must be located within a MISO local resource zone to meet the reliability standard.[71] While Zone 7 did not have enough internal resources to meet its entire PRMR, it is not required to do so under MISO rules, and the zone is able to import 785.5 ZRCs of external resources to meet its PRMR for the current planning year.[72]

Looking ahead, the Staff Report projects that Zone 7 will have more than enough resources to meet both its LCR and the PRMR in each of planning years 2026, 2027, and 2028.[73] Zone 7's LCR surplus will increase each year to reach 4,975 ZRCs by Planning Year 2028, and its PRMR surplus will increase each year to reach 3,428 ZRCs by Planning Year 2028.[74]

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[69] NERC Probabilistic Assessment Technical Guideline, August 2016, p. 2.

[70] MPSC Case No. U-21775, Capacity Demonstration Results Report, May 12, 2025, p. 6.

[71] *Id.* at 16.

[72] *Id.*

[73] *Id.* at p. 26, Appendix C.

[74] *Id.*

vi. MISO approved the retirement of J.H. Campbell after a detailed study process governed by MISO's FERC-approved tariff

More than three years before the Secretary issued Order 202-25-3, MISO determined via a detailed technical study that retirement of J.H. Campbell would not materially impact reliability in MISO. That determination remains in effect.

Section 38.2.7 of MISO's Open Access Transmission, Energy, and Operating Reserve Markets Tariff requires that the owner of a Generation Resource that is planning to suspend operations of all or a portion of that resource must notify MISO at least 26 weeks in advance by submitting a completed Attachment Y Notice.[75] The Tariff states that MISO will perform an Attachment Y Reliability Study to determine whether the Generation Resource is necessary for the reliability of the Transmission System based on analyses described in the Tariff and criteria in the MISO Business Practices Manuals.[76]

On December 14, 2021, Consumers submitted to MISO an Attachment Y notice of intent to suspend J.H. Campbell Units 1, 2, and 3 effective June 1, 2025.[77] After more than a year of study, MISO approved the suspension on March 11, 2022.[78] MISO stated that after reviewing the J.H. Campbell suspension for power system reliability impacts, MISO had determined that "the suspension of Campbell Units 1, 2 & 3 would not result in violations of applicable reliability criteria. Therefore, Campbell Units 1,

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[75] MISO Tariff, Section 38.2.7(a)(i).

[76] MISO Tariff, Section 38.2.7(c).

[77] Attachment C (Letter dated December 14, 2021, from Timothy J. Sparks, Consumers Energy, to Andrew Witmeier, MISO, and Attachment Y Notification of Generating Resources Change of Status).

[78] Attachment C (Letter dated March 11, 2022, from Andrew Witmeier, MISO, to Timothy J. Sparks, Consumers Energy, re: Approval of Campbell Units 1, 2 & 3 Attachment Y Suspension Notice).

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."[79]

On May 27, 2025, MISO requested that Consumers submit a modified Attachment Y request with a new suspension start date of August 21, 2025, consistent with the date in Order 202-25-3.[80] Consumers submitted the modified Attachment Y notice with the new date on May 28, 2025.[81] On May 30, 2025, MISO notified Consumers that with the modification, "the Attachment Y remains as is, still approved, except with a new/different start date."[82]

D. The Order

On May 23, 2025, the Secretary of Energy issued the Order pursuant to section 202(c) of the Federal Power Act, determining that an emergency exists in the region of the country served by MISO "due to a shortage of electric energy, a shortage of facilities for the generation of electric energy, and other causes" and ordering Consumers and MISO to ensure the continued operation of J.H. Campbell for at least 90 days notwithstanding the longstanding plan to retire the facility on May 31, 2025. In issuing the Order, the Department issued a press release that, like Executive

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[79] *Id.*

[80] Attachment C (Email dated May 27, 2025, from Huaitao Zhang, MISO, to Kathy Wetzel, Consumers Energy).

[81] Attachment C (Email dated May 28, 2025, from Rachael Moore, Consumers Energy to Huaitao Zhang, MISO).

[82] Attachment C (Email dated May 30, 2025, from Marc Keyser, MISO, to Rachael Moore, Consumers Energy).

Order 14262, states the Order "is in accordance with President Trump's Executive Order: Declaring a National Energy Emergency."[83]

Over four short paragraphs, the Order outlines the "emergency situation" allegedly necessitating invocation of section 202(c) authority. It points primarily to "*potential* tight reserve margins during the summer 2025 period," citing to the North American Electric Reliability Corporation (NERC) 2025 Summer Reliability Assessment, including the statement that MISO is "at elevated risk of operational reserve shortfalls during periods of high demand or low resource output."[84] The Order then describes the retirement of thermal generation capacity including the retirement of approximately 2,700 MW of coal-fired capacity in Michigan since 2020 and the scheduled May 31, 2025, retirement of J.H. Campbell.[85] The Order acknowledges Consumers' acquisition of 1,200 MW of replacement natural gas capacity and MISO's April 2025 conclusion that its auction resulted in "demonstrated sufficient capacity,"[86] but does not reference, let alone consider, the extensive processes that MISO and the MPSC undertook to evaluate and mitigate any reliability or resource adequacy risk that would be caused by the retirement of J.H. Campbell.[87] Nor does the Order describe any actions that MISO or Consumers have taken or could take to mitigate any alleged emergency conditions short of ordering the continued operation of the plant. Rather, it relies almost exclusively on:

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[83] DOE Press Release (May 23, 2025) available at https://www.energy.gov/articles/energy-secretary-issues-emergency-order-secure-grid-reliability-ahead-summer-months.

[84] DOE Order 202-25-3 at 1 (emphasis added).

[85] *Id.* at 1.

[86] *Id.* at 2.

[87] *See* Section II.C *supra*.

- The general statement in NERC's 2025 Summer Reliability Assessment that there is anticipated to be "elevated risk of operating reserve shortfalls"
- Language in MISO's Planning Resource Auction Results for Planning Year 2025-26 that, "for the northern and central zones, which includes Michigan, 'new capacity additions were insufficient to offset the negative impacts of decreased accreditation, suspensions/retirements and external resources,'" and that the results "reinforce the need to increase capacity" and,
- Language from the MISO Auction Results that the summer months have, relative to other times, the "highest risk and tighter supply-demand balance."[88]

The Order concludes that "additional dispatch of the Campbell Plant," for the 90-day duration of the order and on conditions contained in the order, "is necessary to best meet the emergency and serve the public interest."[89] As a result, the Order mandates that:

- MISO and Consumers Energy take all necessary steps to ensure the Campbell Plant is available for dispatch;[90]
- MISO employ economic dispatch of the plant, and that Consumers comply with all such dispatch orders;[91]
- All operation of J.H. Campbell "must comply with applicable environmental requirements . . . to the maximum extent feasible while operating consistent with the emergency conditions."[92]
- MISO submit reports to DOE on plant operations, environmental impacts, and actions taken to comply with the Order.[93]
- "Relevant governmental authorities" take such action as necessary to enable MISO to effectuate the dispatch and operation of the units.[94]
- Consumers request any necessary revisions or waivers to effectuate the order with FERC.[95]

III. STATEMENT OF ISSUES AND SPECIFICATIONS OF ERROR

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[88] DOE Order 202-25-3 at 2.
[89] DOE Order 202-25-3 at 2.
[90] *Id.* at 2 (Ordering Paragraph A).
[91] *Id.* (Ordering Paragraph A).
[92] *Id.* at 3 (Ordering Paragraph C).
[93] *Id.* at 3 (Ordering Paragraph B, D).
[94] *Id.* at 3 (Ordering Paragraph E).
[95] *Id.* at 3 (Ordering Paragraph F).

As explained in Section IV below, the Michigan Department of Attorney General submits the following statement of issues and specifications of error:

1. The Order is contrary to law because it fails to establish the existence of an emergency under section 202(c) or the Department's regulations implementing section 202(c). The statutory text, legislative history, judicial construction and DOE's regulations all confirm that an "emergency" is an occurrence that is sudden, unexpected and requiring immediate action. The Order introduces no facts that would satisfy that definition. 16 U.S.C. § 824a(c); 10 C.F.R. § 205.371; *Richmond Power and Light v. FERC*, 574 F.2d 610, 615 (D.C. Cir. 1978); *Otter Tail Power Co. v. Fed. Power Comm.*, 429 F.2d 232, 233-34 (1970).

2. The Order is contrary to law because it exceeds the Department's statutory authority. Abusing a statute meant only for emergencies, the Order intrudes on authority reserved to States and to other federal regulators to regulate resource adequacy. Section 202(c) does not vest DOE with general regulatory authority over resource adequacy, or the authority to decide which power plants may retire except for so long as a true emergency exists. The Department may not "discover in a long-extant statute an unheralded power representing a transformative expansion in its regulatory authority." *W. Virginia v. Env't Prot. Agency*, 597 U.S. 697, 724–25, (2022) (quoting *Util. Air Regul. Grp. v. E.P.A.*, 573 U.S. 302, 324 (2014))(internal quotations omitted).

3. The Order fails to present substantial evidence for its emergency determination and fails to exercise reasoned decision-making by ignoring critical facts and shortcomings in its analysis. Specifically, the Order: (i) presents a discussion of the NERC 2025 Summer Reliability Assessment that is unreasoned, incomplete, and that fails to substantiate the existence of an emergency; (ii) the Order's apparent reliance on generator retirements in Michigan as evidence of an emergency is unreasonable; (iii) the Order acknowledges that the most recent MISO auction "demonstrated sufficient capacity" but fails to explain why an emergency exists nonetheless, (iv) the Order fails even to acknowledge that MISO approved the retirement of J.H. Campbell through the study process governed by its FERC-approved tariff; (v) the Order makes no effort to review the proceedings before the MPSC, or to note any consultation with Michigan officials as required by 42 U.S.C. § 7113; (vi) the Order fails to provide any specific evidence or reasoning why J.H. Campbell must remain in operation and why alternative measures are inadequate. *E.g. Emera Maine v. FERC*, 854 F.3d 9, 22 (D.C. Cir. 2017) (order under the Federal Power Act must reflect "a principled and reasoned decision supported by the evidentiary record" (quotation marks omitted)); *Motor Vehicle Mfrs. Ass'n of U.S., Inc. v. State Farm Mut. Auto. Ins. Co.*, 463 U.S. 29, 43 (1983) (agency must examine the relevant data and articulate a satisfactory

explanation for its action including a rational connection between the facts found and the choice made); *Burlington Truck Lines, Inc. v. United States*, 371 U.S. 156, 168 (1962) (an "agency must make findings that support its decision, and those findings must be supported by substantial evidence").

4. The Order is arbitrary and capricious and contrary to law because section 202(c) provides no authority for the Department to command a generator to engage in "economic dispatch." 16 U.S.C. § 824a(c); *Michigan v. EPA*, 268 F.3d 1075, 1081 (D.C. Cir. 2001) (absent statutory authorization, an agency's "action is plainly contrary to law and cannot stand").

5. The Order is arbitrary and capricious and contrary to law because the Department failed to limit its remedy as required by section 202(c)(2). The Order adheres to neither the temporal constraint nor the environmental constraints imposed by section 202(c)(2). 16 U.S.C. § 824a(c)(2).

6. The Order violates the National Environmental Policy Act because it fails to assess the environmental consequences of a major federal action significantly affecting the human environment. 42 U.S.C. § 4321; *et seq*.

IV. REQUEST FOR REHEARING

A. The Department Has Failed to Establish the Existence of an Emergency under Section 202(c) or the Department's Regulations Implementing Section 202(c).

i. Congress limited DOE's authority under section 202(c) to the unique circumstances of war or emergency

Section 202(c) confers an extraordinary power. Enacted in 1935, section 202(c) empowered the Federal Power Commission to command action from market participants and – crucially – to do so freed from most of the core procedural safeguards, jurisdictional boundaries, and substantive limitations that undergird the rest of the Federal Power Act. While the rest of the Act authorizes Commission action only after opportunity for hearing,[96] section 202(c) allows the Commission (now the Department) to act on its own motion and without prior notice. And in profound contrast to the rest the Federal Power Act and general utility law principles,[97] section 202(c) empowers the Department to require utilities to incur costs – through a command to provide generation or transmission service – without first considering the impact to ratepayers or whether the resulting rates will be just and reasonable.

It comes as no surprise, therefore, that when Congress granted the Commission this extraordinary power, Congress restricted its use to extraordinary circumstances. Section 202(c) authorizes action only "[d]uring the continuance of any war in which the United States is engaged, or whenever the Commission determines that an emergency exists by reason of a sudden increase in the demand for electric energy, or a shortage of electric energy or of facilities for the generation or transmission of electric energy, or of fuel or water for generating facilities, or other causes." The Act permits some measure of flexibility with respect to what type of events may cause the emergency, allowing for "other causes" beyond those enumerated. But the Act is clear that any such event, including a "shortage of electric energy," must be one that constitutes an "emergency."

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[96] *See e.g.*, 16 U.S.C. §§ 824a(b), 824a(e), 824a-1(a), 824a-3(f), 824a-4, 824b(a)(4), 824c(b), 824d, 824e, 824f, 824i(b), 824j, 824j-1, 824k, 824m, 824o & 824p.

[97] Two cornerstones of the law of regulated utilities are the filed rate doctrine and the rule against retroactive ratemaking. As FERC has explained, "a central purpose of the filed rate doctrine and the rule against retroactive ratemaking is to protect ratepayers from being subjected to an additional surcharge above the rate on file for service already performed." *Old Dominion Elec. Coop.*, 154 FERC ¶ 61,155 (2016). In its June 6, 2025, complaint filed in FERC Docket No. EL25-90, Consumers asserts that the filed rate doctrine and the rule against retroactive ratemaking are inapplicable in the context of an order under section 202(c).

Because the Act does not define "emergency," the Department must look first to the public meaning of that word at the time of enactment. Webster's New International Dictionary of the English Language (1930) defined "emergency" as a "sudden or unexpected appearance or occurrence . . . . An unforeseen occurrence or combination of circumstances which calls for immediate action or remedy; pressing necessity; exigency." Contemporary dictionaries likewise define "emergency" to refer to a circumstance that is "unexpectedly arising, and urgently demanding immediate attention."[98]

These definitions accord with the legislative history of the Federal Power Act, which characterized section 202(c) as an authority to be used in response to "crises":

> This is a temporary power designed to avoid a repetition of the conditions during the last war, when a serious power shortage arose. Drought and other natural emergencies have created similar crises in certain sections of the country; such conditions should find a federal agency ready to do all that can be done in order to prevent a break-down in electric supply.[99]

The few courts that have had occasion to opine on the meaning of "emergency" in section 202(c) have likewise emphasized that the provision applies in very limited circumstances, and not as a tool to address longer-term, structural concerns. In *Richmond Power and Light v. FERC*, the D.C. Circuit upheld the Commission's judgment that the dependence on foreign oil occasioned by the 1973 oil embargo was

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[98] *See Acuity Ins. Co. v. McDonald's Towing & Rescue, Inc.,* 747 F. App'x 377, 380–81 (6th Cir. 2018) (addressing a statute that leaves "emergency" undefined and quoting 7 Oxford English Dictionary 231 (2012) among others to supply a definition).

[99] S. Rep. No. 74-621 at 49 (1935).

not an "emergency" under the Act, noting that section 202(c) "speaks of 'temporary' emergencies, epitomized by wartime disturbances."[100]

In *Otter Tail Power Co. v. Fed. Power Comm'n,* the U.S. Court of Appeals for the Eighth Circuit described section 202(c) as enabling the Commission to "react to a war or natural disaster." The court also distinguished section 202(c) from section 202(b), under which the Commission may also order interconnections, but only after a hearing. The court explained that, in contrast to section 202(c), which "enables the Commission to proceed without notice or hearing" to address immediate crises, section 202(b) "applies to a crisis which is likely to develop in the foreseeable future but which does not necessitate immediate action on the part of the Commission."[101]

Through its regulations, the Department has also interpreted "emergency" for purposes of section 202(c) to mean circumstances that arise suddenly and unexpectedly:

> "Emergency," as used herein, is defined as an unexpected inadequate supply of electric energy which may result from the unexpected outage or breakdown of facilities for the generation, transmission or distribution of electric power. Such events may be the result of weather conditions, acts of God, or unforeseen occurrences not reasonably within the power of the affected "entity" to prevent. An emergency also can result from a sudden increase in customer demand, an inability to obtain adequate amounts of the necessary fuels to generate electricity, or a regulatory action which prohibits the use of certain electric power supply facilities.[102]

In summary, the plain meaning of the statutory text, its legislative history, judicial construction, and the Department's own regulations all establish that an

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[100] 574 F.2d 610, 615 (D.C. Cir. 1978).
[101] 429 F.2d 232, 234 (8th Cir. 1970).
[102] 10 C.F.R. § 205.371.

"emergency," including one occasioned by a "shortage of electric energy," must be sudden, unexpected, and demanding of "immediate action."

ii. The Order fails to present facts establishing an emergency under section 202(c) or the Department's regulations

Even taken as complete and accurate claims (which they are not), the factual assertions made in the Order fail to describe an "emergency." The Order does not claim that the retirement of J.H. Campbell was sudden or unexpected. Nor could it. The retirement of J.H. Campbell was carefully planned over a period of years and was approved by the MPSC through a public proceeding. Further, Consumers' plan to retire J.H. Campbell included a commitment to procure replacement resources that improved its capacity position. And Consumers' proposal to retire J.H. Campbell was approved in advance by MISO after a thorough review of its impact on reliability.

Nor did the publication of NERC's 2025 Summer Reliability Assessment in May 2025 transform a long-planned retirement into an event with sudden or unexpected implications requiring immediate action. The Order notes that the 2025 NERC Summer Reliability Assessment characterizes MISO as being at an "elevated risk of operating reserve shortfalls." But NERC's "elevated risk" designation in no way signifies an emergency condition. "Elevated risk," it should be emphasized, falls *below* NERC's highest risk designation: that of "high" risk.[103] NERC's decision not to place MISO in the highest risk category in its Summer Reliability Assessment is

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[103] The "High" risk designation refers to a risk of shortfall during normal peak conditions, whereas the "Elevated" risk designation refers to a risk of shortfall during above-normal peak conditions. See Attachment A, NERC, 2025 Summer Reliability Assessment at 6.

in itself powerful evidence that there is no "emergency" stemming from a lack of operating reserves.

The "elevated risk" designation is also far from unusual. In the same report, NERC also designated the systems overseen by SPP, the Electric Reliability Council of Texas (ERCOT), and the New England Independent System Operator (ISO-NE) as at "elevated risk."[104] Except for 2022, when it was designated as "high" risk, MISO has been designated as "elevated" risk in every NERC Summer Reliability Assessment since NERC initiated the practice of designating regions as "high," elevated," or "normal" risk in 2021.[105] NERC has also designated MISO as "elevated" risk in every Winter Reliability Assessment since 2021.[106] In effect, what the Order implies through its reliance on the NERC report's "elevated" risk designation, is that the fifteen states of MISO – along with large swaths in the rest of the United States – have been in an uninterrupted state of emergency for many years on end. This interpretation, if credited, would effectively read the word "emergency" out of section 202(c).

The Order's hand-waving reference to "potential tight reserve margins" identified in the 2025 NERC Summer Reliability Assessment likewise fails to describe an emergency. The very fact that the Order attempts to rely on "potential" future conditions itself contradicts the notion that MISO is presently facing an

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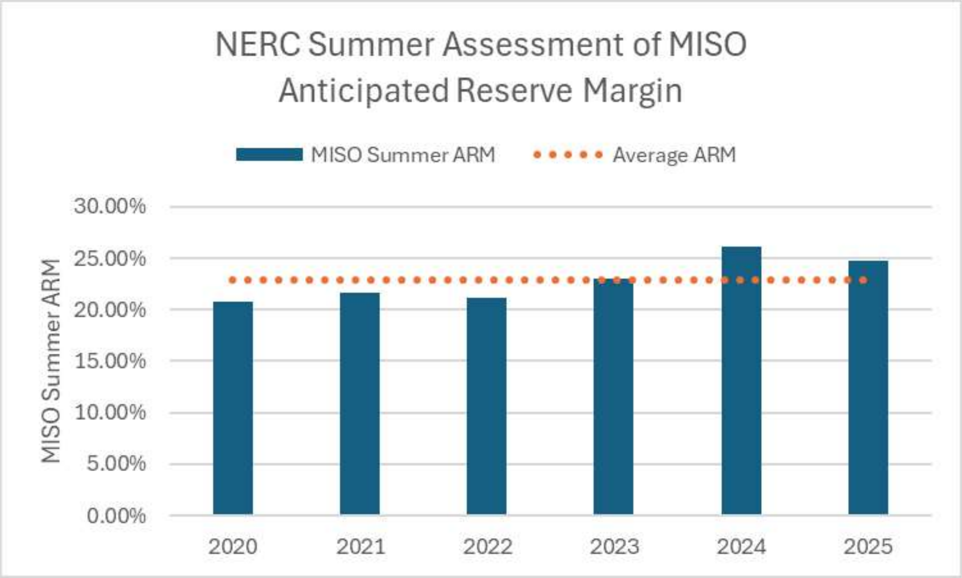
[104] *Id.*

[105] *See* NERC Summer Reliability Assessments years 2021 – 2025, available at https://www.nerc.com/pa/RAPA/ra/Pages/default.aspx.

[106] *See* NERC Winter Reliability Assessments years 2021 – 2025, available at https://www.nerc.com/pa/RAPA/ra/Pages/default.aspx.

emergency as conceived under section 202(c). Moreover, the actual reserve margins in MISO this summer do not support an emergency determination. The NERC report calculated MISO's anticipated reserve margin for Summer 2025 as 24.7%.[107] This figure substantially exceeds NERC's "Reference Margin Level" for MISO of 15.7%,[108] which is the level that NERC has "established for the areas to meet resource adequacy criteria."[109] MISO's anticipated reserve margin of 24.7% is also *higher* than its average of recent years. The chart below shows the anticipated reserve margin for MISO as calculated in the NERC Summer Reliability Assessment for each year.[110] The chart shows that the 2025 anticipated reserve margin of 24.7% exceeds the 2020-2025 average of 22.9%. Again, the Order has failed to describe a circumstance that is "unexpected," "sudden" or "demanding of immediate attention."



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[107] Attachment A, NERC, 2025 Summer Reliability Assessment at 10.

[108] *Id*. at 44.

[109] *Id*. at 15.

[110] *See* NERC Summer Reliability Assessments years 2020 – 2025, available at https://www.nerc.com/pa/RAPA/ra/Pages/default.aspx.

The other factual assertions in the Order likewise fail to describe an emergency. The Order devotes one of its few substantive paragraphs to explaining that various generation units have retired in Michigan, reaching back as far as 1997.[111] But generation units retire everywhere as part of the normal, continuous cycle through which old units are replaced with new ones. The unsurprising fact that generation units have retired in Michigan over the last 28 years says nothing about whether there is presently adequate generation in the State, and even less about whether an emergency exists in the region as a whole.

The Order then points to the results of the April 2025 MISO Planning Resource Auction. But these results explicitly contradict the claim that an emergency exists in MISO. The Order acknowledges MISO's conclusion that the auction "demonstrated sufficient capacity." In fact, the Order truncates this quote, which stated in full that: "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."[112] Remarkably, the Order attempts to brush aside the obvious import of this conclusion, preferring instead to focus on the second half of the sentence. But the second half of that sentence merely refers to the fact that the summer price for capacity in MISO, which separates the auction results by season, is high*er* and has a tight*er* supply/demand balance than those of the fall, winter and spring seasons (a fact illustrated by the chart below the header text).

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[111] Order at 1.

[112] Attachment B, MISO, Planning Resource Auction, Results for Planning Year 2025 – 2026 (April 2025) at 12.

This sentence does not indicate any kind of shortfall in the summer season, much less an emergency shortfall.

The Order also quotes from a slide that states "for North/Central, new capacity additions were insufficient to offset the negative impacts of decreased accreditation, suspensions/retirements and external resources."[113] But this slide is simply noting that the total capacity of resources *offered* into the 2025 auction in the North/Central region was lower than what was offered into the 2024 auction. This slide does not say that the total amount of capacity *procured* in the North/Central region through the auction was inadequate. In other words, this slide is in no way inconsistent with the conclusion in the same report that the "2025 PRA demonstrated sufficient capacity at the regional, subregional and zonal levels."[114] Further, even as a characterization of the total capacity offered into the auction, the Order ignored a crucial fact in this slide. The slide shows that the reason for the decrease in capacity offered was not because of a decrease in physical generating capacity, but because of a change in the capacity accreditation of various resources—most notably, the very "dispatchable generation" that the order prioritizes. This change in MISO's capacity accreditation methodology occurred over the previous year.[115] The bar chart in Attachment B shows a reduction in accredited capacity for gas and coal of 3.4 GW, which is greater than the overall reduction in offered

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[113] *Id*. at 13.
[114] *Id*. at 12.
[115] *Midcontinent Independent System Operator, Inc*., 189 FERC ¶ 61,065 (Oct. 25, 2024).

capacity.[116] In other words, MISO concluded that coal (and gas) resources, such as J.H. Campbell, should be deemed to contribute less to capacity requirements than it had previously assumed.

B. Abusing an Authority Meant for True Emergencies, the Order Intrudes on Authority Reserved to States and to Other Federal Regulators.

i. Resource adequacy is regulated by the states, and by FERC under other provisions of the Federal Power Act

Resource adequacy refers to the capacity of an electric power system to meet demand reliably at all times, including during system peaks and through potential outages. Resource adequacy is "measured at the system level to capture the overall impact of outages of individual components including generators and transmission."[117] Resource adequacy planning is the process by which utilities and system operators, under regulatory supervision, ensure resource adequacy. Resource adequacy planning involves technical and economic considerations that go into determining what resources are added to the grid and which resources should retire and when.

With respect to regulatory oversight for resource adequacy, section 201 of the FPA, 16 U.S.C. § 824(b)(1), reserves authority over generation facilities to the states. It states in pertinent part: "The Commission shall have jurisdiction over all facilities for such transmission or sale of electric energy, *but shall not have jurisdiction*, except as specifically provided in this subchapter and subchapter III of this chapter, *over*

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[116] Attachment B, MISO, Planning Resource Auction, Results for Planning Year 2025 – 2026 (April 2025) at 13.

[117] NREL, Resource Adequacy Basics, available at https://www.nrel.gov/research/resource-adequacy.

facilities used for the generation of electric energy or over facilities used in local distribution or only for the transmission of electric energy in intrastate commerce, or over facilities for the transmission of electric energy consumed wholly by the transmitter."[118]

Some states have retained this authority over resource adequacy in its entirety.[119] Others have directed their utilities to join RTO/ISOs that, through their tariffs, impose resource adequacy requirements. Those RTO/ISOs also generally establish markets that allow market participants to buy and sell capacity and thereby to facilitate market entry and exit decisions based on price signals. Resource adequacy requirements in RTO/ISO tariffs have been held to be practices affecting wholesale rates subject to the jurisdiction of FERC under sections 205 and 206 of the Federal Power Act, 16 U.S.C. §§ 824d & 824e.[120]

In Michigan, the regulation of resource adequacy planning has both a state and federal aspect. As a member of MISO, Consumers has a capacity obligation under the MISO tariff. MISO's resource adequacy requirements, however, are designed to be complementary to the primary role of the states in ensuring resource adequacy.[121]

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[118] *Id.* (emphasis added).

[119] *See Devon Power LLC et al.,* 109 FERC ¶ 61,154, P 47 (2004) ("Resource adequacy is a matter that has traditionally rested with the states, and it should continue to rest there. States have traditionally designated the entities that are responsible for procuring adequate capacity to serve loads within their respective jurisdictions.").

[120] *See Conn. Dep't of Pub. Util. Control v. FERC*, 569 F.3d 477, 483 (D.C. Cir. 2009).

[121] *Midcontinent Indep. Sys. Operator, Inc.*, 170 FERC ¶ 61,215, 62,606 at P 13 (2020) ("approximately 90% of the load in MISO is served by vertically integrated LSEs, the vast majority of which are subject to state integrated resource planning processes. To accommodate the make-up of the MISO's footprint, MISO's proposed Tariff provisions accepted in the February 2018 Order provide that its resource adequacy requirements "are complementary to the reliability mechanisms of the states and the Regional Entities ... within the [MISO] region."); *see also id.* ("MISO's proposed Tariff language

Consumers' investment decisions are regulated by the MPSC. Through the state IRP process (described in Section II.C above), the MPSC exercises regulatory authority over Consumers in order to ensure that the utility obtains the amount of capacity it needs to meet its obligations under the MISO tariff, and that it does so at the best value to ratepayers, and with a composition of resources that otherwise complies with state law, including state environmental requirements.

ii. Section 202(c) does not vest DOE with general regulatory authority over resource adequacy

The Order indicates that the Department believes it has the authority to decide which power plants may retire and when, not based on the kind of real emergency that has justified past action, but rather based on its own policy preferences. The Department appears to want to place its own judgment about operating reserve margins ahead of MISO's, and its own preference for which resources are employed to maintain resource adequacy ahead of Michigan's. In effect, the Department appears to read section 202(c) so as to give itself authority to regulate resource adequacy. Any ambiguity on this point was put to rest by the Department's June 13 letter referring cost recovery issues for J.H. Campbell to FERC. In that letter, the Department, through counsel, acknowledged that resource adequacy concerns

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explains that the resource adequacy requirements 'are not intended to and shall not in any way affect state actions over entities under the states' jurisdiction.' In other words, unlike the centralized capacity constructs used in the Eastern RTOs/ISOs, MISO's Auction is not—*and has never been*—the primary mechanism for its [Load Serving Entities] to procure capacity."); *Midwest Indep. Transmission Sys. Operator, Inc.*, 119 FERC ¶ 61,311, 62,722 at P 75 (2007) ("From the beginning . . . the Commission has recognized the role that state resource planning plays in managing the resource adequacy of [MISO]").

motivated the Order and went so far as to purport to dictate whether J.H. Campbell would be counted as a capacity resource pursuant to the MISO tariff.[122]

Section 202(c) does not provide the Department with the authority it claims. Had Congress intended to vest regulatory authority over resource adequacy in section 202(c), – displacing both state law and sections 205 and 206 of the Federal Power Act, – it would have stated so clearly. But of course it did not. The authorizing language says no more than that DOE may "require by order . . . such generation . . . of electric energy as in its judgment will best meet the emergency and serve the public interest." Indeed, it defies logic that, had Congress intended to empower DOE to be the general decider of which power plants may retire across every utility and independent power producer across the entire country – a function with profound implications for rates, state sovereignty, and a broad array of other stakeholder interests – that Congress would have done so through what may be the only provision in the Federal Power Act that empowers the regulator to act without first assessing the effect on ratepayers or seeking public input, and one of the only provisions that extends to otherwise non-jurisdictional utilities such as public power entities and those in ERCOT.

But even if the text of section 202(c) could, theoretically, be stretched to such an expansive reading (which it cannot), the United States Supreme Court has emphatically rejected statutory interpretations whereby an agency "claim[s] to discover in a long-extant statute an unheralded power representing a transformative

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[122] FERC Docket No. EL25-90, submission of Dep't of Energy, June 13, 2025 ("Because the May 23, 2025 Order is predicated on the shortage of facilities for the generation of electric energy and other causes, such as resource adequacy concerns, the Campbell plant shall not be counted as a capacity resource.").

expansion in its regulatory authority."[123] That is exactly what the Department seeks to do here. It seeks to discover in a 90-year-old statute a basis to exercise much broader regulatory authority than it ever has in the past. While it is true, as we explain above in section II.A, that the Department has used section 202(c) to delay power plant retirements on three occasions over the 90-year history, it has always done so at the request of a system operator or governmental body and in a manner narrowly tailored to prevent a concrete and particularized emergency. It has never done so simply to impose its policy preferences ahead of the judgment of those bodies responsible for resource adequacy.

C. The Order Fails to Present Substantial Evidence for its Emergency Determination and Fails to Exercise Reasoned Decision-making by Ignoring Critical Facts.

The Order relies on three sources of evidence for its emergency determination: the NERC 2025 Summer Reliability Assessment, generator retirements in Michigan, and the results of MISO's 2025 Planning Resource Auction. None of these three sources provide evidence that an emergency exists. By relying on these sources, and by misconstruing each of them, the Order fails to exercise reasoned decision-making.

The Order also entirely ignores several other critical facts and considerations. The Order ignores the fact that MISO approved the deactivation of J.H. Campbell. The Order ignores the conclusions of the MPSC proceeding that approved the retirement of J.H. Campbell. And even if it were correct that a capacity shortfall

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[123] *W. Virginia v. Env't Prot. Agency*, 597 U.S. 697, 724–25, (2022) (quoting *Util. Air Regul. Grp. v. E.P.A.*, 573 U.S. 302, 324 (2014))(internal quotations omitted).

exists in MISO, the Order fails to explain why preventing the retirement of J.H. Campbell through an emergency measure is necessary to address the shortfall.

i. *The Order's discussion of the NERC 2025 Summer Reliability Assessment is unreasoned and incomplete*

As explained above in Section IV.A, the Order's discussion of the NERC 2025 Summer Reliability Assessment is both incomplete and unreasoned. Specifically, the Order fails to explain (i) why the NERC report supports an emergency finding for MISO given that NERC did not put MISO in the "high" risk category, (ii) why NERC's designation of MISO as at "elevated" risk provides evidence of a "sudden" or "unexpected" circumstance given that MISO has been at this risk level or higher for years running, and (iii) why the "potential tight reserve margins" identified in the NERC report constitute an emergency given that MISO well exceeds the NERC reference margin level and even exceeds its own average Summer anticipated reserve margin over the 2020 – 2025 period.

ii. *The Order's apparent reliance on generator retirements in Michigan is unreasonable*

The Order attempts to support its emergency finding by recounting the fact that various power plants have retired in the state of Michigan.[124] As explained above, because power plant retirements are a regular occurrence in the electric power sector, the Order's discussion of this topic fails to present even *prima facie* evidence of an emergency. It also fails to exhibit reasoned decision-making in two key respects. First, it is unreasonable to point to capacity retirements in isolation

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[124] Order at 1.

without also considering all the other factors that contribute to resource adequacy. Such factors include capacity additions, changes in load, load shape and load flexibility, demand response, transmission access to external resources, etc. Of course, MISO *did* consider all those factors in the modeling that went into the Attachment Y process through which it approved the deactivation of J.H. Campbell.[125]

Second, the Order fails to explain how power plant retirements in Michigan are related to the emergency the Department purports to identify. In past orders where the Department has used section 202(c) to delay a power plant's retirement, the Department has acted on application of a utility or system operator to address a discrete, localized emergency that would be caused by the impending retirement.[126] The Department makes no such claim to geographic specificity here. Rather, the remainder of the "Emergency Situation" section of the Order appears to describe a purported emergency throughout MISO, insofar as it relies on NERC's general statements about MISO reserve margins and the results of the MISO Planning Resource Auction. Thus, the Order fails to explain why it is relying on power plant retirements in a single state—Michigan—to support its claim that an emergency exists in the region as a whole.

iii. The Order acknowledges that the most recent MISO auction "demonstrated sufficient capacity" but fails to explain why an emergency exists nonetheless

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[125] *See* MISO Transmission Planning Business Practices Manual, BPM-020-r32 Section 6.2 (Generator Retirement and Suspension Studies and System Support Resources), Section 6.2.3 (Study Scope Development).

[126] *See* Section II.A *supra*.

As explained in Section IV.A above, the Order cites to the MISO planning reserve auction report while ignoring the statement in that report that: "The 2025 PRA demonstrated sufficient capacity at the regional, subregional and zonal levels." It is entirely unreasonable for the Department to cite this report as evidence of an emergency when the report has concluded exactly the opposite. The Order's effort to focus on other aspects of the report are equally unreasonable. The unremarkable statement that summer prices are higher than prices in other seasons and therefore reflect a tighter supply/demand balance falls far short of providing evidence for an emergency. Likewise, the Order's reliance on the fact that less capacity was *offered* in the 2025 auction than was offered into the 2024 auction hardly describes an emergency. Further, the Order fails to note the information conveyed in the slide it quotes from, which shows that the only material change between 2024 and 2025 was a result in a change in capacity accreditation values rather than a change in physical resources available.

iv. The Order fails to acknowledge that MISO approved the retirement of J.H. Campbell

As explained in Section II.C above, after a robust, technical, and considered process, MISO approved the retirement of the three J.H. Campbell units pursuant to the study process governed by its tariff. MISO concluded that "the suspension of Campbell Units 1, 2 & 3 would not result in violations of applicable reliability criteria." As the system operator, MISO has more in-depth knowledge of its system than the Department does. The Department should have explained why it reached a different conclusion than MISO. Instead, the Order failed even to mention that MISO conducted this study and approved the retirement.

v. The Order makes no effort to review the findings of the MPSC or to demonstrate consultation with Michigan as required by 42 U.S.C. § 7113

The Order acknowledges that Consumers acquired the Covert gas plant, but in all other respects fails to acknowledge the MPSC proceeding that approved Consumers' IRP settlement entailing retirement of J.H. Campbell. As explained above in Section II.C, acquiring the Covert gas plant was not the only action Consumers took as part of that IRP. The IRP also delayed the retirement of the peaking units at the Karn facility and included the acquisition of other new resources, with the result that Consumers' capacity position was set to improve materially even after the retirement of J.H. Campbell. The Order also ignores the Michigan capacity demonstration proceedings that found both Consumers and MISO Zone 7 have sufficient capacity resources in 2025 and in the years to come.

Section 103 of the Department of Energy Organization Act, 42 U.S.C. § 7113, provides:

> Whenever any proposed action by the Department conflicts with the energy plan of any State, the Department shall give due consideration to the needs of such State, and where practicable, shall attempt to resolve such conflict through consultations with appropriate State officials.

The Order plainly conflicts with Michigan's energy plan, as reflected in the MPSC's approval of Consumers' IRP. Equally clearly, the Order does not give "due consideration" to the needs of Michigan. Nor does it appear that the Department made any attempt to resolve the conflict it created through consultation with the appropriate State officials. The Department, therefore, has failed to comply with Section 103 of the Department of Energy Organization Act. A practical consequence of the Department's apparent failure to consult with the State is that the Order lacks basic information related to its action, including the Order's inexplicable failure to accurately state the capacity of J.H. Campbell, the lack of awareness as to the operational status of Unit 2, the understatement of resources Consumers acquired to replace J.H. Campbell, and the omission of any reference to the reliability analysis undertaken by the State.

vi. The Order fails to provide any specific evidence or reasoning why J.H. Campbell must remain in operation and why alternative measures are inadequate

Even accepting the Order's contention that there exists a capacity shortfall in MISO, it does not follow that commanding the continued operation of J.H. Campbell is the best or even an appropriate means of alleviating the shortfall. The Order does not assert that there is a local problem on the grid that only J.H. Campbell can solve. In this respect, the Order departs markedly from past uses of section 202(c) and from the Department's regulations implementing section 202(c), which state that: "Actions under this authority are envisioned as meeting a specific inadequate power supply situation."[127]

Rather, the emergency that the Order purports to identify – "potential tight reserve margins" – is one that spans the entire fifteen-state MISO region and one

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[127] 10 C.F.R. § 205.371.

that could presumably be addressed by any number of actions across MISO. And, given that J.H. Campbell amounts to well less than 1% of generation capacity in MISO, there likely were options available that would have had a much greater impact on the overall balance of supply and demand. Further, because J.H. Campbell is an over 60-year-old facility in a largely degraded operational state, there presumably were alternative actions available that could have met the purported need with higher levels of reliability.

Yet the Order does not acknowledge any alternatives or explain whether less burdensome measures were exhausted before taking this action. The question of whether alternative measures could have been used to address the "emergency" is made more challenging by the fact that the Order never quantifies the extent of the emergency it purports to identify within MISO. But that omission merely highlights rather than excuses the deficiencies of the Order.

One possible alternative may have been demand-side measures. The Department's regulations require applicants seeking an order under section 202(c) to provide a "description of any conservation or load reduction actions that have been implemented . . . [and a] discussion of the achieved or expected results."[128] In the Yorktown case, the Department required Dominion to exhaust all demand response measures before dispatching the facility.[129] And yet here the Department failed to make any inquiry or even to consider whether demand-side measures could have

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[128] 10 C.F.R. § 205.373.

[129] *See* DOE Order No. 202-17-4 (Sept. 14, 2017) ("PJM and Dominion shall exhaust all reasonably and practically available resources, including demand response and behind-the-meter generation resources, prior to operating Yorktown Unit 1 or Yorktown Unit 2.")

addressed the purported emergency. Similarly, the Department's regulations require applicants to describe their efforts made to obtain additional power through third parties.[130] But again, the Department failed to consider whether MISO could alleviate the purported emergency through access to external resources.

D. The Department's Direction that MISO Operate J.H. Campbell Using "Economic" Dispatch Is Inconsistent with its Authority under Section 202(c).

The Department's Order directs MISO to "take every step to employ economic dispatch of the Campbell Plant."[131] The Order indicates that the use of economic dispatch is intended to "minimize cost to ratepayers."[132] However, this mandate to MISO exceeds the authority provided by section 202(c). Nor is the use of economic dispatch likely to serve the public interest.

The Order does not define "economic dispatch" or specify how it intends MISO to dispatch the units. In the Energy Policy Act of 2005, Congress adopted a definition of "economic dispatch" that generally conforms to accepted use: "the operation of generation facilities to produce energy at the lowest cost to reliably serve consumers, recognizing any operational limits of generation and transmission facilities."[133] Drawing on this statutory definition, FERC issued a 2006 report, *Security Constrained Economic Dispatch: Definitions, Practices, Issues, and Recommendations,* that provides a useful explanation of the 2-step process that

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[130] 10 C.F.R. § 205.373(h).

[131] Order at 2 (Ordering Paragraph A)

[132] *Id.*

[133] *See* section 1234(b) of the Energy Policy Act of 2005, 42 U.S.C. § 16432(b);

regions have, in practice, adopted to implement economic dispatch.[134] This process includes (1) *day ahead unit commitment*, in which grid operators commit generators to be online in the subsequent 24-hour period, determined based on which generators will be most economic, taking into account each unit's physical operating characteristics, and (2) *unit dispatch*, in which grid operators dispatch committed resources at specified levels, in real-time, determined based on what set of units will minimize total system costs, given actual load, generation, and transmission conditions and constraints.[135]

Section 202(c) authorizes DOE to direct certain actions during emergency conditions. As relevant here, section 202(c)(1) provides DOE with "authority . . . to require by order . . . such generation . . . of electric energy as in its judgment will *best meet the emergency* and serve the public interest." In other words, DOE's power extends only to ordering actions that meet the emergency that the Department has identified.

But economic dispatch is not a rational response to the types of emergencies that section 202(c) authorizes DOE to address. Nor would economic dispatch be a rational approach to addressing the circumstance that DOE is purporting to address with its order—a potential capacity shortfall—if that were within its authority under section 202(c). In fact, DOE has made no effort to explain why economic dispatch is a rational remedy here, — let alone the best means of meeting the "emergency" that it

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[134] FERC, *Security Constrained Economic Dispatch: Definitions, Practices, Issues, and Recommendations* (July 31, 2006), https://www.ferc.gov/sites/default/files/2020-05/final-cong-rpt.pdf.
[135] *Id.* at 5-6.

has identified. And, unlike prior Orders, here DOE acted on its own motion without a request or input of MISO and so cannot rely on the expertise of the cognizant grid operator or operating utility requesting a specific remedy to justify the appropriateness of economic dispatch.[136]

i. Economic dispatch is not a rational response to a shortage of electric energy

Economic dispatch is the standard procedure by which operators (such as MISO) operate the grid. However, outside of normal operations, including during emergency conditions, generation units may be selected "out of merit order" as necessary to ensure that generation and load are balanced. Operating a unit pursuant to economic dispatch is, necessarily, inconsistent with operating the unit in a manner designed to address an emergency, such as a shortage of electric energy. If a unit would be dispatched under purely economic conditions, but electric demand can alternatively be met with other existing supply (or demand response) resources, that unit is *not* necessary to meet the emergency. However, if the unit would, in fact, be needed to address a shortage, it should be dispatched regardless of whether its offer price is above or below the market-clearing price. In other words, economic dispatch is not a dispatch rule that is reasonably tailored to ensure that the unit addresses a shortage of electric energy.

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[136] *See* DOE Order No. 202-18-1 at 4 (The statute requires only that the Secretary use his or her best judgment to meet the emergency and serve the public interest. In this situation, the expertise of the applicant was an important factor. The Department received an application from PJM, which . . . holds the highest-level, federally-regulated reliability responsibilities for the system it manages.), https://www.energy.gov/sites/prod/files/2017/11/f46/Summary%20of%20Findings%20Order%20No.%20202-18-1.pdf.

Prior DOE orders have contained significant operating constraints to satisfy this statutory requirement. Orders have specified that units subject to a section 202(c) order should only run in specific emergency alert conditions — specific conditions in which grid operators have exhausted the capacity of other available generators, imports, and voluntary demand response, and failure to call on additional generation will risk involuntary load shed.[137] Similarly, in its order to delay retirement of the Yorktown plant, DOE recognized that dispatch of the units must be constrained, that continued operation of the units under the standard methodologies used by the local utility (Dominion Energy Virginia) and grid operator (PJM) would not be appropriate, and that Dominion and PJM must exhaust available resources, including demand response and behind-the-meter generation resources, prior to operating Yorktown Units 1 or 2.[138] Similarly, in the case of its 2005 District of Columbia Department of Public Service order, the Department directed Mirant to maintain its facility's capacity to respond when needed, but only ordered it to run when one or both of the 230 kV transmission lines serving downtown D.C. were out of service.[139] And in its 2017 order regarding GRDA's Grand River Energy Center

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[137] DOE Order No. 202-21-1 (authorizing operation only during Energy Emergency Alert Level 2 or Level 3); DOE Order No. 202-21-2 (authorizing operation only during Energy Emergency Alert Level 2 or higher); DOE Order 202-22-1 (same); DOE Order No. 202-22-3 (same); DOE Order No. 202-22-4 (same).

[138] DOE Order No. 202-17-2 (providing that Yorktown units 1 and 2 may be dispatched "only when called upon to address reliability needs" and directing PJM and Dominion Energy Virginia "to provide the dispatch methodology to the Department upon implementation, and to report all dates on which Yorktown Units 1 and 2 are operated"); DOE Order No. 202-18-1 at 3 (relying on the fact that DOE "require[d] PJM and Dominion to exhaust available resources, including demand response and behind-the-meter generation resources, prior to operating Yorktown Units 1 or 2").

[139] DOE Order No. 202-05-3 (Dec. 20, 2005), District of Columbia Public Service Commission at 10 – 11.

Unit 1, the Department strictly limited its remedy, directing GRDA only to provide "dynamic reactive power support and not real power generation, and only when called upon by SPP for reliability purposes."[140] DOE's Order contains no such constraints, and it fails to explain or justify such deviation from consistent past practice.

ii. Economic dispatch is an arbitrary response to any alleged capacity shortage

Indeed, even on DOE's own terms, the justification for the Order does not support ordering J.H. Campbell to operate whenever MISO's economic dispatch rules would select it to operate. The Order points specifically to questions about the sufficiency of electric *capacity* and the ability of MISO to meet load during periods of high demand and low resource output over the next 90 days as the basis for its emergency determination.[141] For example, the Order points to NERC's 2025 Summer Reliability Assessment, and specifically to the finding that "MISO is at elevated risk of operating reserve shortfalls *during periods of high demand and low resource output*."[142] The order repeatedly raises concern about the risk of "*capacity* shortfall for MISO," the extent to which *capacity* of certain generating resources have retired or may retire, and that MISOs' *capacity* market auction (the Planning Resource Auction Results for Planning Year 2025-26) "reinforce the need to increase *capacity*."[143] Dispatch of J.H. Campbell at any time other than a specifically identified operating reserve shortfall (e.g., a concrete expected supply/demand imbalance)—let

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[140] DOE Order No. 202-17-1 at 2.
[141] Order at 1-2
[142] Order at 1 (emphasis added).
[143] Order at 1-2.

alone dispatch whenever the plant would be called upon by MISO's economic dispatch algorithm—is *not* necessary to address the type of emergency that the DOE order identifies. Even if the order sufficiently justified retention of J.H. Campbell as a capacity resource (which it does not for the reasons outlined above), it would not follow that J.H. Campbell's electric *energy* is needed to address the identified emergency. Given the nature of the alleged emergency identified in the Order, no dispatch from J.H. Campbell should be necessary unless and until called upon by MISO expressly to address an emergency purpose.

iii. "Economic dispatch" is not in the public interest in this case

Section 202(c) also requires that DOE determine that a given remedy is in the public interest.[144] The public interest determination is not an independent or sufficient criteria to order any particular action. Rather, Congress's use of the conjunctive "and" in section 202(c)(1) clearly prohibits DOE from ordering actions that the Department believes will advance the public interest if those actions exceed what is needed to address the identified emergency. In fact, DOE acknowledged this limit on its authority in its order denying rehearing of its order directing the retention of the Yorktown power plant.[145] Therefore, for the reasons explained above, economic dispatch is not appropriate even *if* DOE determines that it would advance the public interest.

However, DOE's vague direction to MISO to operate Campbell using "economic dispatch" will not further the public interest. DOE's order does not explain why it

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[144] 16 USC § 824a (c)(1).
[145] DOE Order 202-18-1 at 4.

believes economic dispatch would be in the public interest, other than a general reference to "minimize[ing] cost to ratepayers." However, this justification fails for two reasons. First, the Order's reference to economic dispatch is ambiguous and leaves open the likelihood that Consumers will operate the facility even at times when its operation will have the effect of *increasing* costs to consumers. For example, Consumers is likely to commit J.H. Campbell into MISO's day ahead electricity market as a "must run" unit, rather than using Emergency commitment.[146] In other words, Consumers will operate the units at least at minimum load every day rather than when there is a forecasted shortfall (e.g., due to unexpected load, unit outage, or a natural disaster). In such circumstances, J.H. Campbell will run at its minimum operational level regardless of whether doing so is truly economic. As a result, DOE has not justified, and cannot be reasonably certain, that economic dispatch will "minimize cost to ratepayers" — its sole explanation for the operational profile it has directed MISO to adopt. In other words, DOE's ordering of economic dispatch in this case is arbitrary.

Moreover, by directing economic dispatch, rather than reserving J.H. Campbell for discrete supply shortages by committing it as Emergency status, DOE's order will result in the facility operating significantly more than necessary. Because J.H. Campbell is old, and because Consumers has been deferring maintenance in anticipation of its retirement, a significant step-up in operation caused by must-run commitment and economic dispatch will increase the likelihood that one or more

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[146] *See* MISO Tariff, Section 39.2.5.b.xxvi (discussing Emergency Commitment Status).

units break, requiring costly maintenance to continue operating. Such repairs would likely further increase costs to ratepayers—costs that would be less likely to occur under an operational order better tailored to the emergency that DOE has identified. For example, DOE could have minimized the risk of ratepayer costs had it directed Consumers and MISO to commit (and ultimately dispatch) the facility only after analysis showing a likely near-term supply/demand imbalance or short-term emergency conditions (such as a heatwave, or the forced outage of a large generator or transmission line). The Order is arbitrary and capricious by ordering operation that risks increasing costs to ratepayers, the very outcome DOE has said it is looking to avoid.

Second, the Order fails to consider, let alone explain away, the fact that the State of Michigan has made an independent judgment that it would be in the best interest of ratepayers, the state, and the environment, to accept Consumers' proposal to retire J.H. Campbell. As explained above, the State of Michigan and MISO each went through robust processes to assess the need for J.H. Campbell (or lack thereof), as well as the economic and environmental impacts of its continued operation. The State of Michigan appears not to have been consulted on DOE's Order, notwithstanding the extensive process that it underwent to evaluate whether retirement would be in the public interest. Here, the public interest is best effectuated by respecting the Michigan's considered decision to approve the closure of J.H. Campbell plant, rather than to allow its near continuous operation at ratepayer expense.

Finally, for the reasons explained more fully below, the Order fails to consider the increased air and water pollution that will be caused by J.H. Campbell operating pursuant to economic dispatch instructions. DOE fails to even consider these harms, let alone weigh them against the (alleged) benefits of increased operation, in its determination that economic dispatch of the J.H. Campbell plant will further the public interest.

E. The Department failed to limit its remedy as required by 202(c)(2).

Section 202(c) imposes strict substantive limits on the Department's authority to issue emergency orders that may result in conflicts with any Federal, State, or local environmental law or regulation. Congress deliberately included these limitations to prevent section 202(c) from becoming a de facto exemption from environmental regulation. Here, DOE failed to comply with either of the statute's two express constraints and therefore acted unlawfully.

i. Section 202(c)(2) contains two distinct and binding legal constraints

Congress imposed two critical limitations on the scope of a DOE emergency order under section 202(c):

Temporal Constraint. First, DOE must "ensure that such order requires generation . . . of electric energy only during hours necessary to meet the emergency and serve the public interest."[147] Again, this is a conjunctive requirement such that both conditions—operation in a given hour must be necessary to meet the emergency

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[147] 16 U.S.C. § 824a(c)(2).

and operation in a given hour must serve the public interest—must be satisfied.[148] Moreover, by referring to the "hours" necessary to meet the emergency, Congress placed a high burden on DOE to demonstrate that the remedy provided was narrowly tailored to the specifics of the emergency that the order is designed to address.

Environmental Constraint. Second, the Department must "ensure that such order . . ., to the maximum extent practicable, is consistent with any applicable Federal, State, or local environmental law or regulation and minimizes any adverse environmental impacts."[149]

The Department acknowledges that, "additional generation may result in a conflict with environmental standards and requirements" and so it is required to limit additional generation from J.H. Campbell. However, the Order then wholly fails to meet the acknowledged temporal and environmental constraints in the particular ordering conditions that it establishes.

ii. The Order violates Section 202(c)(2)'s temporal constraint

The Order states that its direction to Campbell is "limited in duration to align with the emergency circumstances."[150] But, in fact, DOE has directed the unit to operate for the entire statutory maximum of 90 days. And, as described in more detail *supra,* within that 90-day window, DOE has directed the use of "economic dispatch"—an operational direction that will likely result in Campbell operating at least at its

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[148] DOE Order No. 202-18-1, 4(Nov. 6, 2017).

[149] 16 U.S.C. § 824a(c)(2).

[150] Order at 2.

minimum output level, and more likely at the maximum output Consumers Energy can manage, taking into account the state of the facility, continuously for the 90-day period—without providing any other temporal limitation on operations. In other words, the Order appears to assume, without explanation, that an emergency will exist in every hour over the entire 90-day period of the Order that Consumers happens to submit a bid into MISO's energy auction that is lower than the market-clearing price.[151] There is no reason to expect that this will actually be the case.

For these and all the reasons explained in section IV.C, the Order's direction that MISO dispatch J.H. Campbell economically is flatly inconsistent with section 202(c)'s requirement that emergency orders be limited to "only" those "hours" in which operation is necessary to meet the emergency. DOE cannot transform an hour-by-hour limitation into a blanket summer-season waiver through hand-waving at "elevated risk" of tight operating reserves and "*potential* electricity shortfalls."

DOE's failure to limit dispatch to discrete periods when the generation is needed to address the purported emergency renders the Order unlawful under the plain terms of § 202(c).

iii. The Order violates section 202(c)(2)'s environmental constraint

Section 202(c)(2) also requires DOE to ensure, "to the maximum extent practicable," that its orders (1) are consistent with applicable environmental laws and

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[151] In fact, it is not clear that DOE will limit operation to 90 days. DOE is authorized to extend the Order beyond 90 days under section 202(c), 16 U.S.C. § 824a(c)(4)(A), and has made no representation that the "emergency" is likely to be resolved by the end of the 90-day period.

regulations and (2) "minimize any adverse environmental impacts." The Department makes no serious effort to comply with this mandate.

First, the Order contains no analysis of J.H. Campbell's environmental obligations. J.H. Campbell is subject to air pollution requirements limiting its emissions of SO_2, NO_x, particulate matter, and mercury, and mandates the use of pollution control equipment such as baghouses, dry sorbent injection, and activated carbon injection systems.[152] DOE does not reference these requirements, direct Consumers to optimize the use of pollution controls or avoid operation during air quality episodes (even if those episodes occur at a time when the marginal energy from J.H. Campbell is not needed to meet electric demand), or provide any guidance for how Consumers is to operate the facility in the event that these requirements would come in conflict with its ability to provide power at any given time. It does not clarify what steps Consumers Energy would have to take to ensure continued operation of pollution control equipment in the event such equipment malfunctioned during the 90-day period. Nor does it appear the Department consulted with the State of Michigan, including its environmental regulator, to identify mechanisms to allow J.H. Campbell to remain available in a way that would minimize conflicts with state environmental laws, which the State was uniquely positioned to advise on and which

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[152] *See* Michigan Department of Environment, Great Lakes, and Energy, Renewable Operating Permit Issued to Consumers Energy, J.H. Campbell Generating Complex [J.H. Campbell ROP] (July 2, 2021), accessible through the Michigan Department of Environment, Great Lakes, and Energy's "MiEnviro Portal," https://www.michigan.gov/egle/maps-data/mienviroportal, and also accessible at https://www.egle.state.mi.us/aps/downloads/rop/pub_ntce/B2835/B2835%20FINAL%2007-01-21.pdf.

is required by section 103 of the Department of Energy Organization Act.[153] Instead, the Order offers only generic language about "compliance with applicable requirements… to the maximum extent feasible."

Second, the Order does not establish any operational criteria to "minimize any adverse environmental impacts" as required by section 202(c)(2). This requirement is in addition to the direction to minimize conflicts between operations and environmental requirements. It makes clear that Congress intended DOE to go beyond just avoiding regulatory conflicts but to proactively consider the environmental impact of its emergency orders. But DOE did not design its order to minimize environmental impacts of continued operation of J.H. Campbell. In fact, DOE's order runs directly contrary to the objective of minimizing environmental impacts by expressly directing MISO to operate J.H. Campbell on an "economic dispatch" basis. That instruction prioritizes low-cost dispatch irrespective of environmental impact.

F. The Order Violates NEPA.

Orders issued under section 202(c) are major federal actions subject to NEPA.[154] Such orders direct federal interventions that may affect environmental conditions. The direction to continue operation of J.H. Campbell is unquestionably a major action that significantly affects the environment. Continued operation of J.H. Campbell will result in significant increases of air and water pollution compared to a

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[153] *See* 42 U.S.C. § 7113.

[154] 42 U.S.C. § 4336e(10) (defining a "major federal action" as one in which the agency carrying out such action determines subject to substantial Federal control and responsibility.").

scenario in which Campbell retired as planned.[155] In fact, the Order directly concedes this point, stating "the additional generation may result in a conflict with environmental standards and requirements."[156]

For any DOE action affecting the quality of the environment, DOE must comply with NEPA—including through issuance of an environmental impact statement, environmental assessment, categorical exclusion, or special environmental analysis.[157] DOE has not taken, or even initiated, any such action. As such, it is acting contrary to its own NEPA regulations and to its obligations under NEPA.

DOE has previously sought to comply with NEPA for section 202(c) orders through categorical exclusions or special environmental assessments. Neither have been undertaken in this instance. Moreover, neither would be applicable here.

DOE has previously pointed to categorical exclusion B4.4 for "power management activities." However, that categorical exclusion is applicable only "provided that the operations of generating projects would remain within normal operating limits." Here, the Order explicitly authorizes the J.H. Campbell plant to operate beyond its normal permitted limits. Consequently, neither categorical exclusion B4.4, nor any other available exclusion, applies.

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[155] *See* J.H. Campbell ROP, *supra* n. 152; State of Michigan Department of Environmental Quality, Authorization to Discharge Under the National Pollutant Discharge Elimination System, Permit No. MI0001422 (May 29, 2018), accessible through the Michigan Department of Environment, Great Lakes, and Energy's "MiEnviro Portal," https://www.michigan.gov/egle/maps-data/mienviroportal.
[156] Order at 2.
[157] *See* 10 C.F.R. § 1021.102(b).

More recently, DOE has, on certain occasions, relied on emergency provisions that can excuse agencies from preparing environmental documents before taking such actions,[158] and instead prepared after-the-fact Special Environmental Analyses in the event that an order results in a significant effect on the environment.[159] However, these instances involved sudden emergencies that provided DOE substantially less notice compared to the months or years of advance warning DOE received regarding J.H Campbell's scheduled retirement. In this case, DOE acted in response to circumstances known well in advance: the long-scheduled retirement of J.H. Campbell on May 31, 2025. Given considerable lead time, DOE had ample opportunity to prepare, at a minimum, an EA prior to issuing its Order. DOE's failure to initiate any environmental review thus lacks justification.

Moreover, there will be even less justification for a failure to initiate appropriate environmental review for any extension of the Order beyond the initial 90 days. Under section 202(c)(3), orders conflicting with environmental laws are strictly limited to 90 days but may be extended. However, such extension requires consultation with other federal agencies responsible for regulating or with expertise in such environmental impacts.[160] Any justification that NEPA can be sidestepped to

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[158] *See* 10 C.F.R. § 1021.343(a); 40 C.F.R. § 1506.12.

[159] *See* DOE, Air Quality and Environmental Justice Memorandum (2021), https://www.energy.gov/sites/default/files/2022-01/sea-05-ercot-air-quality-and-ej-analysis-2021-07-21.pdf; DOE, Special Environmental Analysis for Actions Taken Under U.S Department of Energy Emergency Orders Regarding Operation of the Potomac River Generating Station in Alexandria Virginia (2006), https://www.energy.gov/sites/default/files/nepapub/nepa_documents/RedDont/SEA-04-2006.pdf

[160] 16 U.S.C. § 824a(c)(4)(B).

address an emergency need fades as DOE's orders extend beyond the initial 90-day period.

V. CONCLUSION

For the foregoing reasons, the Michigan Attorney General's request for rehearing should be granted.

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Attachment A

2025 NERC 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

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[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.

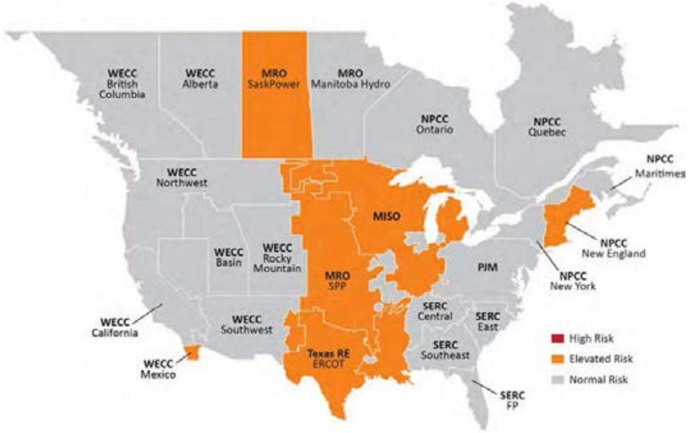

Figure 1: Summer Reliability Risk Area Summary

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.

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[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.

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[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.

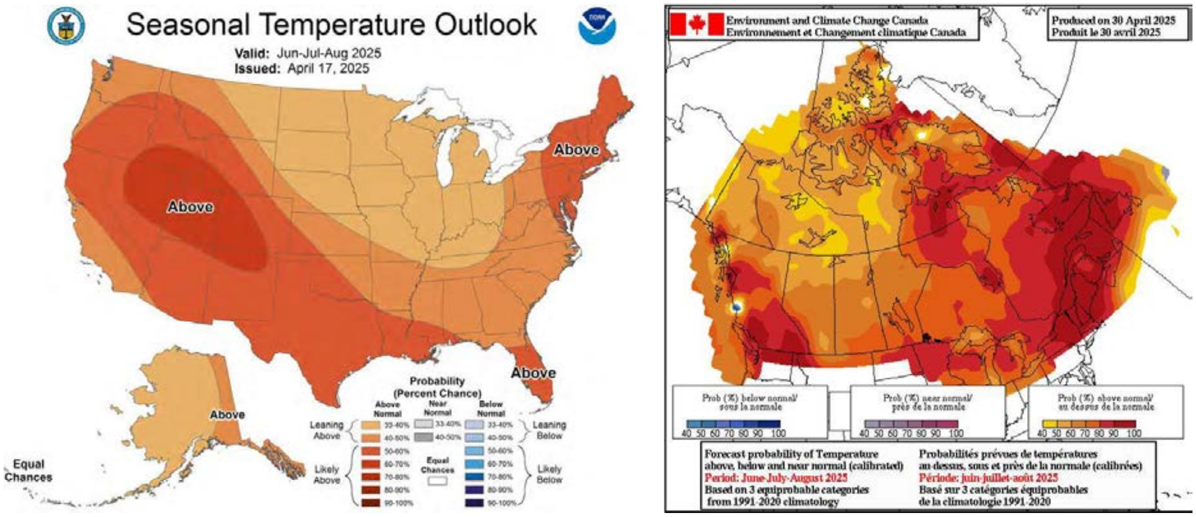

Figure 2: United States and Canada Summer Temperature Outlook[10]

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[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.

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[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.

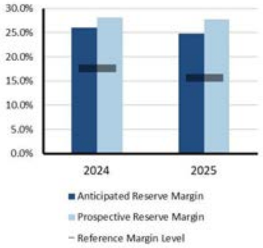
Highlights

- 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.

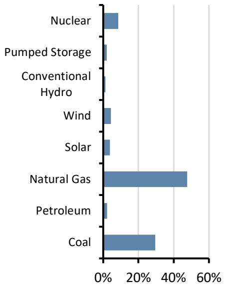
Risk Scenario Summary

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 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 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

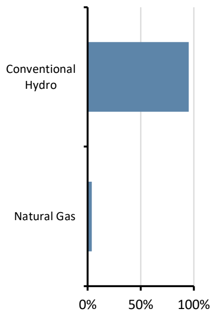
- Manitoba Hydro is not anticipating any operational challenges and/or emerging reliability issues in its assessment area for Summer 2025; the Anticipated Reserve Margin for Summer 2025 exceeds the 12% Reference Margin Level.
- While Manitoba Hydro experienced demand growth in the past year, the growth 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

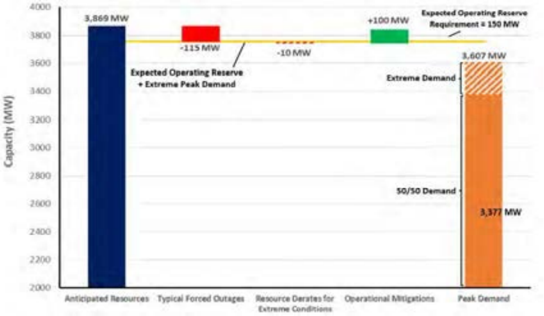
Expected resources meet operating reserve requirements under the assessed scenarios.

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

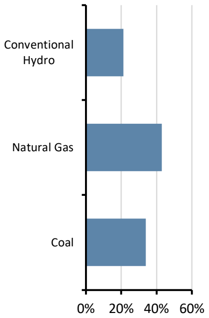
- Although Saskatchewan is mainly a winter-peaking region, summer can also bring high electricity demand due to extreme heat.
- Each year, SaskPower works with Manitoba Hydro on a joint summer operating study with input from the Western Area Power Administration and Basin Electric to develop operational 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.

Risk Scenario Summary

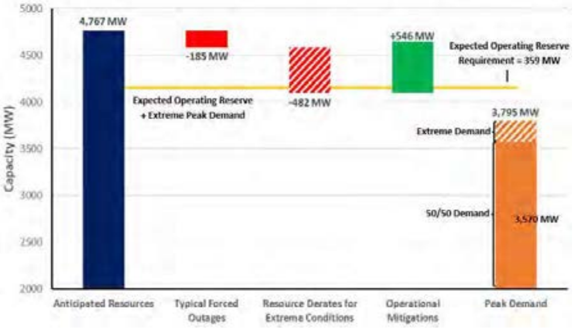
Expected resources meet operating reserve requirements under normal peak demand and outage conditions. Above-normal summer peak load and outage conditions are likely to result in the need to employ operating mitigations (e.g., demand response and transfers) and EEAs.

On-Peak 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 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

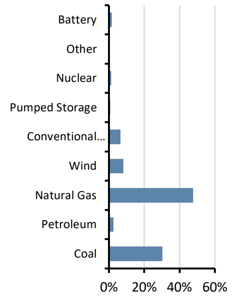
- SPP projects a low likelihood of any emerging reliability issues impacting the area for the 2025 Summer season.
- Generation availability is not expected to be impacted by fuel shortages or river conditions this summer.
- BA generation capacity deficiency risks remain depending on wind generation output 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

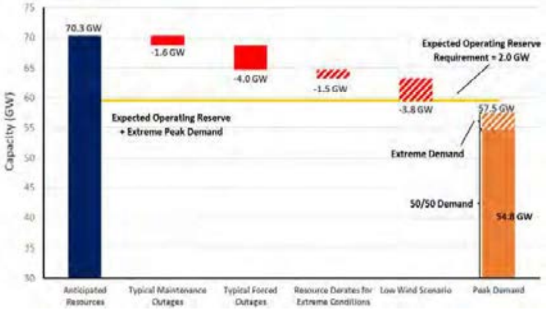
Expected resources are sufficient to meet operating reserve requirements under normal peak-demand and outage scenarios. Above-normal summer peak load, low wind conditions, and higher-than-normal forced outages could result in the need for operating mitigations (e.g., demand response and transfers from 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

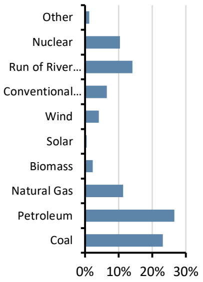
- As Maritimes is a winter-peaking system, no issues are expected for the upcoming summer assessment period with sufficient firm capacity to meet forecast peak demand. If an event were to occur, emergency operations and planning procedures are in place.
- Probabilistic analysis performed by NPCC for 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

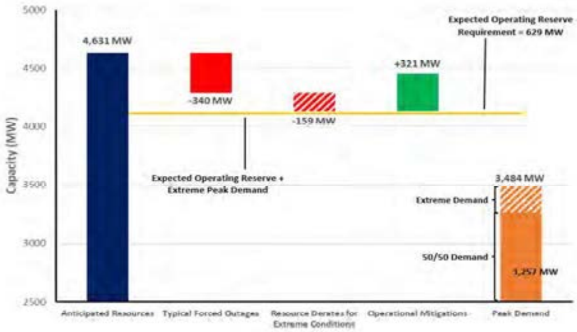
Risk Scenario Summary

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

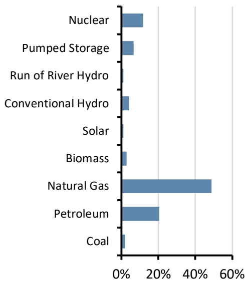
- ISO-NE forecasts adequate transmission capability and manageable capacity margins to meet the expected peak demand.
- Probabilistic analysis performed by NPCC for the NPCC *Summer Reliability Assessment* identified small amounts of cumulative LOLE, LOLH, and EUE for the expected load with anticipated 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

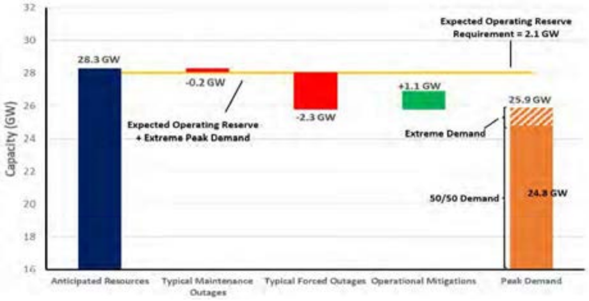
Risk Scenario Summary

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

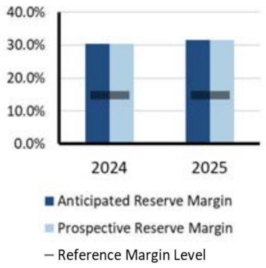
NPCC-New York

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.

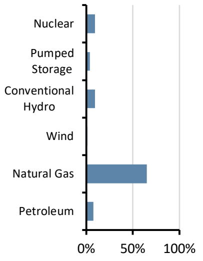
On-Peak Reserve Margin



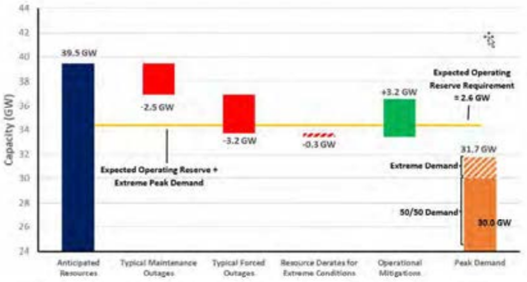
Risk Scenario Summary

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

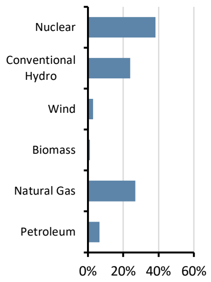
- Overall, Ontario is operating within a period where generation and transmission outages are more challenging to accommodate. The IESO is prepared and expects to have adequate supply for Summer 2025.
- The IESO has been actively coordinating and planning with market participants to maintain reliability.
- 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

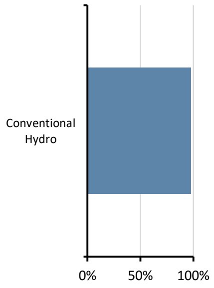
- The Québec area forecasted summer peak demand is 23,283 MW during the week beginning August 3, 2025, with a forecasted net margin of 5,698 MW (24.5%).
- Resource adequacy issues are not expected this summer.
- The Québec area expects to be able to assist other areas.
- Modeling was made more precise 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

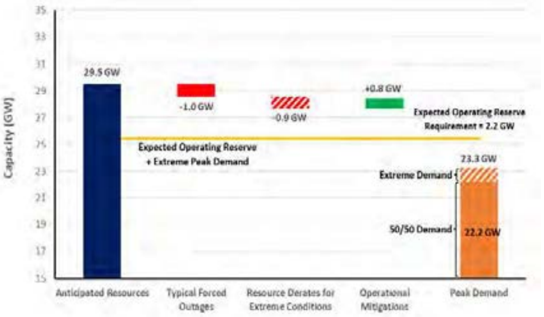
Expected resources meet operating reserve requirements under the assessed scenarios.

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.

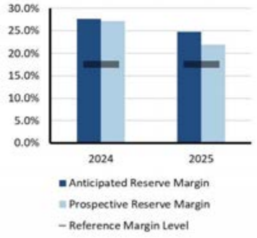
PJM

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.

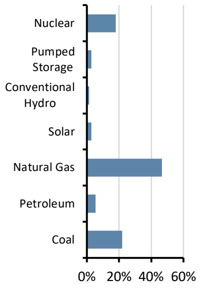
On-Peak Reserve Margin



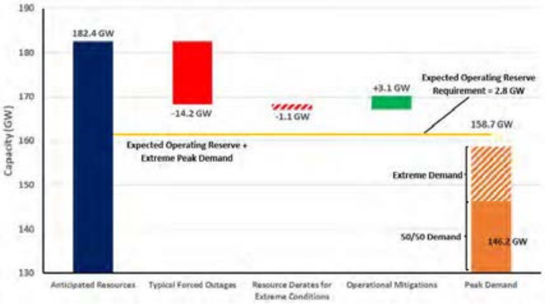
Risk Scenario Summary

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 (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

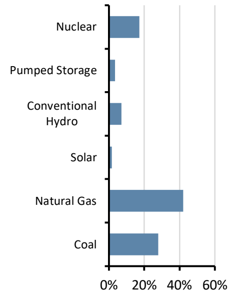
- SERC-Central saw a sizable increase in its reserves last summer, but coal retirements this summer will result in SERC-Central having lower reserves.
- SERC-Central's anticipated resources meet operating reserve requirements under the expected conditions and under the summer risk period scenario.
- 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

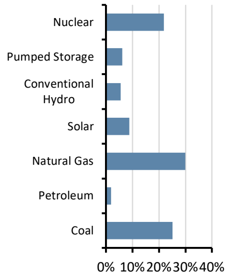
- SERC-East's reserves are largely unchanged compared to the reference margin as compared to last summer's assessment.
- SERC-East's anticipated resources meet operating reserve requirements under the expected conditions and under the summer risk period scenario.
- While the last probabilistic analysis 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.

On-Peak Reserve Margin

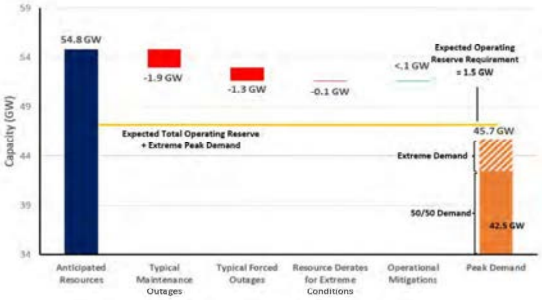
Risk Scenario Summary

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

Operational Mitigations: A total of 45 MW based on operational/emergency procedures

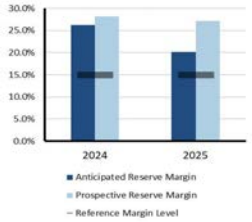
SERC-Florida Peninsula

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.

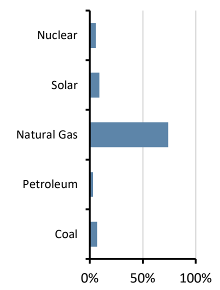
On-Peak Reserve Margin



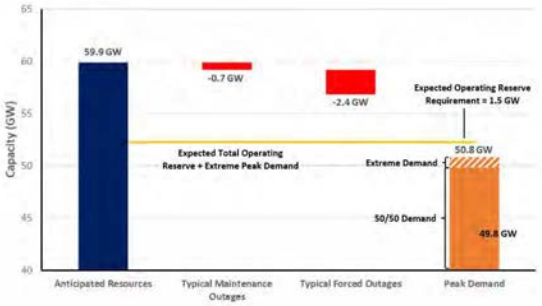
Risk Scenario Summary

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

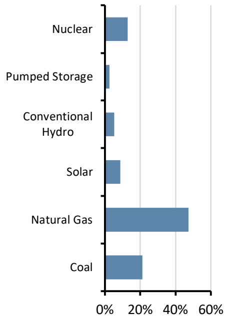
- An area within SERC-Southeast notes that natural gas pipeline constraints could impact reliability in summer, but this is not expected to pose a significant summer operational challenge.
- SERC-Southeast's anticipated resources meet operating reserve requirements under the expected conditions and under 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

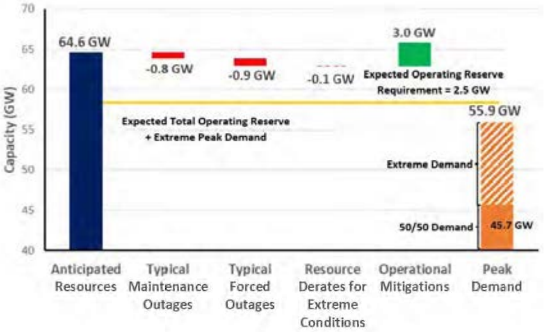
Risk Scenario Summary

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.

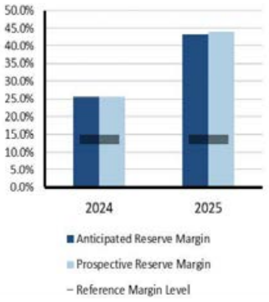
Highlights

- 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.

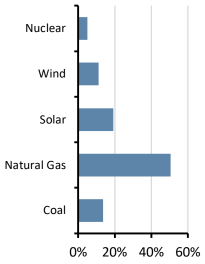
Risk Scenario Summary

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.

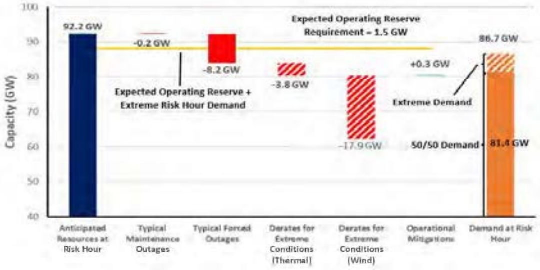
On-Peak Reserve Margin



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.

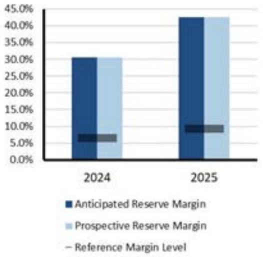
Highlights

- 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.

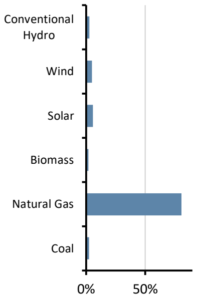
Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed scenarios.

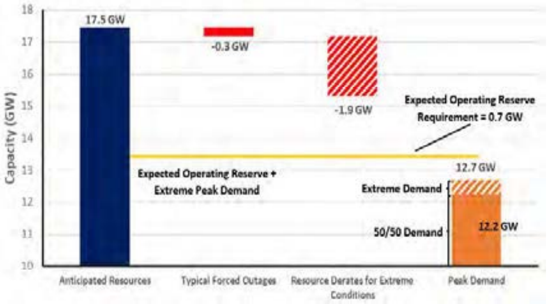
On-Peak Reserve Margin



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.

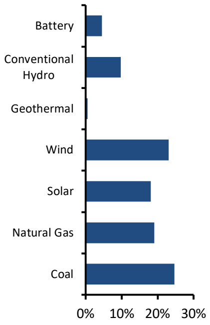
Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed scenarios with imports.

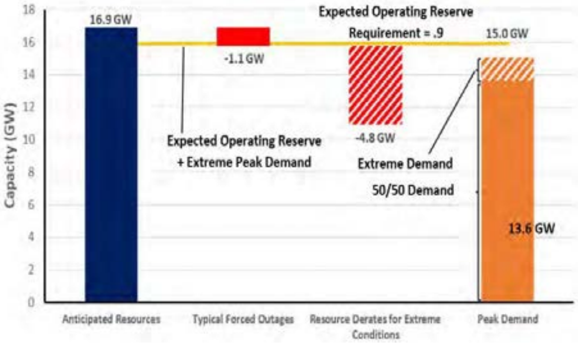
On-Peak Reserve Margin

(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

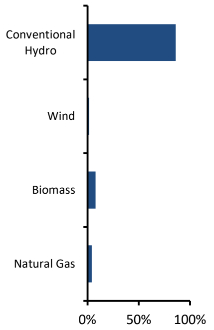
- Existing capacity reserve margin has increased from 19% to 22%, and anticipated and prospective reserve margin from 19% to 24%.
- Reserve margins are not anticipated to fall below the reference margin for the upcoming summer.
- The peak hour is forecast for early August at 4:00 p.m., two hours earlier 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

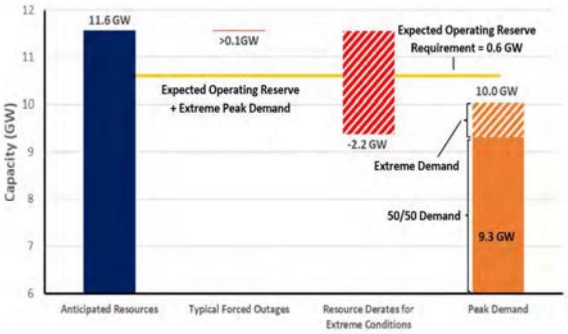
Expected resources meet operating reserve requirements under the assessed scenarios.

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

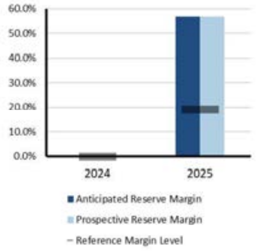
- Demand response is down 8.6% since last summer, existing-certain capacity is up 5.8%, and Tier 1 planned capacity is up 41.2% for a net increase in anticipated resources of 9%; anticipated and prospective reserve margins are up by 11.4%. The peak hour is still forecasted for early September around 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.

Risk Scenario Summary

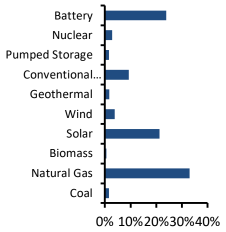
Expected resources meet operating reserve requirements under assessed scenarios, and a probabilistic assessment of normal and extreme resource/demand scenarios reveals neither EUE nor LOLH.

On-Peak Reserve Margin

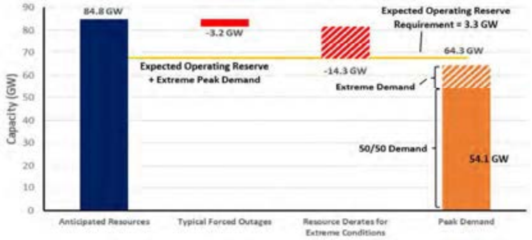
(Note: year comparison not available)



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) 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

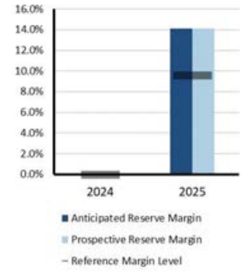
- Total and net internal expected (50/50) demand are up 6.8%, existing-certain capacity is up 29.8% or 989 MW, and Tier 1 planned capacity has fallen 100% to zero, leading to a decrease in the anticipated reserve margin from 22.9% down to 14.1%
- The peak hour is expected to occur in early August around 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

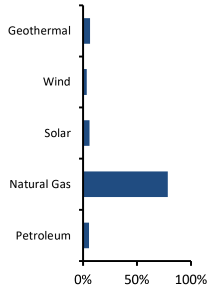
Expected resources at normal peak demand and outage conditions require some imports to maintain operating reserves. Thus, above-normal demand, high forced outage conditions, or transmission derates in the neighboring area could place WECC-Mexico in an energy emergency.

On-Peak Reserve Margin

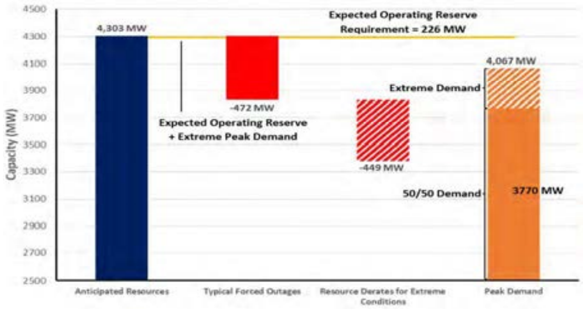
(Note: year comparison not available)



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*.

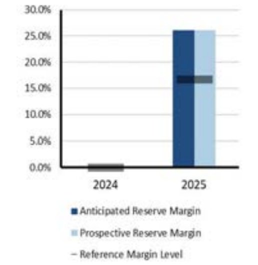
Highlights

- 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

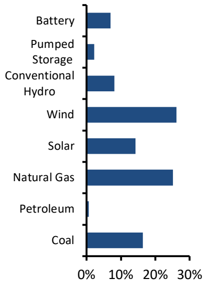
Expected resources meet operating reserve requirements under assessed scenarios with imports.

On-Peak Reserve Margin

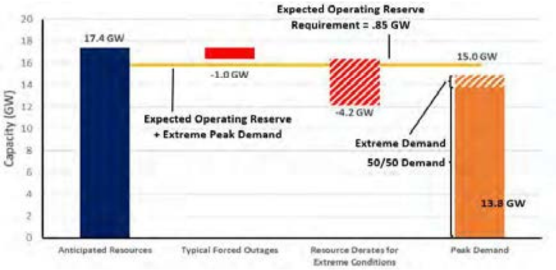


(Note: year comparison not available)

On-Peak Fuel Mix



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-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.

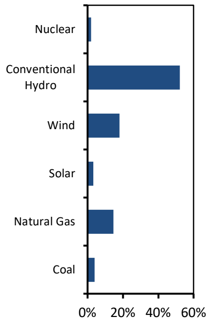
Risk Scenario Summary

Expected resources meet operating reserve requirements under assessed scenarios with imports.

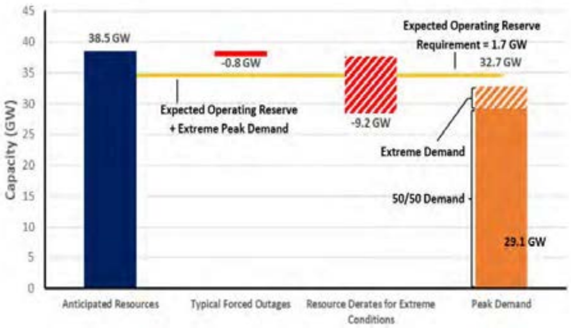
On-Peak Reserve Margin

(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.

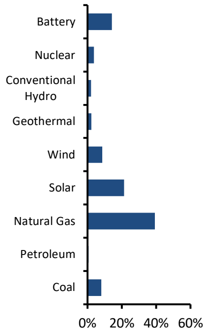
Risk Scenario Summary

Expected resources meet operating reserve requirements under assessed scenarios with imports.

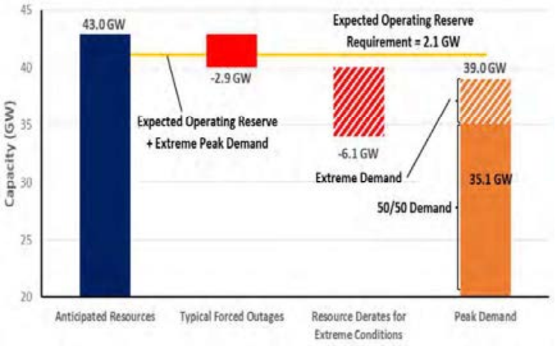
On-Peak Reserve Margin

(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 (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.

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[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**.

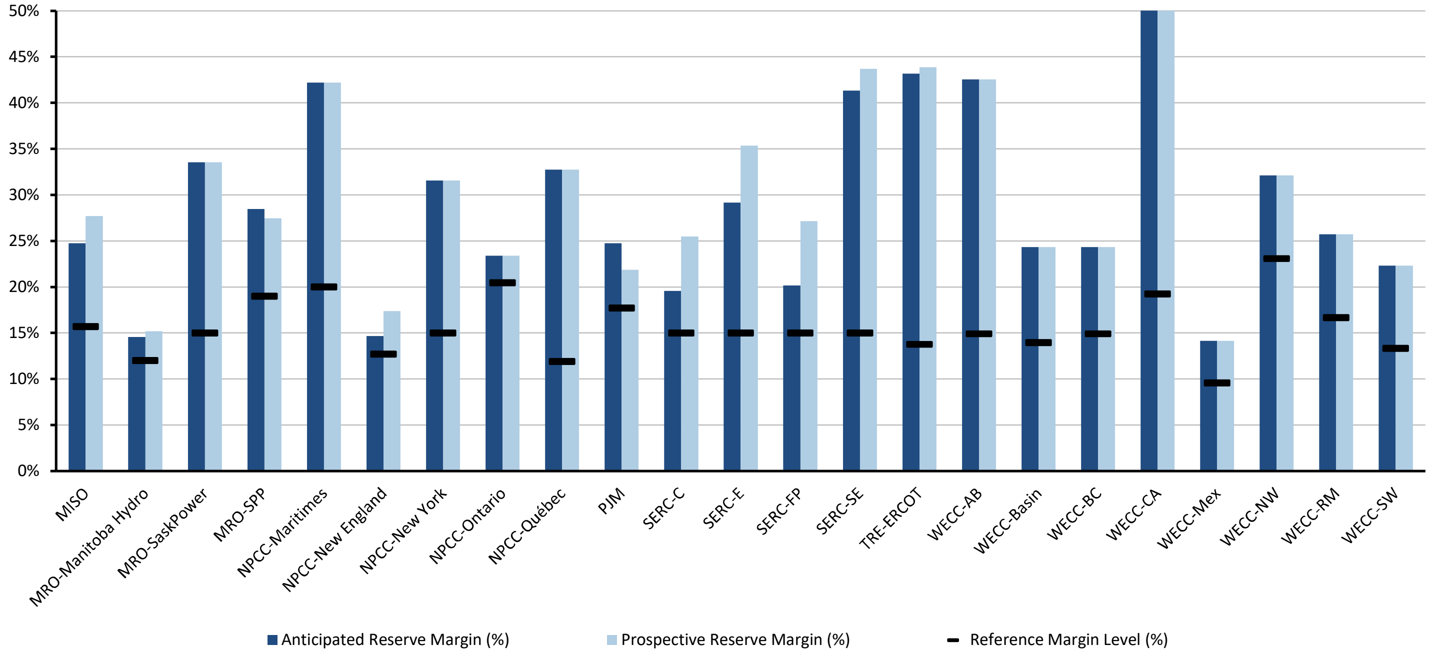

Figure 4: Summer 2025 Anticipated/Prospective Reserve Margins Compared to Reference Margin Level

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[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.

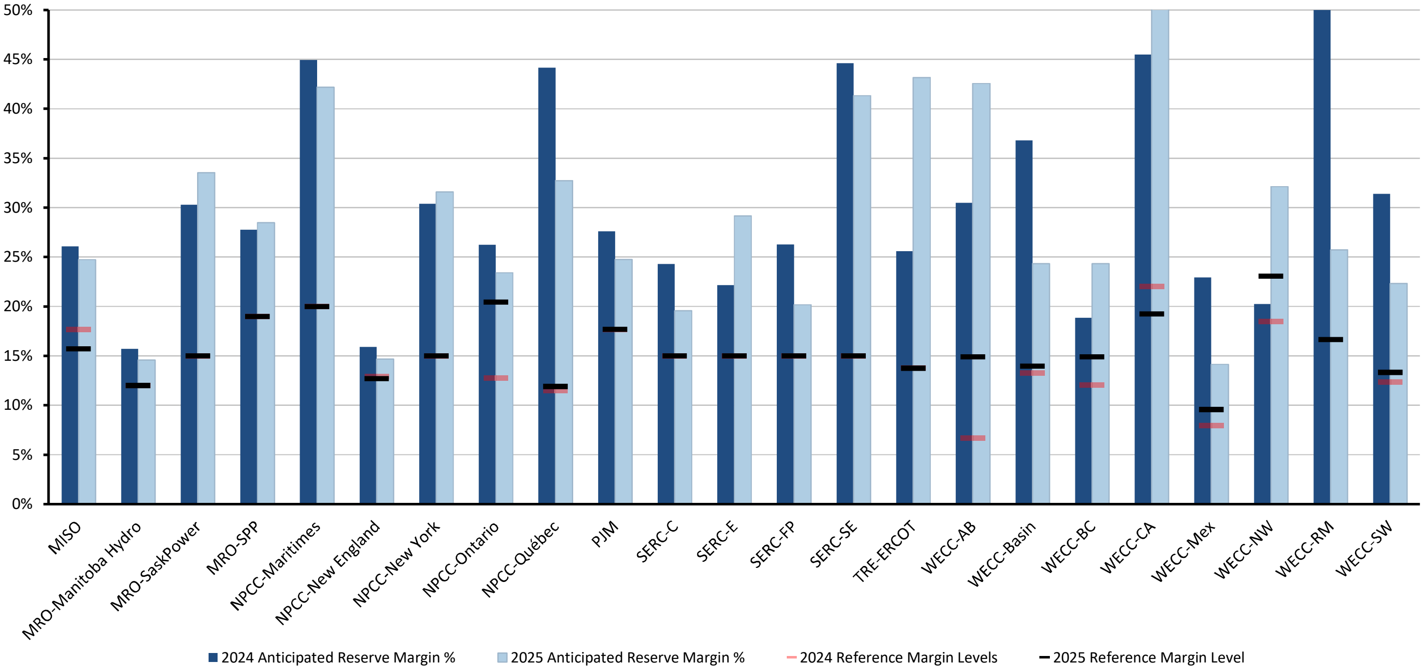

Figure 5: Summer 2024 and Summer 2025 Anticipated Reserve Margins Year-to-Year Change

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.

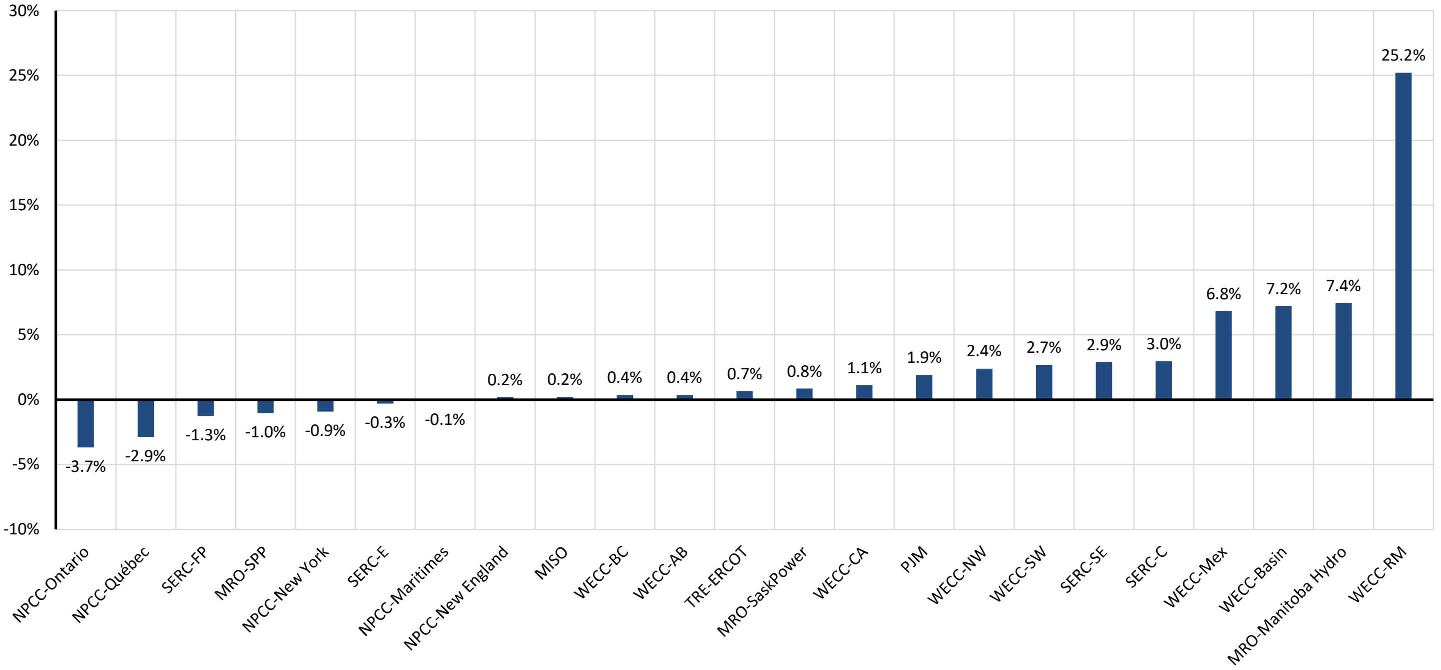

Figure 6: Changes in Net Internal Demand—Summer 2024 Forecast Compared to Summer 2025 Forecast

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[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

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-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

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.

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[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.

Attachment B

MISO 2025 PRA Report

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…

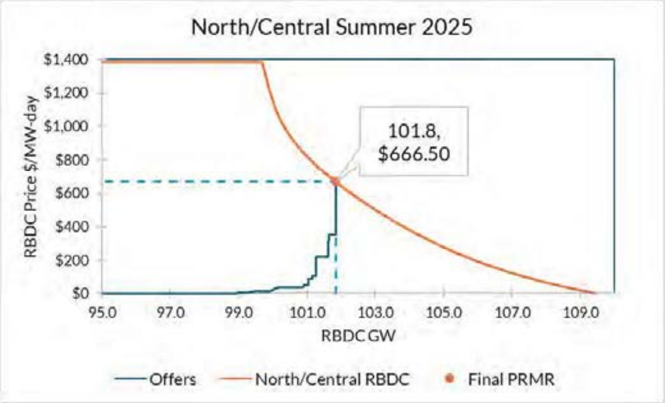
- Delivers competitive prices aligned with seasonal risks and tightening surplus
    - Prioritizes summer availability, the system's highest-risk season (based on 1-in-10 LOLE)
- Values incremental capacity above and below the LOLE target based on its reliability
    - Clears capacity above target Planning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

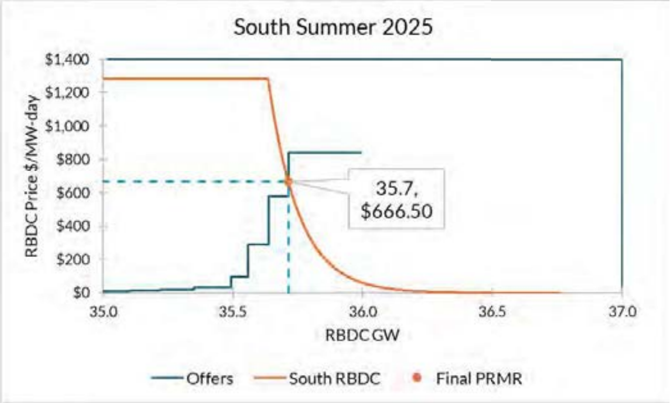
Why it Matters

- 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



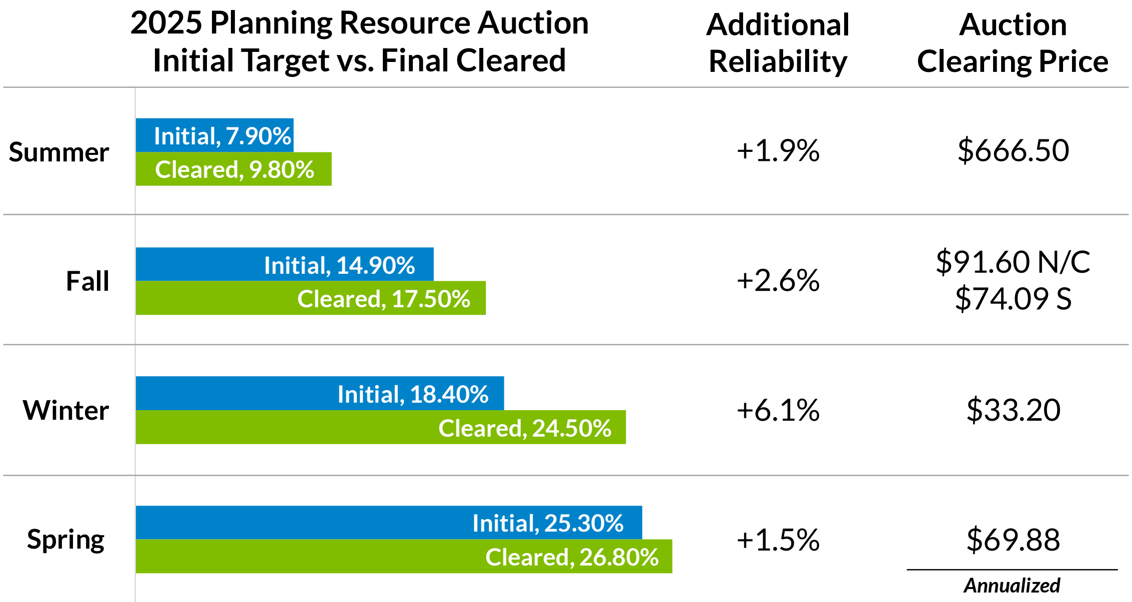


- Summer clearing of $666.50 reflects highest reliability risk and reducing surplus capacity year-over-year
    - Surplus capacity in the summer has reduced from approximately 6.5 GW in 2023, to 4.6 GW in 2024, to 2.6 GW in 2025
- Incremental capacity cleared beyond the target Planning Reserve Margin 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



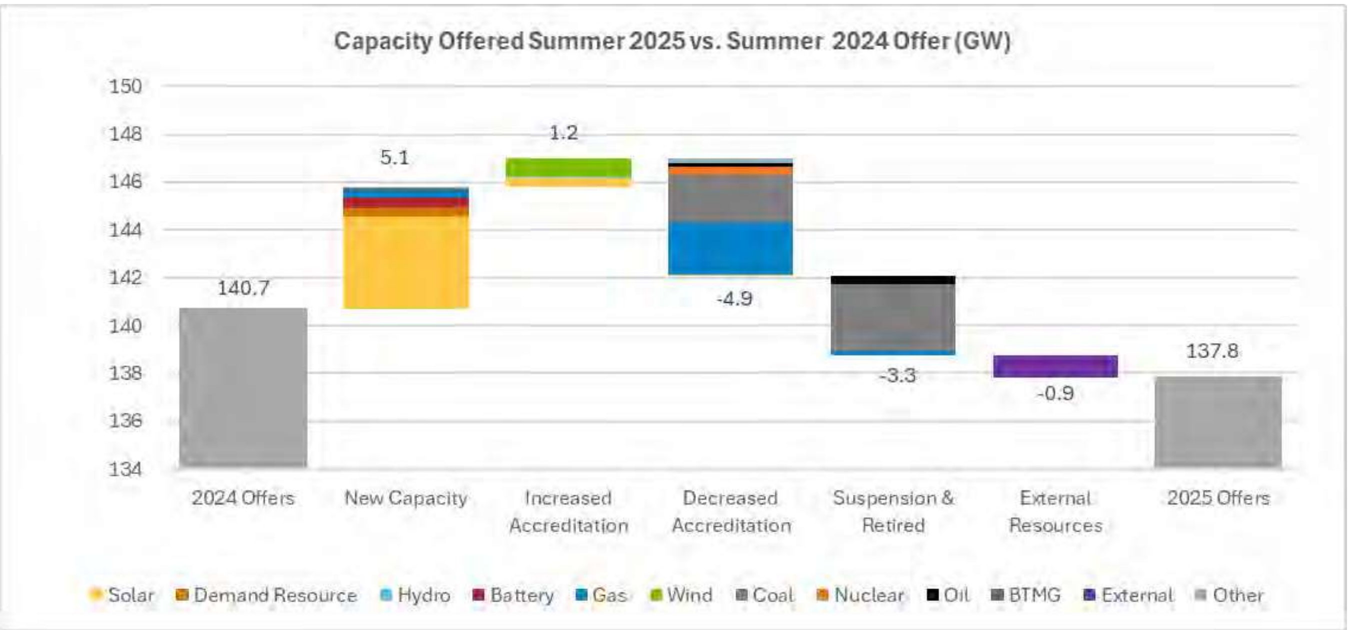
	2025 Planning Resource Auction Initial Target vs. Final Cleared	Additional Reliability	Auction Clearing Price
Summer	Initial, 7.90% Cleared, 9.80%	+1.9%	$666.50
Fall	Initial, 14.90% Cleared, 17.50%	+2.6%	$91.60 N/C $74.09 S
Winter	Initial, 18.40% Cleared, 24.50%	+6.1%	$33.20
Spring	Initial, 25.30% Cleared,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

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

PRM: Planning Reserve Margin

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

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

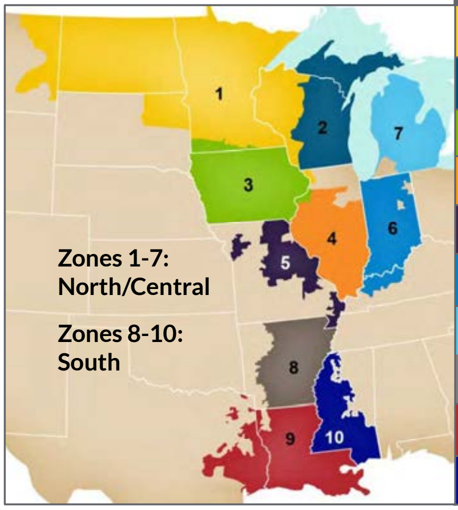
Table of Contents

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

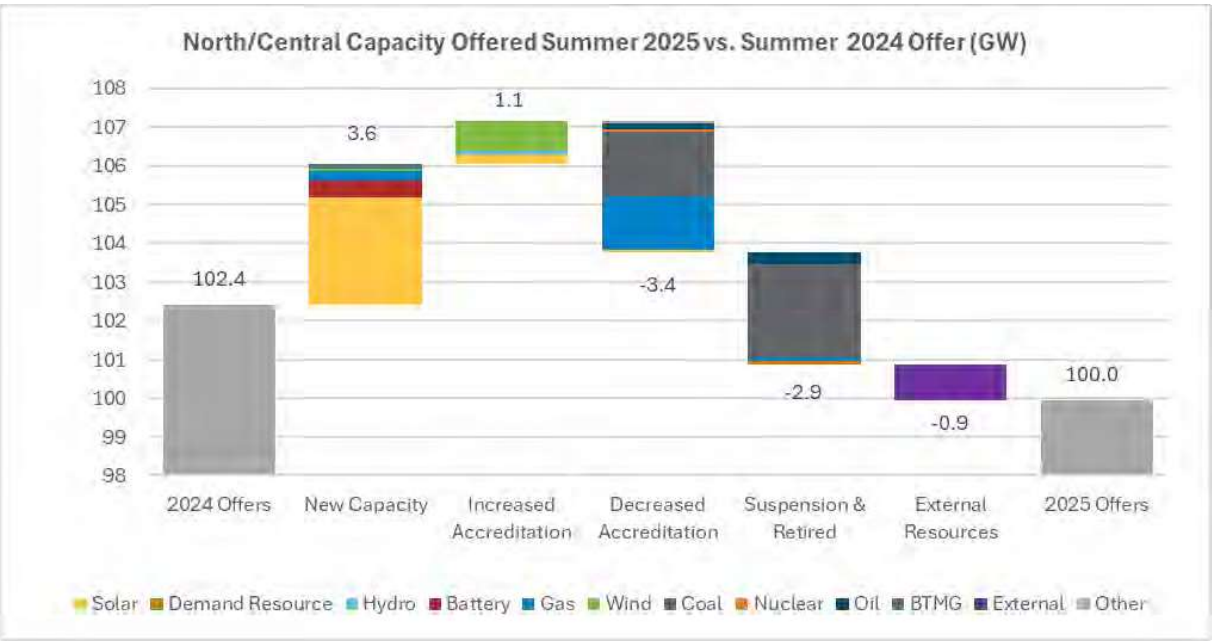


2025 PRA Results

	Price/MW-Day			
	Summer	Fall	Winter	Spring
1	$666.50	$91.60	$33.20	$69.88
2				
3				
4				
5				
6				
7				
8		$74.09		
9				
10				

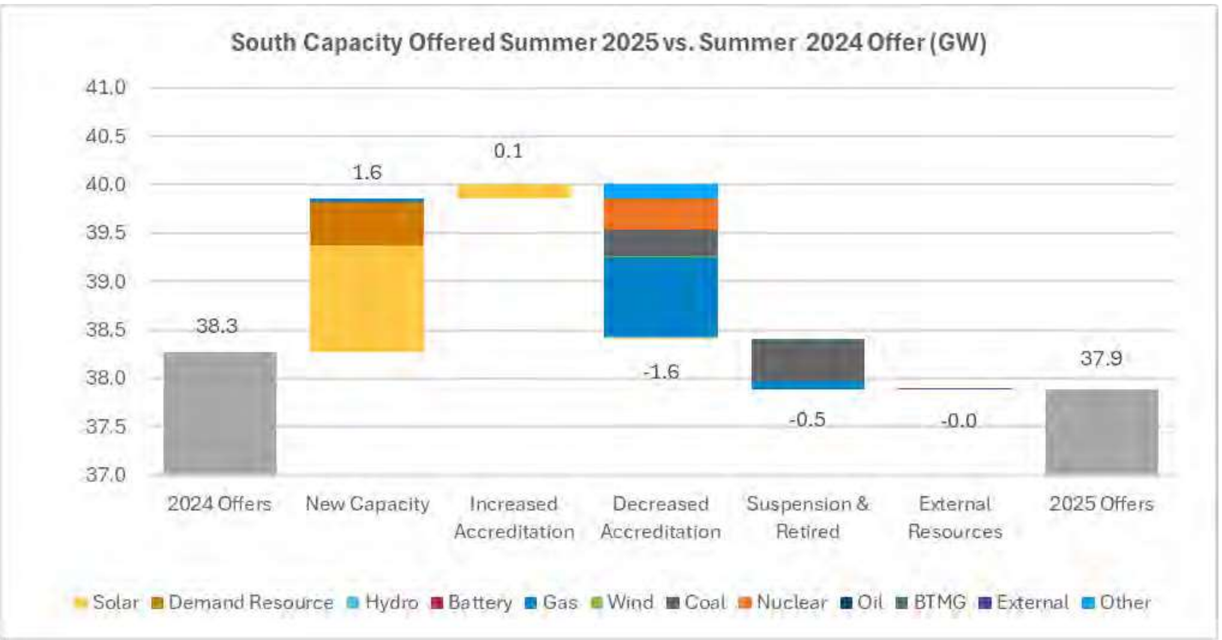
Annualized
$217 (North/Central)
$212 (South)

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



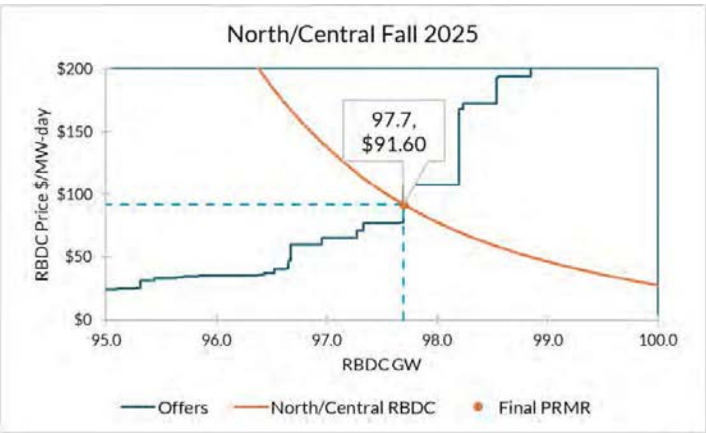
BTMG: Behind the Meter Generation | Capacity indicated is offered accredited value

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



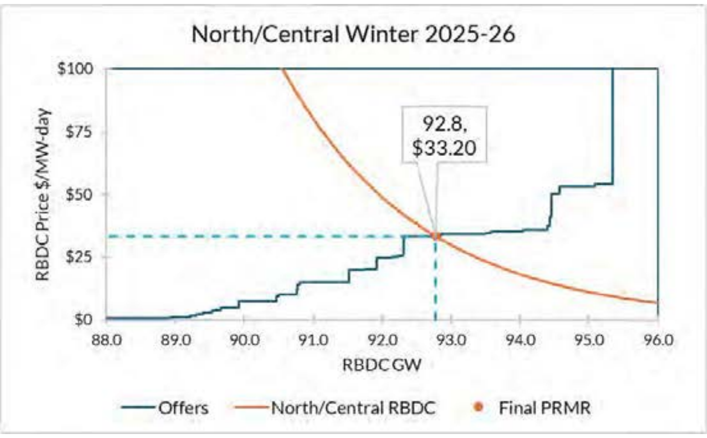
BTMG: Behind the Meter Generation | *Capacity indicated is offered accredited value*

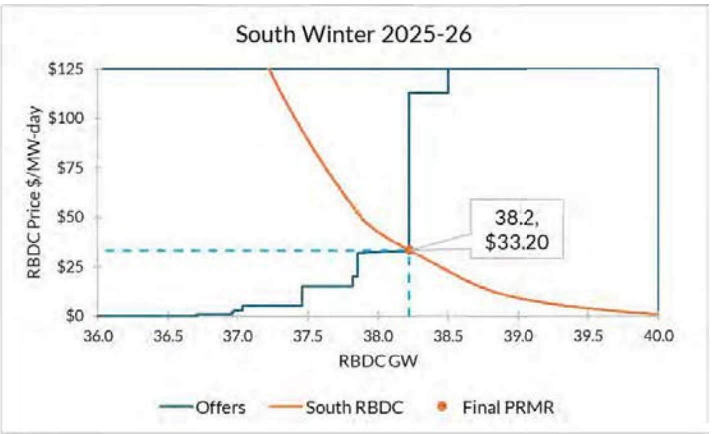
Fall 2025 Reliability-Based Demand Curve, Offer Curves and Auction Clearing Prices



- 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%

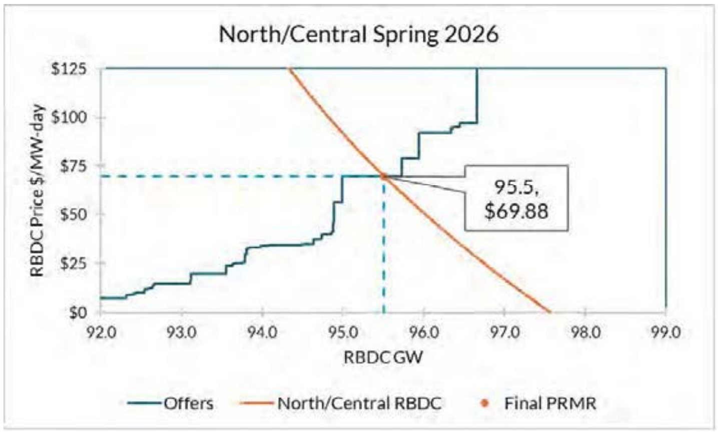
Winter 2025/26 Reliability-Based Demand Curve, Offer Curves and Auction Clearing Prices





- 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%

Summer 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.

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

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)

<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><th>System CONE (Seasonal)</th><th>North/Central CONE (Seasonal)</th><th>South CONE (Seasonal)</th></tr>
<tr><td>Summer 2025</td><td colspan="11">$666.50</td><td>$1,353.84</td><td>$1,384.36</td><td>$1,282.61</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><td>$1,368.71</td><td>$1,399.58</td><td>$1,296.70</td></tr>
<tr><td>Winter 2025-26</td><td colspan="11">$33.20</td><td>$1,383.92</td><td>$1,415.13</td><td>$1,311.11</td></tr>
<tr><td>Spring 2026</td><td colspan="11">$69.88</td><td>$1,353.84</td><td>$1,384.36</td><td>$1,282.61</td></tr>
<tr><td>Cost of New Entry (Annual)</td><td>$127,720</td><td>$125,090</td><td>$121,220</td><td>$126,040</td><td>$136,170</td><td>$124,360</td><td>$130,930</td><td>$118,960</td><td>$117,710</td><td>$117,330</td><td>$136,170</td><td></td><td></td><td></td></tr>
<tr><td>IMM Conduct Threshold*</td><td>$34.99</td><td>$34.27</td><td>$33.21</td><td>$34.53</td><td>$37.31</td><td>$34.07</td><td>$35.87</td><td>$32.59</td><td>$32.25</td><td>$32.15</td><td>-</td><td></td><td></td><td></td></tr>
</table>

- *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

PY	Zone 1	Zone 2	Zone 3	Zone 4	Zone 5	Zone 6	Zone 7	Zone 8	Zone 9	Zone 10	ERZs
Fall 2023	$15.00								$59.21	$15.00	
Fall 2024	$15.00				$719.81	$15.00					
Fall 2025	$91.60							$74.09			$83.24-$91.60

- 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

PY	Zone 1	Zone 2	Zone 3	Zone 4	Zone 5	Zone 6	Zone 7	Zone 8	Zone 9	Zone 10	ERZs
Spring 2024	$10.00										
Spring 2025	$34.10				$719.81	$34.10					
Spring 2026	$69.88										

- 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

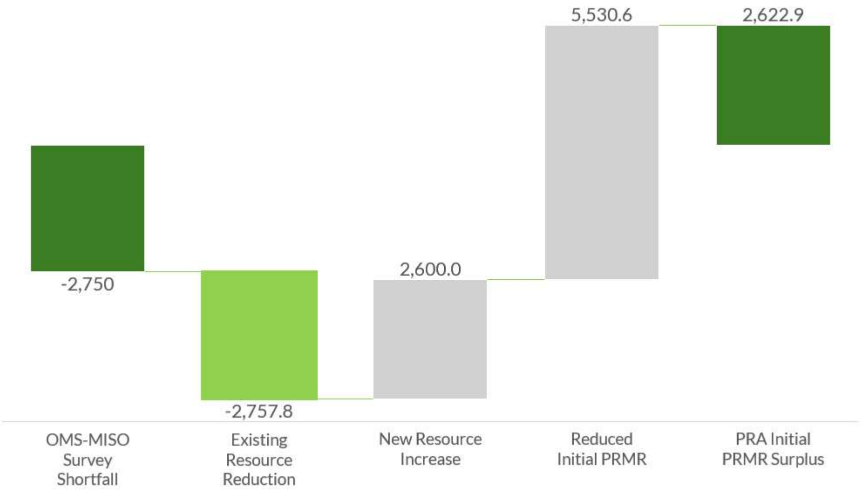
05/29/2025: MISO Planning Resource Auction for Planning Year 2025/26 Results Posting

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

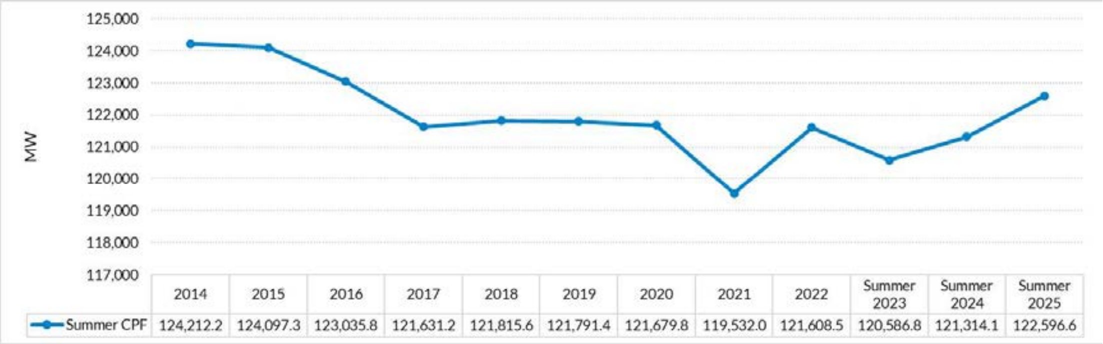
2024 OMS-MISO Survey Projection vs. 2025 PRA Actual PRMR Surplus (MW)



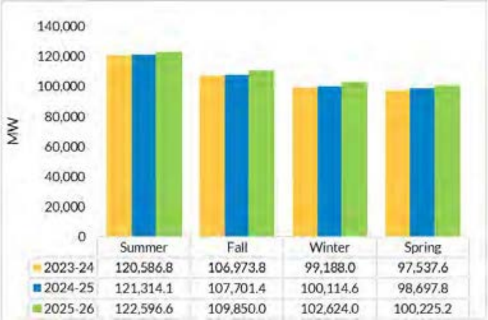
*PRA Shortfall/Surplus relative to Initial PRMR | PRMR: Planning Reserve Margin Requirement

Coincident Peak Forecast

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



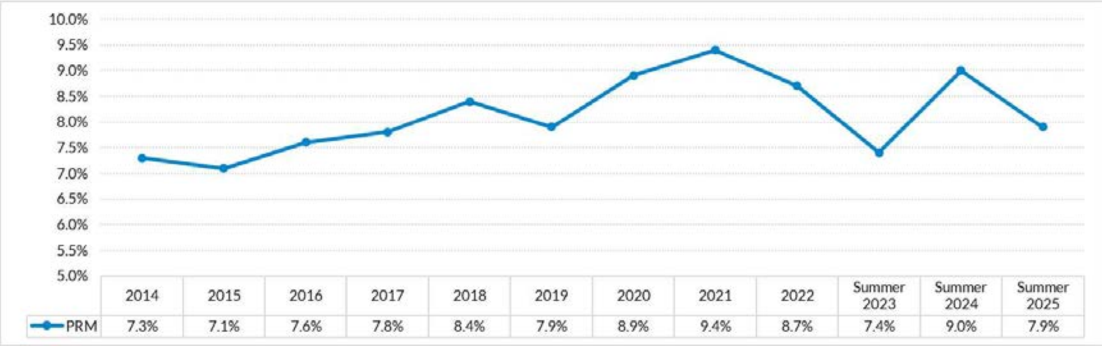
	2014	2015	2016	2017	2018	2019	2020	2021	2022	Summer 2023	Summer 2024	Summer 2025
Summer CPF	124,212.2	124,097.3	123,035.8	121,631.2	121,815.6	121,791.4	121,679.8	119,532.0	121,608.5	120,586.8	121,314.1	122,596.6



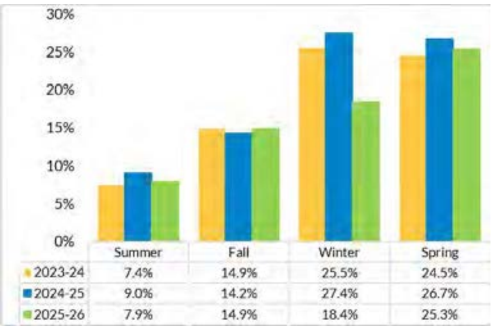
	Summer	Fall	Winter	Spring
🟨 2023-24	120,586.8	106,973.8	99,188.0	97,537.6
🟦 2024-25	121,314.1	107,701.4	100,114.6	98,697.8
🟩 2025-26	122,596.6	109,850.0	102,624.0	100,225.2

PRMR: Planning Reserve Margin Requirement

Planning Reserve Margin (%)

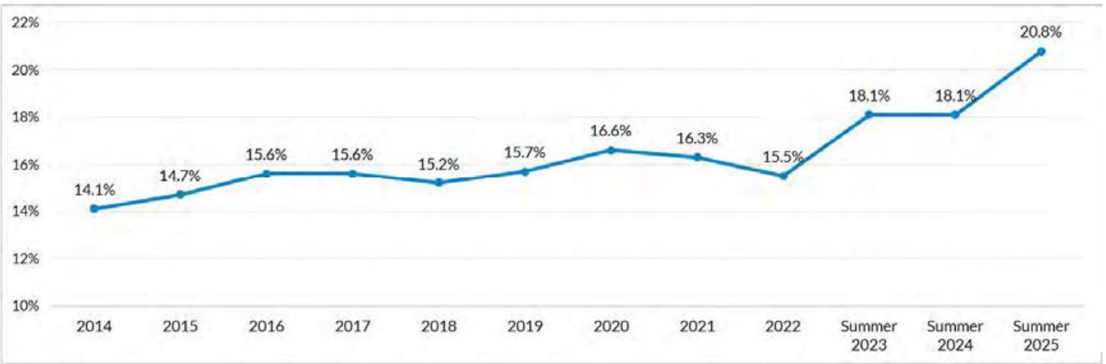


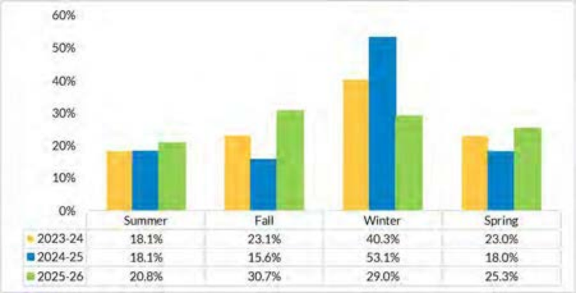
	2014	2015	2016	2017	2018	2019	2020	2021	2022	Summer 2023	Summer 2024	Summer 2025
PRM	7.3%	7.1%	7.6%	7.8%	8.4%	7.9%	8.9%	9.4%	8.7%	7.4%	9.0%	7.9%



	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 (%)



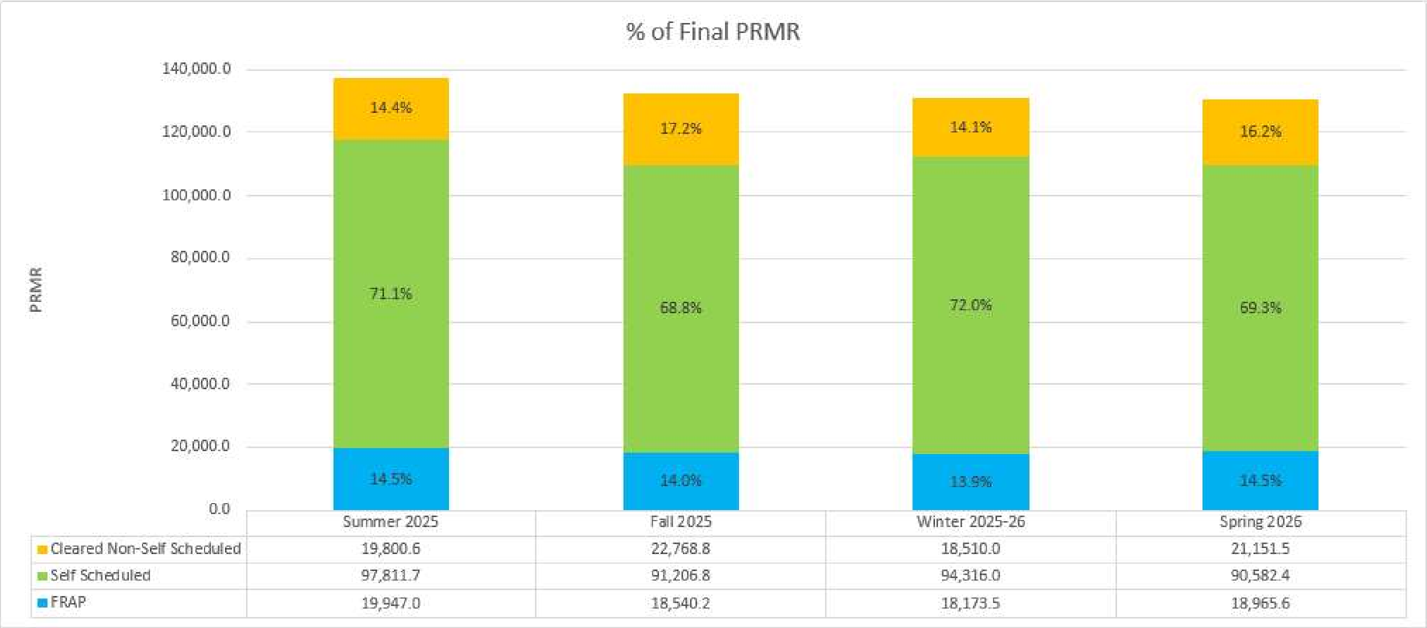


	Summer	Fall	Winter	Spring
🟨 2023-24	18.1%	23.1%	40.3%	23.0%
🟦 2024-25	18.1%	15.6%	53.1%	18.0%
🟩 2025-26	20.8%	30.7%	29.0%	25.3%

- 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



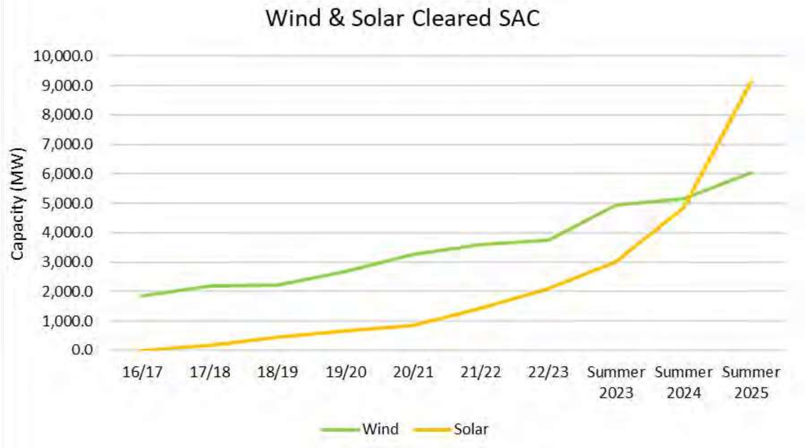
	Summer 2025	Fall 2025	Winter 2025-26	Spring 2026
🟨 Cleared Non-Self Scheduled	19,800.6	22,768.8	18,510.0	21,151.5
🟩 Self Scheduled	97,811.7	91,206.8	94,316.0	90,582.4
🟦 FRAP	19,947.0	18,540.2	18,173.5	18,965.6

PRMR: Planning Reserve Margin Requirement

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

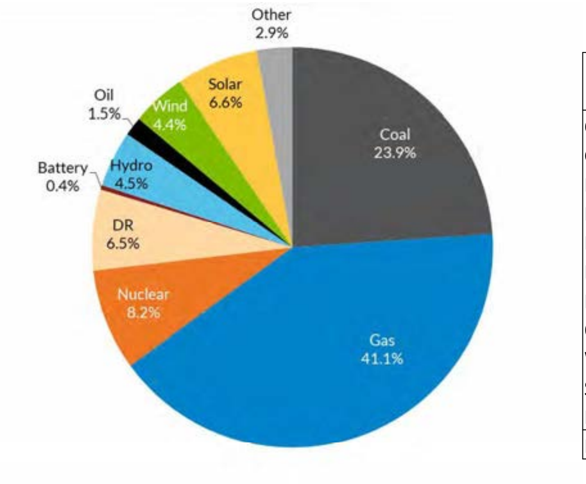
- 9.1 GW of solar cleared this year’s auction, an increase of 88% from Planning Year 2024/25 (4.9 GW)

- 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

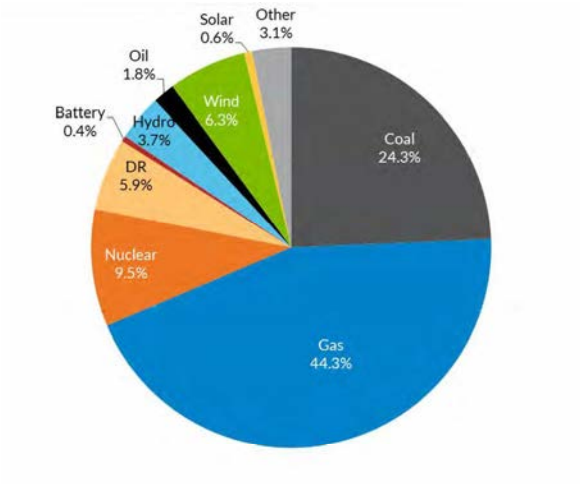
Summer 2025



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

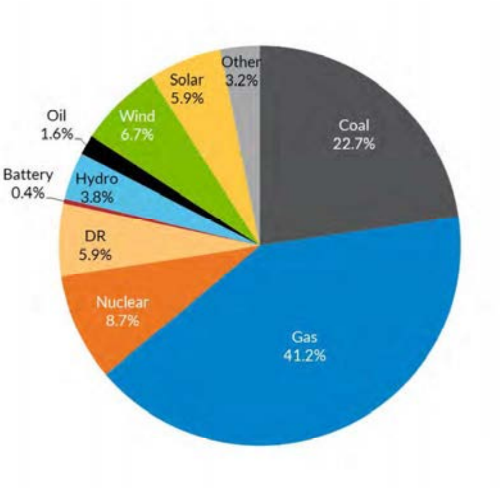
Winter 2025/26



PRMR: Planning Reserve Margin Requirement

Fall 2025 and Spring 2026 - Cleared ZRCs and Final PRMR

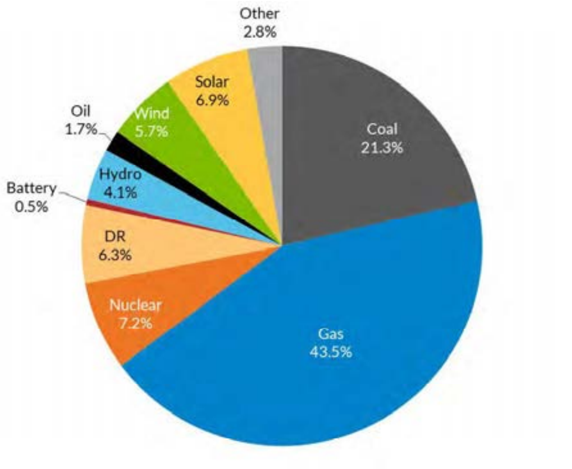
Fall 2025



MISO-Wide

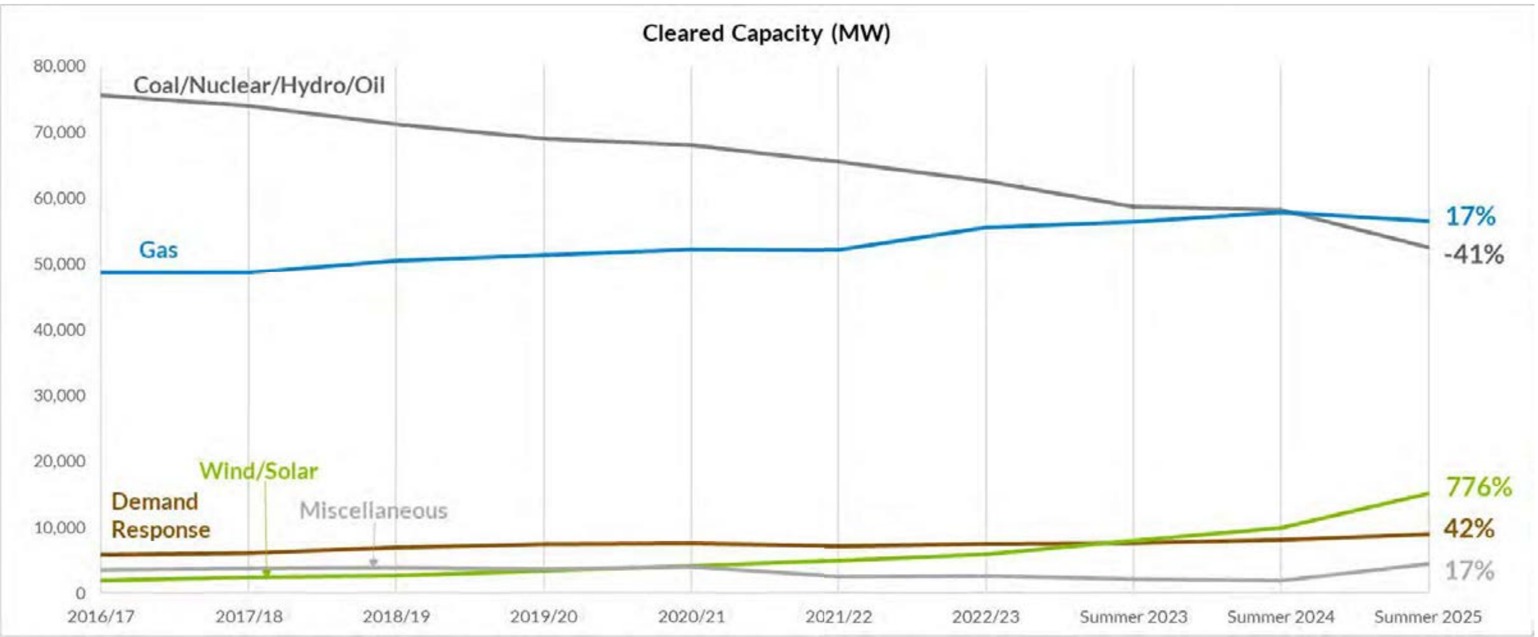
Cleared ZRC	Fall 2025	Spring 2026
Coal	30,038.9	27,886.8
Gas	54,636.4	56,820.7
Nuclear	11,482.1	9,405.4
DR	7,767.8	8,240.5
Battery	497.9	663.3
EE	28.1	30.5
Hydro	5,047.4	5,415.8
Oil	2,123.8	2,190.4
Wind	8,864.8	7,438.0
Solar	7,843.8	8,975.1
Misc	4,184.8	3,633.0
PRMR	132,515.8	130,699.5

Spring 2026

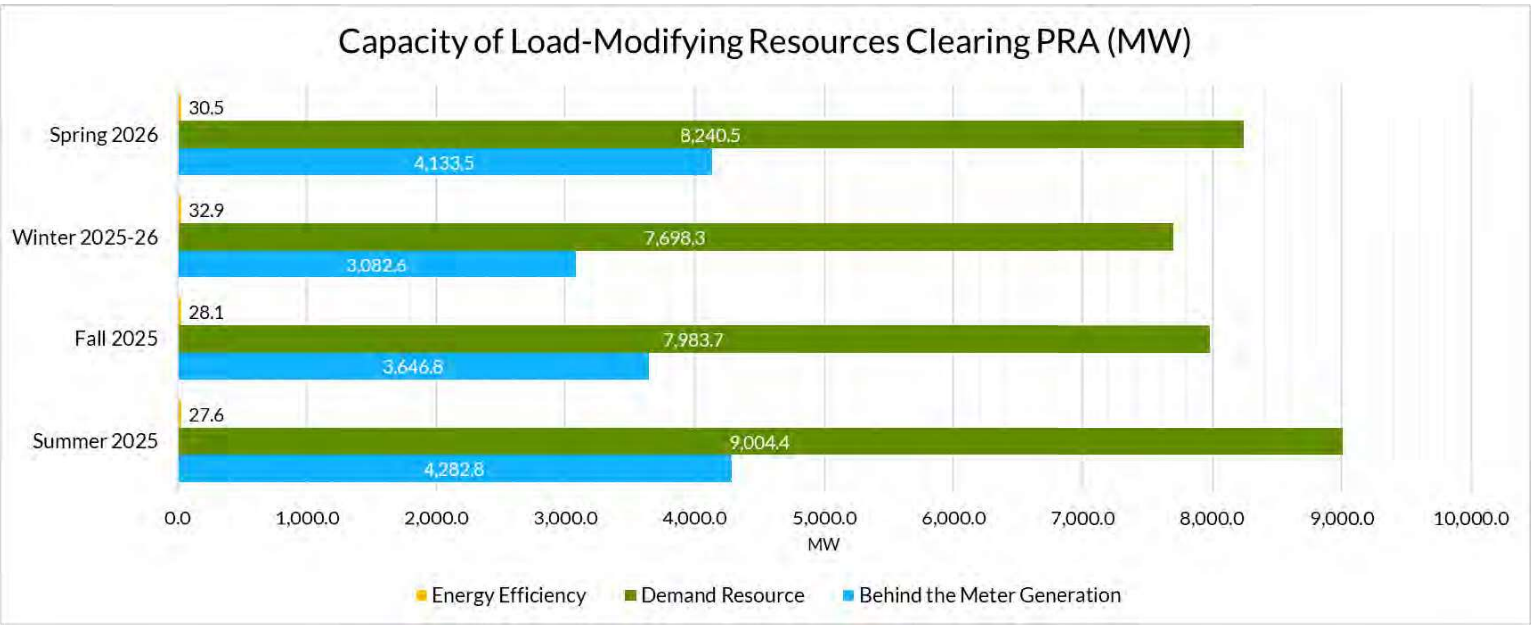


PRMR: Planning Reserve Margin Requirement

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/

Attachment C

Collection of MISO Attachment Y materials

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

Electric Supply
Contract/Commitment Cover Sheet

*(**Note:** Contracts, purchase orders, or other commitment instruments will not be signed unless this sheet is completed in full)*

Subject/Commitment: MISO Attachment Y Notification of Generating Resources /SCU/ Pseudo-tied Out Generator Change of Status / Including Notification of Rescission Form

Reason: Notice to Suspend Karn Units 3 & 4 effective June 1, 2023.

Check One			
Yes	**No***	**N/A**	
☐	☐	☒	**1) Gateway Assessment Tool completed and attached**
☒	☐	☐	**2) Legal Review / Approval to Form**
☐	☐	☒	**3) Credit Risk Management Approval**
☐	☐	☒	**4) Competitive Bid**
☐	☐	☒	**5) Sole Source Approval completed and attached**

***If No is checked or special circumstances apply, please explain:**

Legal review by Emerson Hilton.

***Contract Owner: Kathy Wetzel**

Department Sign Off
(Signature & Date Required)

ML Metz
Merchant Ops & PSCR

KG Troyer
EGI Contracts & Settlements
Renewables

BD Gallaway
Fuel Supply

TP Clark
Electric Supply

12/14/2021

TJ Sparks
Electric Grid Integration

Form Revised: 04/16/21

**Contract Owner Responsible for Scanning & Placing on SharePoint Site*

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

☒ 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

Consumers Energy
Count on Us

VIA EMAIL

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

May 28, 2025

Re: Modified Suspension Date for Campbell Units 1, 2, & 3

Mr. Witmeier:

On December 14, 2021, Consumers Energy Company ("Consumers Energy") submitted an Attachment Y Notice to the Midcontinent Independent System Operating, Inc. ("MISO") for the suspension of Units 1, 2, and 3 at the J.H. Campbell Generation Complex ("Campbell Plant"), effective June 1, 2025. After reviewing 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"), MISO determined the suspension of Campbell Plant Units 1, 2, and 3, would not result in violations of applicable reliability criteria, as outlined in the Tariff. On March 11, 2022, MISO approved the suspension of Campbell Plant Units 1, 2, and 3 without the need for the generators to be designated as System Support Resource units as defined in the Tariff.

On May 23, 2025, the U.S. Department of Energy ("DOE") issued Order No. 202-25-3 (the "Order"), requiring the Campbell Plant to be available to MISO through August 20, 2025.

In order to comply with the Order, Consumers Energy hereby provides notice to MISO, consistent with Section 38.2.7(d)(ii)(1) of the Tariff, of its intent to modify the current Attachment Y Notice such that the Campbell Plant will now suspend on August 21, 2025.

As noted in Consumers Energy's original Attachment Y Notice, Campbell Unit 3 is jointly owned by Consumers Energy (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 it has notified all Campbell Unit 3 owners of this submittal.

In the event you have any questions regarding this matter, please contact Derek Anspaugh at (517) 788-1869.

Regards,

Sri M.

Consumers Energy
One Energy Plaza
Jackson, MI 49201-2357

www.consumersenergy.com

Sri Maddipati
VP Electric Supply
1945 W. Parnell Rd
Jackson, MI 49901

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 form must be submitted to the Transmission Provider via its online application tool in the manner specified by the Transmission Planning Business Practices Manual (BPM-020), and a form will be considered complete on the date of such online application.

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 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, and MISO, FERC Docket No. ER24-1359
Campbell Unit 3: FERC Docket No. 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 21 [day] of August [month] of 2025 [year]

[ ] Rescind the current notice to Suspend

The 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: Srikanth Maddipati

Title: VP Electric Supply

Date: May 28, 2025

Contact Information

Email: sri.maddipati@cmsenergy.com

Phone: 517-788-0635

From: Marc Keyser
To: Rachael H. Moore; Huaitao Zhang; DEREK S. ANSPAUGH; Adam C. French; NICHOLAS B. TENNEY; Emerson J. Hilton
Cc: Sumit Pal Brar
Subject: RE: [EXT]RE: Order from Secretary of Energy to keep Campbell Unit ON for the summer (until Aug 21, 2025) - Action required
Date: Friday, May 30, 2025 4:05:01 PM

Rachael: I'm responding back on behalf of the team, after they briefly reviewed with legal here:

we received the Attachment Y, and the new cessation is 8/21/2025. Additionally, you have until 8/21/2027 to submit a new replacement request before the suspension period ends. In other words, the Attachment Y remains as is, still approved, except with a new/different start date.

From: Rachael H. Moore <Rachael.Moore@cmsenergy.com>
Sent: Friday, May 30, 2025 12:15 PM
To: Huaitao Zhang <HZhang@misoenergy.org>; Derek Anspaugh <Derek.Anspaugh@cmsenergy.com>; Adam French <adam.french@cmsenergy.com>; NICHOLAS B. TENNEY <NICHOLAS.TENNEY@cmsenergy.com>; Emerson J. Hilton <Emerson.Hilton@cmsenergy.com>
Cc: Sumit Pal Brar <SBrar@misoenergy.org>; Marc Keyser <MKeyser@misoenergy.org>
Subject: RE: [EXT]RE: Order from Secretary of Energy to keep Campbell Unit ON for the summer (until Aug 21, 2025) - Action required

Thank you, Huaitao. Can you confirm that this modification of the suspension start date provided consistent with Section 38.2.7(d)(ii)(1) of the Tariff does not impact the overall approval of the Attachment Y the Company previously received on March 11, 2022, and that the Company is still approved to enter suspension (now effective 8/21/25)?

Thank you!

Rachael Moore | Senior Attorney
[redacted]

From: Huaitao Zhang <HZhang@misoenergy.org>
Sent: Wednesday, May 28, 2025 1:47 PM

To: Rachael H. Moore <Rachael.Moore@cmsenergy.com>; DEREK S. ANSPAUGH <DEREK.ANSPAUGH@cmsenergy.com>; Adam C. French <ADAM.FRENCH@cmsenergy.com>; NICHOLAS B. TENNEY <NICHOLAS.TENNEY@cmsenergy.com>; Emerson J. Hilton <Emerson.Hilton@cmsenergy.com>
Cc: Sumit Pal Brar <SBrar@misoenergy.org>; Marc Keyser <MKeyser@misoenergy.org>
Subject: RE: [EXT]RE: Order from Secretary of Energy to keep Campbell Unit ON for the summer (until Aug 21, 2025) - Action required

Rachael,

Thanks for the quick response, and we are all good.

Thanks,
Huaitao

From: Rachael H. Moore <Rachael.Moore@cmsenergy.com>
Sent: Wednesday, May 28, 2025 12:40 PM
To: Huaitao Zhang <HZhang@misoenergy.org>; Derek Anspaugh <Derek.Anspaugh@cmsenergy.com>; Adam French <adam.french@cmsenergy.com>; NICHOLAS B. TENNEY <NICHOLAS.TENNEY@cmsenergy.com>; Emerson J. Hilton <Emerson.Hilton@cmsenergy.com>
Cc: Sumit Pal Brar <SBrar@misoenergy.org>; Marc Keyser <MKeyser@misoenergy.org>
Subject: [EXT]RE: Order from Secretary of Energy to keep Campbell Unit ON for the summer (until Aug 21, 2025) - Action required

Huaitao –

Attached is the modified Attachment Y with the amended suspension start date of 8/21/2025. Please let me know if we should send this notice of Modified Attachment Y to anyone else at MISO or if you would like us to mail a physical copy as well.

Thank you,
Rachael

Rachael Moore | Senior Attorney
[redacted]

From: Rachael H. Moore
Sent: Tuesday, May 27, 2025 11:52 AM
To: Adam C. French <adam.french@cmsenergy.com>; Huaitao Zhang <HZhang@misoenergy.org>; NICHOLAS B. TENNEY <nicholas.tenney@cmsenergy.com>
Cc: Sumit Pal Brar <SBrar@misoenergy.org>; Marc Keyser <MKeyser@misoenergy.org>
Subject: RE: Order from Secretary of Energy to keep Campbell Unit ON for the summer (until Aug 21, 2025) - Action required

Good afternoon,

Yes, I will be working with members of the Company to ensure we have the Attachment Y notice updated by 5/28. Please let me know if there is a specific contact at MISO we should plan to send this to.

Thank you!
Rachael

Rachael Moore | Senior Attorney
[redacted]

From: Adam C. French <ADAM.FRENCH@cmsenergy.com>
Sent: Tuesday, May 27, 2025 11:49 AM
To: Huaitao Zhang <HZhang@misoenergy.org>; NICHOLAS B. TENNEY <NICHOLAS.TENNEY@cmsenergy.com>; Rachael H. Moore <Rachael.Moore@cmsenergy.com>
Cc: Sumit Pal Brar <SBrar@misoenergy.org>; Marc Keyser <MKeyser@misoenergy.org>
Subject: RE: Order from Secretary of Energy to keep Campbell Unit ON for the summer (until Aug 21, 2025) - Action required

It is my understanding that is being handled by Rachael Moore
RACHAEL.MOORE@CMSENERGY.COM

From: Huaitao Zhang <HZhang@misoenergy.org>
Sent: Tuesday, May 27, 2025 11:41 AM
To: NICHOLAS B. TENNEY <NICHOLAS.TENNEY@cmsenergy.com>; Adam C. French <ADAM.FRENCH@cmsenergy.com>
Cc: Sumit Pal Brar <SBrar@misoenergy.org>; Marc Keyser <MKeyser@misoenergy.org>
Subject: FW: Order from Secretary of Energy to keep Campbell Unit ON for the summer (until Aug 21, 2025) - Action required

Nick and Adam,

Marc pointed to me that you are the contact for this request.

Thanks,
Huaitao

From: Huaitao Zhang
Sent: Tuesday, May 27, 2025 11:05 AM
To: KATHY S. WETZEL <KATHY.WETZEL@cmsenergy.com>
Cc: timothy.sparks@cmsenergy.com; Sumit Pal Brar <SBrar@misoenergy.org>; Marc Keyser <MKeyser@misoenergy.org>; Jagdesh Shivani <JShivani@misoenergy.org>
Subject: Order from Secretary of Energy to keep Campbell Unit ON for the summer (until Aug 21, 2025) - Action required

Hi Kathy,

Pertain to the Order from Secretary of Energy regarding the suspension/cessation date of Campbell units 1,2&3, MISO requests Consumer Energy to submit the following application updates to MISO by 5/28/2025:

Attachment Y request with suspension start date as 8/21/2025

FYI, the order link is https://www.energy.gov/sites/default/files/2025-05/Midcontinent%20Independent%20System%20Operator%20%28MISO%29%20202%28c%29%20Order_1.pdf [energy.gov]

Thanks,
Huaitao Zhang
Resource Utilization Engineer

Integrity | Collaboration | Commitment | Creativity | Adaptability

Attachment D

Consumers' Responses from June 10, 2025

Question:

23. Absent continued operation of the Campbell Plant, what was Consumers Energy's Zone Resource Credit (ZRC) position for planning year 2025-2026.

Response:

The table below shows our capacity positions using the initial Planning Reserve Margin Requirement (PRMR) for each season of planning year 2025. These numbers do not include any contributions from the Campbell coal-fired generating units.

PY2025	**ZRC**
Summer	272.9
Fall	842.7
Winter	0.0
Spring	4.3

Date: June 10, 2025

Question:

24. How many ZRCs does Consumers anticipate will be accredited for the continued operation of the Campbell Plant?

Response:

At this time we do not anticipate the Campbell units contributing any Zonal Resource Credits to our capacity positions throughout planning year 2025.

Date: June 10, 2025

Attachment Q

Petition for Review - COA DC SOM v USDOE
(DOE Order No. 202-25-3)

IN THE UNITED STATES COURT OF APPEALS
FOR THE DISTRICT OF COLUMBIA CIRCUIT

THE PEOPLE OF THE STATE OF MICHIGAN,
Petitioner,

v.

UNITED STATES DEPARTMENT OF ENERGY,
and CHRIS WRIGHT, Secretary,
UNITED STATES DEPARTMENT OF ENERGY
Respondents.

DOE Order No. 202-25-3

PETITION FOR REVIEW

Pursuant to Rule 15 of the Federal Rules of Appellate Procedure, Circuit Rule 15, and section 313(b) of the Federal Power Act, 16 U.S.C. § 825*l*(b), Michigan Attorney General Dana Nessel, on behalf of the People of the State of Michigan, hereby petitions the Court for review of the Order No. 202-25-3 of Respondents, Chris Wright, Secretary, United States Department of Energy, and the United States Department of Energy, issued on May 23, 2025 (the "Campbell Order," attached as Exhibit A). The Department of Energy issued the Campbell Order pursuant to section 202(c) of the Federal Power Act, 16 U.S.C. § 824a(c), a provision initially vested in the Federal Power Commission that was assigned to the Department through the Department of Energy Organization Act, 42 U.S.C. § 7151(b). As an order issued under the Federal Power Act, the Campbell Order is subject to the rehearing and judicial review provisions of 16 U.S.C. § 825*l*. *See* 42 U.S.C. § 7192(a) ("Judicial review of agency action taken under any law the functions of which are vested by law in, or transferred or delegated to the Secretary [of Energy] . . . shall, notwithstanding such vesting, transfer, or delegation, be made in the manner specified in or for such law.").

On behalf of the People of the State of Michigan, the Michigan Attorney General participated in the proceedings before the Department of Energy and timely filed a request for rehearing of the Campbell Order. That rehearing request may be deemed denied by operation of law because the Department did not act upon it within 30 days. *See* 16 U.S.C. § 825*l*(a); Allegheny Def. Project v. FERC, 964 F.3d 1, 18-19 (D.C. Cir. 2020). Therefore, the Michigan Attorney General may file this petition for review under 16 U.S.C. § 825*l*(b). This Court has jurisdiction, and venue in this Court is proper, under 16 U.S.C. § 825*l*(b). The Michigan Attorney General respectfully requests that this Court hold unlawful, vacate, and set aside the Campbell Order, and grant such further relief as may be deemed just and proper.

Dated: July 24, 2025

Respectfully submitted,

Dana Nessel,
Michigan Attorney General

/s/ Michael Moody
Michael E. Moody (P51985)
Lucas Wollenzien (P86928)
Assistant Attorneys General
Special Litigation Division
P.O. Box 30755
Lansing, MI 48909
517-335-7627
MoodyM2@michigan.gov
WollenzienL@michigan.gov

Christopher M. Bzdok (P53094)
Special Assistant Attorney General
chris@tropospherelegal.com

CC:
DOE:
AskCR@hq.doe.gov
The.secretary@hq.doe.gov

CECo:
Bret.totoraitis@cmsenergy.com
Kelly.hall@cmsenergy.com

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msoules@earthjustice.org
lpiette@earthjustice.org
sdoshi@earthjustice.org
cpowell@earthjustice.org
atom@earthjustice.org
astatler@earthjustice.org

MEC:
charlotte@environmentalcouncil.org

Sierra Club:
greg.wannier@sierraclub.org
sanjay.narayan@sierraclub.org
elena.saxonhouse@sierraclub.org

NRDC:
creiser@nrdc.org
gmccabe@nrdc.org

ELPC:
bklein@elpc.org

Clean Air Task Force:
dfidler@catf.us
fsturges@catf.us

Public Citizen, Inc.:
tslocum@citizen.org

Ecology Center:
alexis@ecocenter.org

Union of Concerned Scientists:
jgignac@ucs.org

UCC:
sergio@uccgr.org

Environmental Defense Fund:
tekelly@edf.org
tcarbonell@edf.org

Vote Solar:
will@votesolar.org

Midcontinent Independent:
tcaister@misoenergy.org
mkessler@misoenergy.org
jholsclaw@calfee.com
tcarpenter@calfee.com

Michigan Public Power:
arobbins@washingtonenergylaw.com
droby@washingtonenergylaw.com
tsteiger@washingtonenergylaw.com

Maryland Office of People:
William.fields@maryland.gov
Philip.sussler@maryland.gov
Alexis.lewis@maryland.gov

MISO States:
brad@misostates.org
tricia@misostates.org

Order No. 202-25-3

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 for the reasons set forth below, I hereby determine that an emergency exists in portions of the Midwest region of the United States 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

The Midcontinent Independent System Operator (MISO) faces potential tight reserve margins during the summer 2025 period, particularly during periods of high demand or low generation resource output. The North American Electric Reliability Corporation (NERC) released its 2025 Summer Reliability Assessment on May 14, 2025. In its assessment, NERC indicated that "[d]emand forecasts and resource data indicate that MISO is at elevated risk of operating reserve shortfalls during periods of high demand or low resource output."[1] In particular, the retirement of thermal generation capacity creates the potential for electricity supply shortfalls. NERC anticipates that the near-term period of highest capacity shortfall for MISO will occur in August.[2]

Multiple generation facilities in Michigan have retired in recent years. According to the U.S. Energy Information Administration (EIA), "[s]ince 2020, about 2,700 megawatts of coal-fired generating capacity have been retired and no new coal-fired facilities are planned."[3] Additionally EIA stated, "[t]ypically Michigan's nuclear power plants have supplied about 30% of in-state electricity, but the amount of electricity generated by nuclear power plants in Michigan has declined as plants have been decommissioned."[4] The state's Big Rock Point nuclear power plant shut down in 1997 and the Palisades nuclear power plant closed in 2022. While the Palisades nuclear power plant may reopen in 2025, it will not be available during the peak demand period this summer.

The 1,560 MW J.H. Campbell coal-fired power plant in West Olive, MI, is scheduled to cease operations on May 31, 2025. Its retirement would further decrease available dispatchable generation within MISO's service territory, removing additional such generation along with the other 1,575 MW of natural gas and coal-fired generation that has retired since the summer of 2024. In 2021, Consumers announced that it planned to "speed closure" of Campbell in 2025, several years before the end of its scheduled design life.[5] Although MISO and Consumers have

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[1] 2025 summer reliability assessment. (May 14, 2025). https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_SRA_2025.pdf

[2] *Id.*

[3] U.S. Energy Information Administration, Michigan State Energy Profile, Oct. 17, 2024, *available at*: https://www.eia.gov/state/print.php?sid=mi.

[4] *Id.*

[5] https://www.consumersenergy.com/news-releases/news-release-details/2021/06/23/consumers-energy-announces-plan-to-end-coal-use-by-2025-lead-michigans-clean-energy-transformation

incorporated the planned retirement into their supply forecasts and acquired a 1,200 MW natural gas power plant in Covert, MI, the NERC Assessment still anticipates "elevated risk of operating reserve shortfalls."

MISO's Planning Resource Auction Results for Planning Year 2025-26, released in April 2025, note that for the northern and central zones, which includes Michigan, "new capacity additions were insufficient to offset the negative impacts of decreased accreditation, suspensions/retirements and external resources." While the results "demonstrated sufficient capacity," the summer months reflected the "highest risk and a tighter supply-demand balance" and the results "reinforce the need to increase capacity."[6]

ORDER

Given the determination that an emergency exists as discussed above, the responsibility of MISO to ensure reliability of its system, and the ability of MISO to identify and dispatch generation necessary to meet load requirements, I have determined that, under the conditions specified below, additional dispatch of the Campbell Plant is necessary to best meet the emergency and serve the public interest for purposes of FPA section 202(c). This determination is based on the insufficiency of dispatchable capacity and anticipated demand during the summer months, and the potential loss of power to homes and local businesses in the areas that may be affected by curtailments or outages, presenting a risk to public health and safety.

This Order is limited in duration to align with the emergency circumstances. Because the additional generation may result in a conflict with environmental standards and requirements, I am authorizing only the necessary additional generation on the conditions contained in this Order, with reporting requirements as described below.

FPA section 202(c) requires the Secretary of Energy to ensure that any 202(c) 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.

Based on my determination of an emergency set forth above, I hereby order:

A. From the time this Order is issued on May 23, 2025, MISO and Consumers Energy shall take all measures necessary to ensure that the Campbell Plant is available to operate. For the duration of this order, MISO is directed to take every step to employ economic dispatch of the Campbell Plant to minimize cost to ratepayers. Following conclusion of this Order, sufficient time for orderly ramp down is permitted, consistent with industry practices. Consumers Energy is directed to comply with all orders from MISO related to the availability and dispatch of the Campbell Plant.

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[6] https://cdn.misoenergy.org/2025%20PRA%20Results%20Posting%2020250428694160.pdf

B. To minimize adverse environmental impacts, this Order limits operation of dispatched units through the expiration of the Order. MISO shall provide a daily notification to the Department (via AskCR@hq.doe.gov) reporting whether the Campbell Plant has operated in compliance with the allowances contained in this Order.

C. All operation of the Campbell Plant 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.

D. By June 15, 2025, MISO is directed to provide the Department of Energy (via AskCR@hq.doe.gov) with information concerning the measures it has taken and is planning to take to ensure the operational availability and economic dispatch of the Campbell Plant consistent with the public interest. MISO shall also 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 of Energy from time to time.

E. The extent to which MISO's current Tariff provisions are inapposite to effectuate the dispatch and operation of the units for the reasons specified herein, the relevant governmental authorities are directed to take such action and make accommodations as may be necessary to do so.

F. Consumers is directed to file with the Federal Energy Regulatory Commission Tariff revisions or waivers necessary to effectuate this order. Rate recovery is available pursuant to 16 U.S.C. § 824a(c).

G. This Order shall not preclude the need for the Campbell Plant to comply with applicable state, local, or Federal law or regulations following the expiration of this Order.

H. This Order shall be effective upon its issuance, and shall expire at 00:00 EDT on August 21, 2025, with the exception of the reporting requirements in paragraph D and applicable compliance obligations in paragraph E.

I. Issued in Washington, D.C. at 3:15:pm Eastern Daylight Time on this 23rd day of May 2025.

Chris Wright
Secretary of Energy

cc: **FERC Commissioners**
Chairman Mark Christie
Commissioner David Rosner
Commissioner Lindsay S. See
Commissioner Judy W. Chang

Michigan Public Service Commissioners
Chairman Dan Cripps
Commissioner Katherine Peretick
Commissioner Alessandra Carreon

UNITED STATES OF AMERICA
BEFORE THE
UNITED STATES DEPARTMENT OF ENERGY

Order No. 202-25-3

REQUEST FOR REHEARING BY MICHIGAN ATTORNEY GENERAL DANA NESSEL

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Dated: June 18, 2025

Pursuant to section 313*l* of the Federal Power Act ("the Act"), 16 U.S.C. § 825*l*, Michigan Attorney General Dana Nessel, on behalf of the people of the State of Michigan, requests that the Department of Energy (Department or DOE) grant rehearing of Order No. 202-25-3 (May 23, 2025) ("Order"). The Order invoked the Department's emergency authority under section 202(c) of the Act to prevent the scheduled retirement of the J.H. Campbell power plant (J.H. Campbell) in West Olive, Michigan.

The Order is an unlawful abuse of the Department's emergency authority. Until now, the Department has reserved section 202(c) for real emergencies like natural disasters and extreme weather and has typically acted at the behest of grid operators or governmental bodies. In the Order, acting on its own motion and without notice, the Department declares that the retirement of J.H. Campbell presents an emergency. But the Order's emergency determination cannot bear even the mildest scrutiny.

The scheduled retirement of J.H. Campbell was the culmination of a carefully planned process that unfolded over four years. Under the oversight of the Michigan Public Service Commission (MPSC), Consumers Energy (Consumers) executed a plan to retire an old and inefficient facility, J.H. Campbell, and replace it largely with newer resources that would both increase Consumers' available generation capacity and save its ratepayers money. J.H. Campbell's proposed retirement was also studied carefully by the Midcontinent Independent System Operator (MISO), the regional grid operator, which determined that the facility could retire without causing reliability issues.

In the Order, the Department uses its authority under section 202(c) in a manner untethered from the need to identify a real emergency and unhindered by the statutory requirement that the actions it orders go no further than necessary to address the emergency. The result of this overreach will be unnecessary costs imposed on already-overburdened ratepayers, needless pollution emitted into Michigan and its neighboring states, and an unprecedented intrusion into the authority of states and the Federal Energy Regulatory Commission to regulate the resource adequacy of our electric grid.

I. MOTION TO INTERVENE

The Michigan Attorney General,[1] on behalf of the people of the State of Michigan, moves to intervene in this proceeding and thereby to become a party for purposes of Section 313*l* of the Act, 16 U.S.C. § 825*l*. The People of the State of Michigan have an interest in and are aggrieved by the Order in several ways. First, households and businesses in Michigan will pay higher electricity bills as a result of the Order. The retirement of J.H. Campbell and its replacement with more cost-effective resources were elements of a careful plan expected to save Michigan

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[1] *See* MCL 14.28 ("The attorney general . . . may, when in [her] own judgment the interests of the state require it, intervene in and appear for the people of this state in any other court or tribunal, in any cause or matter, civil or criminal, in which the people of this state may be a party or interested."). *See also In re Certified Question*, 465 Mich 537, 543-545; 638 NW2d 409 (2002), *Gremore v Peoples Community Hospital Authority*, 8 Mich App 56; 153 NW2d 377 (1967), and *People v O'Hara*, 278 Mich 281; 270 NW2d 298 (1936).

ratepayers nearly $600 million.[2] By ordering the continued operation of J.H. Campbell, the Order ensures that Michigan ratepayers will pay higher costs. Although the precise amounts of costs are not yet known, it is certain that Michigan ratepayers will be stuck with substantial new costs in excess of what they would have paid absent the Order.

Second, the People of the State of Michigan will suffer environmental harms as a result of the Order. J.H. Campbell is a significant source of particulate matter, nitrogen oxides, sulfur oxides, and carbon dioxide,[3] among other pollutants. By prolonging the operations of J.H. Campbell beyond its planned retirement date, the Order will increase the amount of pollution emitted in the state of Michigan, causing harms to the public health and welfare.

Third, the retirement of J.H. Campbell on May 31, 2025, was a provision agreed to as part of a settlement agreement in Michigan Public Service Commission Case (MPSC) No. U-21090, to which the Michigan Attorney General was a party. Because the Order deprives the Michigan Attorney General of the benefit of her bargain under the settlement agreement, the Michigan Attorney General will suffer a discrete and separate harm as a result of the Order.

II. BACKGROUND

A. DOE's Historical Use of Section 202(c).

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[2] *See* Michigan Public Service Commission Case No. U-21090-0867, Reply Brief of Consumers at 1 – 2, available at https://mi-psc.my.site.com/sfc/servlet.shepherd/version/download/0688y0000032ZSXAA2.

[3] *See In the Matter of the Application of Consumers Energy Co. for Approval of Its Integrated Res. Plan Pursuant to Mcl 460.6t & for Other Relief.*, No. U-21090, 2022 WL 2915368, at *73 (June 23, 2022).

In the past, the Department has used section 202(c) sparingly. The Department has used this authority only in response to concrete, particularized emergencies, and subject to limitations to ensure that the Department's reach extends no further than necessary to address the emergency at hand.

Between enactment of the Department of Energy Organization Act in 1977, Pub. L. No. 95-91, and the end of last year, the Department appears to have used section 202(c) nineteen times, not counting amendments and extension orders. DOE's first usage of section 202(c) came in response to the California Energy Crisis in 2000.[4] That order was followed by two others directing the operation of the Cross-Sound Cable, a submarine transmission line connecting New York and Connecticut that was complete but that had been delayed from entering service due to environmental permitting issues.[5] But by far the most common usage – comprising 13 of 19 instances – has been in response to extreme weather events such as hurricanes,[6] extreme cold,[7] and extreme heat.[8] In each of these weather-driven cases, the exercise of emergency power was requested by the relevant system operator or responsible utility, or both.

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[4] DOE, *Order Pursuant to Section 202(c) of the Federal Power Act* (Dec. 14, 2000). Section 202(c) was used by the Federal Power Commission prior to the Department of Energy Organization Act's creation of DOE. Those uses were generally limited to orders directing interconnection as a result of discrete and sudden emergencies or war. *See* Benjamin Rolsma, *The New Reliability Override*, 57 U. Conn. L. Rev. 789, 822 (2025).

[5] *See* DOE Order No. 202-02-1 (Aug. 16, 2002); DOE Order No. 202-03-01 (Aug. 14, 2003).

[6] *See* DOE Order Nos. 202-05-1 & -2 (Sept. 28, 2005) (response to Hurricane Rita); DOE Order No. 202-08-1 (Sept. 14, 2008) (Hurricane Ike); DOE Order No. 202-20-1 (Aug. 27, 2020) (Hurricane Laura); DOE Order No. 202-24-1 (Oct. 9, 2024) (Hurricane Milton).

[7] *See* DOE Order No. 202-21-1 (Feb. 14, 2021); DOE Order No. 202-22-3 (Dec. 23, 2022); DOE Order No. 202-22-4 (Dec. 24, 2022).

[8] *See* DOE Order No. 202-20-2 (Sept. 6, 2020) (responding to extreme heat in California); DOE Order No. 202-21-2 (responding to extreme heat, wildfires and drought in California); DOE Order Nos. 202-22-1 & 2 and amendments (same).

And in each, DOE carefully limited its remedy to ensure that generation facilities were only ordered to run in circumstances necessary to address the emergency and in a manner so as to minimize any conflict with environmental requirements.[9] DOE also limited the duration of those orders to the minimum period necessary to address the emergency, often shorter than 10 days.[10]

Prior to the Order, DOE had used section 202(c) on three occasions to delay the retirement of generation facilities.[11] These cases had key features in common. In each: (i) the order was requested by a system operator or governmental body; (ii) the generation facility had ceased or would soon cease operation due to an inability to comply with environmental laws; (iii) the request aimed to address a concrete and particularized emergency threatening an imminent loss of load; and, (iv) DOE tailored its order to go no further than necessary to address the emergency.

The first such instance came in 2004, when the District of Columbia's Public Service Commission requested an order directing the continued operation of a power plant located in Alexandria, Virginia, owned by the Mirant Corporation (Mirant). After its state regulator found the plant to be out of compliance with its air permit, Mirant abruptly announced that the plant would close.[12] The D.C. Public Service Commission, supported by the local utility, PEPCO, explained that the Mirant facility

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[9] *See supra* notes 3 – 5.

[10] *Id.*

[11] Nor did the DOE's predecessor agency, the Federal Power Commission, use section 202(c) to delay retirement of any generation units between the section's enactment in 1935 and the formation of DOE in 1977. *See* Rolsma, 57 U. Conn. L. Rev. at 843-46.

[12] DOE Order No. 202-05-3 (Dec. 20, 2005) at 1 (explaining that Mirant provided emissions information to its state regulator on August 19, 2005, the regulator demanded immediate action that same day, and Mirant decided to cease operations on August 24).

directly powered downtown D.C. and that, without it, critical federal infrastructure faced an unacceptable risk of blackout.[13] Before acting on the request, the Department commissioned an analysis from the Oak Ridge National Laboratory that confirmed the threat that the plant's closure would pose to reliability in D.C.[14] Based on that study, and based on the severity of the harm that could result from a prolonged power outage to downtown D.C., the Department issued an order directing the continued operation of the Mirant facility.[15] The Department took pains, however, to limit its order to go no further than necessary to address the emergency. The Department directed Mirant to maintain the facility's capacity to respond when needed, but only ordered it to run when one or both of the 230 kV transmission lines serving downtown D.C. were out of service.[16]

Twelve years later, in 2017, the Department received a request from the Grand River Dam Authority (GRDA), an Oklahoma state agency, to direct the continued operation of Unit No. 1 at the Grand River Energy Center. GRDA explained that the Grand River Energy Center was needed to provide dynamic reactive power support to the local grid, a fact confirmed by the region's Reliability Coordinator, the Southwest Power Pool (SPP). GRDA explained, however, that it would be unable to provide reactive power without action from DOE. Unit No.1, the subject of the request, had been ordered to close by an Administrative Order of the Environmental Protection Agency. Unit No. 2 had been struck by lightning and was under repair.

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[13] *Id*. at 2.
[14] *Id*. at 3 – 4.
[15] *Id*. at 5 – 8.
[16] *Id*. at 10 – 11.

And, construction of the new Unit No. 3 had been delayed because flooding in Louisiana interfered with the fabrication of essential project materials.[17] The Department granted GRDA's request, ordering Unit No. 1 to remain in operation for 90 days or until Unit No. 2 or Unit No. 3 were brought online, whichever came first.[18] The Department strictly limited its remedy, directing GRDA only to provide "dynamic reactive power support and not real power generation, and only when called upon by SPP for reliability purposes."[19]

Later that year, the Department received a pair of requests from PJM and Dominion Virginia (Dominion) to direct the continued operation of Units 1 and 2 of the Yorktown Power Station. PJM and Dominion explained that, based on PJM load flow studies, these units were necessary to prevent uncontrolled power disruptions and shedding of critical loads in the North Hampton Roads area east of Richmond.[20] DOE issued an order directing Dominion to maintain operation at the two units, but to dispatch those units "only when called upon by PJM for reliability purposes."[21] DOE later extended the order several times due to the delayed completion of the transmission line needed to resolve the reliability issue. In doing so, DOE cited the "imminent" risk of load-shedding in the North Hampton Roads area absent extension of the order.[22] In its extension order, the Department continued to limit dispatch of

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[17] Letter Request of Grand River Dam Authority, April 11, 2017. Available at https://www.energy.gov/sites/default/files/2017/05/f34/GRDA%20public%20202%28c%29%20letter.pdf.

[18] DOE Order No. 202-17-1 at 2.

[19] *Id.*

[20] DOE Order No. 202-17-2, at 1.

[21] *Id.* at 2.

[22] DOE Order No. 202-17-4, Summary of Findings, Sept. 14, 2017.

the units only when called upon by PJM for reliability purposes and, further, directed PJM and Dominion to exhaust available resources, including demand response and behind-the-meter generation resources, prior to operating the units.[23]

B. Executive Order 14262 and the White House Strategy to Prop Up the Coal Industry.

Over the past several months, the White House and the Department have sought to radically transform how section 202(c) of the Federal Power Act is applied, departing in almost every material respect from the longstanding approach described above. As shown below, the Order cannot be understood intelligibly as a response to a discrete event or emergency akin to past orders under section 202(c). Rather, it can only be understood as part of a long-term and multi-part strategy to preserve coal and other fossil fuel generation under the guise of grid reliability concerns.

On April 8, 2025, President Trump issued Executive Order 14262, *Strengthening the Reliability and Security of the United States Electric Grid*.[24] The Executive Order was issued concurrently with three other executive actions aimed at supporting the coal industry that were announced at a White House political event explicitly focused on that objective.[25] This event, and the related Executive Order, are one of several in a series of public actions by the Administration aimed at reversing coal plant retirements and promoting fossil fuel generation.

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[23] DOE Order No. 202-17-4 at 2.

[24] Executive Order 14262, 90 Fed. Reg. 15521 (April 14, 2025).

[25] New York Times, *Trump Signs Orders Aimed at Reviving a Struggling Coal Industry* (April 8, 2025); Executive Order 14261, *Reinvigorating Americans Beautiful Clean Coal Industry and Amending Executive Order 14241*, 90 Fed. Reg. 15517 (April 14, 2025); Executive Order 14260, *Protecting American Energy from State Overreach*, 90 Fed. Reg. 15513 (April 14, 2025); *Regulatory Relief for Certain Stationary Sources To Promote American Energy*, 90 Fed. Reg. 16777 (April 21, 2025).

Executive Order 14262 directs DOE to, among other things, streamline and expedite the issuance of emergency orders under section 202(c), specifically in order to "safeguard the reliability and security of the United States' electric grid during periods when the relevant grid operator forecasts a temporary interruption of electricity supply [that] is necessary to prevent a complete grid failure."[26] It also directs DOE to take a subsequent series of actions related to national resource adequacy, including mandating:

- the development of a uniform methodology for assessing reserve margins and identifying "at-risk" regions;
- establishment of a process by which the developed methodology and any analysis results are regularly assessed; and,
- establishment of a protocol to identify generation resources within a region that are critical to system reliability, a mechanism under section 202(c) to ensure such generation resources are appropriately retained and, for resources over 50MW, are prevented from leaving the bulk-power system or converting their source of fuel.[27]

DOE has not yet published the analysis or protocols—the deadline provided in Executive Order 14262 is July 7.

Executive Order 14262 states that it is intended to help address the national energy emergency declared in the earlier-issued Executive Order 14,156, *Declaring a National Energy Emergency*.[28] In fact, this order is part of a broader pattern in which the Administration has expansively invoked emergency powers to achieve long-standing political objectives, rather than respond to genuine, unforeseen crises. The

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[26] Executive Order 14262 section 3(a).
[27] Executive Order 14262 section 3(b), (c).
[28] Executive Order 14262, section 2.

President has declared eight national emergencies in 2025 alone—more than any other President in the first 100 days of an administration.[29]

C. The Planned Retirement of JH Campbell.

i. Description of J.H. Campbell

J.H. Campbell is a three-unit coal-fired power plant with a total rated net generating capability of approximately 1,450 megawatts (MW).[30] (The Order incorrectly states that J.H. Campbell has a capacity of 1,560 MW). In its current degraded condition, however, J.H. Campbell has a maximum capacity of 920 MW.[31] Part of that difference comes from the fact that Unit 2 is not operational, nor was it operational when the Order was issued. When Unit 2 comes back on-line later this month, the maximum capacity of the facility will be 1,180 MW. J.H. Campbell Unit 1 is 63-years-old and has a rated net generating capability of 261 MW, but now has an effective maximum output of 220 MW.[32] Unit 2 is 58-years-old and has a rated net generating capability of 356 MW. Currently out of service, when Unit 2 comes back online it will have a maximum capacity of 260 MW.[33] Unit 3 is 45 years old and has a rated net generating capability of 843 MW. The current maximum capacity of Unit 3 is 700 MW.[34] Consumers operates the entire J.H. Campbell plant and is the sole

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[29] *See* https://www.brennancenter.org/our-work/research-reports/declared-national-emergencies-under-national-emergencies-act.

[30] Michigan Public Service Commission (MPSC) Case No. U-21585, Direct Testimony of Richard Blumenstock, p. 7, Table 1 (5 Tr 1394-95); see also, https://www.consumersenergy.com/about-us/electric-generation/campbell-complex-retirement, last checked June 11, 2025 (reporting 1,450 MW of capacity).

[31] Conversation between representatives of Consumers and the undersigned counsel, June 12, 2025.

[32] *Id.*

[33] *Id.*

[34] *Id.*

owner of Units 1 and 2. Consumers owns about 93% of Unit 3, the Michigan Public Power Agency owns 4.8% of Unit 3, and Wolverine Power Supply Cooperative owns less than 2% of Unit 3.[35]

J.H. Campbell and Consumers' service territory are located within MISO Local Resource Zone 7. Most of the lower peninsula of Michigan is in MISO Zone 7, except for a small area in the southwest portion of the State, which is in PJM.

ii. State proceeding approving the retirement of J.H. Campbell

In 2021, Consumers proposed to retire J.H. Campbell in 2025 for economic reasons. The MPSC thoroughly reviewed the proposed retirement for a year in an integrated resource plan (IRP) proceeding governed by Michigan statute.[36] No party in the case opposed the retirement of Units 1 and 2; and only a few opposed the retirement of Unit 3.[37] The MPSC ultimately approved Consumers' proposed retirement of J.H. Campbell in a settlement joined by most of the parties to the case. A single party appealed the MPSC's decision to approve the retirement of Unit 3, but the Michigan Court of Appeals affirmed that decision in 2023.[38] Both the MPSC and the appeals court found that Michigan would still have more than enough generating capacity to serve demand after J.H. Campbell retired.[39]

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[35] MPSC Case No. U-21090 (Kapala Direct, 7 Tr 1739); Ex. WPSC-1, p. 19 (Agreement, p. 11), section 2.1, available at https://mi-psc.my.site.com/sfc/servlet.shepherd/version/download/0688y000001QqldAAC.

[36] MCL 460.6t.

[37] MPSC Case No. U-21090, Order approving contested settlement, June 23, 2022, p. 8.

[38] *Wolverine Power Supply Coop., Inc. v Michigan Public Service Commission (In re Consumers Energy)*, 2023 Mich. App. LEXIS 2045; 2023 WL 2620437 (March 23, 2023).

[39] *Id.*

Michigan's IRP statute requires electric utilities whose rates are regulated by the MPSC to periodically file an integrated resource plan. The IRP is a projection of the utility's load obligations and a plan to meet those obligations.[40] The IRP statute directs the MPSC to approve a plan if the MPSC determines that it "represents the most reasonable and prudent means of meeting the electric utility's energy and capacity needs."[41] To make that decision, the statute instructs the MPSC to consider whether the IRP appropriately balances seven statutory factors: (i) resource adequacy and capacity to serve anticipated peak electric load, applicable planning reserve margin, and local clearing requirement; (ii) compliance with applicable state and federal environmental regulations; (iii) competitive pricing; (iv) reliability; (v) commodity price risks; (vi) diversity of generation supply; and (vii) whether proposed levels of peak load reduction and energy waste reduction are reasonable and cost effective.[42]

The IRP statute also directs the MPSC to establish – among other things – computer modeling scenarios that must be used to analyze the costs of possible plans in an IRP, including costs associated with plant retirement dates.[43] In the modeling used to prepare its 2021 IRP, Consumers determined that it would be most cost-effective to retire the entire J.H. Campbell plant in 2025.[44] Later in the proceeding, Consumers conducted more modeling that compared other possible retirement dates

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[40] MCL 460.6t(3).

[41] MCL 460.6t(8)(a).

[42] *Id.*

[43] MCL 460.6t(1).

[44] MPSC Case No. U-21090 (Blumenstock Direct, 3 Tr 99 and 147-49), available at https://mi-psc.my.site.com/sfc/servlet.shepherd/version/download/0688y000001OEXnAAO.

to a 2025 retirement and again concluded that the most cost-effective retirement date was 2025.[45] Among other things, parties to the IRP case noted that the 2025 retirement of J.H. Campbell would save ratepayers $150 million in avoidable capital expenditures.[46]

After months of litigation, most of the parties reached a settlement agreement, which Consumers filed with the MPSC on April 20, 2022.[47] The settlement agreement approved the retirement of J.H. Campbell – but it also approved the construction, procurement, and extension of other major generating resources. The net effect of these changes was to substantially increase the total generating resources available to MISO Zone 7.

iii. Effect of Consumers' overall plan on resource adequacy

MISO measures capacity for resource adequacy purposes in zonal resource credits (ZRCs). One ZRC is equal to one MW of deliverable seasonal accredited capacity, which is the net amount of capacity MISO calculates it can reasonably expect from a resource.[48]

Consumers' IRP projected that the entire J.H. Campbell plant would provide 1,346 ZRCs in 2024, its last full year of planned operation.[49] In recognition of the

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[45] *Id.* (Walz Rebuttal, 3 Tr 364-73 & Ex A-123; Blumenstock Rebuttal, 3 Tr 178-79).

[46] MPSC Case No. U-21090, Order approving contested settlement, June 23, 2022, pp. 48, 55.

[47] MPSC Case No. U-21090-0777 (Settlement Agreement), available at https://mi-psc.my.site.com/sfc/servlet.shepherd/version/download/0688y000002gLkGAAU.

[48] MISO Knowledge Base, KA-01402, available at https://help.misoenergy.org/knowledgebase/article/KA-01402/en-us#:~:text=Zonal%20Resource%20Credits%20(ZRC)%20are,Seasonal%20Accredited%20Capacity%20(SAC); MISO, Resource Adequacy, available at https://www.misoenergy.org/planning/resource-adequacy2/resource-adequacy/#t=10&p=0&s=FileName&sd=desc.

[49] MPSC Case No. U-21090, Order approving contested settlement, June 23, 2022, p. 33.

reduced capacity that would result from the retirement of J.H. Campbell, the settlement authorized Consumers to acquire the Covert gas plant, which Consumers has done.[50] At the time, the Covert plant was in the PJM regional transmission organization – but after acquiring it, Consumers redesignated the Covert plant as part of MISO Zone 7.[51] This action added 1,114 ZRCs to Zone 7 – almost enough by itself to offset the ZRCs removed by the Campbell retirement.[52]

The settlement also authorized Consumers to continue operating Units 3 and 4 of the Karn plant – peaking units that burn natural gas and oil – until 2031, rather than retire them in 2023 as originally planned.[53] This action maintained another 784 ZRCs in Zone 7 beyond what was in Consumers' original plan.[54] The settlement agreement also authorized Consumers to develop or acquire 250 ZRCs of new solar generation by mid-2025, increasing to 852 ZRCs by mid-2028; added 94 ZRCs of demand response and energy waste reduction by mid-2025; and added 71 ZRCs of new battery storage in 2024-2027.[55] The settlement also provided that Consumers would issue a solicitation for power purchase agreements (PPAs) that would provide capacity beginning in 2025/2026, right after J.H. Campbell's retirement.[56] The PPA solicitation would seek up to 500 MW of dispatchable generation, and up to 200 MW of clean energy resources.[57]

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[50] *Id.* at 5.
[51] *Id.* at 91.
[52] *Id.* at 50.
[53] *Id.* at 11.
[54] *Id.*
[55] *Id.* at 23.
[56] *Id.* at 6 – 7. In MISO, the planning year runs from June 1 through May 31.
[57] *Id.*

Overall, the plan approved in the settlement was projected to increase Zone 7's capacity by at least 127 ZRCs by June 2025 – an increase that will grow to at least 923 ZRCs by 2028, not including the 700 MW of additional capacity sought in the PPA solicitations.[58]

iv. MPSC approval of the settlement and affirmance on appeal

Consumers' IRP settlement agreement was supported by most parties in the case, including Consumers, Staff, the Attorney General, consumer advocates, a transmission company, commercial and industrial customers, businesses in the advanced energy sector, environmental groups, and third-party energy developers.[59] The MPSC approved the Settlement Agreement on June 23, 2022.[60] The state commission found that the plan embodied in the settlement "is the most reasonable and prudent means of meeting Consumers' energy and capacity needs."[61]

In reaching these conclusions, the MPSC specifically addressed resource adequacy.[62] After discussing the record evidence regarding the Covert plant, Karn units 3 and 4, new battery storage, and ongoing investments in solar, energy waste reduction, and demand response,[63] the MPSC concluded that "the approval of the settlement agreement will enhance resource adequacy in Zone 7 in both the near-term and long-term."[64] One party, Wolverine Power Supply Cooperative, appealed

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[58] *Id*. at 24.

[59] *Id*. at 30 – 31.

[60] *Id*. at 87-93.

[61] *Id*. at 95.

[62] *Id*. at 90-93.

[63] *Id*.

[64] *Id*. at 92.

the MPSC's decision to approve the Campbell plant retirement. The Michigan Court of Appeals affirmed the MPSC. The court specifically addressed resource adequacy, quoted the MPSC's findings about the generating resource additions, and found that the state commission's decision was based on substantial evidence.[65]

v. Subsequent proceedings before the MPSC show that both Consumers' service territory and Michigan as a whole will have sufficient capacity this summer and for years to come

Filings in MPSC proceedings regarding capacity supply and resource adequacy demonstrate that there is no capacity shortfall. To the contrary, the most current available information is that both Consumers and MISO Zone 7 will have sufficient capacity this summer and for years to come. On June 10, 2025, Consumers reported that it now has a surplus of 273 ZRCs for this summer.[66] Consumers further reported that it expects J.H. Campbell will not contribute any ZRCs to the Company's summer position.[67]

Consumers' ZRC projections compare Consumers' available resources not just to projected actual demand but to the planning reserve margin requirement (PRMR). MISO establishes the PRMR as the amount of reserve margin target necessary to meet NERC's Loss of Load Expectation (LOLE) standard of 1 day in 10 years.[68] NERC

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[65] *Wolverine Power Supply Coop., Inc. v Michigan Public Service Commission (In re Consumers Energy)*, 2023 Mich. App. LEXIS 2045; 2023 WL 2620437 (March 23, 2023).

[66] *See* Attachment D, Consumers' Responses from June 10, 2025.

[67] *Id.*

[68] MISO Resource Adequacy Business Practices Manual, BPM-011-r31, p. 27, Section 3.4.2 LOLE Analysis; MPSC Case No. U-21775, Capacity Demonstration Results Report, May 12, 2025, p. 9.

defines the LOLE as "the expected number of days per year for which the available generation capacity is insufficient to serve the daily peak demand."[69]

For Michigan as a whole, the MPSC Staff finds in its annual capacity demonstration report that – except for one small municipal utility – all Michigan load serving entities "were able to procure the necessary capacity to demonstrate compliance for the current planning year in all four seasons" in Planning Year 2025-26.[70] The Staff Report also finds that there are more than enough resources in Zone 7 to meet the MISO Local Clearing Requirement (LCR) – which is the minimum amount of resources that must be located within a MISO local resource zone to meet the reliability standard.[71] While Zone 7 did not have enough internal resources to meet its entire PRMR, it is not required to do so under MISO rules, and the zone is able to import 785.5 ZRCs of external resources to meet its PRMR for the current planning year.[72]

Looking ahead, the Staff Report projects that Zone 7 will have more than enough resources to meet both its LCR and the PRMR in each of planning years 2026, 2027, and 2028.[73] Zone 7's LCR surplus will increase each year to reach 4,975 ZRCs by Planning Year 2028, and its PRMR surplus will increase each year to reach 3,428 ZRCs by Planning Year 2028.[74]

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[69] NERC Probabilistic Assessment Technical Guideline, August 2016, p. 2.

[70] MPSC Case No. U-21775, Capacity Demonstration Results Report, May 12, 2025, p. 6.

[71] *Id.* at 16.

[72] *Id.*

[73] *Id.* at p. 26, Appendix C.

[74] *Id.*

vi. *MISO approved the retirement of J.H. Campbell after a detailed study process governed by MISO's FERC-approved tariff*

More than three years before the Secretary issued Order 202-25-3, MISO determined via a detailed technical study that retirement of J.H. Campbell would not materially impact reliability in MISO. That determination remains in effect.

Section 38.2.7 of MISO's Open Access Transmission, Energy, and Operating Reserve Markets Tariff requires that the owner of a Generation Resource that is planning to suspend operations of all or a portion of that resource must notify MISO at least 26 weeks in advance by submitting a completed Attachment Y Notice.[75] The Tariff states that MISO will perform an Attachment Y Reliability Study to determine whether the Generation Resource is necessary for the reliability of the Transmission System based on analyses described in the Tariff and criteria in the MISO Business Practices Manuals.[76]

On December 14, 2021, Consumers submitted to MISO an Attachment Y notice of intent to suspend J.H. Campbell Units 1, 2, and 3 effective June 1, 2025.[77] After more than a year of study, MISO approved the suspension on March 11, 2022.[78] MISO stated that after reviewing the J.H. Campbell suspension for power system reliability impacts, MISO had determined that "the suspension of Campbell Units 1, 2 & 3 would not result in violations of applicable reliability criteria. Therefore, Campbell Units 1,

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[75] MISO Tariff, Section 38.2.7(a)(i).

[76] MISO Tariff, Section 38.2.7(c).

[77] Attachment C (Letter dated December 14, 2021, from Timothy J. Sparks, Consumers Energy, to Andrew Witmeier, MISO, and Attachment Y Notification of Generating Resources Change of Status).

[78] Attachment C (Letter dated March 11, 2022, from Andrew Witmeier, MISO, to Timothy J. Sparks, Consumers Energy, re: Approval of Campbell Units 1, 2 & 3 Attachment Y Suspension Notice).

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."[79]

On May 27, 2025, MISO requested that Consumers submit a modified Attachment Y request with a new suspension start date of August 21, 2025, consistent with the date in Order 202-25-3.[80] Consumers submitted the modified Attachment Y notice with the new date on May 28, 2025.[81] On May 30, 2025, MISO notified Consumers that with the modification, "the Attachment Y remains as is, still approved, except with a new/different start date."[82]

D. The Order

On May 23, 2025, the Secretary of Energy issued the Order pursuant to section 202(c) of the Federal Power Act, determining that an emergency exists in the region of the country served by MISO "due to a shortage of electric energy, a shortage of facilities for the generation of electric energy, and other causes" and ordering Consumers and MISO to ensure the continued operation of J.H. Campbell for at least 90 days notwithstanding the longstanding plan to retire the facility on May 31, 2025. In issuing the Order, the Department issued a press release that, like Executive

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[79] *Id.*

[80] Attachment C (Email dated May 27, 2025, from Huaitao Zhang, MISO, to Kathy Wetzel, Consumers Energy).

[81] Attachment C (Email dated May 28, 2025, from Rachael Moore, Consumers Energy to Huaitao Zhang, MISO).

[82] Attachment C (Email dated May 30, 2025, from Marc Keyser, MISO, to Rachael Moore, Consumers Energy).

Order 14262, states the Order "is in accordance with President Trump's Executive Order: Declaring a National Energy Emergency."[83]

Over four short paragraphs, the Order outlines the "emergency situation" allegedly necessitating invocation of section 202(c) authority. It points primarily to "*potential* tight reserve margins during the summer 2025 period," citing to the North American Electric Reliability Corporation (NERC) 2025 Summer Reliability Assessment, including the statement that MISO is "at elevated risk of operational reserve shortfalls during periods of high demand or low resource output."[84] The Order then describes the retirement of thermal generation capacity including the retirement of approximately 2,700 MW of coal-fired capacity in Michigan since 2020 and the scheduled May 31, 2025, retirement of J.H. Campbell.[85] The Order acknowledges Consumers' acquisition of 1,200 MW of replacement natural gas capacity and MISO's April 2025 conclusion that its auction resulted in "demonstrated sufficient capacity,"[86] but does not reference, let alone consider, the extensive processes that MISO and the MPSC undertook to evaluate and mitigate any reliability or resource adequacy risk that would be caused by the retirement of J.H. Campbell.[87] Nor does the Order describe any actions that MISO or Consumers have taken or could take to mitigate any alleged emergency conditions short of ordering the continued operation of the plant. Rather, it relies almost exclusively on:

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[83] DOE Press Release (May 23, 2025) available at https://www.energy.gov/articles/energy-secretary-issues-emergency-order-secure-grid-reliability-ahead-summer-months.
[84] DOE Order 202-25-3 at 1 (emphasis added).
[85] *Id.* at 1.
[86] *Id.* at 2.
[87] *See* Section II.C *supra*.

- The general statement in NERC's 2025 Summer Reliability Assessment that there is anticipated to be "elevated risk of operating reserve shortfalls"
- Language in MISO's Planning Resource Auction Results for Planning Year 2025-26 that, "for the northern and central zones, which includes Michigan, 'new capacity additions were insufficient to offset the negative impacts of decreased accreditation, suspensions/retirements and external resources,'" and that the results "reinforce the need to increase capacity" and,
- Language from the MISO Auction Results that the summer months have, relative to other times, the "highest risk and tighter supply-demand balance."[88]

The Order concludes that "additional dispatch of the Campbell Plant," for the 90-day duration of the order and on conditions contained in the order, "is necessary to best meet the emergency and serve the public interest."[89] As a result, the Order mandates that:

- MISO and Consumers Energy take all necessary steps to ensure the Campbell Plant is available for dispatch;[90]
- MISO employ economic dispatch of the plant, and that Consumers comply with all such dispatch orders;[91]
- All operation of J.H. Campbell "must comply with applicable environmental requirements . . . to the maximum extent feasible while operating consistent with the emergency conditions."[92]
- MISO submit reports to DOE on plant operations, environmental impacts, and actions taken to comply with the Order.[93]
- "Relevant governmental authorities" take such action as necessary to enable MISO to effectuate the dispatch and operation of the units.[94]
- Consumers request any necessary revisions or waivers to effectuate the order with FERC.[95]

III. STATEMENT OF ISSUES AND SPECIFICATIONS OF ERROR

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[88] DOE Order 202-25-3 at 2.
[89] DOE Order 202-25-3 at 2.
[90] *Id.* at 2 (Ordering Paragraph A).
[91] *Id.* (Ordering Paragraph A).
[92] *Id.* at 3 (Ordering Paragraph C).
[93] *Id.* at 3 (Ordering Paragraph B, D).
[94] *Id.* at 3 (Ordering Paragraph E).
[95] *Id.* at 3 (Ordering Paragraph F).

As explained in Section IV below, the Michigan Department of Attorney General submits the following statement of issues and specifications of error:

1. The Order is contrary to law because it fails to establish the existence of an emergency under section 202(c) or the Department's regulations implementing section 202(c). The statutory text, legislative history, judicial construction and DOE's regulations all confirm that an "emergency" is an occurrence that is sudden, unexpected and requiring immediate action. The Order introduces no facts that would satisfy that definition. 16 U.S.C. § 824a(c); 10 C.F.R. § 205.371; *Richmond Power and Light v. FERC*, 574 F.2d 610, 615 (D.C. Cir. 1978); *Otter Tail Power Co. v. Fed. Power Comm.*, 429 F.2d 232, 233-34 (1970).

2. The Order is contrary to law because it exceeds the Department's statutory authority. Abusing a statute meant only for emergencies, the Order intrudes on authority reserved to States and to other federal regulators to regulate resource adequacy. Section 202(c) does not vest DOE with general regulatory authority over resource adequacy, or the authority to decide which power plants may retire except for so long as a true emergency exists. The Department may not "discover in a long-extant statute an unheralded power representing a transformative expansion in its regulatory authority." *W. Virginia v. Env't Prot. Agency*, 597 U.S. 697, 724–25, (2022) (quoting *Util. Air Regul. Grp. v. E.P.A.*, 573 U.S. 302, 324 (2014))(internal quotations omitted).

3. The Order fails to present substantial evidence for its emergency determination and fails to exercise reasoned decision-making by ignoring critical facts and shortcomings in its analysis. Specifically, the Order: (i) presents a discussion of the NERC 2025 Summer Reliability Assessment that is unreasoned, incomplete, and that fails to substantiate the existence of an emergency; (ii) the Order's apparent reliance on generator retirements in Michigan as evidence of an emergency is unreasonable; (iii) the Order acknowledges that the most recent MISO auction "demonstrated sufficient capacity" but fails to explain why an emergency exists nonetheless, (iv) the Order fails even to acknowledge that MISO approved the retirement of J.H. Campbell through the study process governed by its FERC-approved tariff; (v) the Order makes no effort to review the proceedings before the MPSC, or to note any consultation with Michigan officials as required by 42 U.S.C. § 7113; (vi) the Order fails to provide any specific evidence or reasoning why J.H. Campbell must remain in operation and why alternative measures are inadequate. *E.g. Emera Maine v. FERC*, 854 F.3d 9, 22 (D.C. Cir. 2017) (order under the Federal Power Act must reflect "a principled and reasoned decision supported by the evidentiary record" (quotation marks omitted)); *Motor Vehicle Mfrs. Ass'n of U.S., Inc. v. State Farm Mut. Auto. Ins. Co.*, 463 U.S. 29, 43 (1983) (agency must examine the relevant data and articulate a satisfactory

explanation for its action including a rational connection between the facts found and the choice made); *Burlington Truck Lines, Inc. v. United States*, 371 U.S. 156, 168 (1962) (an "agency must make findings that support its decision, and those findings must be supported by substantial evidence").

4. The Order is arbitrary and capricious and contrary to law because section 202(c) provides no authority for the Department to command a generator to engage in "economic dispatch." 16 U.S.C. § 824a(c); *Michigan v. EPA*, 268 F.3d 1075, 1081 (D.C. Cir. 2001) (absent statutory authorization, an agency's "action is plainly contrary to law and cannot stand").

5. The Order is arbitrary and capricious and contrary to law because the Department failed to limit its remedy as required by section 202(c)(2). The Order adheres to neither the temporal constraint nor the environmental constraints imposed by section 202(c)(2). 16 U.S.C. § 824a(c)(2).

6. The Order violates the National Environmental Policy Act because it fails to assess the environmental consequences of a major federal action significantly affecting the human environment. 42 U.S.C. § 4321; *et seq*.

IV. REQUEST FOR REHEARING

A. The Department Has Failed to Establish the Existence of an Emergency under Section 202(c) or the Department's Regulations Implementing Section 202(c).

i. Congress limited DOE's authority under section 202(c) to the unique circumstances of war or emergency

Section 202(c) confers an extraordinary power. Enacted in 1935, section 202(c) empowered the Federal Power Commission to command action from market participants and – crucially – to do so freed from most of the core procedural safeguards, jurisdictional boundaries, and substantive limitations that undergird the rest of the Federal Power Act. While the rest of the Act authorizes Commission action only after opportunity for hearing,[96] section 202(c) allows the Commission (now the Department) to act on its own motion and without prior notice. And in profound contrast to the rest the Federal Power Act and general utility law principles,[97] section 202(c) empowers the Department to require utilities to incur costs – through a command to provide generation or transmission service – without first considering the impact to ratepayers or whether the resulting rates will be just and reasonable.

It comes as no surprise, therefore, that when Congress granted the Commission this extraordinary power, Congress restricted its use to extraordinary circumstances. Section 202(c) authorizes action only "[d]uring the continuance of any war in which the United States is engaged, or whenever the Commission determines that an emergency exists by reason of a sudden increase in the demand for electric energy, or a shortage of electric energy or of facilities for the generation or transmission of electric energy, or of fuel or water for generating facilities, or other causes." The Act permits some measure of flexibility with respect to what type of events may cause the emergency, allowing for "other causes" beyond those enumerated. But the Act is clear that any such event, including a "shortage of electric energy," must be one that constitutes an "emergency."

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[96] *See e.g.*, 16 U.S.C. §§ 824a(b), 824a(e), 824a-1(a), 824a-3(f), 824a-4, 824b(a)(4), 824c(b), 824d, 824e, 824f, 824i(b), 824j, 824j-1, 824k, 824m, 824o & 824p.

[97] Two cornerstones of the law of regulated utilities are the filed rate doctrine and the rule against retroactive ratemaking. As FERC has explained, "a central purpose of the filed rate doctrine and the rule against retroactive ratemaking is to protect ratepayers from being subjected to an additional surcharge above the rate on file for service already performed." *Old Dominion Elec. Coop.*, 154 FERC ¶ 61,155 (2016). In its June 6, 2025, complaint filed in FERC Docket No. EL25-90, Consumers asserts that the filed rate doctrine and the rule against retroactive ratemaking are inapplicable in the context of an order under section 202(c).

Because the Act does not define "emergency," the Department must look first to the public meaning of that word at the time of enactment. Webster's New International Dictionary of the English Language (1930) defined "emergency" as a "sudden or unexpected appearance or occurrence . . . . An unforeseen occurrence or combination of circumstances which calls for immediate action or remedy; pressing necessity; exigency." Contemporary dictionaries likewise define "emergency" to refer to a circumstance that is "unexpectedly arising, and urgently demanding immediate attention."[98]

These definitions accord with the legislative history of the Federal Power Act, which characterized section 202(c) as an authority to be used in response to "crises":

> This is a temporary power designed to avoid a repetition of the conditions during the last war, when a serious power shortage arose. Drought and other natural emergencies have created similar crises in certain sections of the country; such conditions should find a federal agency ready to do all that can be done in order to prevent a break-down in electric supply.[99]

The few courts that have had occasion to opine on the meaning of "emergency" in section 202(c) have likewise emphasized that the provision applies in very limited circumstances, and not as a tool to address longer-term, structural concerns. In *Richmond Power and Light v. FERC*, the D.C. Circuit upheld the Commission's judgment that the dependence on foreign oil occasioned by the 1973 oil embargo was

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[98] *See Acuity Ins. Co. v. McDonald's Towing & Rescue, Inc.,* 747 F. App'x 377, 380–81 (6th Cir. 2018) (addressing a statute that leaves "emergency" undefined and quoting 7 Oxford English Dictionary 231 (2012) among others to supply a definition).

[99] S. Rep. No. 74-621 at 49 (1935).

not an “emergency” under the Act, noting that section 202(c) “speaks of ‘temporary’ emergencies, epitomized by wartime disturbances.”[100]

In *Otter Tail Power Co. v. Fed. Power Comm’n,* the U.S. Court of Appeals for the Eighth Circuit described section 202(c) as enabling the Commission to “react to a war or natural disaster.” The court also distinguished section 202(c) from section 202(b), under which the Commission may also order interconnections, but only after a hearing. The court explained that, in contrast to section 202(c), which “enables the Commission to proceed without notice or hearing” to address immediate crises, section 202(b) “applies to a crisis which is likely to develop in the foreseeable future but which does not necessitate immediate action on the part of the Commission.”[101]

Through its regulations, the Department has also interpreted “emergency” for purposes of section 202(c) to mean circumstances that arise suddenly and unexpectedly:

> “Emergency,” as used herein, is defined as an unexpected inadequate supply of electric energy which may result from the unexpected outage or breakdown of facilities for the generation, transmission or distribution of electric power. Such events may be the result of weather conditions, acts of God, or unforeseen occurrences not reasonably within the power of the affected “entity” to prevent. An emergency also can result from a sudden increase in customer demand, an inability to obtain adequate amounts of the necessary fuels to generate electricity, or a regulatory action which prohibits the use of certain electric power supply facilities.[102]

In summary, the plain meaning of the statutory text, its legislative history, judicial construction, and the Department’s own regulations all establish that an

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[100] 574 F.2d 610, 615 (D.C. Cir. 1978).
[101] 429 F.2d 232, 234 (8th Cir. 1970).
[102] 10 C.F.R. § 205.371.

"emergency," including one occasioned by a "shortage of electric energy," must be sudden, unexpected, and demanding of "immediate action."

ii. The Order fails to present facts establishing an emergency under section 202(c) or the Department's regulations

Even taken as complete and accurate claims (which they are not), the factual assertions made in the Order fail to describe an "emergency." The Order does not claim that the retirement of J.H. Campbell was sudden or unexpected. Nor could it. The retirement of J.H. Campbell was carefully planned over a period of years and was approved by the MPSC through a public proceeding. Further, Consumers' plan to retire J.H. Campbell included a commitment to procure replacement resources that improved its capacity position. And Consumers' proposal to retire J.H. Campbell was approved in advance by MISO after a thorough review of its impact on reliability.

Nor did the publication of NERC's 2025 Summer Reliability Assessment in May 2025 transform a long-planned retirement into an event with sudden or unexpected implications requiring immediate action. The Order notes that the 2025 NERC Summer Reliability Assessment characterizes MISO as being at an "elevated risk of operating reserve shortfalls." But NERC's "elevated risk" designation in no way signifies an emergency condition. "Elevated risk," it should be emphasized, falls *below* NERC's highest risk designation: that of "high" risk.[103] NERC's decision not to place MISO in the highest risk category in its Summer Reliability Assessment is

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[103] The "High" risk designation refers to a risk of shortfall during normal peak conditions, whereas the "Elevated" risk designation refers to a risk of shortfall during above-normal peak conditions. See Attachment A, NERC, 2025 Summer Reliability Assessment at 6.

in itself powerful evidence that there is no "emergency" stemming from a lack of operating reserves.

The "elevated risk" designation is also far from unusual. In the same report, NERC also designated the systems overseen by SPP, the Electric Reliability Council of Texas (ERCOT), and the New England Independent System Operator (ISO-NE) as at "elevated risk."[104] Except for 2022, when it was designated as "high" risk, MISO has been designated as "elevated" risk in every NERC Summer Reliability Assessment since NERC initiated the practice of designating regions as "high," elevated," or "normal" risk in 2021.[105] NERC has also designated MISO as "elevated" risk in every Winter Reliability Assessment since 2021.[106] In effect, what the Order implies through its reliance on the NERC report's "elevated" risk designation, is that the fifteen states of MISO – along with large swaths in the rest of the United States – have been in an uninterrupted state of emergency for many years on end. This interpretation, if credited, would effectively read the word "emergency" out of section 202(c).

The Order's hand-waving reference to "potential tight reserve margins" identified in the 2025 NERC Summer Reliability Assessment likewise fails to describe an emergency. The very fact that the Order attempts to rely on "potential" future conditions itself contradicts the notion that MISO is presently facing an

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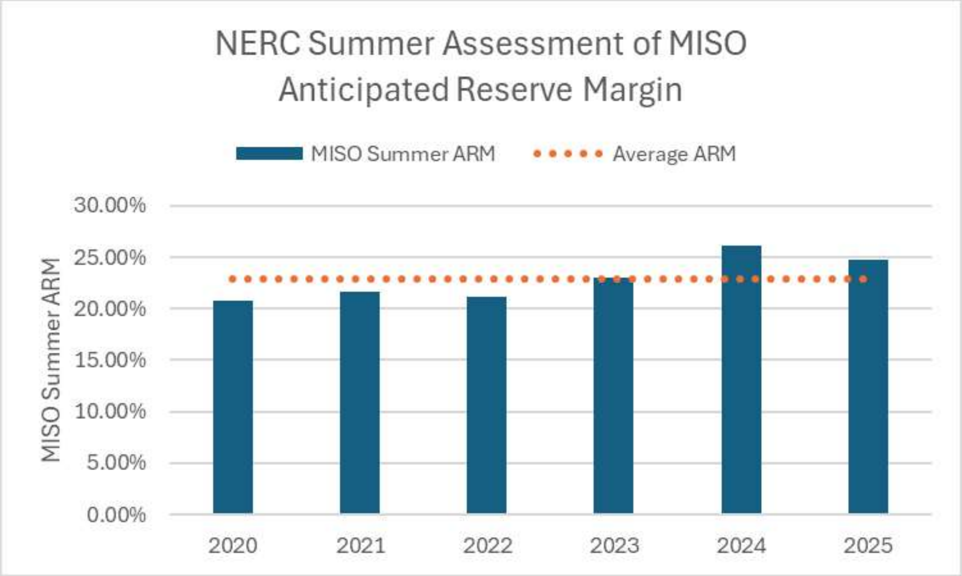
[104] *Id.*

[105] *See* NERC Summer Reliability Assessments years 2021 – 2025, available at https://www.nerc.com/pa/RAPA/ra/Pages/default.aspx.

[106] *See* NERC Winter Reliability Assessments years 2021 – 2025, available at https://www.nerc.com/pa/RAPA/ra/Pages/default.aspx.

emergency as conceived under section 202(c). Moreover, the actual reserve margins in MISO this summer do not support an emergency determination. The NERC report calculated MISO's anticipated reserve margin for Summer 2025 as 24.7%.[107] This figure substantially exceeds NERC's "Reference Margin Level" for MISO of 15.7%,[108] which is the level that NERC has "established for the areas to meet resource adequacy criteria."[109] MISO's anticipated reserve margin of 24.7% is also *higher* than its average of recent years. The chart below shows the anticipated reserve margin for MISO as calculated in the NERC Summer Reliability Assessment for each year.[110] The chart shows that the 2025 anticipated reserve margin of 24.7% exceeds the 2020-2025 average of 22.9%. Again, the Order has failed to describe a circumstance that is "unexpected," "sudden" or "demanding of immediate attention."



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[107] Attachment A, NERC, 2025 Summer Reliability Assessment at 10.
[108] *Id*. at 44.
[109] *Id*. at 15.
[110] *See* NERC Summer Reliability Assessments years 2020 – 2025, available at https://www.nerc.com/pa/RAPA/ra/Pages/default.aspx.

The other factual assertions in the Order likewise fail to describe an emergency. The Order devotes one of its few substantive paragraphs to explaining that various generation units have retired in Michigan, reaching back as far as 1997.[111] But generation units retire everywhere as part of the normal, continuous cycle through which old units are replaced with new ones. The unsurprising fact that generation units have retired in Michigan over the last 28 years says nothing about whether there is presently adequate generation in the State, and even less about whether an emergency exists in the region as a whole.

The Order then points to the results of the April 2025 MISO Planning Resource Auction. But these results explicitly contradict the claim that an emergency exists in MISO. The Order acknowledges MISO's conclusion that the auction "demonstrated sufficient capacity." In fact, the Order truncates this quote, which stated in full that: "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."[112] Remarkably, the Order attempts to brush aside the obvious import of this conclusion, preferring instead to focus on the second half of the sentence. But the second half of that sentence merely refers to the fact that the summer price for capacity in MISO, which separates the auction results by season, is high*er* and has a tight*er* supply/demand balance than those of the fall, winter and spring seasons (a fact illustrated by the chart below the header text).

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[111] Order at 1.

[112] Attachment B, MISO, Planning Resource Auction, Results for Planning Year 2025 – 2026 (April 2025) at 12.

This sentence does not indicate any kind of shortfall in the summer season, much less an emergency shortfall.

The Order also quotes from a slide that states "for North/Central, new capacity additions were insufficient to offset the negative impacts of decreased accreditation, suspensions/retirements and external resources."[113] But this slide is simply noting that the total capacity of resources *offered* into the 2025 auction in the North/Central region was lower than what was offered into the 2024 auction. This slide does not say that the total amount of capacity *procured* in the North/Central region through the auction was inadequate. In other words, this slide is in no way inconsistent with the conclusion in the same report that the "2025 PRA demonstrated sufficient capacity at the regional, subregional and zonal levels."[114] Further, even as a characterization of the total capacity offered into the auction, the Order ignored a crucial fact in this slide. The slide shows that the reason for the decrease in capacity offered was not because of a decrease in physical generating capacity, but because of a change in the capacity accreditation of various resources—most notably, the very "dispatchable generation" that the order prioritizes. This change in MISO's capacity accreditation methodology occurred over the previous year.[115] The bar chart in Attachment B shows a reduction in accredited capacity for gas and coal of 3.4 GW, which is greater than the overall reduction in offered

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[113] *Id.* at 13.

[114] *Id.* at 12.

[115] *Midcontinent Independent System Operator, Inc.*, 189 FERC ¶ 61,065 (Oct. 25, 2024).

capacity.[116] In other words, MISO concluded that coal (and gas) resources, such as J.H. Campbell, should be deemed to contribute less to capacity requirements than it had previously assumed.

B. Abusing an Authority Meant for True Emergencies, the Order Intrudes on Authority Reserved to States and to Other Federal Regulators.

i. Resource adequacy is regulated by the states, and by FERC under other provisions of the Federal Power Act

Resource adequacy refers to the capacity of an electric power system to meet demand reliably at all times, including during system peaks and through potential outages. Resource adequacy is "measured at the system level to capture the overall impact of outages of individual components including generators and transmission."[117] Resource adequacy planning is the process by which utilities and system operators, under regulatory supervision, ensure resource adequacy. Resource adequacy planning involves technical and economic considerations that go into determining what resources are added to the grid and which resources should retire and when.

With respect to regulatory oversight for resource adequacy, section 201 of the FPA, 16 U.S.C. § 824(b)(1), reserves authority over generation facilities to the states. It states in pertinent part: "The Commission shall have jurisdiction over all facilities for such transmission or sale of electric energy, *but shall not have jurisdiction*, except as specifically provided in this subchapter and subchapter III of this chapter, *over*

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[116] Attachment B, MISO, Planning Resource Auction, Results for Planning Year 2025 – 2026 (April 2025) at 13.

[117] NREL, Resource Adequacy Basics, available at https://www.nrel.gov/research/resource-adequacy.

facilities used for the generation of electric energy or over facilities used in local distribution or only for the transmission of electric energy in intrastate commerce, or over facilities for the transmission of electric energy consumed wholly by the transmitter."[118]

Some states have retained this authority over resource adequacy in its entirety.[119] Others have directed their utilities to join RTO/ISOs that, through their tariffs, impose resource adequacy requirements. Those RTO/ISOs also generally establish markets that allow market participants to buy and sell capacity and thereby to facilitate market entry and exit decisions based on price signals. Resource adequacy requirements in RTO/ISO tariffs have been held to be practices affecting wholesale rates subject to the jurisdiction of FERC under sections 205 and 206 of the Federal Power Act, 16 U.S.C. §§ 824d & 824e.[120]

In Michigan, the regulation of resource adequacy planning has both a state and federal aspect. As a member of MISO, Consumers has a capacity obligation under the MISO tariff. MISO's resource adequacy requirements, however, are designed to be complementary to the primary role of the states in ensuring resource adequacy.[121]

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[118] *Id.* (emphasis added).

[119] *See Devon Power LLC et al.,* 109 FERC ¶ 61,154, P 47 (2004) ("Resource adequacy is a matter that has traditionally rested with the states, and it should continue to rest there. States have traditionally designated the entities that are responsible for procuring adequate capacity to serve loads within their respective jurisdictions.").

[120] *See Conn. Dep't of Pub. Util. Control v. FERC*, 569 F.3d 477, 483 (D.C. Cir. 2009).

[121] *Midcontinent Indep. Sys. Operator, Inc.*, 170 FERC ¶ 61,215, 62,606 at P 13 (2020) ("approximately 90% of the load in MISO is served by vertically integrated LSEs, the vast majority of which are subject to state integrated resource planning processes. To accommodate the make-up of the MISO's footprint, MISO's proposed Tariff provisions accepted in the February 2018 Order provide that its resource adequacy requirements "are complementary to the reliability mechanisms of the states and the Regional Entities ... within the [MISO] region."); *see also id.* ("MISO's proposed Tariff language

Consumers' investment decisions are regulated by the MPSC. Through the state IRP process (described in Section II.C above), the MPSC exercises regulatory authority over Consumers in order to ensure that the utility obtains the amount of capacity it needs to meet its obligations under the MISO tariff, and that it does so at the best value to ratepayers, and with a composition of resources that otherwise complies with state law, including state environmental requirements.

ii. Section 202(c) does not vest DOE with general regulatory authority over resource adequacy

The Order indicates that the Department believes it has the authority to decide which power plants may retire and when, not based on the kind of real emergency that has justified past action, but rather based on its own policy preferences. The Department appears to want to place its own judgment about operating reserve margins ahead of MISO's, and its own preference for which resources are employed to maintain resource adequacy ahead of Michigan's. In effect, the Department appears to read section 202(c) so as to give itself authority to regulate resource adequacy. Any ambiguity on this point was put to rest by the Department's June 13 letter referring cost recovery issues for J.H. Campbell to FERC. In that letter, the Department, through counsel, acknowledged that resource adequacy concerns

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explains that the resource adequacy requirements 'are not intended to and shall not in any way affect state actions over entities under the states' jurisdiction.' In other words, unlike the centralized capacity constructs used in the Eastern RTOs/ISOs, MISO's Auction is not—*and has never been*—the primary mechanism for its [Load Serving Entities] to procure capacity."); *Midwest Indep. Transmission Sys. Operator, Inc.*, 119 FERC ¶ 61,311, 62,722 at P 75 (2007) ("From the beginning . . . the Commission has recognized the role that state resource planning plays in managing the resource adequacy of [MISO]").

motivated the Order and went so far as to purport to dictate whether J.H. Campbell would be counted as a capacity resource pursuant to the MISO tariff.[122]

Section 202(c) does not provide the Department with the authority it claims. Had Congress intended to vest regulatory authority over resource adequacy in section 202(c), – displacing both state law and sections 205 and 206 of the Federal Power Act, – it would have stated so clearly. But of course it did not. The authorizing language says no more than that DOE may "require by order . . . such generation . . . of electric energy as in its judgment will best meet the emergency and serve the public interest." Indeed, it defies logic that, had Congress intended to empower DOE to be the general decider of which power plants may retire across every utility and independent power producer across the entire country – a function with profound implications for rates, state sovereignty, and a broad array of other stakeholder interests – that Congress would have done so through what may be the only provision in the Federal Power Act that empowers the regulator to act without first assessing the effect on ratepayers or seeking public input, and one of the only provisions that extends to otherwise non-jurisdictional utilities such as public power entities and those in ERCOT.

But even if the text of section 202(c) could, theoretically, be stretched to such an expansive reading (which it cannot), the United States Supreme Court has emphatically rejected statutory interpretations whereby an agency "claim[s] to discover in a long-extant statute an unheralded power representing a transformative

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[122] FERC Docket No. EL25-90, submission of Dep't of Energy, June 13, 2025 ("Because the May 23, 2025 Order is predicated on the shortage of facilities for the generation of electric energy and other causes, such as resource adequacy concerns, the Campbell plant shall not be counted as a capacity resource.").

expansion in its regulatory authority."[123] That is exactly what the Department seeks to do here. It seeks to discover in a 90-year-old statute a basis to exercise much broader regulatory authority than it ever has in the past. While it is true, as we explain above in section II.A, that the Department has used section 202(c) to delay power plant retirements on three occasions over the 90-year history, it has always done so at the request of a system operator or governmental body and in a manner narrowly tailored to prevent a concrete and particularized emergency. It has never done so simply to impose its policy preferences ahead of the judgment of those bodies responsible for resource adequacy.

C. The Order Fails to Present Substantial Evidence for its Emergency Determination and Fails to Exercise Reasoned Decision-making by Ignoring Critical Facts.

The Order relies on three sources of evidence for its emergency determination: the NERC 2025 Summer Reliability Assessment, generator retirements in Michigan, and the results of MISO's 2025 Planning Resource Auction. None of these three sources provide evidence that an emergency exists. By relying on these sources, and by misconstruing each of them, the Order fails to exercise reasoned decision-making.

The Order also entirely ignores several other critical facts and considerations. The Order ignores the fact that MISO approved the deactivation of J.H. Campbell. The Order ignores the conclusions of the MPSC proceeding that approved the retirement of J.H. Campbell. And even if it were correct that a capacity shortfall

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[123] *W. Virginia v. Env't Prot. Agency*, 597 U.S. 697, 724–25, (2022) (quoting *Util. Air Regul. Grp. v. E.P.A.*, 573 U.S. 302, 324 (2014))(internal quotations omitted).

exists in MISO, the Order fails to explain why preventing the retirement of J.H. Campbell through an emergency measure is necessary to address the shortfall.

i. The Order's discussion of the NERC 2025 Summer Reliability Assessment is unreasoned and incomplete

As explained above in Section IV.A, the Order's discussion of the NERC 2025 Summer Reliability Assessment is both incomplete and unreasoned. Specifically, the Order fails to explain (i) why the NERC report supports an emergency finding for MISO given that NERC did not put MISO in the "high" risk category, (ii) why NERC's designation of MISO as at "elevated" risk provides evidence of a "sudden" or "unexpected" circumstance given that MISO has been at this risk level or higher for years running, and (iii) why the "potential tight reserve margins" identified in the NERC report constitute an emergency given that MISO well exceeds the NERC reference margin level and even exceeds its own average Summer anticipated reserve margin over the 2020 – 2025 period.

ii. The Order's apparent reliance on generator retirements in Michigan is unreasonable

The Order attempts to support its emergency finding by recounting the fact that various power plants have retired in the state of Michigan.[124] As explained above, because power plant retirements are a regular occurrence in the electric power sector, the Order's discussion of this topic fails to present even *prima facie* evidence of an emergency. It also fails to exhibit reasoned decision-making in two key respects. First, it is unreasonable to point to capacity retirements in isolation

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[124] Order at 1.

without also considering all the other factors that contribute to resource adequacy. Such factors include capacity additions, changes in load, load shape and load flexibility, demand response, transmission access to external resources, etc. Of course, MISO *did* consider all those factors in the modeling that went into the Attachment Y process through which it approved the deactivation of J.H. Campbell.[125]

Second, the Order fails to explain how power plant retirements in Michigan are related to the emergency the Department purports to identify. In past orders where the Department has used section 202(c) to delay a power plant's retirement, the Department has acted on application of a utility or system operator to address a discrete, localized emergency that would be caused by the impending retirement.[126] The Department makes no such claim to geographic specificity here. Rather, the remainder of the "Emergency Situation" section of the Order appears to describe a purported emergency throughout MISO, insofar as it relies on NERC's general statements about MISO reserve margins and the results of the MISO Planning Resource Auction. Thus, the Order fails to explain why it is relying on power plant retirements in a single state—Michigan—to support its claim that an emergency exists in the region as a whole.

iii. The Order acknowledges that the most recent MISO auction "demonstrated sufficient capacity" but fails to explain why an emergency exists nonetheless

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[125] *See* MISO Transmission Planning Business Practices Manual, BPM-020-r32 Section 6.2 (Generator Retirement and Suspension Studies and System Support Resources), Section 6.2.3 (Study Scope Development).

[126] *See* Section II.A *supra*.

As explained in Section IV.A above, the Order cites to the MISO planning reserve auction report while ignoring the statement in that report that: "The 2025 PRA demonstrated sufficient capacity at the regional, subregional and zonal levels." It is entirely unreasonable for the Department to cite this report as evidence of an emergency when the report has concluded exactly the opposite. The Order's effort to focus on other aspects of the report are equally unreasonable. The unremarkable statement that summer prices are higher than prices in other seasons and therefore reflect a tighter supply/demand balance falls far short of providing evidence for an emergency. Likewise, the Order's reliance on the fact that less capacity was *offered* in the 2025 auction than was offered into the 2024 auction hardly describes an emergency. Further, the Order fails to note the information conveyed in the slide it quotes from, which shows that the only material change between 2024 and 2025 was a result in a change in capacity accreditation values rather than a change in physical resources available.

iv. The Order fails to acknowledge that MISO approved the retirement of J.H. Campbell

As explained in Section II.C above, after a robust, technical, and considered process, MISO approved the retirement of the three J.H. Campbell units pursuant to the study process governed by its tariff. MISO concluded that "the suspension of Campbell Units 1, 2 & 3 would not result in violations of applicable reliability criteria." As the system operator, MISO has more in-depth knowledge of its system than the Department does. The Department should have explained why it reached a different conclusion than MISO. Instead, the Order failed even to mention that MISO conducted this study and approved the retirement.

v. The Order makes no effort to review the findings of the MPSC or to demonstrate consultation with Michigan as required by 42 U.S.C. § 7113

The Order acknowledges that Consumers acquired the Covert gas plant, but in all other respects fails to acknowledge the MPSC proceeding that approved Consumers' IRP settlement entailing retirement of J.H. Campbell. As explained above in Section II.C, acquiring the Covert gas plant was not the only action Consumers took as part of that IRP. The IRP also delayed the retirement of the peaking units at the Karn facility and included the acquisition of other new resources, with the result that Consumers' capacity position was set to improve materially even after the retirement of J.H. Campbell. The Order also ignores the Michigan capacity demonstration proceedings that found both Consumers and MISO Zone 7 have sufficient capacity resources in 2025 and in the years to come.

Section 103 of the Department of Energy Organization Act, 42 U.S.C. § 7113, provides:

> Whenever any proposed action by the Department conflicts with the energy plan of any State, the Department shall give due consideration to the needs of such State, and where practicable, shall attempt to resolve such conflict through consultations with appropriate State officials.

The Order plainly conflicts with Michigan's energy plan, as reflected in the MPSC's approval of Consumers' IRP. Equally clearly, the Order does not give "due consideration" to the needs of Michigan. Nor does it appear that the Department made any attempt to resolve the conflict it created through consultation with the appropriate State officials. The Department, therefore, has failed to comply with Section 103 of the Department of Energy Organization Act. A practical consequence of the Department's apparent failure to consult with the State is that the Order lacks basic information related to its action, including the Order's inexplicable failure to accurately state the capacity of J.H. Campbell, the lack of awareness as to the operational status of Unit 2, the understatement of resources Consumers acquired to replace J.H. Campbell, and the omission of any reference to the reliability analysis undertaken by the State.

vi. The Order fails to provide any specific evidence or reasoning why J.H. Campbell must remain in operation and why alternative measures are inadequate

Even accepting the Order's contention that there exists a capacity shortfall in MISO, it does not follow that commanding the continued operation of J.H. Campbell is the best or even an appropriate means of alleviating the shortfall. The Order does not assert that there is a local problem on the grid that only J.H. Campbell can solve. In this respect, the Order departs markedly from past uses of section 202(c) and from the Department's regulations implementing section 202(c), which state that: "Actions under this authority are envisioned as meeting a specific inadequate power supply situation."[127]

Rather, the emergency that the Order purports to identify – "potential tight reserve margins" – is one that spans the entire fifteen-state MISO region and one

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[127] 10 C.F.R. § 205.371.

that could presumably be addressed by any number of actions across MISO. And, given that J.H. Campbell amounts to well less than 1% of generation capacity in MISO, there likely were options available that would have had a much greater impact on the overall balance of supply and demand. Further, because J.H. Campbell is an over 60-year-old facility in a largely degraded operational state, there presumably were alternative actions available that could have met the purported need with higher levels of reliability.

Yet the Order does not acknowledge any alternatives or explain whether less burdensome measures were exhausted before taking this action. The question of whether alternative measures could have been used to address the "emergency" is made more challenging by the fact that the Order never quantifies the extent of the emergency it purports to identify within MISO. But that omission merely highlights rather than excuses the deficiencies of the Order.

One possible alternative may have been demand-side measures. The Department's regulations require applicants seeking an order under section 202(c) to provide a "description of any conservation or load reduction actions that have been implemented . . . [and a] discussion of the achieved or expected results."[128] In the Yorktown case, the Department required Dominion to exhaust all demand response measures before dispatching the facility.[129] And yet here the Department failed to make any inquiry or even to consider whether demand-side measures could have

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[128] 10 C.F.R. § 205.373.

[129] *See* DOE Order No. 202-17-4 (Sept. 14, 2017) ("PJM and Dominion shall exhaust all reasonably and practically available resources, including demand response and behind-the-meter generation resources, prior to operating Yorktown Unit 1 or Yorktown Unit 2.")

addressed the purported emergency. Similarly, the Department's regulations require applicants to describe their efforts made to obtain additional power through third parties.[130] But again, the Department failed to consider whether MISO could alleviate the purported emergency through access to external resources.

D. The Department's Direction that MISO Operate J.H. Campbell Using "Economic" Dispatch Is Inconsistent with its Authority under Section 202(c).

The Department's Order directs MISO to "take every step to employ economic dispatch of the Campbell Plant."[131] The Order indicates that the use of economic dispatch is intended to "minimize cost to ratepayers."[132] However, this mandate to MISO exceeds the authority provided by section 202(c). Nor is the use of economic dispatch likely to serve the public interest.

The Order does not define "economic dispatch" or specify how it intends MISO to dispatch the units. In the Energy Policy Act of 2005, Congress adopted a definition of "economic dispatch" that generally conforms to accepted use: "the operation of generation facilities to produce energy at the lowest cost to reliably serve consumers, recognizing any operational limits of generation and transmission facilities."[133] Drawing on this statutory definition, FERC issued a 2006 report, *Security Constrained Economic Dispatch: Definitions, Practices, Issues, and Recommendations,* that provides a useful explanation of the 2-step process that

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[130] 10 C.F.R. § 205.373(h).

[131] Order at 2 (Ordering Paragraph A)

[132] *Id.*

[133] *See* section 1234(b) of the Energy Policy Act of 2005, 42 U.S.C. § 16432(b);

regions have, in practice, adopted to implement economic dispatch.[134] This process includes (1) *day ahead unit commitment*, in which grid operators commit generators to be online in the subsequent 24-hour period, determined based on which generators will be most economic, taking into account each unit's physical operating characteristics, and (2) *unit dispatch*, in which grid operators dispatch committed resources at specified levels, in real-time, determined based on what set of units will minimize total system costs, given actual load, generation, and transmission conditions and constraints.[135]

Section 202(c) authorizes DOE to direct certain actions during emergency conditions. As relevant here, section 202(c)(1) provides DOE with "authority . . . to require by order . . . such generation . . . of electric energy as in its judgment will *best meet the emergency* and serve the public interest." In other words, DOE's power extends only to ordering actions that meet the emergency that the Department has identified.

But economic dispatch is not a rational response to the types of emergencies that section 202(c) authorizes DOE to address. Nor would economic dispatch be a rational approach to addressing the circumstance that DOE is purporting to address with its order—a potential capacity shortfall—if that were within its authority under section 202(c). In fact, DOE has made no effort to explain why economic dispatch is a rational remedy here, — let alone the best means of meeting the "emergency" that it

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[134] FERC, *Security Constrained Economic Dispatch: Definitions, Practices, Issues, and Recommendations* (July 31, 2006), https://www.ferc.gov/sites/default/files/2020-05/final-cong-rpt.pdf.
[135] *Id.* at 5-6.

has identified. And, unlike prior Orders, here DOE acted on its own motion without a request or input of MISO and so cannot rely on the expertise of the cognizant grid operator or operating utility requesting a specific remedy to justify the appropriateness of economic dispatch.[136]

i. Economic dispatch is not a rational response to a shortage of electric energy

Economic dispatch is the standard procedure by which operators (such as MISO) operate the grid. However, outside of normal operations, including during emergency conditions, generation units may be selected "out of merit order" as necessary to ensure that generation and load are balanced. Operating a unit pursuant to economic dispatch is, necessarily, inconsistent with operating the unit in a manner designed to address an emergency, such as a shortage of electric energy. If a unit would be dispatched under purely economic conditions, but electric demand can alternatively be met with other existing supply (or demand response) resources, that unit is *not* necessary to meet the emergency. However, if the unit would, in fact, be needed to address a shortage, it should be dispatched regardless of whether its offer price is above or below the market-clearing price. In other words, economic dispatch is not a dispatch rule that is reasonably tailored to ensure that the unit addresses a shortage of electric energy.

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[136] *See* DOE Order No. 202-18-1 at 4 (The statute requires only that the Secretary use his or her best judgment to meet the emergency and serve the public interest. In this situation, the expertise of the applicant was an important factor. The Department received an application from PJM, which . . . holds the highest-level, federally-regulated reliability responsibilities for the system it manages.), https://www.energy.gov/sites/prod/files/2017/11/f46/Summary%20of%20Findings%20Order%20No.%20202-18-1.pdf.

Prior DOE orders have contained significant operating constraints to satisfy this statutory requirement. Orders have specified that units subject to a section 202(c) order should only run in specific emergency alert conditions — specific conditions in which grid operators have exhausted the capacity of other available generators, imports, and voluntary demand response, and failure to call on additional generation will risk involuntary load shed.[137] Similarly, in its order to delay retirement of the Yorktown plant, DOE recognized that dispatch of the units must be constrained, that continued operation of the units under the standard methodologies used by the local utility (Dominion Energy Virginia) and grid operator (PJM) would not be appropriate, and that Dominion and PJM must exhaust available resources, including demand response and behind-the-meter generation resources, prior to operating Yorktown Units 1 or 2.[138] Similarly, in the case of its 2005 District of Columbia Department of Public Service order, the Department directed Mirant to maintain its facility's capacity to respond when needed, but only ordered it to run when one or both of the 230 kV transmission lines serving downtown D.C. were out of service.[139] And in its 2017 order regarding GRDA's Grand River Energy Center

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[137] DOE Order No. 202-21-1 (authorizing operation only during Energy Emergency Alert Level 2 or Level 3); DOE Order No. 202-21-2 (authorizing operation only during Energy Emergency Alert Level 2 or higher); DOE Order 202-22-1 (same); DOE Order No. 202-22-3 (same); DOE Order No. 202-22-4 (same).

[138] DOE Order No. 202-17-2 (providing that Yorktown units 1 and 2 may be dispatched "only when called upon to address reliability needs" and directing PJM and Dominion Energy Virginia "to provide the dispatch methodology to the Department upon implementation, and to report all dates on which Yorktown Units 1 and 2 are operated"); DOE Order No. 202-18-1 at 3 (relying on the fact that DOE "require[d] PJM and Dominion to exhaust available resources, including demand response and behind-the-meter generation resources, prior to operating Yorktown Units 1 or 2").

[139] DOE Order No. 202-05-3 (Dec. 20, 2005), District of Columbia Public Service Commission at 10 – 11.

Unit 1, the Department strictly limited its remedy, directing GRDA only to provide "dynamic reactive power support and not real power generation, and only when called upon by SPP for reliability purposes."[140] DOE's Order contains no such constraints, and it fails to explain or justify such deviation from consistent past practice.

ii. Economic dispatch is an arbitrary response to any alleged capacity shortage

Indeed, even on DOE's own terms, the justification for the Order does not support ordering J.H. Campbell to operate whenever MISO's economic dispatch rules would select it to operate. The Order points specifically to questions about the sufficiency of electric *capacity* and the ability of MISO to meet load during periods of high demand and low resource output over the next 90 days as the basis for its emergency determination.[141] For example, the Order points to NERC's 2025 Summer Reliability Assessment, and specifically to the finding that "MISO is at elevated risk of operating reserve shortfalls *during periods of high demand and low resource output*."[142] The order repeatedly raises concern about the risk of "*capacity* shortfall for MISO," the extent to which *capacity* of certain generating resources have retired or may retire, and that MISOs' *capacity* market auction (the Planning Resource Auction Results for Planning Year 2025-26) "reinforce the need to increase *capacity*."[143] Dispatch of J.H. Campbell at any time other than a specifically identified operating reserve shortfall (e.g., a concrete expected supply/demand imbalance)—let

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[140] DOE Order No. 202-17-1 at 2.

[141] Order at 1-2

[142] Order at 1 (emphasis added).

[143] Order at 1-2.

alone dispatch whenever the plant would be called upon by MISO's economic dispatch algorithm—is *not* necessary to address the type of emergency that the DOE order identifies. Even if the order sufficiently justified retention of J.H. Campbell as a capacity resource (which it does not for the reasons outlined above), it would not follow that J.H. Campbell's electric *energy* is needed to address the identified emergency. Given the nature of the alleged emergency identified in the Order, no dispatch from J.H. Campbell should be necessary unless and until called upon by MISO expressly to address an emergency purpose.

iii. "Economic dispatch" is not in the public interest in this case

Section 202(c) also requires that DOE determine that a given remedy is in the public interest.[144] The public interest determination is not an independent or sufficient criteria to order any particular action. Rather, Congress's use of the conjunctive "and" in section 202(c)(1) clearly prohibits DOE from ordering actions that the Department believes will advance the public interest if those actions exceed what is needed to address the identified emergency. In fact, DOE acknowledged this limit on its authority in its order denying rehearing of its order directing the retention of the Yorktown power plant.[145] Therefore, for the reasons explained above, economic dispatch is not appropriate even *if* DOE determines that it would advance the public interest.

However, DOE's vague direction to MISO to operate Campbell using "economic dispatch" will not further the public interest. DOE's order does not explain why it

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[144] 16 USC § 824a (c)(1).

[145] DOE Order 202-18-1 at 4.

believes economic dispatch would be in the public interest, other than a general reference to “minimize[ing] cost to ratepayers.” However, this justification fails for two reasons. First, the Order’s reference to economic dispatch is ambiguous and leaves open the likelihood that Consumers will operate the facility even at times when its operation will have the effect of *increasing* costs to consumers. For example, Consumers is likely to commit J.H. Campbell into MISO’s day ahead electricity market as a “must run” unit, rather than using Emergency commitment.[146] In other words, Consumers will operate the units at least at minimum load every day rather than when there is a forecasted shortfall (e.g., due to unexpected load, unit outage, or a natural disaster). In such circumstances, J.H. Campbell will run at its minimum operational level regardless of whether doing so is truly economic. As a result, DOE has not justified, and cannot be reasonably certain, that economic dispatch will “minimize cost to ratepayers” — its sole explanation for the operational profile it has directed MISO to adopt. In other words, DOE’s ordering of economic dispatch in this case is arbitrary.

Moreover, by directing economic dispatch, rather than reserving J.H. Campbell for discrete supply shortages by committing it as Emergency status, DOE’s order will result in the facility operating significantly more than necessary. Because J.H. Campbell is old, and because Consumers has been deferring maintenance in anticipation of its retirement, a significant step-up in operation caused by must-run commitment and economic dispatch will increase the likelihood that one or more

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[146] *See* MISO Tariff, Section 39.2.5.b.xxvi (discussing Emergency Commitment Status).

units break, requiring costly maintenance to continue operating. Such repairs would likely further increase costs to ratepayers—costs that would be less likely to occur under an operational order better tailored to the emergency that DOE has identified. For example, DOE could have minimized the risk of ratepayer costs had it directed Consumers and MISO to commit (and ultimately dispatch) the facility only after analysis showing a likely near-term supply/demand imbalance or short-term emergency conditions (such as a heatwave, or the forced outage of a large generator or transmission line). The Order is arbitrary and capricious by ordering operation that risks increasing costs to ratepayers, the very outcome DOE has said it is looking to avoid.

Second, the Order fails to consider, let alone explain away, the fact that the State of Michigan has made an independent judgment that it would be in the best interest of ratepayers, the state, and the environment, to accept Consumers' proposal to retire J.H. Campbell. As explained above, the State of Michigan and MISO each went through robust processes to assess the need for J.H. Campbell (or lack thereof), as well as the economic and environmental impacts of its continued operation. The State of Michigan appears not to have been consulted on DOE's Order, notwithstanding the extensive process that it underwent to evaluate whether retirement would be in the public interest. Here, the public interest is best effectuated by respecting the Michigan's considered decision to approve the closure of J.H. Campbell plant, rather than to allow its near continuous operation at ratepayer expense.

Finally, for the reasons explained more fully below, the Order fails to consider the increased air and water pollution that will be caused by J.H. Campbell operating pursuant to economic dispatch instructions. DOE fails to even consider these harms, let alone weigh them against the (alleged) benefits of increased operation, in its determination that economic dispatch of the J.H. Campbell plant will further the public interest.

E. The Department failed to limit its remedy as required by 202(c)(2).

Section 202(c) imposes strict substantive limits on the Department's authority to issue emergency orders that may result in conflicts with any Federal, State, or local environmental law or regulation. Congress deliberately included these limitations to prevent section 202(c) from becoming a de facto exemption from environmental regulation. Here, DOE failed to comply with either of the statute's two express constraints and therefore acted unlawfully.

i. Section 202(c)(2) contains two distinct and binding legal constraints

Congress imposed two critical limitations on the scope of a DOE emergency order under section 202(c):

Temporal Constraint. First, DOE must "ensure that such order requires generation . . . of electric energy only during hours necessary to meet the emergency and serve the public interest."[147] Again, this is a conjunctive requirement such that both conditions—operation in a given hour must be necessary to meet the emergency

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[147] 16 U.S.C. § 824a(c)(2).

and operation in a given hour must serve the public interest—must be satisfied.[148] Moreover, by referring to the "hours" necessary to meet the emergency, Congress placed a high burden on DOE to demonstrate that the remedy provided was narrowly tailored to the specifics of the emergency that the order is designed to address.

Environmental Constraint. Second, the Department must "ensure that such order . . ., to the maximum extent practicable, is consistent with any applicable Federal, State, or local environmental law or regulation and minimizes any adverse environmental impacts."[149]

The Department acknowledges that, "additional generation may result in a conflict with environmental standards and requirements" and so it is required to limit additional generation from J.H. Campbell. However, the Order then wholly fails to meet the acknowledged temporal and environmental constraints in the particular ordering conditions that it establishes.

ii. The Order violates Section 202(c)(2)'s temporal constraint

The Order states that its direction to Campbell is "limited in duration to align with the emergency circumstances."[150] But, in fact, DOE has directed the unit to operate for the entire statutory maximum of 90 days. And, as described in more detail *supra,* within that 90-day window, DOE has directed the use of "economic dispatch"—an operational direction that will likely result in Campbell operating at least at its

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[148] DOE Order No. 202-18-1, 4(Nov. 6, 2017).
[149] 16 U.S.C. § 824a(c)(2).
[150] Order at 2.

minimum output level, and more likely at the maximum output Consumers Energy can manage, taking into account the state of the facility, continuously for the 90-day period—without providing any other temporal limitation on operations. In other words, the Order appears to assume, without explanation, that an emergency will exist in every hour over the entire 90-day period of the Order that Consumers happens to submit a bid into MISO's energy auction that is lower than the market-clearing price.[151] There is no reason to expect that this will actually be the case.

For these and all the reasons explained in section IV.C, the Order's direction that MISO dispatch J.H. Campbell economically is flatly inconsistent with section 202(c)'s requirement that emergency orders be limited to "only" those "hours" in which operation is necessary to meet the emergency. DOE cannot transform an hour-by-hour limitation into a blanket summer-season waiver through hand-waving at "elevated risk" of tight operating reserves and "*potential* electricity shortfalls."

DOE's failure to limit dispatch to discrete periods when the generation is needed to address the purported emergency renders the Order unlawful under the plain terms of § 202(c).

iii. The Order violates section 202(c)(2)'s environmental constraint

Section 202(c)(2) also requires DOE to ensure, "to the maximum extent practicable," that its orders (1) are consistent with applicable environmental laws and

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[151] In fact, it is not clear that DOE will limit operation to 90 days. DOE is authorized to extend the Order beyond 90 days under section 202(c), 16 U.S.C. § 824a(c)(4)(A), and has made no representation that the "emergency" is likely to be resolved by the end of the 90-day period.

regulations and (2) "minimize any adverse environmental impacts." The Department makes no serious effort to comply with this mandate.

First, the Order contains no analysis of J.H. Campbell's environmental obligations. J.H. Campbell is subject to air pollution requirements limiting its emissions of SO_2, NO_x, particulate matter, and mercury, and mandates the use of pollution control equipment such as baghouses, dry sorbent injection, and activated carbon injection systems.[152] DOE does not reference these requirements, direct Consumers to optimize the use of pollution controls or avoid operation during air quality episodes (even if those episodes occur at a time when the marginal energy from J.H. Campbell is not needed to meet electric demand), or provide any guidance for how Consumers is to operate the facility in the event that these requirements would come in conflict with its ability to provide power at any given time. It does not clarify what steps Consumers Energy would have to take to ensure continued operation of pollution control equipment in the event such equipment malfunctioned during the 90-day period. Nor does it appear the Department consulted with the State of Michigan, including its environmental regulator, to identify mechanisms to allow J.H. Campbell to remain available in a way that would minimize conflicts with state environmental laws, which the State was uniquely positioned to advise on and which

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[152] *See* Michigan Department of Environment, Great Lakes, and Energy, Renewable Operating Permit Issued to Consumers Energy, J.H. Campbell Generating Complex [J.H. Campbell ROP] (July 2, 2021), accessible through the Michigan Department of Environment, Great Lakes, and Energy's "MiEnviro Portal," https://www.michigan.gov/egle/maps-data/mienviroportal, and also accessible at https://www.egle.state.mi.us/aps/downloads/rop/pub_ntce/B2835/B2835%20FINAL%2007-01-21.pdf.

is required by section 103 of the Department of Energy Organization Act.[153] Instead, the Order offers only generic language about "compliance with applicable requirements… to the maximum extent feasible."

Second, the Order does not establish any operational criteria to "minimize any adverse environmental impacts" as required by section 202(c)(2). This requirement is in addition to the direction to minimize conflicts between operations and environmental requirements. It makes clear that Congress intended DOE to go beyond just avoiding regulatory conflicts but to proactively consider the environmental impact of its emergency orders. But DOE did not design its order to minimize environmental impacts of continued operation of J.H. Campbell. In fact, DOE's order runs directly contrary to the objective of minimizing environmental impacts by expressly directing MISO to operate J.H. Campbell on an "economic dispatch" basis. That instruction prioritizes low-cost dispatch irrespective of environmental impact.

F. The Order Violates NEPA.

Orders issued under section 202(c) are major federal actions subject to NEPA.[154] Such orders direct federal interventions that may affect environmental conditions. The direction to continue operation of J.H. Campbell is unquestionably a major action that significantly affects the environment. Continued operation of J.H. Campbell will result in significant increases of air and water pollution compared to a

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[153] *See* 42 U.S.C. § 7113.

[154] 42 U.S.C. § 4336e(10) (defining a "major federal action" as one in which the agency carrying out such action determines subject to substantial Federal control and responsibility.").

scenario in which Campbell retired as planned.[155] In fact, the Order directly concedes this point, stating "the additional generation may result in a conflict with environmental standards and requirements."[156]

For any DOE action affecting the quality of the environment, DOE must comply with NEPA—including through issuance of an environmental impact statement, environmental assessment, categorical exclusion, or special environmental analysis.[157] DOE has not taken, or even initiated, any such action. As such, it is acting contrary to its own NEPA regulations and to its obligations under NEPA.

DOE has previously sought to comply with NEPA for section 202(c) orders through categorical exclusions or special environmental assessments. Neither have been undertaken in this instance. Moreover, neither would be applicable here.

DOE has previously pointed to categorical exclusion B4.4 for "power management activities." However, that categorical exclusion is applicable only "provided that the operations of generating projects would remain within normal operating limits." Here, the Order explicitly authorizes the J.H. Campbell plant to operate beyond its normal permitted limits. Consequently, neither categorical exclusion B4.4, nor any other available exclusion, applies.

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[155] *See* J.H. Campbell ROP, *supra* n. 152; State of Michigan Department of Environmental Quality, Authorization to Discharge Under the National Pollutant Discharge Elimination System, Permit No. MI0001422 (May 29, 2018), accessible through the Michigan Department of Environment, Great Lakes, and Energy's "MiEnviro Portal," https://www.michigan.gov/egle/maps-data/mienviroportal.

[156] Order at 2.

[157] *See* 10 C.F.R. § 1021.102(b).

More recently, DOE has, on certain occasions, relied on emergency provisions that can excuse agencies from preparing environmental documents before taking such actions,[158] and instead prepared after-the-fact Special Environmental Analyses in the event that an order results in a significant effect on the environment.[159] However, these instances involved sudden emergencies that provided DOE substantially less notice compared to the months or years of advance warning DOE received regarding J.H Campbell's scheduled retirement. In this case, DOE acted in response to circumstances known well in advance: the long-scheduled retirement of J.H. Campbell on May 31, 2025. Given considerable lead time, DOE had ample opportunity to prepare, at a minimum, an EA prior to issuing its Order. DOE's failure to initiate any environmental review thus lacks justification.

Moreover, there will be even less justification for a failure to initiate appropriate environmental review for any extension of the Order beyond the initial 90 days. Under section 202(c)(3), orders conflicting with environmental laws are strictly limited to 90 days but may be extended. However, such extension requires consultation with other federal agencies responsible for regulating or with expertise in such environmental impacts.[160] Any justification that NEPA can be sidestepped to

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[158] *See* 10 C.F.R. § 1021.343(a); 40 C.F.R. § 1506.12.

[159] *See* DOE, Air Quality and Environmental Justice Memorandum (2021), https://www.energy.gov/sites/default/files/2022-01/sea-05-ercot-air-quality-and-ej-analysis-2021-07-21.pdf; DOE, Special Environmental Analysis for Actions Taken Under U.S Department of Energy Emergency Orders Regarding Operation of the Potomac River Generating Station in Alexandria Virginia (2006), https://www.energy.gov/sites/default/files/nepapub/nepa_documents/RedDont/SEA-04-2006.pdf

[160] 16 U.S.C. § 824a(c)(4)(B).

address an emergency need fades as DOE's orders extend beyond the initial 90-day period.

V. CONCLUSION

For the foregoing reasons, the Michigan Attorney General's request for rehearing should be granted.

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Dated: June 18, 2025

Attachment A

2025 NERC 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

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[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.

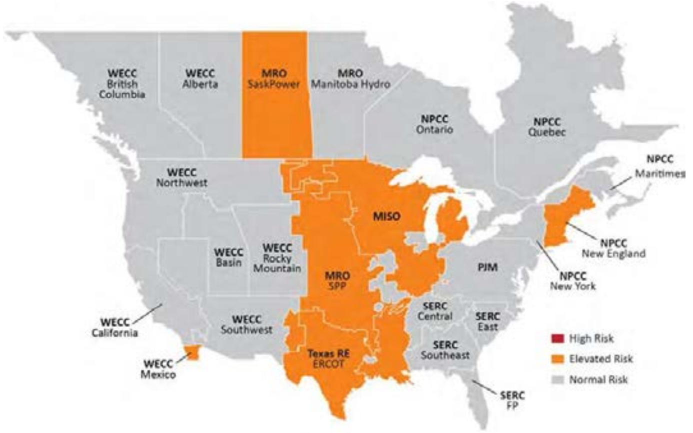

Figure 1: Summer Reliability Risk Area Summary

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.

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[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.

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[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.

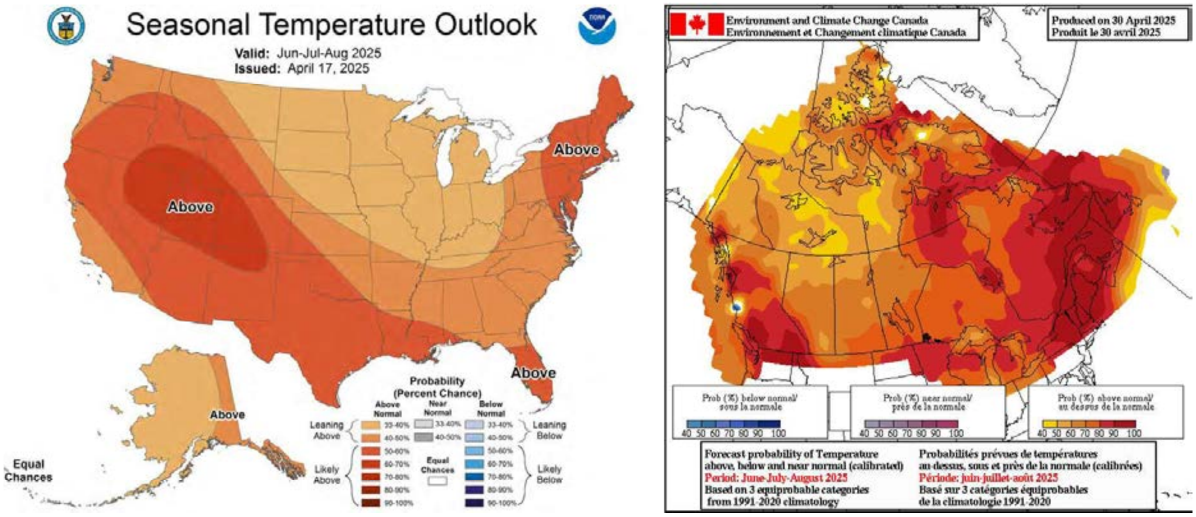

Figure 2: United States and Canada Summer Temperature Outlook[10]

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[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	- 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]
Potential for insufficient operating reserves in normal peak conditions	
Elevated	- 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]
Potential for insufficient operating reserves in above-normal conditions	
Normal	- 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]
Sufficient operating reserves expected	

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.

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[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

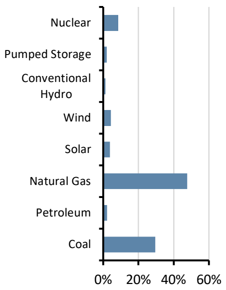
- Demand forecasts and resource data indicate that MISO is at elevated risk of operating reserve shortfalls during periods of high demand or low resource output.
- The performance of wind and solar generators during periods of high electricity demand is a key factor in determining whether system operators 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.

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 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 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

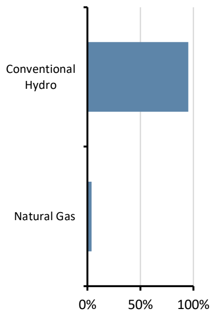
- Manitoba Hydro is not anticipating any operational challenges and/or emerging reliability issues in its assessment area for Summer 2025; the Anticipated Reserve Margin for Summer 2025 exceeds the 12% Reference Margin Level.
- While Manitoba Hydro experienced demand growth in the past year, the growth 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

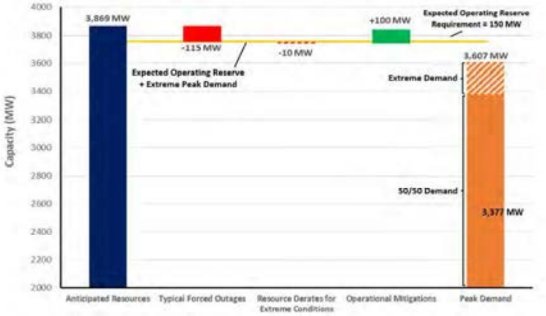
Expected resources meet operating reserve requirements under the assessed scenarios.

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

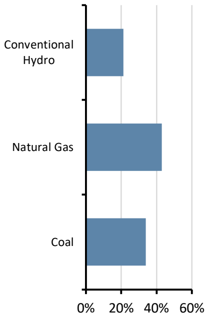
- Although Saskatchewan is mainly a winter-peaking region, summer can also bring high electricity demand due to extreme heat.
- Each year, SaskPower works with Manitoba Hydro on a joint summer operating study with input from the Western Area Power Administration and Basin Electric to develop operational 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

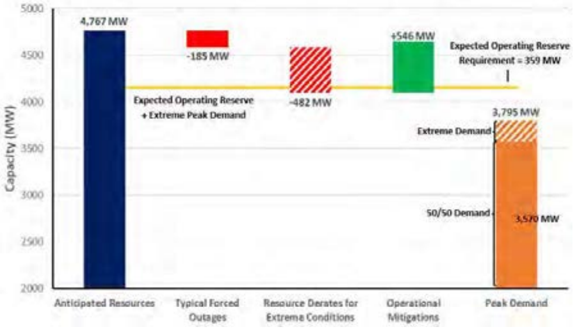
Risk Scenario Summary

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

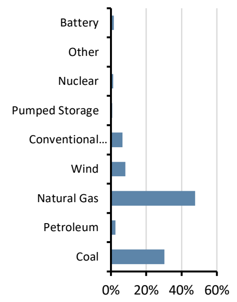
- SPP projects a low likelihood of any emerging reliability issues impacting the area for the 2025 Summer season.
- Generation availability is not expected to be impacted by fuel shortages or river conditions this summer.
- BA generation capacity deficiency risks remain depending on wind generation output 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

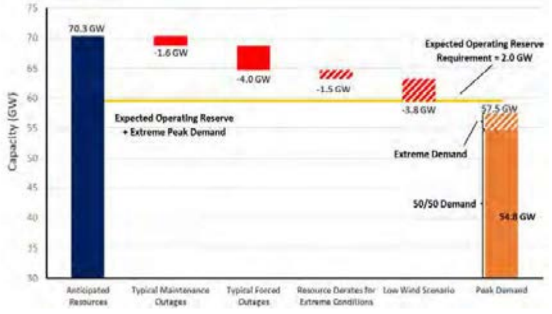
Expected resources are sufficient to meet operating reserve requirements under normal peak-demand and outage scenarios. Above-normal summer peak load, low wind conditions, and higher-than-normal forced outages could result in the need for operating mitigations (e.g., demand response and transfers from 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

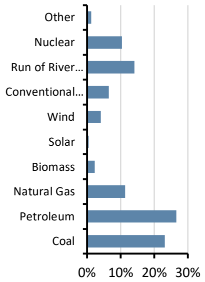
- As Maritimes is a winter-peaking system, no issues are expected for the upcoming summer assessment period with sufficient firm capacity to meet forecast peak demand. If an event were to occur, emergency operations and planning procedures are in place.
- Probabilistic analysis performed by NPCC for 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

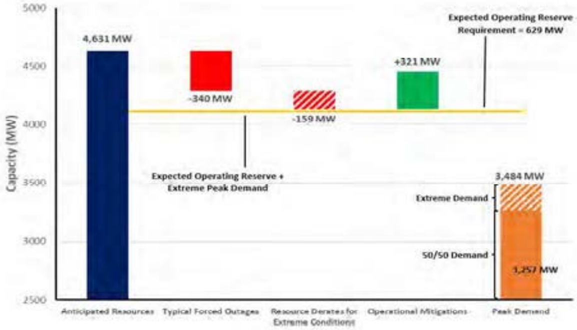
Risk Scenario Summary

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

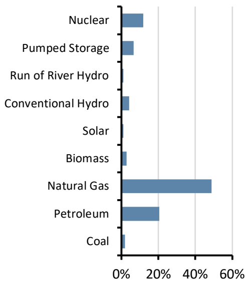
- ISO-NE forecasts adequate transmission capability and manageable capacity margins to meet the expected peak demand.
- Probabilistic analysis performed by NPCC for the NPCC *Summer Reliability Assessment* identified small amounts of cumulative LOLE, LOLH, and EUE for the expected load with anticipated 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

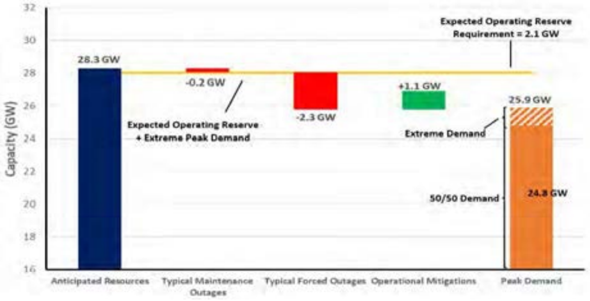
Risk Scenario Summary

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

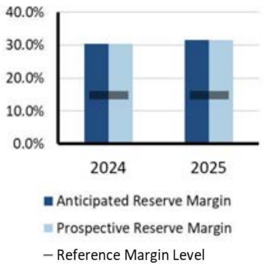
NPCC-New York

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.

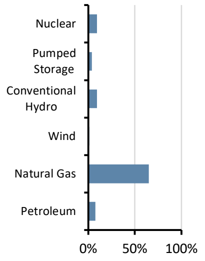
On-Peak Reserve Margin



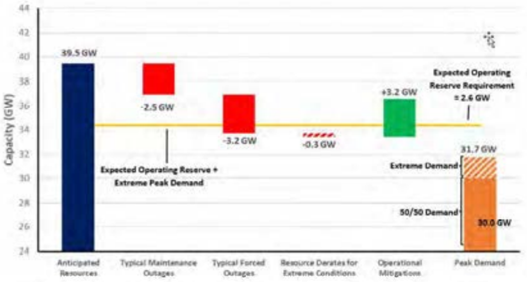
Risk Scenario Summary

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

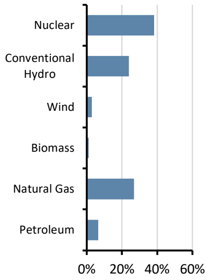
- Overall, Ontario is operating within a period where generation and transmission outages are more challenging to accommodate. The IESO is prepared and expects to have adequate supply for Summer 2025.
- The IESO has been actively coordinating and planning with market participants to maintain reliability.
- 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

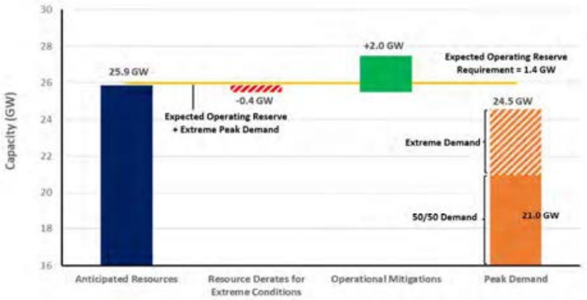
Risk Scenario Summary

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

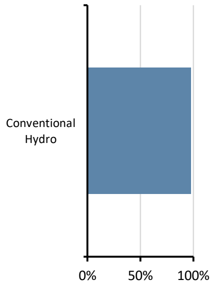
- The Québec area forecasted summer peak demand is 23,283 MW during the week beginning August 3, 2025, with a forecasted net margin of 5,698 MW (24.5%).
- Resource adequacy issues are not expected this summer.
- The Québec area expects to be able to assist other areas.
- Modeling was made more precise 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.

On-Peak Reserve Margin

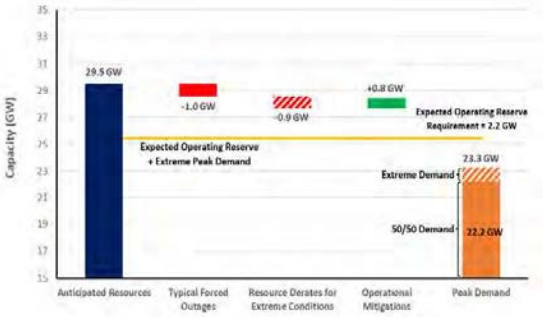
Risk Scenario Summary

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 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.

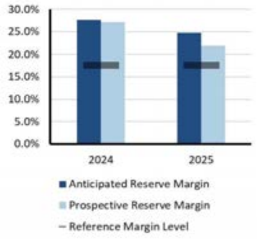
PJM

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.

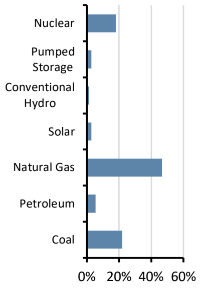
On-Peak Reserve Margin



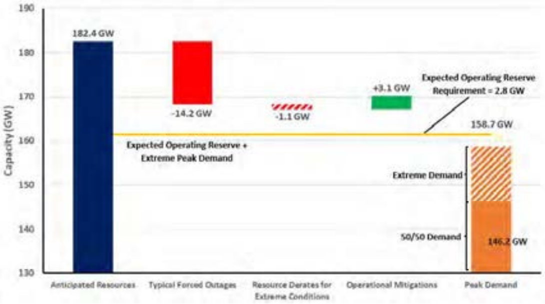
Risk Scenario Summary

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 (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

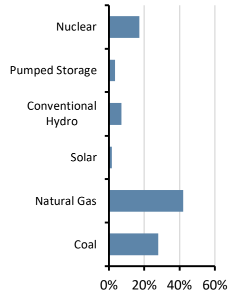
- SERC-Central saw a sizable increase in its reserves last summer, but coal retirements this summer will result in SERC-Central having lower reserves.
- SERC-Central's anticipated resources meet operating reserve requirements under the expected conditions and under the summer risk period scenario.
- 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

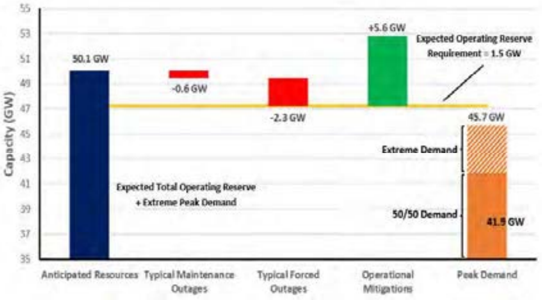
Risk Scenario Summary

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

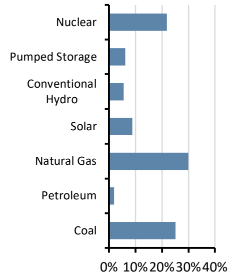
- SERC-East's reserves are largely unchanged compared to the reference margin as compared to last summer's assessment.
- SERC-East's anticipated resources meet operating reserve requirements under the expected conditions and under the summer risk period scenario.
- While the last probabilistic analysis 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

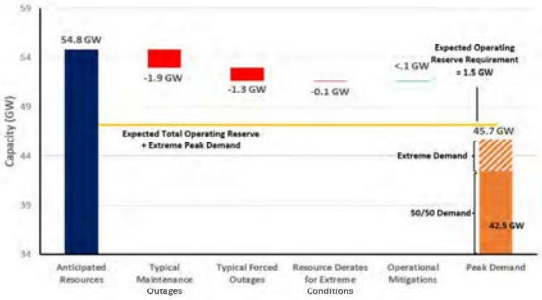
Expected resources meet operating reserve requirements under the assessed scenarios.

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

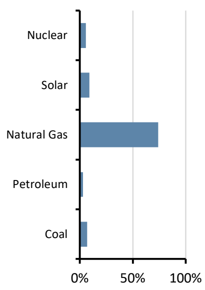
- SERC Florida-Peninsula's anticipated resources meet operating reserve requirements under the expected conditions and under the summer risk period scenario.
- The probabilistic analysis metrics indicate adequate energy resources for the subregion during the summer.
- Members of SERC-Florida Peninsula 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

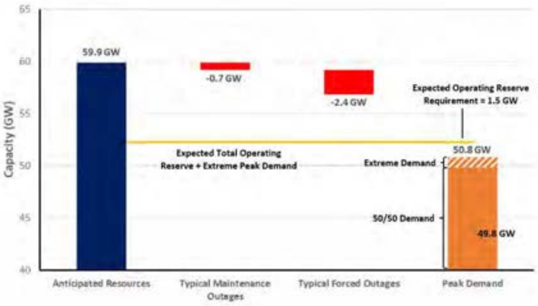
Risk Scenario Summary

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

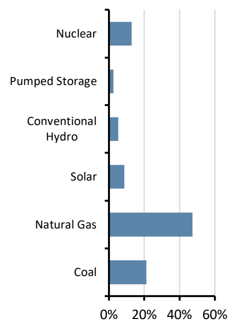
- An area within SERC-Southeast notes that natural gas pipeline constraints could impact reliability in summer, but this is not expected to pose a significant summer operational challenge.
- SERC-Southeast's anticipated resources meet operating reserve requirements under the expected conditions and under 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.

Risk Scenario Summary

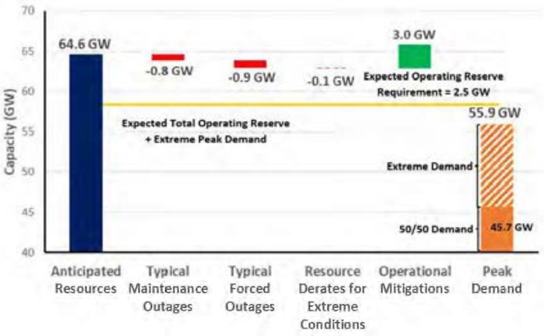
Expected resources meet operating reserve requirements under the assessed scenarios.

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

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

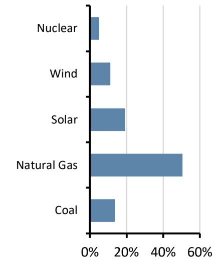
- ERCOT expects to have sufficient operating reserves for the August peak load hour given normal summer system conditions.
- ERCOT's probabilistic risk assessment indicates a low risk of having to declare EEAs during the expected August (and summer) peak load day; the EEA probability for the highest-risk 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.

Risk Scenario Summary

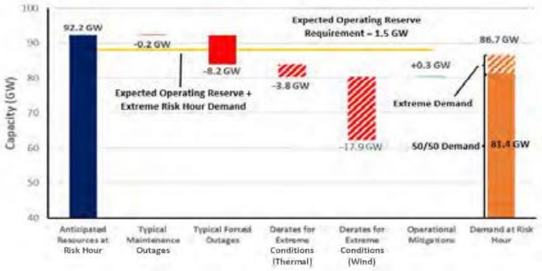
Expected resources meet operating reserve requirements for the peak demand hour scenario. However, there is a risk of supply shortages during evening hours (when solar generation ramps down and demand remains high) if there are conventional generation forced outages or extreme low-wind conditions.

On-Peak Reserve Margin

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

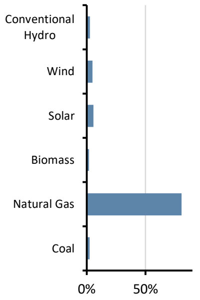
- Anticipated and prospective reserve margins are projected to remain above the Reference Margin Level.
- All resource margins have increased by about 50% since last summer with the addition of 23.2% new capacity, including almost 2,700 MW of new natural gas capacity, 1,200 MW of new wind (+27%), 200 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.

On-Peak Reserve Margin

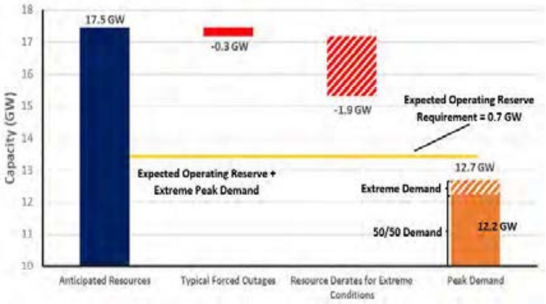
Risk Scenario Summary

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 (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

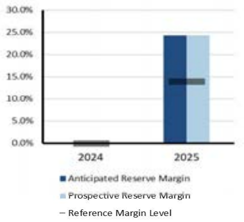
- Total internal expected demand has increased 8% and demand response has increased almost 28% for a net internal demand increase of 7.2%.
- Reserve margins are not anticipated to fall below the reference margin (14%) for the upcoming summer; an early July peak is expected at around 3:00 p.m.
- During 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

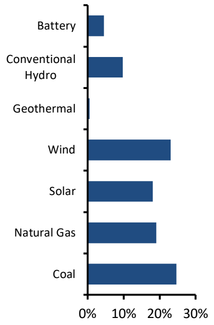
Expected resources meet operating reserve requirements under the assessed scenarios with imports.

On-Peak Reserve Margin

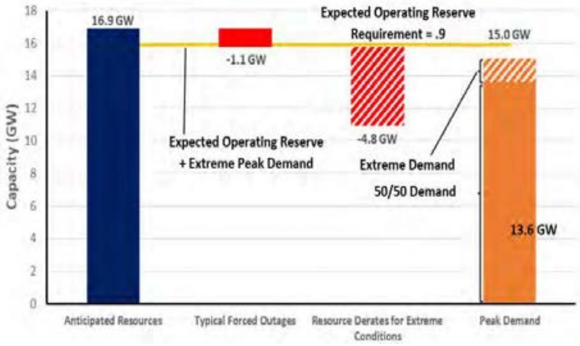
(Note: year comparison not available)



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

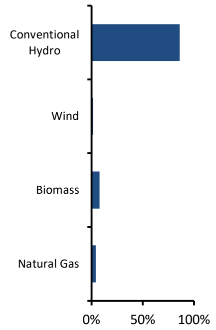
- Existing capacity reserve margin has increased from 19% to 22%, and anticipated and prospective reserve margin from 19% to 24%.
- Reserve margins are not anticipated to fall below the reference margin for the upcoming summer.
- The peak hour is forecast for early August at 4:00 p.m., two hours earlier 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

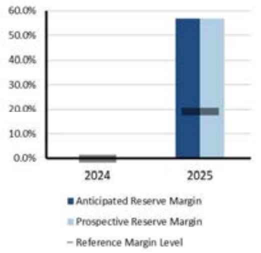
- Demand response is down 8.6% since last summer, existing-certain capacity is up 5.8%, and Tier 1 planned capacity is up 41.2% for a net increase in anticipated resources of 9%; anticipated and prospective reserve margins are up by 11.4%. The peak hour is still forecasted for early September around 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.

Risk Scenario Summary

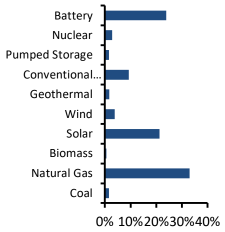
Expected resources meet operating reserve requirements under assessed scenarios, and a probabilistic assessment of normal and extreme resource/demand scenarios reveals neither EUE nor LOLH.

On-Peak Reserve Margin

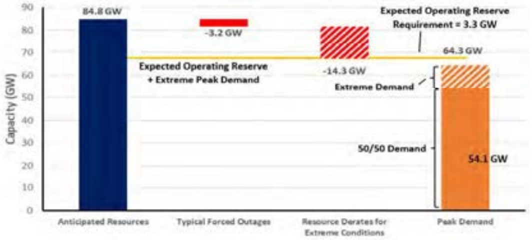
(Note: year comparison not available)



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) 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

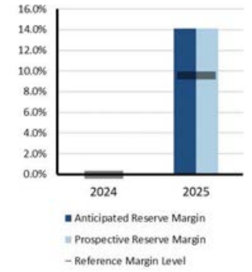
- Total and net internal expected (50/50) demand are up 6.8%, existing-certain capacity is up 29.8% or 989 MW, and Tier 1 planned capacity has fallen 100% to zero, leading to a decrease in the anticipated reserve margin from 22.9% down to 14.1%
- The peak hour is expected to occur in early August around 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

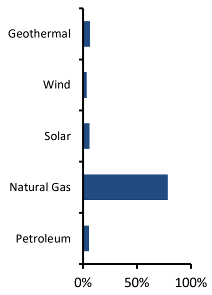
Expected resources at normal peak demand and outage conditions require some imports to maintain operating reserves. Thus, above-normal demand, high forced outage conditions, or transmission derates in the neighboring area could place WECC-Mexico in an energy emergency.

On-Peak Reserve Margin

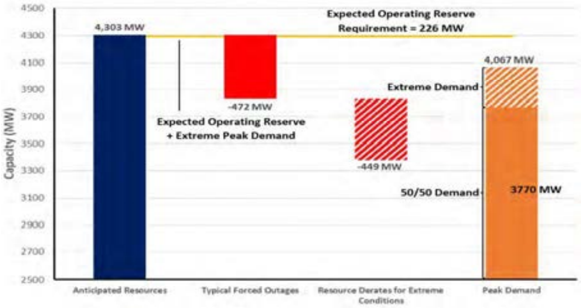
(Note: year comparison not available)



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.

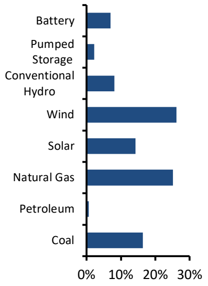
Risk Scenario Summary

Expected resources meet operating reserve requirements under assessed scenarios with imports.

On-Peak Reserve Margin

(Note: year comparison not available)

On-Peak Fuel Mix



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-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.

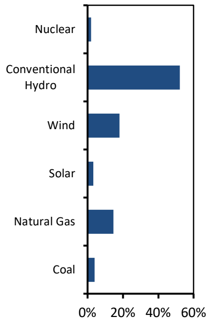
Risk Scenario Summary

Expected resources meet operating reserve requirements under assessed scenarios with imports.

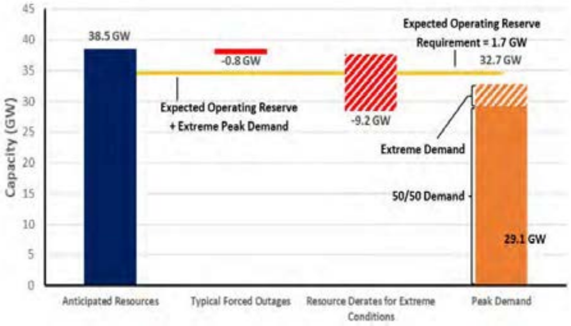
On-Peak Reserve Margin

(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.

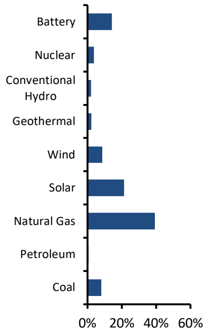
Risk Scenario Summary

Expected resources meet operating reserve requirements under assessed scenarios with imports.

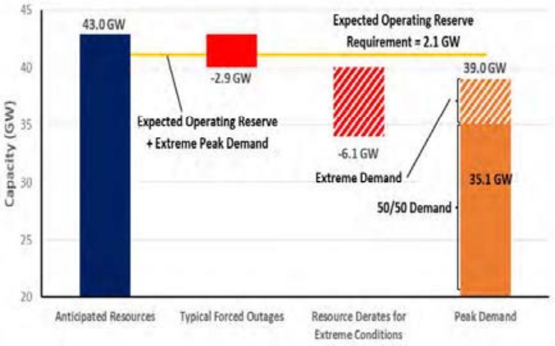
On-Peak Reserve Margin

(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 (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.

<u>Anticipated Resources:</u>

- **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.

<u>Prospective Resources:</u> 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.

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[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**.

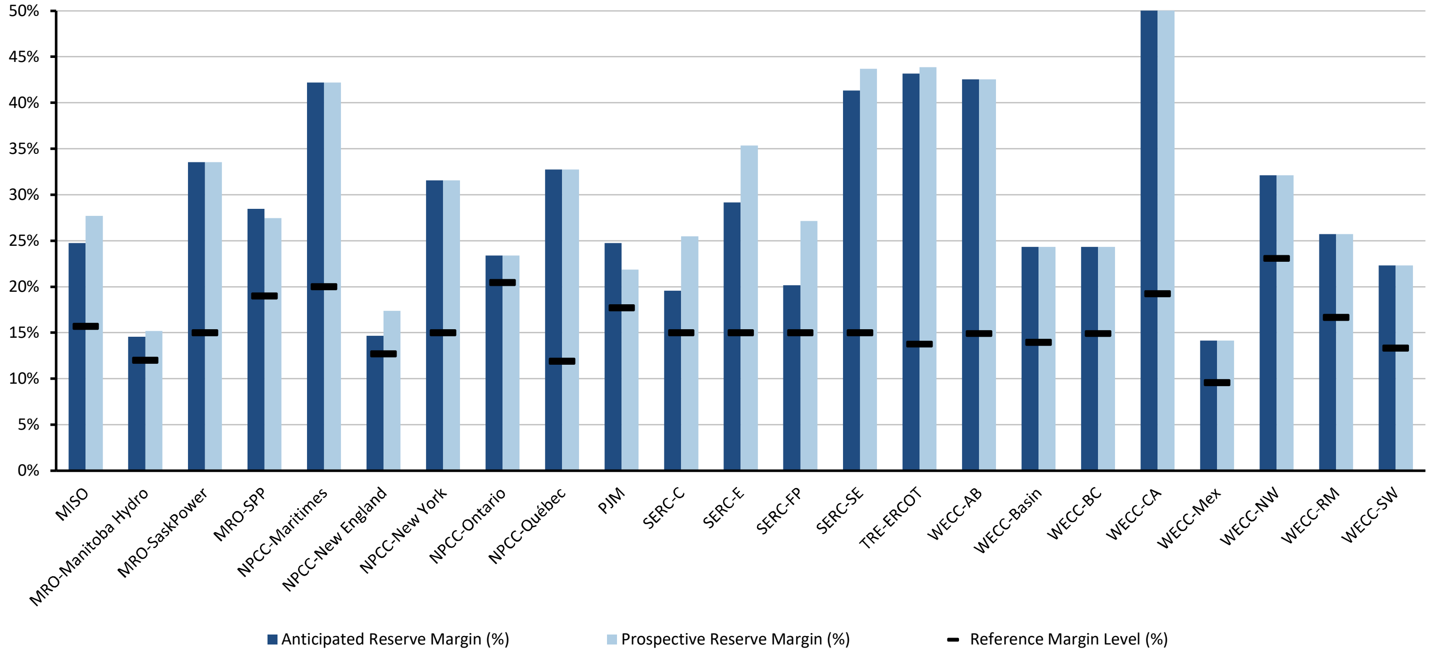

Figure 4: Summer 2025 Anticipated/Prospective Reserve Margins Compared to Reference Margin Level

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[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.

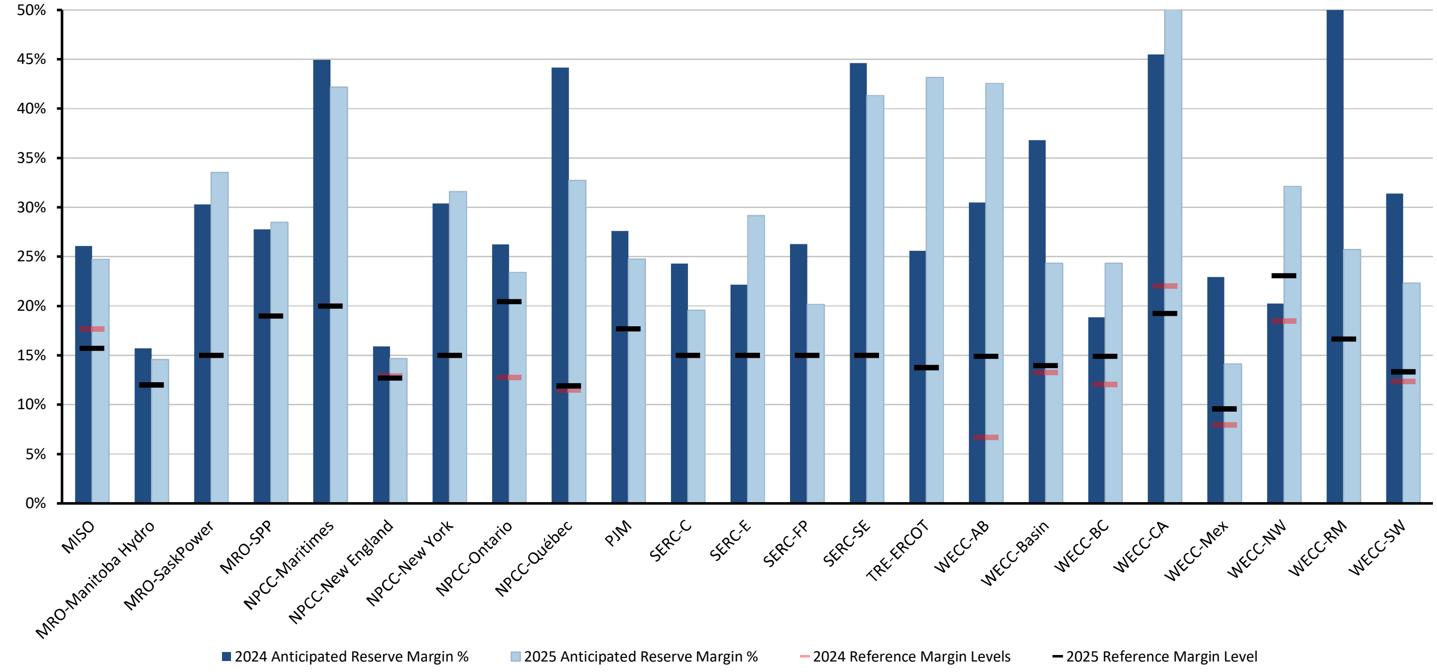

Figure 5: Summer 2024 and Summer 2025 Anticipated Reserve Margins Year-to-Year Change

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.

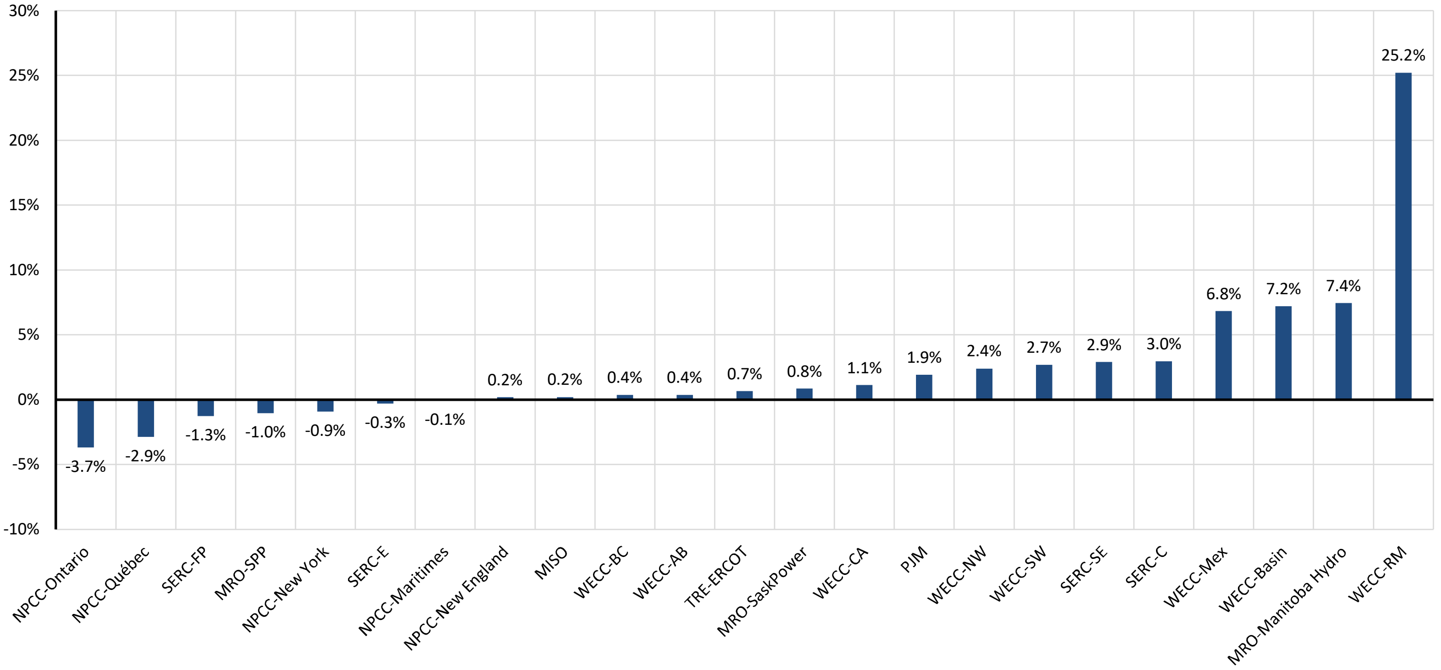

Figure 6: Changes in Net Internal Demand—Summer 2024 Forecast Compared to Summer 2025 Forecast

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[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.

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[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.

Attachment B

MISO 2025 PRA Report

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…

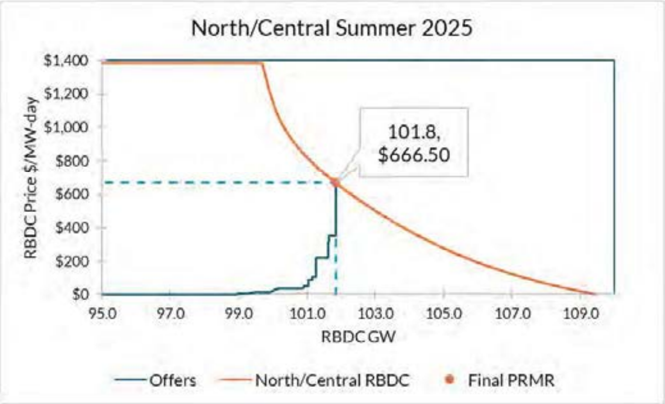
- Delivers competitive prices aligned with seasonal risks and tightening surplus
    - Prioritizes summer availability, the system's highest-risk season (based on 1-in-10 LOLE)
- Values incremental capacity above and below the LOLE target based on its reliability
    - Clears capacity above target Planning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

Why it Matters

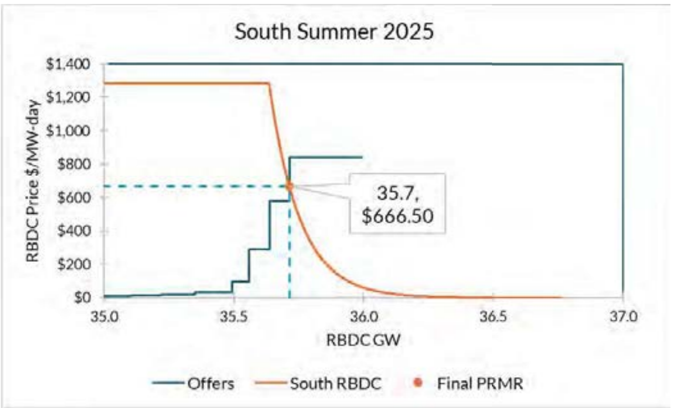
- Sends clear and stable investment signals across the system, including to external resources
- Provides transparent value for capacity that exceeds the Planning Reserve Margin target
- Reflects subregional capacity needs and clears accordingly across all seasons

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



North/Central Summer 2025



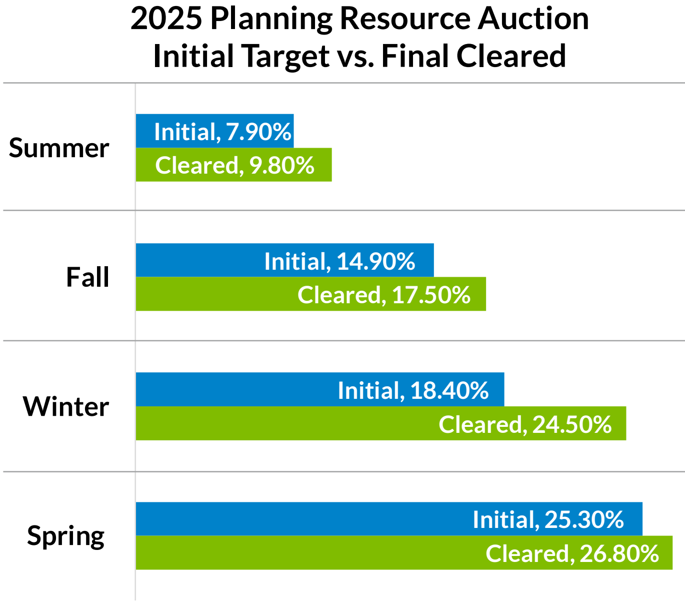
South Summer 2025

- 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



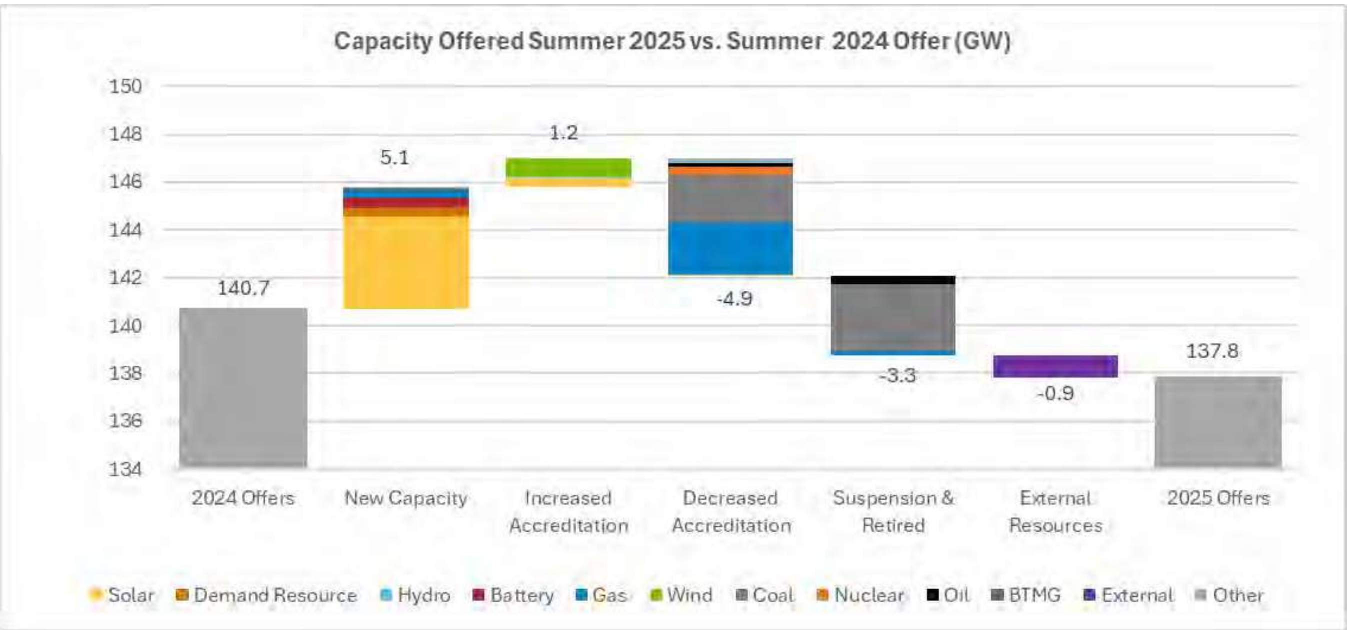
	2025 Planning Resource Auction Initial Target vs. Final Cleared	Additional Reliability	Auction Clearing Price
Summer	Initial, 7.90% Cleared, 9.80%	+1.9%	$666.50
Fall	Initial, 14.90% Cleared, 17.50%	+2.6%	$91.60 N/C $74.09 S
Winter	Initial, 18.40% Cleared, 24.50%	+6.1%	$33.20
Spring	Initial, 25.30% Cleared,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

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

PRM: Planning Reserve Margin

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

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

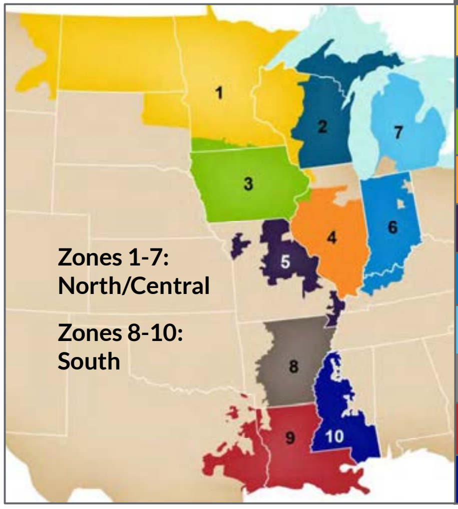
Acronyms

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

2025 PRA Results

MISO Resource Adequacy Zones



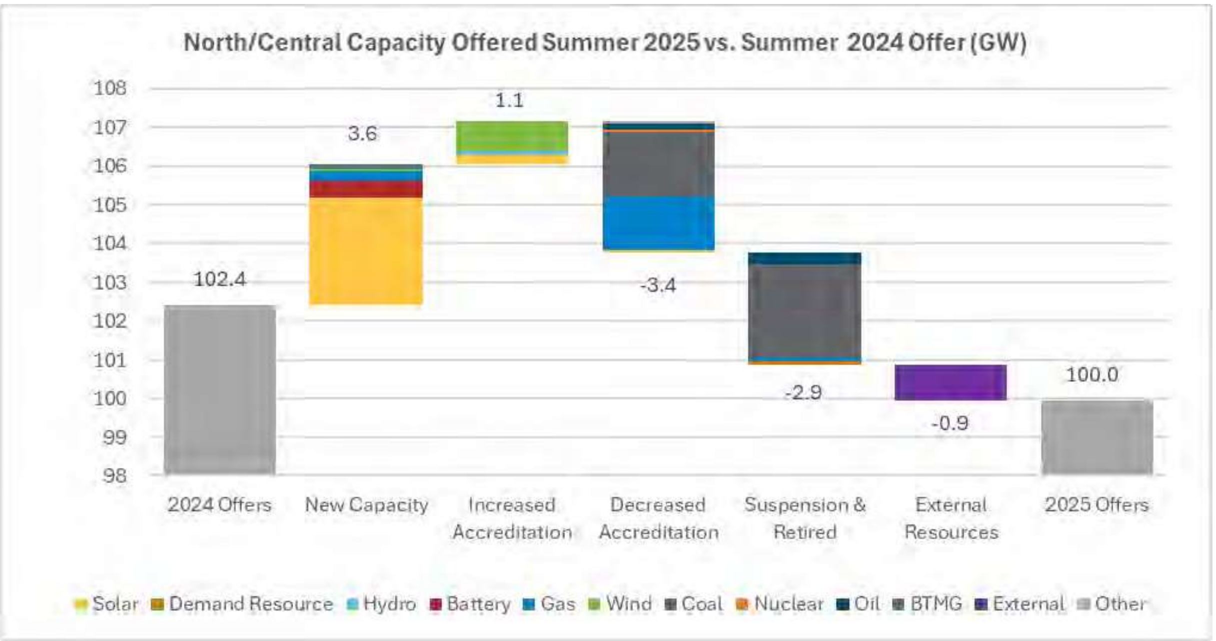
Zones 1-7: North/Central

Zones 8-10: South

	Price/MW-Day			
	Summer	Fall	Winter	Spring
1	**$666.50**	**$91.60**	**$33.20**	**$69.88**
2				
3				
4				
5				
6				
7				
8		**$74.09**		
9				
10				

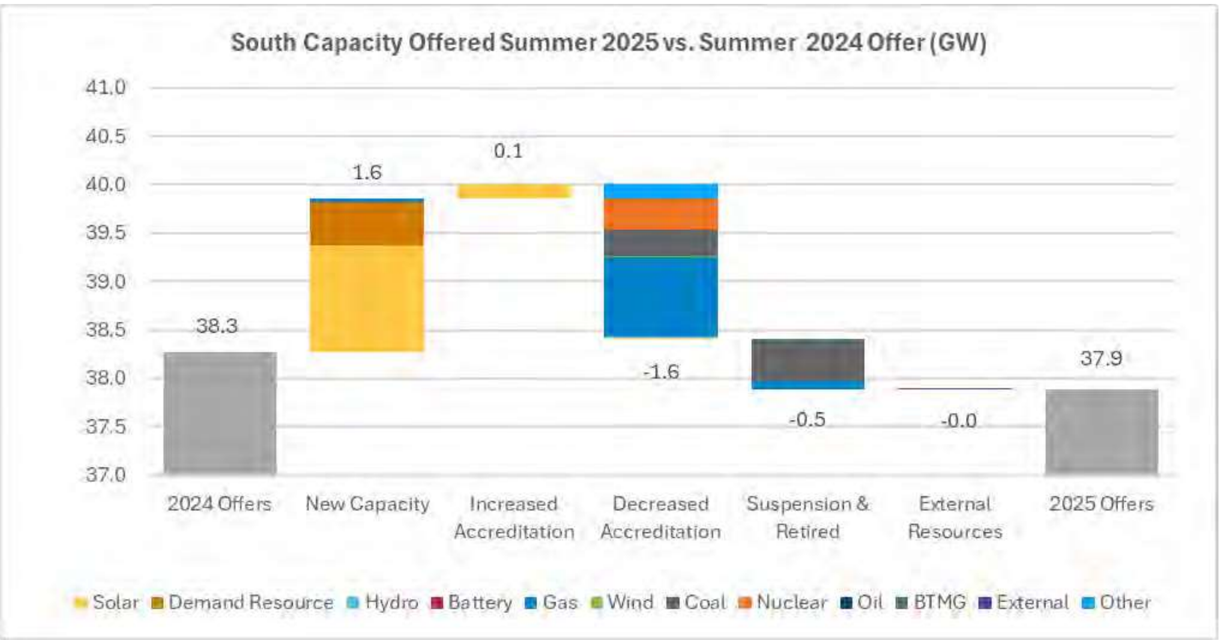
Annualized
$217 (North/Central)
$212 (South)

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



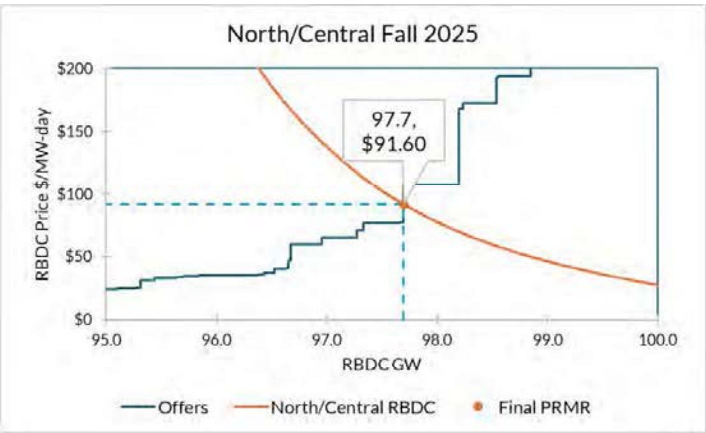
BTMG: Behind the Meter Generation | *Capacity indicated is offered accredited value*

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



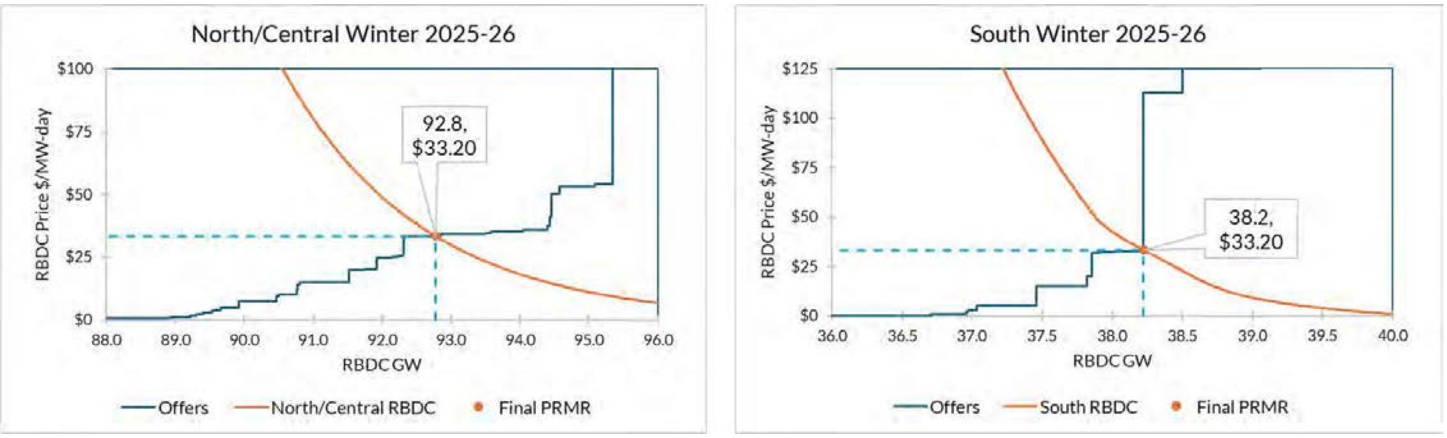
BTMG: Behind the Meter Generation | Capacity indicated is offered accredited value

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



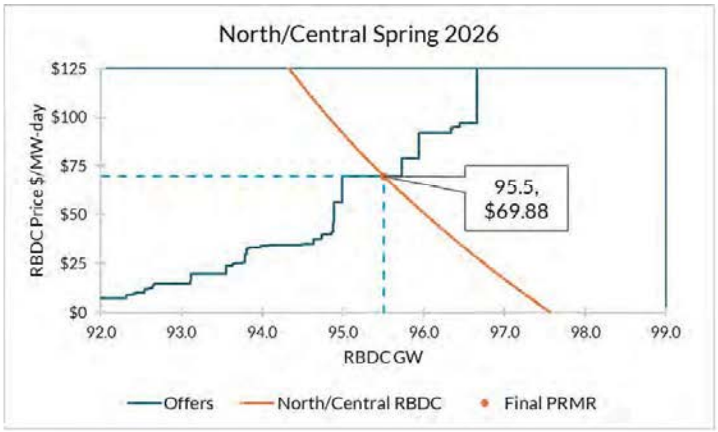
- Subregional RBDCs are determining clearing for both subregions
- Subregional Power Balance Constraint (SRPBC), South to North, is binding resulting in price separation between North/Central and South subregions in Fall season
    - ACP for North subregion is $91.60, and $74.09 South subregion
    - 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



95.5, $69.88

35.2, $69.88

- 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%

Summer 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)

<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><th>System CONE (Seasonal)</th><th>North/Central CONE (Seasonal)</th><th>South CONE (Seasonal)</th></tr>
<tr><td>Summer 2025</td><td colspan="11">$666.50</td><td>$1,353.84</td><td>$1,384.36</td><td>$1,282.61</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><td>$1,368.71</td><td>$1,399.58</td><td>$1,296.70</td></tr>
<tr><td>Winter 2025-26</td><td colspan="11">$33.20</td><td>$1,383.92</td><td>$1,415.13</td><td>$1,311.11</td></tr>
<tr><td>Spring 2026</td><td colspan="11">$69.88</td><td>$1,353.84</td><td>$1,384.36</td><td>$1,282.61</td></tr>
<tr><td>Cost of New Entry (Annual)</td><td>$127,720</td><td>$125,090</td><td>$121,220</td><td>$126,040</td><td>$136,170</td><td>$124,360</td><td>$130,930</td><td>$118,960</td><td>$117,710</td><td>$117,330</td><td>$136,170</td><td></td><td></td><td></td></tr>
<tr><td>IMM Conduct Threshold*</td><td>$34.99</td><td>$34.27</td><td>$33.21</td><td>$34.53</td><td>$37.31</td><td>$34.07</td><td>$35.87</td><td>$32.59</td><td>$32.25</td><td>$32.15</td><td>-</td><td></td><td></td><td></td></tr>
</table>

- *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

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

- 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

PY	Zone 1	Zone 2	Zone 3	Zone 4	Zone 5	Zone 6	Zone 7	Zone 8	Zone 9	Zone 10	ERZs
Winter 2023-24	$2.00								$18.88	$2.00	
Winter 2024-25	$0.75										
Winter 2025-26	$33.20										

- Auction Clearing Prices shown in $/MW-Day

ERZ: External Resource Zones

Spring Auction Clearing Price Comparison

PY	Zone 1	Zone 2	Zone 3	Zone 4	Zone 5	Zone 6	Zone 7	Zone 8	Zone 9	Zone 10	ERZs
Spring 2024	$10.00										
Spring 2025	$34.10				$719.81	$34.10					
Spring 2026	$69.88										

- 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

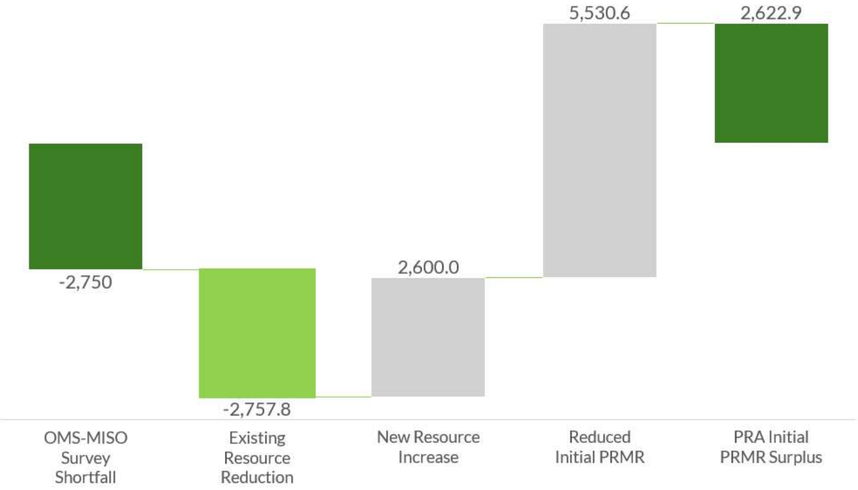
05/29/2025: MISO Planning Resource Auction for Planning Year 2025/26 Results Posting

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

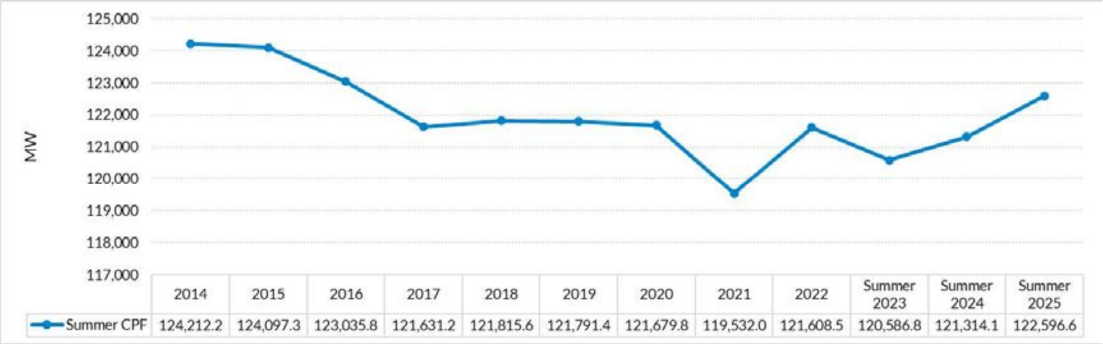
2024 OMS-MISO Survey Projection vs. 2025 PRA Actual PRMR Surplus (MW)



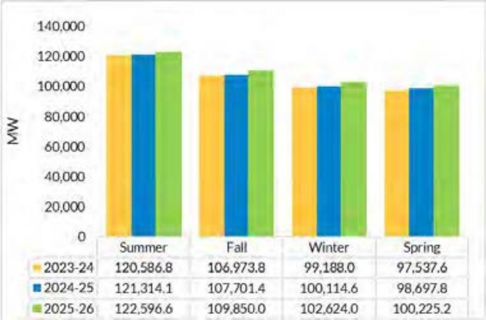
PRA Shortfall/Surplus relative to Initial PRMR | PRMR: Planning Reserve Margin Requirement

Coincident Peak Forecast

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



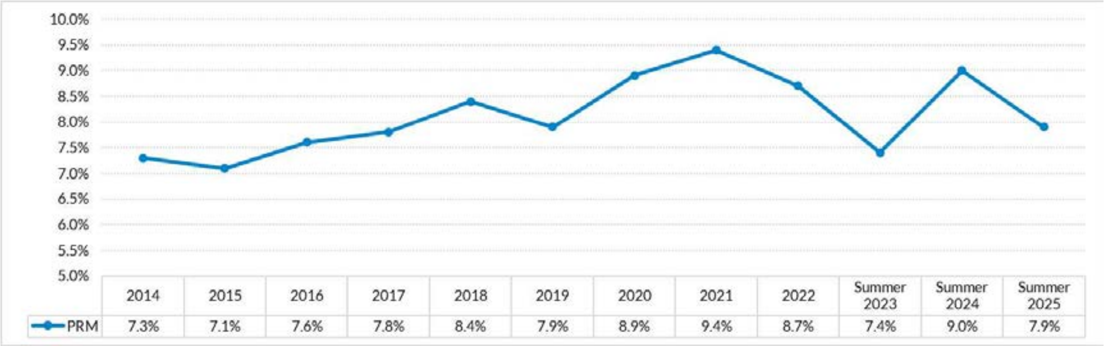
	2014	2015	2016	2017	2018	2019	2020	2021	2022	Summer 2023	Summer 2024	Summer 2025
Summer CPF	124,212.2	124,097.3	123,035.8	121,631.2	121,815.6	121,791.4	121,679.8	119,532.0	121,608.5	120,586.8	121,314.1	122,596.6



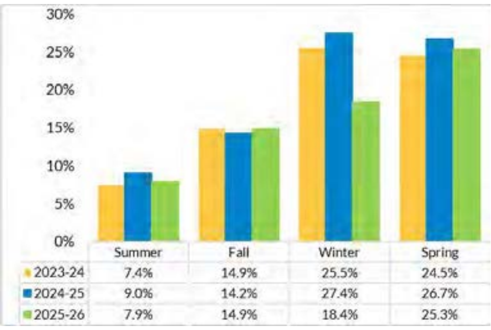
	Summer	Fall	Winter	Spring
2023-24	120,586.8	106,973.8	99,188.0	97,537.6
2024-25	121,314.1	107,701.4	100,114.6	98,697.8
2025-26	122,596.6	109,850.0	102,624.0	100,225.2

PRMR: Planning Reserve Margin Requirement

Planning Reserve Margin (%)

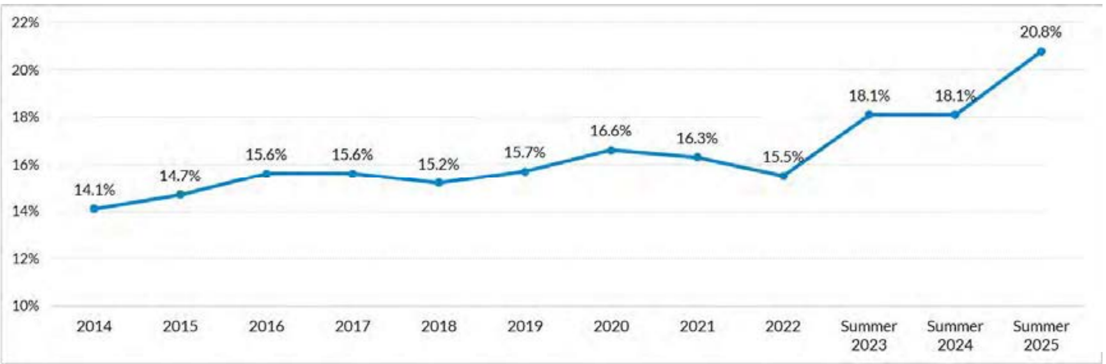


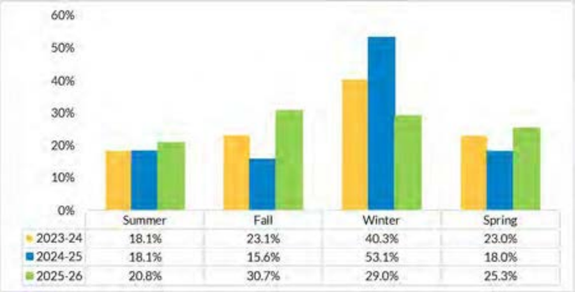
	2014	2015	2016	2017	2018	2019	2020	2021	2022	Summer 2023	Summer 2024	Summer 2025
PRM	7.3%	7.1%	7.6%	7.8%	8.4%	7.9%	8.9%	9.4%	8.7%	7.4%	9.0%	7.9%



	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 (%)



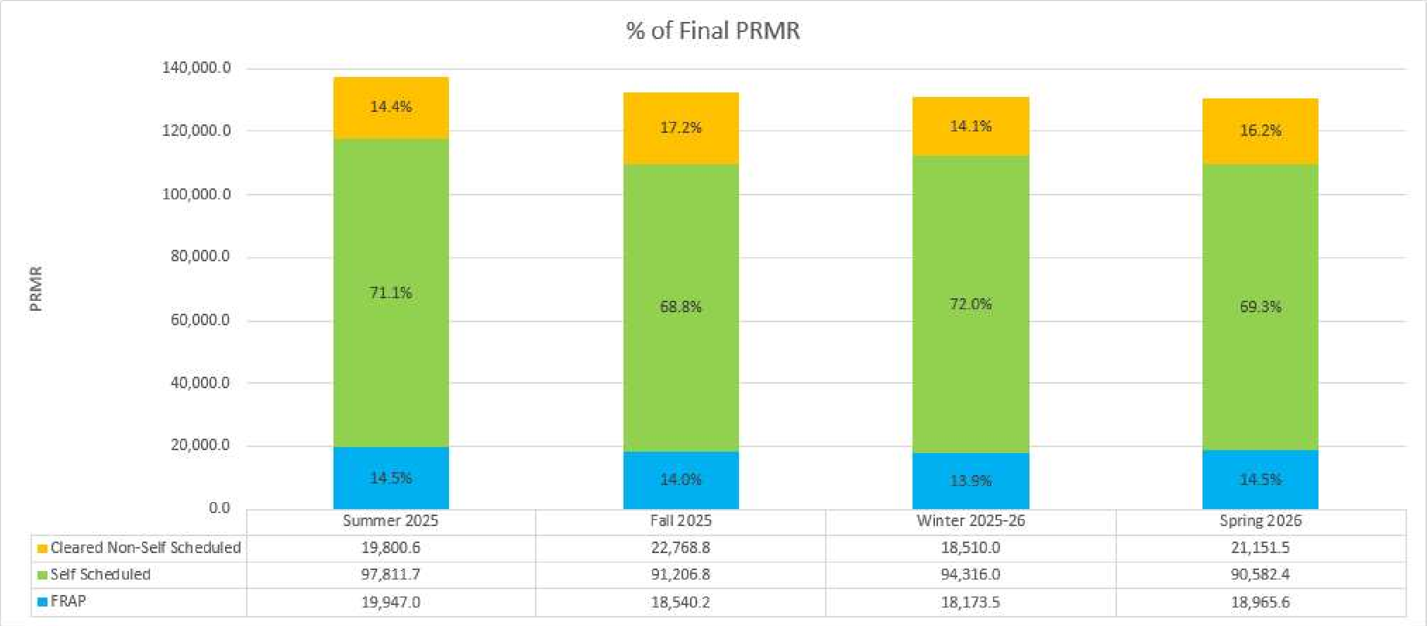


	Summer	Fall	Winter	Spring
🟨 2023-24	18.1%	23.1%	40.3%	23.0%
🟦 2024-25	18.1%	15.6%	53.1%	18.0%
🟩 2025-26	20.8%	30.7%	29.0%	25.3%

- 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

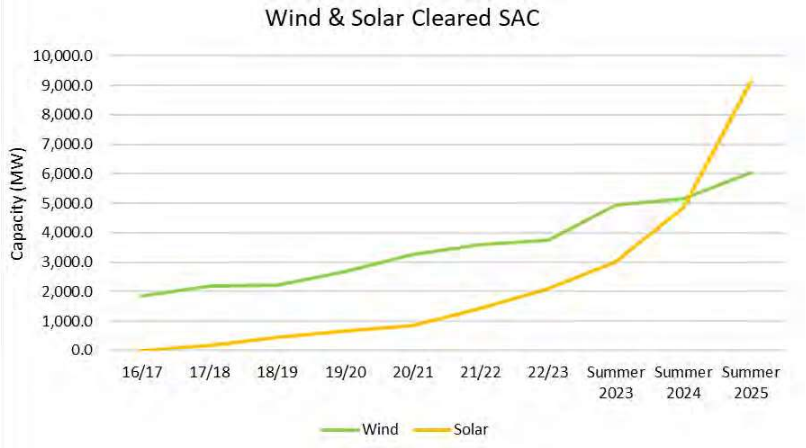


	Summer 2025	Fall 2025	Winter 2025-26	Spring 2026
🟨 Cleared Non-Self Scheduled	19,800.6	22,768.8	18,510.0	21,151.5
🟩 Self Scheduled	97,811.7	91,206.8	94,316.0	90,582.4
🟦 FRAP	19,947.0	18,540.2	18,173.5	18,965.6

PRMR: Planning Reserve Margin Requirement

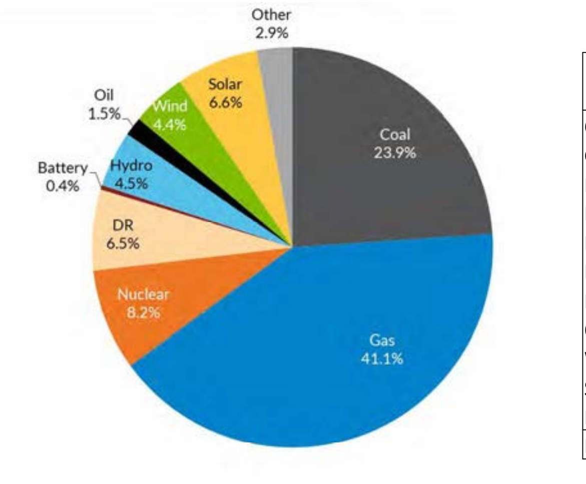
Although conventional generation still comprises most of the capacity, wind and solar continue to grow

- 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

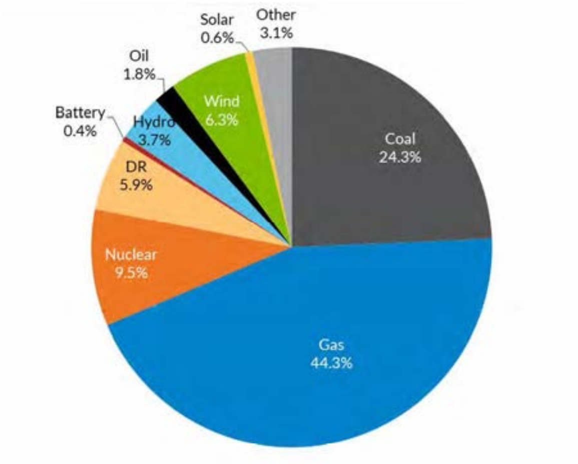
Summer 2025



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

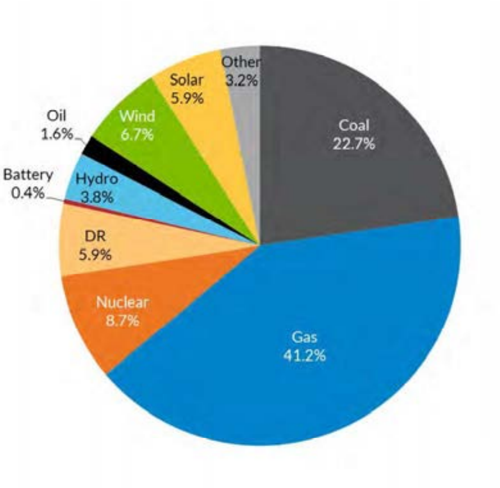
Winter 2025/26



PRMR: Planning Reserve Margin Requirement

Fall 2025 and Spring 2026 - Cleared ZRCs and Final PRMR

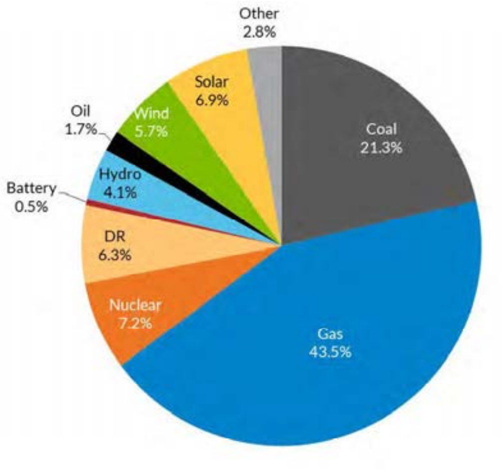
Fall 2025



MISO-Wide

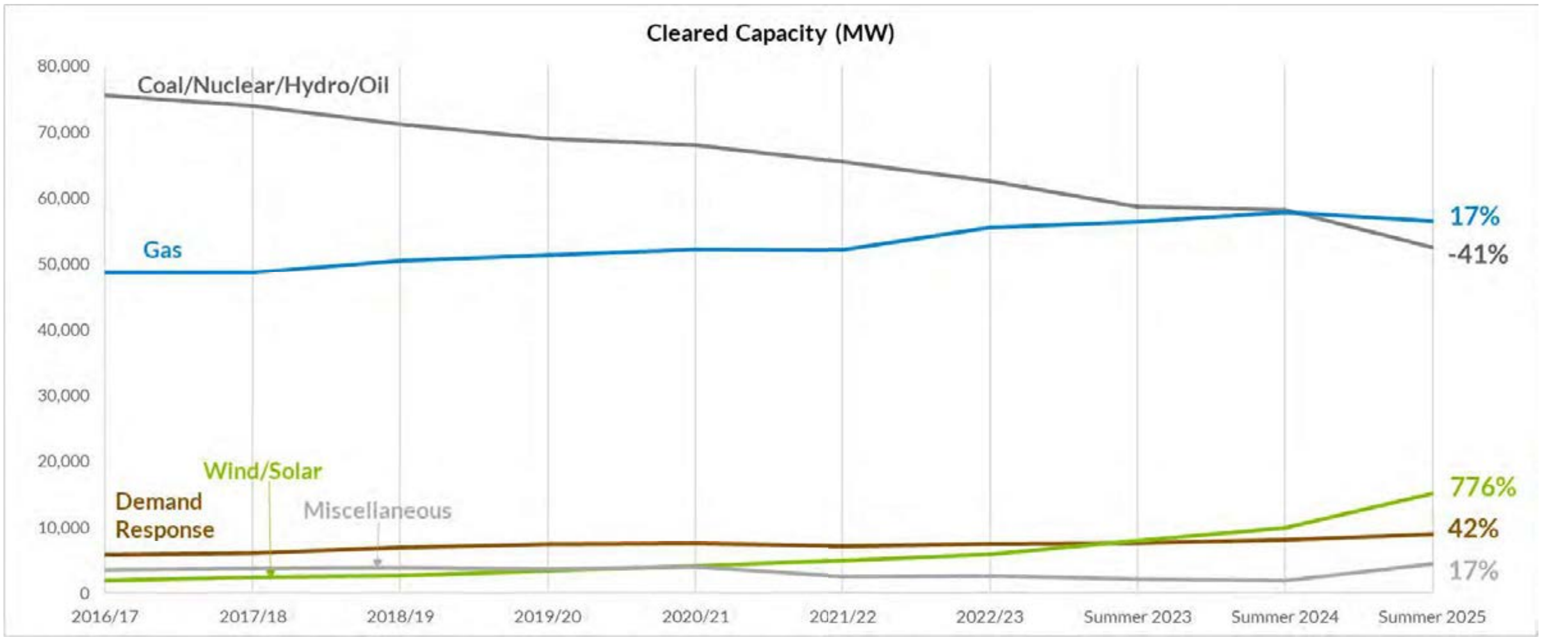
Cleared ZRC	Fall 2025	Spring 2026
Coal	30,038.9	27,886.8
Gas	54,636.4	56,820.7
Nuclear	11,482.1	9,405.4
DR	7,767.8	8,240.5
Battery	497.9	663.3
EE	28.1	30.5
Hydro	5,047.4	5,415.8
Oil	2,123.8	2,190.4
Wind	8,864.8	7,438.0
Solar	7,843.8	8,975.1
Misc	4,184.8	3,633.0
PRMR	132,515.8	130,699.5

Spring 2026

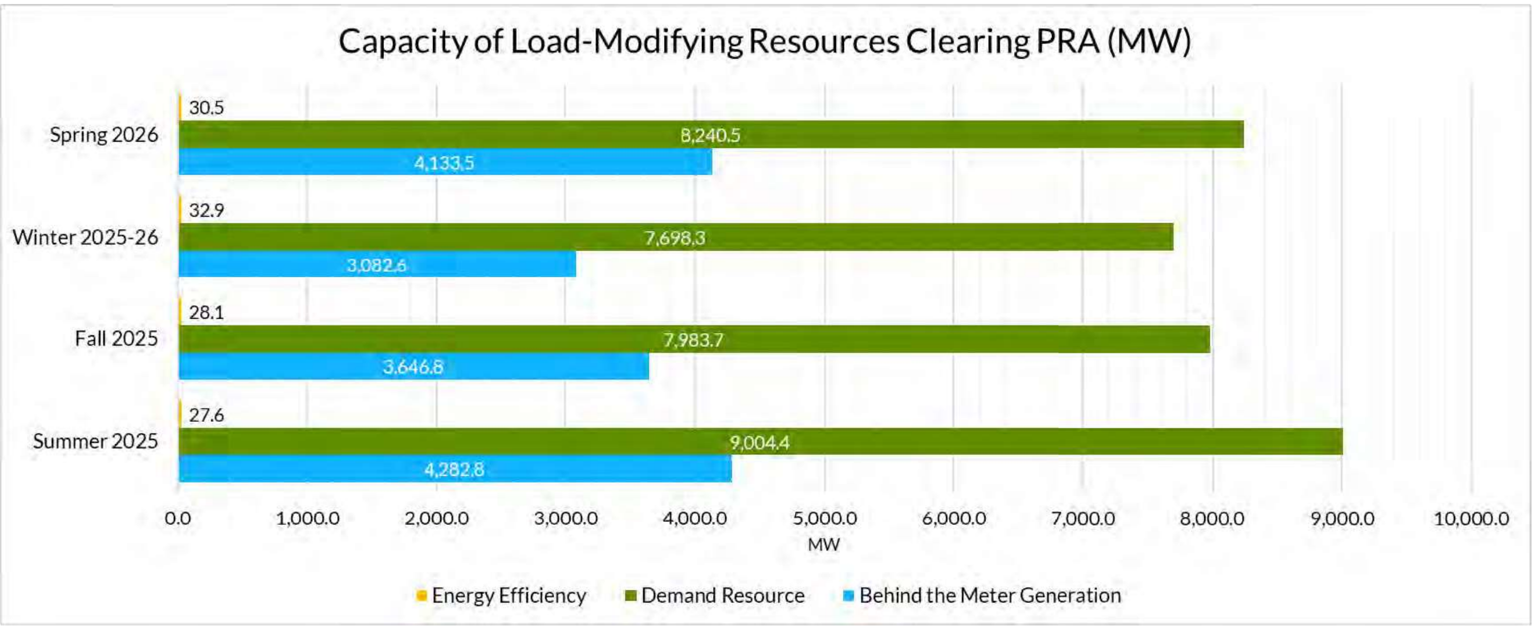


PRMR: Planning Reserve Margin Requirement

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/

Attachment C

Collection of MISO Attachment Y materials

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

Electric Supply
Contract/Commitment Cover Sheet

*(**Note:** Contracts, purchase orders, or other commitment instruments <u>will not be signed unless this sheet is completed in full</u>)*

Subject/Commitment: **MISO Attachment Y Notification of Generating Resources /SCU/ Pseudo-tied Out Generator Change of Status / Including Notification of Rescission Form**

Reason: Notice to Suspend Karn Units 3 & 4 effective June 1, 2023.

Check One

Yes	No*	N/A	
☐	☐	☒	1) **Gateway Assessment Tool completed and attached**
☒	☐	☐	2) **Legal Review / Approval to Form**
☐	☐	☒	3) **Credit Risk Management Approval**
☐	☐	☒	4) **Competitive Bid**
☐	☐	☒	5) **Sole Source Approval completed and attached**

***If <u>No</u> is checked or special circumstances apply, please explain:**

Legal review by Emerson Hilton.

***Contract Owner: Kathy Wetzel**

Department Sign Off
(Signature & Date Required)

ML Metz
Merchant Ops & PSCR

KG Troyer
EGI Contracts & Settlements
Renewables

BD Gallaway
Fuel Supply

TP Clark
Electric Supply

12/14/2021

TJ Sparks
Electric Grid Integration

Form Revised: 04/16/21

**Contract Owner Responsible for Scanning & Placing on SharePoint Site*

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

☒ 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

Consumers Energy
Count on Us

VIA EMAIL

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

May 28, 2025

Re: Modified Suspension Date for Campbell Units 1, 2, & 3

Mr. Witmeier:

On December 14, 2021, Consumers Energy Company ("Consumers Energy") submitted an Attachment Y Notice to the Midcontinent Independent System Operating, Inc. ("MISO") for the suspension of Units 1, 2, and 3 at the J.H. Campbell Generation Complex ("Campbell Plant"), effective June 1, 2025. After reviewing 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"), MISO determined the suspension of Campbell Plant Units 1, 2, and 3, would not result in violations of applicable reliability criteria, as outlined in the Tariff. On March 11, 2022, MISO approved the suspension of Campbell Plant Units 1, 2, and 3 without the need for the generators to be designated as System Support Resource units as defined in the Tariff.

On May 23, 2025, the U.S. Department of Energy ("DOE") issued Order No. 202-25-3 (the "Order"), requiring the Campbell Plant to be available to MISO through August 20, 2025.

In order to comply with the Order, Consumers Energy hereby provides notice to MISO, consistent with Section 38.2.7(d)(ii)(1) of the Tariff, of its intent to modify the current Attachment Y Notice such that the Campbell Plant will now suspend on August 21, 2025.

As noted in Consumers Energy's original Attachment Y Notice, Campbell Unit 3 is jointly owned by Consumers Energy (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 it has notified all Campbell Unit 3 owners of this submittal.

In the event you have any questions regarding this matter, please contact Derek Anspaugh at (517) 788-1869.

Regards,

Sri M.

Consumers Energy
One Energy Plaza
Jackson, MI 49201-2357

www.consumersenergy.com

Sri Maddipati
VP Electric Supply
1945 W. Parnell Rd
Jackson, MI 49901

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 form must be submitted to the Transmission Provider via its online application tool in the manner specified by the Transmission Planning Business Practices Manual (BPM-020), and a form will be considered complete on the date of such online application.

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 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, and MISO, FERC Docket No. ER24-1359
Campbell Unit 3: FERC Docket No. 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 21 [day] of August [month] of 2025 [year]

[ ] Rescind the current notice to Suspend

The 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: Srikanth Maddipati

Title: VP Electric Supply

Date: May 28, 2025

Contact Information

Email: sri.maddipati@cmsenergy.com

Phone: 517-788-0635

From: Marc Keyser
To: Rachael H. Moore; Huaitao Zhang; DEREK S. ANSPAUGH; Adam C. French; NICHOLAS B. TENNEY; Emerson J. Hilton
Cc: Sumit Pal Brar
Subject: RE: [EXT]RE: Order from Secretary of Energy to keep Campbell Unit ON for the summer (until Aug 21, 2025) - Action required
Date: Friday, May 30, 2025 4:05:01 PM

Rachael: I'm responding back on behalf of the team, after they briefly reviewed with legal here:

we received the Attachment Y, and the new cessation is 8/21/2025. Additionally, you have until 8/21/2027 to submit a new replacement request before the suspension period ends. In other words, the Attachment Y remains as is, still approved, except with a new/different start date.

From: Rachael H. Moore <Rachael.Moore@cmsenergy.com>
Sent: Friday, May 30, 2025 12:15 PM
To: Huaitao Zhang <HZhang@misoenergy.org>; Derek Anspaugh <Derek.Anspaugh@cmsenergy.com>; Adam French <adam.french@cmsenergy.com>; NICHOLAS B. TENNEY <NICHOLAS.TENNEY@cmsenergy.com>; Emerson J. Hilton <Emerson.Hilton@cmsenergy.com>
Cc: Sumit Pal Brar <SBrar@misoenergy.org>; Marc Keyser <MKeyser@misoenergy.org>
Subject: RE: [EXT]RE: Order from Secretary of Energy to keep Campbell Unit ON for the summer (until Aug 21, 2025) - Action required

Thank you, Huaitao. Can you confirm that this modification of the suspension start date provided consistent with Section 38.2.7(d)(ii)(1) of the Tariff does not impact the overall approval of the Attachment Y the Company previously received on March 11, 2022, and that the Company is still approved to enter suspension (now effective 8/21/25)?

Thank you!

Rachael Moore | Senior Attorney
[redacted]

From: Huaitao Zhang <HZhang@misoenergy.org>
Sent: Wednesday, May 28, 2025 1:47 PM

To: Rachael H. Moore <Rachael.Moore@cmsenergy.com>; DEREK S. ANSPAUGH <DEREK.ANSPAUGH@cmsenergy.com>; Adam C. French <ADAM.FRENCH@cmsenergy.com>; NICHOLAS B. TENNEY <NICHOLAS.TENNEY@cmsenergy.com>; Emerson J. Hilton <Emerson.Hilton@cmsenergy.com>
Cc: Sumit Pal Brar <SBrar@misoenergy.org>; Marc Keyser <MKeyser@misoenergy.org>
Subject: RE: [EXT]RE: Order from Secretary of Energy to keep Campbell Unit ON for the summer (until Aug 21, 2025) - Action required

Rachael,

Thanks for the quick response, and we are all good.

Thanks,
Huaitao

From: Rachael H. Moore <Rachael.Moore@cmsenergy.com>
Sent: Wednesday, May 28, 2025 12:40 PM
To: Huaitao Zhang <HZhang@misoenergy.org>; Derek Anspaugh <Derek.Anspaugh@cmsenergy.com>; Adam French <adam.french@cmsenergy.com>; NICHOLAS B. TENNEY <NICHOLAS.TENNEY@cmsenergy.com>; Emerson J. Hilton <Emerson.Hilton@cmsenergy.com>
Cc: Sumit Pal Brar <SBrar@misoenergy.org>; Marc Keyser <MKeyser@misoenergy.org>
Subject: [EXT]RE: Order from Secretary of Energy to keep Campbell Unit ON for the summer (until Aug 21, 2025) - Action required

Huaitao –

Attached is the modified Attachment Y with the amended suspension start date of 8/21/2025. Please let me know if we should send this notice of Modified Attachment Y to anyone else at MISO or if you would like us to mail a physical copy as well.

Thank you,
Rachael

Rachael Moore | Senior Attorney
[redacted]

From: Rachael H. Moore
Sent: Tuesday, May 27, 2025 11:52 AM
To: Adam C. French <adam.french@cmsenergy.com>; Huaitao Zhang <HZhang@misoenergy.org>; NICHOLAS B. TENNEY <nicholas.tenney@cmsenergy.com>
Cc: Sumit Pal Brar <SBrar@misoenergy.org>; Marc Keyser <MKeyser@misoenergy.org>
Subject: RE: Order from Secretary of Energy to keep Campbell Unit ON for the summer (until Aug 21, 2025) - Action required

Good afternoon,

Yes, I will be working with members of the Company to ensure we have the Attachment Y notice updated by 5/28. Please let me know if there is a specific contact at MISO we should plan to send this to.

Thank you!
Rachael

Rachael Moore | Senior Attorney
[redacted]

From: Adam C. French <ADAM.FRENCH@cmsenergy.com>
Sent: Tuesday, May 27, 2025 11:49 AM
To: Huaitao Zhang <HZhang@misoenergy.org>; NICHOLAS B. TENNEY <NICHOLAS.TENNEY@cmsenergy.com>; Rachael H. Moore <Rachael.Moore@cmsenergy.com>
Cc: Sumit Pal Brar <SBrar@misoenergy.org>; Marc Keyser <MKeyser@misoenergy.org>
Subject: RE: Order from Secretary of Energy to keep Campbell Unit ON for the summer (until Aug 21, 2025) - Action required

It is my understanding that is being handled by Rachael Moore
RACHAEL.MOORE@CMSENERGY.COM

From: Huaitao Zhang <HZhang@misoenergy.org>
Sent: Tuesday, May 27, 2025 11:41 AM
To: NICHOLAS B. TENNEY <NICHOLAS.TENNEY@cmsenergy.com>; Adam C. French <ADAM.FRENCH@cmsenergy.com>
Cc: Sumit Pal Brar <SBrar@misoenergy.org>; Marc Keyser <MKeyser@misoenergy.org>
Subject: FW: Order from Secretary of Energy to keep Campbell Unit ON for the summer (until Aug 21, 2025) - Action required

> You don't often get email from hzhang@misoenergy.org. Learn why this is important [aka.ms]

##CAUTION##: This email originated from outside of CMS/CE. Remember your security awareness training: Stop, think, and use caution before clicking links/attachments.

Nick and Adam,

Marc pointed to me that you are the contact for this request.

Thanks,
Huaitao

From: Huaitao Zhang
Sent: Tuesday, May 27, 2025 11:05 AM
To: KATHY S. WETZEL <KATHY.WETZEL@cmsenergy.com>
Cc: timothy.sparks@cmsenergy.com; Sumit Pal Brar <SBrar@misoenergy.org>; Marc Keyser <MKeyser@misoenergy.org>; Jagdesh Shivani <JShivani@misoenergy.org>
Subject: Order from Secretary of Energy to keep Campbell Unit ON for the summer (until Aug 21, 2025) - Action required

Hi Kathy,

Pertain to the Order from Secretary of Energy regarding the suspension/cessation date of Campbell units 1,2&3, MISO requests Consumer Energy to submit the following application updates to MISO by 5/28/2025:

Attachment Y request with suspension start date as 8/21/2025

FYI, the order link is https://www.energy.gov/sites/default/files/2025-05/Midcontinent%20Independent%20System%20Operator%20%28MISO%29%20202%28c%29%20Order_1.pdf [energy.gov]

Thanks,
Huaitao Zhang
Resource Utilization Engineer

Integrity | Collaboration | Commitment | Creativity | Adaptability

Attachment D

Consumers' Responses from June 10, 2025

Question:

23. Absent continued operation of the Campbell Plant, what was Consumers Energy's Zone Resource Credit (ZRC) position for planning year 2025-2026.

Response:

The table below shows our capacity positions using the initial Planning Reserve Margin Requirement (PRMR) for each season of planning year 2025. These numbers do not include any contributions from the Campbell coal-fired generating units.

PY2025	**ZRC**
Summer	272.9
Fall	842.7
Winter	0.0
Spring	4.3

Date: June 10, 2025

Question:

24. How many ZRCs does Consumers anticipate will be accredited for the continued operation of the Campbell Plant?

Response:

At this time we do not anticipate the Campbell units contributing any Zonal Resource Credits to our capacity positions throughout planning year 2025.

Date: June 10, 2025

Attachment R

DOE Final EO Report (FINAL JULY 7)

U.S. DEPARTMENT
of ENERGY

Resource Adequacy Report

Evaluating the Reliability and Security of the United States Electric Grid

July 2025

Acknowledgments

This report and associated analysis were prepared for DOE purposes to evaluate both the current state of resource adequacy as well as future pressures resulting from the combination of announced retirements and large load growth.

It was developed in collaboration with and with assistance from the Pacific Northwest National Laboratory (PNNL) and National Renewable Energy Laboratory (NREL). We thank the North American Electric Reliability Corporation (NERC) for providing data used in this study, the Telos Corporation for their assistance in interpreting this data, and the U.S Energy Information Administration (EIA) for their dissemination of historical datasets. In addition, thank you to NREL for providing synthetic weather data created by Evolved Energy Research for the Regional Energy Deployment System (ReEDS) model.

DOE acknowledges that the resource adequacy analysis that was performed in support of this study could benefit greatly from the in-depth engineering assessments which occur at the regional and utility level. The DOE study team built the methodology and analysis upon the best data that was available. However, entities responsible for the maintenance and operation of the grid have access to a range of data and insights that could further enhance the robustness of reliability decisions, including resource adequacy, operational reliability, and resilience.

Historically, the nation’s power system planners would have shared electric reliability information with DOE through mechanisms such as EIA-411, which has been discontinued. Thus, one of the key takeaways from this study process is the underscored “call to action” for strengthened regional engagement, collaboration, and robust data exchange which are critical to addressing the urgency of reliability and security concerns that underpin our collective economic and national security.

Table of Contents

List of Figures

List of Tables

Additional figures and tables in appendices

List of Acronyms

AI	Artificial Intelligence
CAISO	California Independent System Operator
DOE	U.S. Department of Energy
EIA	Energy Information Administration
EO	Executive Order
EPRI	Electric Power Research Institute
ERCOT	Electric Reliability Council of Texas
EUE	Expected Unserved Energy
FERC	Federal Energy Regulatory Commission
GADS	Generating Availability Data System
ISO	Independent System Operator
ISO-NE	ISO New England Inc.
ITCS	Interregional Transfer Capability Study
LBNL	Lawrence Berkeley National Laboratory
LOLE	Loss of Load Expectation
LOLH	Loss of Load Hours
LTRA	Long-Term Reliability Assessment
MISO	Midcontinent Independent System Operator
NERC	North American Electric Reliability Corporation
NREL	National Renewable Energy Laboratory
NYISO	New York Independent System Operator
PJM	PJM Interconnection, LLC
PNNL	Pacific Northwest National Laboratory
ReEDS	Regional Energy Deployment System
RTO	Regional Transmission Organization
SERC	SERC Reliability Corporation
TPR	Transmission Planning Region
USE	Unserved Energy

Background to this Report

On April 8, 2025, President Trump issued Executive Order 14262, "Strengthening the Reliability and Security of the United States Electric Grid.” EO 14262 builds on EO 14156, “Declaring a National Emergency (Jan. 20, 2025),” which declared that the previous administration had driven the Nation into a national energy emergency where a precariously inadequate and intermittent energy supply and increasingly unreliable grid require swift action. The United States’ ability to remain at the forefront of technological innovation depends on a reliable supply of energy and the integrity of our Nation’s electrical grid.

EO 14262 mandates the development of a uniform methodology for analyzing current and anticipated reserve margins across regions of the bulk power system regulated by the Federal Energy Regulatory Commission (FERC). Among other things, EO 14262 requires that such methodology accredit generation resources based on the historical performance of each generation resource type. This report serves as DOE’s response to Section 3(b) of EO 14262 by delivering the required uniform methodology to identify at-risk region(s) and guide reliability interventions. The methodology described herein and any analysis it produces will be assessed on a regular basis to ensure its usefulness for effective action among industry and government decision-makers across the United States.

Executive Summary

Our Nation possesses abundant energy resources and capabilities such as oil and gas, coal, and nuclear. The current administration has made great strides—such as deregulation, permitting reform, and other measures—to enable addition of more energy infrastructure crucial to the utilization of these resources. However, even with these foundational strengths, the accelerated retirement of existing generation capacity and the insufficient pace of firm, dispatchable generation additions (partly due to a recent focus on intermittent rather than dispatchable sources of energy) undermine this energy outlook.

Absent decisive intervention, the Nation's power grid will be unable to meet projected demand for manufacturing, re-industrialization, and data centers driving artificial intelligence (AI) innovation. A failure to power the data centers needed to win the AI arms race or to build the grid infrastructure that ensures our energy independence could result in adversary nations shaping digital norms and controlling digital infrastructure, thereby jeopardizing U.S. economic and national security.

Despite current advancements in the U.S. energy mix, this analysis underscores the urgent necessity of robust and rapid reforms. Such reforms are crucial to powering enough data centers while safeguarding grid reliability and a low cost of living for all Americans.

Key Takeaways

- **Status Quo is Unsustainable**. The status quo of more generation retirements and less dependable replacement generation is neither consistent with winning the AI race and ensuring affordable energy for all Americans, nor with continued grid reliability (ensuring "resource adequacy"). Absent intervention, it is impossible for the nation's bulk power system to meet the AI growth requirements while maintaining a reliable power grid and keeping energy costs low for our citizens.

- **Grid Growth Must Match Pace of AI Innovation**. The magnitude and speed of projected load growth cannot be met with existing approaches to load addition and grid management. The situation necessitates a radical change to unleash the transformative potential of innovation.

- **Retirements Plus Load Growth Increase Risk of Power Outages by 100x in 2030**. The retirement of firm power capacity is exacerbating the resource adequacy problem. 104 GW of firm capacity are set for retirement by 2030. This capacity is not being replaced on a one-to-one basis and losing this generation could lead to significant outages when weather conditions do not accommodate wind and solar generation. In the "plant closures" scenario of this analysis, annual loss of load hours (LOLH) increased by a factor of a hundred.

- **Planned Supply Falls Short, Reliability is at Risk**. The 104 GW of retirements are projected to be replaced by 209 GW of new generation by 2030; however, only 22 GW would come from firm baseload generation sources. Even assuming no retirements, the model found increased risk of outages in 2030 by a factor of 34.

- **Old Tools Won't Solve New Problems.** Antiquated approaches to evaluating resource adequacy do not sufficiently account for the realities of planning and operating modern power grids. At a minimum, modern methods of evaluating resource adequacy need to incorporate frequency, magnitude, and duration of power outages; move beyond exclusively analyzing peak load time periods; and develop integrated models to enable proper analysis of increasing reliance on neighboring grids.

This report clearly demonstrates the need for rapid and robust reform to address resource adequacy issues across the Nation. Inadequate resource adequacy will hinder the development of new manufacturing in America, slow the re-industrialization of the U.S. economy, drive up the cost of living for all Americans, and eliminate the potential to sustain enough data centers to win the AI arms race.

Developing a Uniform Methodology

DOE's resource adequacy methodology assesses the U.S. electric grid's ability to meet future demand through 2030. It provides a forward-looking snapshot of resource adequacy that is tied to electricity supply and new load growth, systematically exploring a range of dimensions that can be compared across regions. As detailed in the methodology section of this report, the model is derived from the North American Electric Reliability Corporation (NERC) Interregional Transfer Capability Study (ITCS) which leverages time-correlated generation and outages based on actual historic data.[1] A deterministic approach[2] simulates system stress in all hours of the year and incorporates varied grid conditions and operating scenarios based on historical events:

- **Demand for Electricity – Assumed Load Growth:** The methodology accounts for the significant impact of data centers, particularly those supporting AI workloads, on electricity demand. Various organizations' projections for incremental data center electricity use by 2030 range widely (35 GW to 108 GW). DOE adopted a national midpoint assumption of 50 GW by 2030, aligning with central projections from Electric Power Research Institute (EPRI)[3] and Lawrence Berkeley National Laboratory (LBNL).[4] This 50 GW was allocated regionally using state-level growth ratios from S&P's forecast,[5] reflecting infrastructure characteristics, siting trends, and market activity; and, mapped to NERC Transmission Planning Regions (TPRs).

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1. This model differs from traditional peak hour reliability assessments in that it explicitly simulates grid performance hour-by-hour across multiple weather years with finer geographic detail and optimized inter-regional transfers, and explores various retirement and build-out scenarios. Furthermore, the DOE approach integrates weather-synchronized outage data.

2. Deterministic approaches evaluate resource adequacy using relatively stable or fixed assumptions about the representation of the power system. Probabilistic approaches incorporate data and advanced modeling techniques to represent uncertainty that require more computing power. Deterministic was chosen for this analysis for transparency and to model detailed historic system conditions.

3. EPRI, "Powering Intelligence: Analyzing Artificial Intelligence and Data Center Energy Consumption," March 2024, https://www.epri.com/research/products/3002028905.

4. Shehabi, A., et al., "2024 United States Data Center Energy Usage Report," https://escholarship.org/uc/item/32d6m0d1.

5. S&P Global – Market Intelligence, "US Datacenters and Energy Report," 2024.

An additional 51 GW of non-data center load was modeled using NERC data, historical loads (2019-2023), and simulated weather years (2007-2013), adjusted by the Energy Information Administration's (EIA) 2022 energy forecast, with interpolation between 2024 and 2033 to estimate 2030 demand.

- **Supply of Electricity – Assumed Generation Retirements and Additions:** Between the current system and the projected 2030 system, the model considers three scenarios for generator retirements and additions. These scenarios were selected to describe the metrics of interest and how they change during certain assumptions of generation growth and retirements.

The resource adequacy standard (or criterion) is the measure that defines the desired level of adequacy needed for a given system. Conceptually, a resource adequacy criterion has two components—metrics and target levels—that determine whether a system is considered adequate. Comprehensive resource adequacy metrics[6] are incorporated in this analysis to capture the magnitude and duration of system stress events:

- **Magnitude of Outages – Normalized Unserved Energy (NUSE):** Measures the amount of unmet electrical energy demand because of insufficient generation or transmission, typically measured in megawatt hours (MWh).

  While USE describes the absolute amount of energy not delivered, it is less useful when comparing systems of different size or across different periods. Normalizing, by dividing by total load over a whole period (for example, a year) allows comparison of these metrics across different system sizes, demand levels, and periods of analysis. For example, 100 MWh of USE in a small, isolated microgrid can be more impactful than 100 MWh of USE in a larger regional grid that serves millions of people. USE is normalized by dividing by total load:

$$\frac{100\ MWh\ (of\ unserved\ energy)}{10{,}000{,}000\ MWh\ (of\ total\ energy\ delivered\ in\ a\ year)} x100 = 0.001\ percent$$

Although the use of NUSE is not standardized in the U.S. today,[7] several system operators domestically and across the world have begun using NUSE as a useful metric.

- **Duration of Outages – Loss of Load Hours (LOLH):** Measures the expected duration of power outages when a system's load exceeds its available generation capacity. At the core, LOLH helps assess how frequently and for how long the power system is likely to experience insufficient supply, providing a picture of reliability in terms of time. LOLH is calculated as both a total and average value per year, in addition to the maximum percentage of load lost in any given hour per year.

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[6] In the interest of technical accuracy, and separate from their contextualization in the main text, NUSE is more precisely a measure of volume that is expressed as a percentage. Similarly, 2.4 hours of LOLH represents the cumulative sum of distinct periods of load loss, not a singular, continuous duration.

[7] There is no common planning criterion for this metric in North America. NERC's Long-Term Reliability Assessment employs a normalized expected unserved energy (NEUE) metric to define target risk levels for each region. Grid operators, such as ISO-NE, have also considered NUSE in energy adequacy studies. For example, see ISO-NE, "Regional Energy Shortfall Threshold (REST): ISO's Current Thinking Regarding Tail Selection," April 2025, https://www.iso-ne.com/static-assets/documents/100022/a09_rest_april_2025.pdf.

Reliability Standard

DOE's methodology recognizes that the traditional 1-in-10 loss of load expectation (LOLE) criterion is insufficient for a complete assessment of resource adequacy and risk profile. This antiquated criterion is not calculated uniformly and fails to adequately account for crucial factors such as the duration and magnitude of potential outages.[8] To provide a comprehensive understanding of system reliability and, specifically, to complement current resource adequacy standards while informing the creation of new criteria, the methodology uses the following reliability standard:

- **Duration of Outages:** No more than 2.4 hours of lost load in an individual year.[9] This translates into one day of lost load in ten years to meet the 1-in-10 criteria.

- **Magnitude of Outages:** No more than an NUSE of 0.002%.[10] This means that the total amount of energy that cannot be supplied to customers is 0.002% of the total energy demanded in a given year.

Achieving Reliability Standard

- **Perfect Capacity Surplus/Deficit:** Defined as the amount of generation capacity (in MW) a region would need to achieve specified threshold conditions. Based on these thresholds, this standard helps answer the hypothetical question of how much more (or less) power plant capacity is needed for a power system to be considered "perfectly reliable" according to pre-defined standards. This methodology employs this perfect capacity metric to identify the amount of capacity needed to remedy potential shortfalls (or excesses) in generation.

Key Results Summary

This analysis developed three separate cases for 2030. The "**Plant Closures"** case assumes all announced retirements occur plus mature generation additions based on NERC's Tier 1 resources category,[11] which encompasses completed and under-construction power generation projects, as well as those with firm-signed and approved interconnection service or power purchase agreements. The "**No Plant Closures"** case assumes no retirements plus mature additions. A "**Required Build**" case further compares the impacts of retirements on perfect capacity additions needed to return 2030 to the current system level of reliability.

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8. While 1-in-10 analyses have evolved, industry experts have raised concerns about its effectiveness to address future system risks. Concerns include energy constraints that arise from intermittent resources, increasing battery storage, limited fuel supplies, and the shifting away of peak load periods from times of supply shortfalls.

9. The "1-in-10 year" reliability standard for electricity grids means that, on average, there should be no more than one day (24 hours) of lost load over a ten-year period. This translates to a maximum of 2.4 hours of lost load per year.

10. This analysis targets NUSE below 0.002% for each region because this is the target NERC uses to represent high risk in resource adequacy analyses. Estimates used in industry and analyzed recently range from 0.0001% to 0.003%.

10. Mature generation additions are based on NERC's 2024 LTRA Tier 1 resources, which assume that only projects considered very mature in the development pipeline will be built. For example, Tier 1 additions are those with signed interconnection agreements or power purchase agreements, or included in an integrated resource plan, indicating a high degree of certainty in their addition to the grid. Full details of the retirement and addition assumptions can be found in the methodology section of this report.

DOE ran simulations using 12 different years of historical weather. Every hour was based on actual data for wind, solar, load, and thermal availability to stress test the grid under a range of realistic weather conditions. The benefit of this approach is that it allows for transparent review of how actual conditions manifest themselves in capacity shortfalls. For all scenarios, LOLH and NUSE are calculated and used to compare how they change based on generation growth, retirements, and potential weather conditions.

- **Current System:** Supply of power (generation) and demand for power (load) consistent with 2024 NERC Long-Term Reliability Assessment (LTRA), including 2023 actual generation plus Tier 1 additions for 2024.

- **Plant Closures:** This case assumes 104 GW of announced retirements based on NERC estimates including approximately 71 GW of coal and 25 GW of natural gas, which closely align with retirement numbers in EIA's 2025 Annual Energy Outlook. In addition, this case assumes 100% of 2024 NERC LTRA Tier 1 additions totaling 209 GW are constructed by 2030. This includes 20 GW of new natural gas, 31 GW of additional 4-hour batteries, 124 GW of new solar and 32 GW of incremental wind. Details of the breakdown can be found in Appendix A.

- **No Plant Closures:** This case adds all the Tier 1 NERC additions but assumes no retirements.

- **Required Build:** To understand how much capacity may need to be added to reach reliability targets, the analysis adds hypothetical perfect capacity (which is idealized capacity that has no outages or profile) until a NUSE target of 0.002% is realized in each region. This scenario includes the same assumptions about retirements as our Plant Closures scenario described above.

As shown in the figures and tables below, the model shows a significant decline in all reliability metrics between the current system scenario and the 2030 Plant Closures scenario. Most notably, there is a hundredfold increase in annual LOLH from 8.1 hours per year in the current case to 817 hours per year in the 2030 Plant Closures. In the worst weather year assessed, the total lost load hours increase from 50 hours to 1,316 hours.

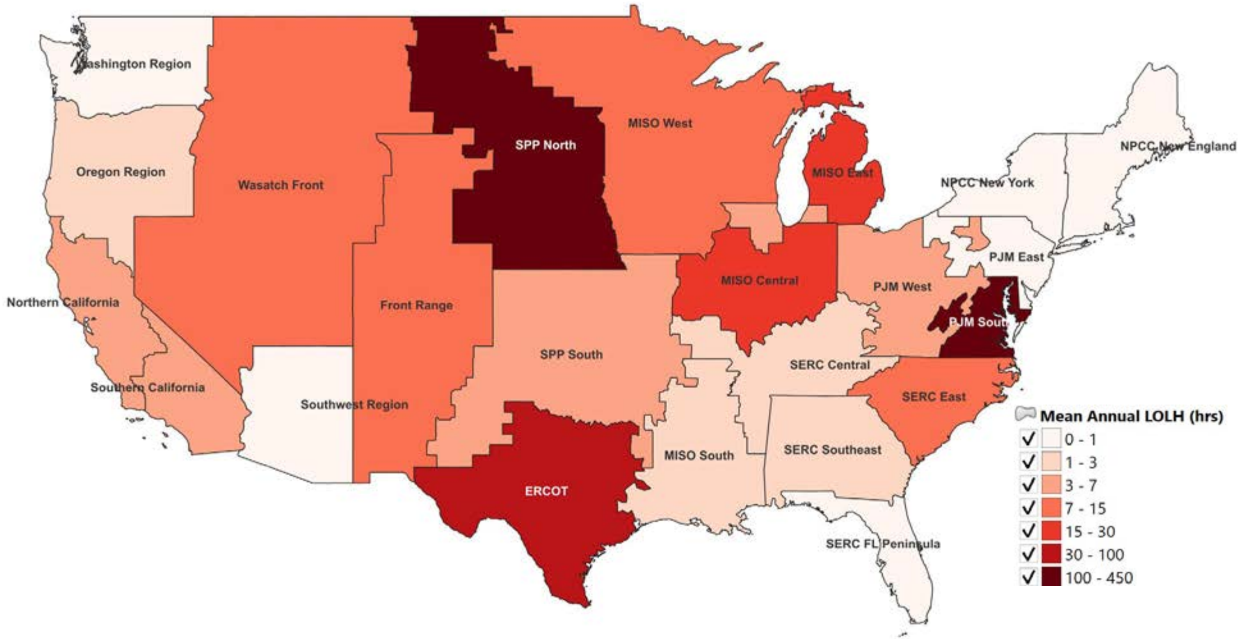

Figure 1. Mean Annual LOLH by Region (2030) – Plant Closures

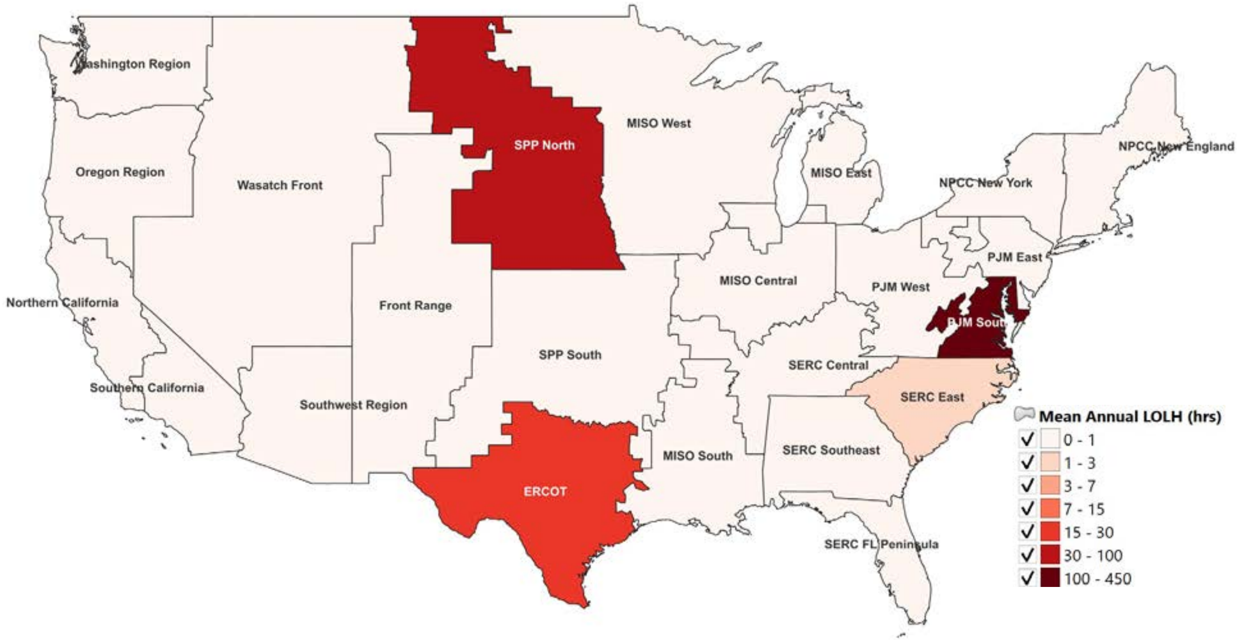

Figure 2. Mean Annual LOLH by Region (2030) – No Plant Closures

Table 1. Summary Metrics Across Cases

Reliability Metric		2030 Projection		
	Current System	Plant Closures	No Plant Closures	Required Build
AVERAGE OVER 12 WEATHER YEARS				
Average Loss of Load Hours	8.1	817.7	269.9	13.3
Normalized Unserved Energy (%)	0.0005	0.0465	0.0164	0.00048
WORST WEATHER YEAR				
Annual Loss of Load Hours	50	1316	658	53
Normalized Unserved Load (%)	0.0033	0.1119	0.0552	0.002

Current System Analysis

Analysis of the current system shows all regions except ERCOT have less than 2.4 hours of average loss of load per year and less than 0.002% NUSE. This indicates relative reliability for most regions based on the average indicators of risk used in this study. In the current system case, ERCOT would be expected to experience on average 3.8 LOLH annually going forward and a NUSE of 0.0032%. When looking at metrics in the worst weather years, regions meet or exceed additional criteria. All regions experienced less than 20% of lost load in any hour.

However, PJM, ERCOT,[12] and SPP experienced significant loss of load events during 2021 and 2022 winter storms Uri and Elliot which translated into more than 20 hours of lost load. This results in a concentration of lost load within certain years such that some regions exceeded 3-hours-per-year of lost load. It is worth noting that in the case of PJM and SPP, the current system model shortfalls occurred within subregions rather than for the entire ISO footprint.

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[12] ERCOT has since winterized its generation fleet and did not suffer any outages during Winter Storm Elliot.

2030 Model Results

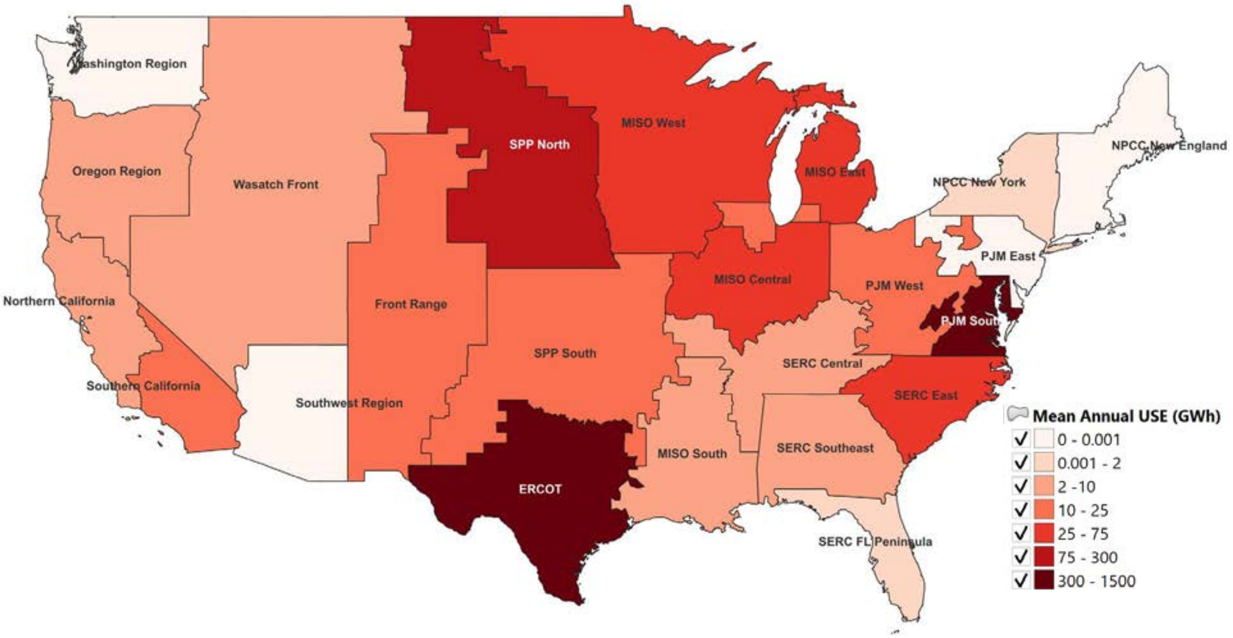


Figure 3. Mean Annual NUSE by Region (2030) -Plant Closures

Key Findings – Plant Closures Case:

- **Systemwide Failures**: All regions except ISO-NE and NYISO failed reliability thresholds. These two regions did not have additional AI/data center (AI/DC) load growth modeled.
- **Loss of Load Hours (LOLH)**: Ranged from 7 hours/year in CAISO to 430 hours/year in PJM.
- **Load Shortfall Severity**: Max shortfall reached as high as 43% of hourly load in PJM; 31% in CAISO.
- **Normalized Unserved Energy**: Normalized values ranged from 0.0032% (non-CAISO West) to 0.1473% (PJM), far exceeding thresholds of 0.002%.
- **Extreme Events**: Most regions experienced ≥3 hours of unserved load in at least one year. PJM had 1,052 hours in its worst year.
- **Spatial Takeaways**: Subregions in PJM, MISO, and SERC met thresholds—indicating possible benefits from transmission—but SPP and CAISO failed in all subregions.

Key Findings – No Plant Closures Case:

- **Improved System Performance**: Most regions avoided loss of load events. PJM, SPP, and SERC still experienced shortfalls.
- **Regional Failures**:

- **PJM**: 214 hours/year average, 0.066% normalized unserved energy, 644 hours in worst year, max 36% of load lost.

- **SPP**: 48 hours/year average, 0.008% normalized unserved energy, max 19% load lost.

- **ERCOT**: 20 average hours, 0.028% normalized unserved energy, 101 max hours/year, peak shortfall of 27%.

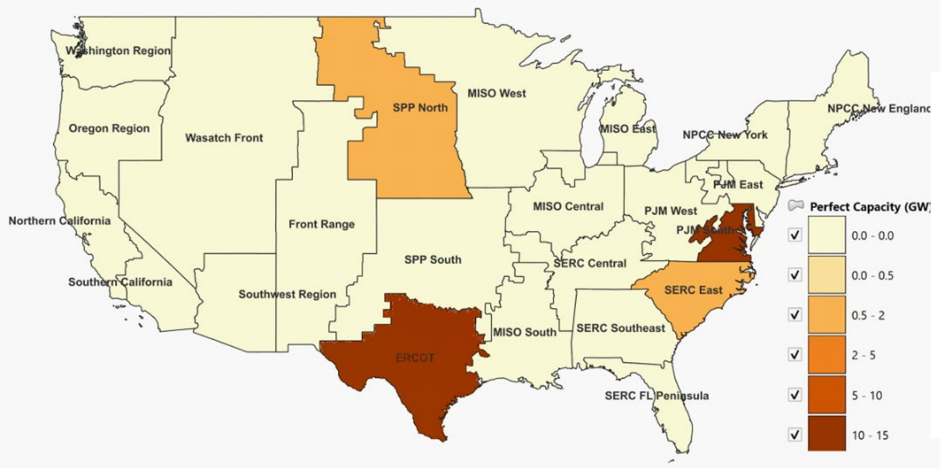
- **SERC-East**: Generally adequate (avg. 1 hour/year, 0.0003% NUSE), but Elliot storm in 2022 caused 42 hours of shortfall.

The overall takeaway is that avoiding announced retirements improves grid reliability, but shortfalls persist in PJM, SPP, ERCOT, and SERC, particularly in winter.

Required Build

This required build analysis quantifies "hypothetical capacity," defined as power that is 100% reliable and available that is needed to resolve the shortfalls. Known in industry as "perfect capacity," this metric is utilized to avoid the complex decision of selecting specific generation technologies, as that is ultimately an optimization of reliability against cost considerations. Nevertheless, it serves as a valuable indicator, illustrating either the magnitude of a resource gap or the scale of large load that will be unable to interconnect. For the Required Build case, this hypothetical capacity was calculated by adding new generating resources to each region until a target of 0.002% of NUSE is reached.

The table below shows the tuned perfect capacity results. For the current system, this analysis identifies an additional 2.4 MW of capacity to meet the NUSE target for PJM, which experiences shortfalls due to the winter storm Elliot historical weather year. By 2030, without considering any generation retirements, an additional 12.5 GW of generating capacity is needed across PJM, SPP, and SERC to reduce shortfalls.



	2024-Current System (MW)	2030-No Plant Closures (MW)
PJM	2400	10,500
SERC-E		500
SPP-N		1,500
ERCOT	1600	10500
Total	4000	23000

Perfect Capacity/Additions

Figure 4. Tuned Perfect Capacity (MW) By Region

1 Modeling Methodology

The methodology uses a zonal PLEXOS[13] model with hourly time-synchronous datasets for load, generation, and interregional transfer for the 23 U.S. subregions (referred to as TPRs in this study)[14] including ERCOT (see Figure 5 below). While ERCOT operates outside of FERC's general jurisdiction,[15] it provides a valuable case for understanding broader reliability and resource adequacy challenges in the U.S. electric grid, and FPA Section 202(c) allows DOE to issue emergency orders to ERCOT.

We base this analysis on actual weather and power plant outage data from 2007 to 2023 using NERC's ITCS[16] base dataset. DOE specifically decided to start this analysis with the ITCS dataset since it is a complete representation of the interconnected electrical system for the lower 48 and it has been thoroughly reviewed by industry experts in a public and transparent process. DOE has in turn made modifications to the dataset to fit the needs of this study. The contents of this section focus on those modifications which DOE implemented for purposes of this study.

PLEXOS is an industry-trusted simulation tool used for energy optimization, resource adequacy, and production cost modeling. This study leverages PLEXOS' ability to exercise an hourly production cost model to determine the balance between loads, generation, and imports for each region. Modeling was carried out using a deterministic approach that evaluates whether a power system has sufficient resources to meet projected demand under a pre-defined set of conditions which correspond to the past few years of real-world events. The model ultimately determines the amount of unmet load if generation resources and imports are not sufficient for meeting the load in each discrete time period.

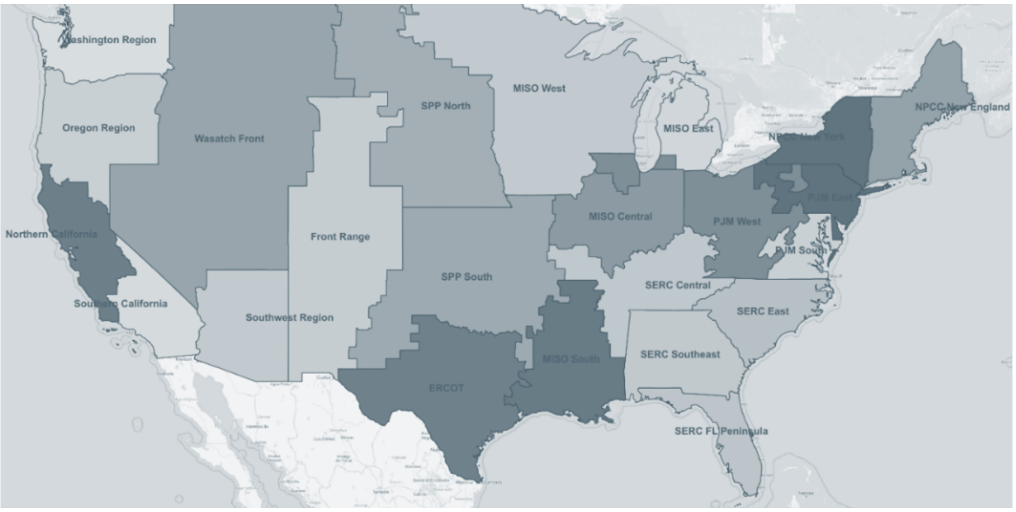


Figure 5. TPRs used in NERC ITCS

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[13] Energy Exemplar, "PLEXOS," https://www.energyexemplar.com/plexos.

[14] The TPRs match the regional subdivisions in the NERC ITCS study, itself based on FERC's transmission planning regions.

[15] Transmission within ERCOT is intrastate commerce. 16 U.S.C. § 824(b)(1) (provisions applying to "the transmission of electric energy in interstate commerce").

[16] NERC "Integrated Transmission and Capacity System (ITCS)," accessed June 25, 2025, https://www.nerc.com/pa/RAPA/Pages/ITCS.aspx.

This methodology developed a current model and series of scenarios to explore how different assumptions impact resource adequacy. This sensitivity analysis includes assumptions regarding load growth, generation build-outs and retirements, and transfer capabilities. By comparing the results of the current model with the scenario results, we can assess how generation retirements and load growth affect future generation needs.

The assessment uses data from 2007–2013 (synthetic weather data) and 2019–2023 (historical data). A brief summary of the methodological assumptions is provided here, with additional details available in the relevant appendixes.

- **Solar and Wind Availability** – Created from historical output from EIA 930 data, with bias correction of any nonhistorical data to match regional capacity factors, as calibrated to EIA 930 data.[17] Synthetic years used 2018 technology characteristics from NREL based on the Variable Energy Potential (reV) model, then mapped to synthetic weather year data. See Appendix A for more details.

- **Thermal Availability** – Calculated according to NERC LTRA capacity data, adjusted for historical outages and derates, primarily with GADS data. GADS data does not capture historical outages caused by fuel supply interruptions.[18]

- **Hydroelectric Availability** – Historical outputs are processed by NERC to establish monthly power rating limits and energy budgets, but energy budgets are not enforced in alignment with how they were treated in the ITCS. The team evaluated performance under different energy budget restrictions, but did not find significant differences during peak hours, justifying NERC ITCS assumptions that hydroelectric resources could generally be dispatched to peak load conditions. Later work may benefit from exploring drought scenarios or combinations of weather and hydrological years, where energy budgets may be significantly decreased.

- **Outages and Derates** – Data for the actual data period (2019–2023) are based on historical forced outage rates and deratings. Outage and deratings data for the synthetic period (2007–2013) are based on the historical relationships observed between temperature and outages (see Appendix G of the NERC ITCS Final Report for more information).

- **Load Projections and AI Growth** – Load growth through 2030 is assumed to match NERC 2024 ITCS projections, scaling the 12 weather years to meet 2030 projections. Additional AI and data center load is then added according to reports from EPRI and S&P regarding potential futures.

- **Transfer Capabilities and Imports/Exports -** Each subregion is treated as a “copper plate,” with the transfer capacity between each subregion defined by the availability of transmission pathways. It is an approximation that assumes all resources are connected to a single point, simplifying the transmission system within the model. Subregions are generally assumed to exhaust their own capacity before utilizing capacity available from their neighbors. Once the net remaining capacity is at or below 10 percent of load, the subregion begins to use capacity from a neighbor.

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17. See ITCS Final Report, Appendix F, for the method that was implemented to scale synthetic weather years 2007–2013.
18. See ITCS Final Report, Appendix G, for outage and derate methods.

  - Imports are assumed to be available up to the minimum total transfer capacity and spare generation in the neighboring subregion.
  - To the extent the remaining capacity after transmission and demand response falls below the 6 percent or 3 percent needed for error forecasting and ancillary services, depending on the scenario, the model projects an energy shortfall. See "Outputs" in the appendix for more details.
  - To ensure that transfers are dispatched only after local resources are exhausted, a wheeling charge of $1,000 is applied for every megawatt-hour of energy transferred between regions through transmission pathways.

- **Storage** – In alignment with the NERC ITCS methodology, storage was split into pumped hydro and battery storage. Pumped hydro was assumed to have 12 hours duration at rated capacity with 30% round-trip losses, while battery storage was assumed to have four hours and 13% round-trip losses. Storage is dispatched as an optimization to minimize USE and demand response usage under various constraints and is recharged during periods of surplus energy.
- **Demand Response –** Demand Response (DR) is treated as a supply-side resource and dynamically scheduled after all other regional resources and imports are exhausted. It is modeled with both capacity (MW) and energy (MWh) limitations and assumed to have three hours of availability at capacity but could be spread across more than three hours up to the energy limit. DR capacity was based on LTRA Form A data submissions for "Controllable and Dispatchable Demand Response – Available", or firm, controllable DR capacity.
- **Retirements** – Retirements as per the NERC LTRA 2024 model. To disaggregate generation capacity from the NERC assessment areas to the ITCS regions, EIA 860 plant level data are used to tabulate generation retirement or addition capacity for each ITCS region and NERC assessment area. Disaggregation fractions are then calculated by technology based on planned retirements through 2030. See Appendix B for further information. Retirements are categorized into two categories:
  1. *Announced Retirements*: Includes both confirmed retirements and announced retirements. Confirmed retirements are generators formally recognized by system operators as having started the official retirement process and are assumed to retire on their expected date. To go from LTRA regions to ITCS regions, weighting factors are derived in the same way as in the generation set, based on EIA retirement data. In addition to confirmed retirements, announced retirements are generators that have publicly stated retirement plans that have not formally notified system operators and initiated the retirement process. This disaggregation method for announced retirements mirrors used for confirmed retirements.[19]
  2. *None*: Removes all retirements (after 2024) for comparison. Delaying or canceling some near-term retirements may not be feasible, but this case can help determine how much retirement contributes to some of the adequacy challenges in some regions.

- **Additions** – Assumes only projects that are very mature in the pipeline (such as those with a signed interconnection agreement) will be built. This data is based on projects

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[19] If announced retirements were less than or equal to confirmed retirements, the model adjusted the announced retirement to equal confirmed.

designated as Tier 1 in the NERC 2024 LTRA and are mapped to ITCS regions with EIA 860-derived weighting factors similar to those described for the retirements above. See Appendix A for further information.

- **Perfect Capacity Required** - Estimates perfect capacity (which is idealized capacity that has no outages or profile and is described in Section 2) until we reach a pre-defined reliability target. We used a metric of NUSE given the deterministic nature of the model, to be consistent with evolving metrics, and to be consistent with NERC's recent LTRAs. We targeted NUSE of below 0.002% for each region.

1.1 Modeling Resource Adequacy

This model calculates several reliability metrics to assess resource adequacy. These metrics were calculated using PLEXOS simulation outputs, which report the USE (in MWh) for all 8,760 hourly periods in each of the 12 weather years:

- **USE** refers to the amount of electricity demand that could not be met due to insufficient generation and/or transmission capacity. Several USE-derived indicators were considered:
    - *Normalized USE (percentage %):* The total amount of unserved load over 12 years of weather data, normalized by dividing by total load, and reported as a percentage.[20]
    - *Mean Annual USE (GWh)*: The 12-year average of each region's total USE in each weather year. This mean value represents the average annual USE across weather variability.
    - *Mean Max Unserved Power (GW)*: The 12-year average of each region's maximum USE value in each weather year. This mean value characterizes the typical non-coincident peak stress on system reliability.
    - *% Max Unserved Power*: The Mean Max Unserved Power expressed as a percentage of the average native load during those peak unserved hours for each region. This percentage value provides a normalized measure of the severity of peak unserved events relative to demand.
    - *Total number of customers without power*. The Mean Max Unserved Power expressed as the equivalent number of typical U.S. persons assuming a ratio of 17,625 persons/MW lost. This estimation contextualizes the effects of the outage on average Americans.
- **Loss of Load Hours (LOLH)** refers to the number of hours during which the system experiences USE (i.e., any hour with non-zero USE). Two LOLH-based indicators were considered:

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[20] NUSE can be reported as parts per million or as a percentage (or parts per hundred); though for power system reliability, this would include several zeros after the decimal point.

- *Mean Annual LOLH*: for each weather year and *TPR*, we count the total number of hours with USE across all 8,760 hours, and we then take the average of those 12 totals. *Annual LOLH Distribution* is represented in box and whisker plots for 12 samples, each sample corresponding to a unique weather year.

- *Max Consecutive LOLH (hours)*[21]: The longest continuous period with reported USE in each weather year.

It should be noted that USE is not an indication that reliability coordinators would allow this level of load growth to jeopardize the reliability of the system. Rather, it represents the unrealizable AI and data center load growth under the given assumptions for generator build outs by 2030, generator retirements by 2030, reserve requirements, and potential load growth. These numbers are used as indicators to determine where it may be beneficial to encourage increased generation and transmission capacity to meet an expected need.

This study does not employ common probabilistic industry metrics such as EUE or LOLE due to their reliance on probabilistic modeling. Instead, deterministic equivalents are used.

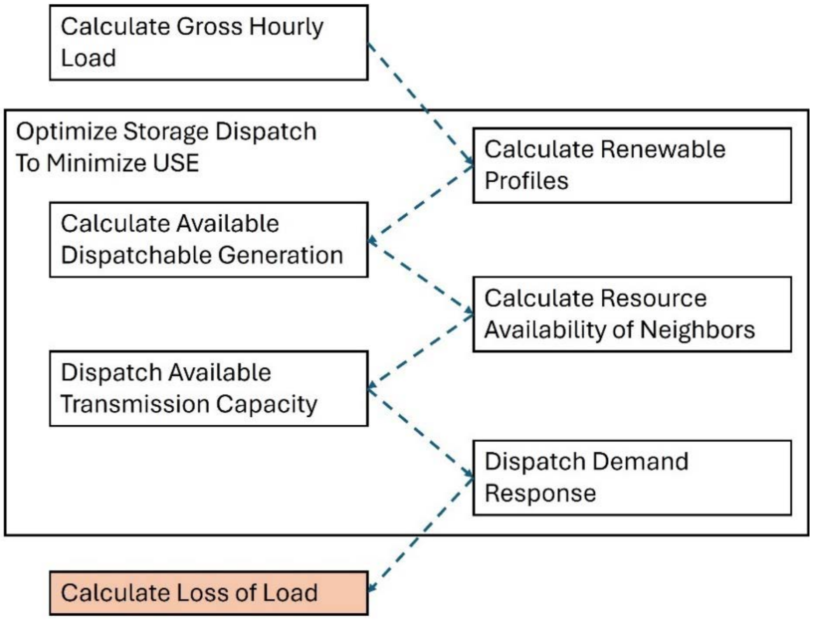

Figure 6. Simplified Overview of Model

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[21] One caveat on the maximum consecutive LOLH and max USE values is in how storage is dispatched in the model. Storage is dispatched to minimize the overall USE and is indifferent to the peak depth or the duration of the event. This may construe some of the max USE and max consecutive LOLH values to be higher than if storage was dispatched to minimize these values.

1.2 Planning Years and Weather Years

For the planning year (2030), historical weather year data are applied based on conditions between 2007 and 2024 to calculate load, wind and solar generation, and hydro generation. Dispatchable capacity (including dispatchable hydro capacity) is calculated through adjustment of the 2024 LTRA capacity data for historical outages from GADS data. Storage assets are scheduled to arbitrage hourly energy margins or else charge during periods of high energy margins (surplus resources) and discharge during periods of lower energy margins.

1.3 Load Modeling

Data Center Growth

Several utilities and financial and industry analysts identify data centers, particularly those supporting AI workloads, as a key driver of electricity demand growth. Multiple organizations have developed a wide range of projections for U.S. data center electricity use through 2030 and beyond, each using distinct methodologies tailored to their institutional expertise.

These datasets were used to explore reasonable boundaries for what different parts of the economy envision for the future state of AI and data center (AI/DC) load growth. For the purposes of this study, rather than focusing on any specific analysis, a more generic sweep was performed across AI/DC load growth and the various sensitivities that fit within those assumptions, as summarized below:

- McKinsey & Company projects ~10% annual growth in U.S. data center electricity demand, reaching 2,445 TWh by 2050. Their model blends internal scenarios with public signals, including announced projects, capital investment, server shipments, and chip-level power trends, supported by third-party market data.

- Lawrence Berkeley National Laboratory (LBNL) uses a bottom-up approach based on historical and projected IT equipment shipments, paired with assumptions on power draw, utilization, and infrastructure efficiency (PUE, WUE). Their projections through 2028 account for AI hardware adoption, operational shifts, and evolving cooling technologies.

- EPRI combines public data, expert input, and historical trends to define four national growth scenarios, low to higher, for 2023–2030, reflecting data processing demand, efficiency improvements, and AI-driven load impacts.

- S&P Global merges technology and power-sector models, evaluating grid readiness and facility growth under varying demand scenarios. Their forecasts consider AI adoption, efficiency trends, grid and permitting constraints, on-site generation, and offshoring risk, resulting in a wide range of outcomes.

These projections show wide variation, with 2030 electricity demand ranging from approximately 35 GW to 108 GW of average load. Given this uncertainty, including differences in hardware intensity, thermal management, siting assumptions, and behind-the-meter generation, the modeling team adopted a national midpoint assumption of approximately 50 GW by 2030.

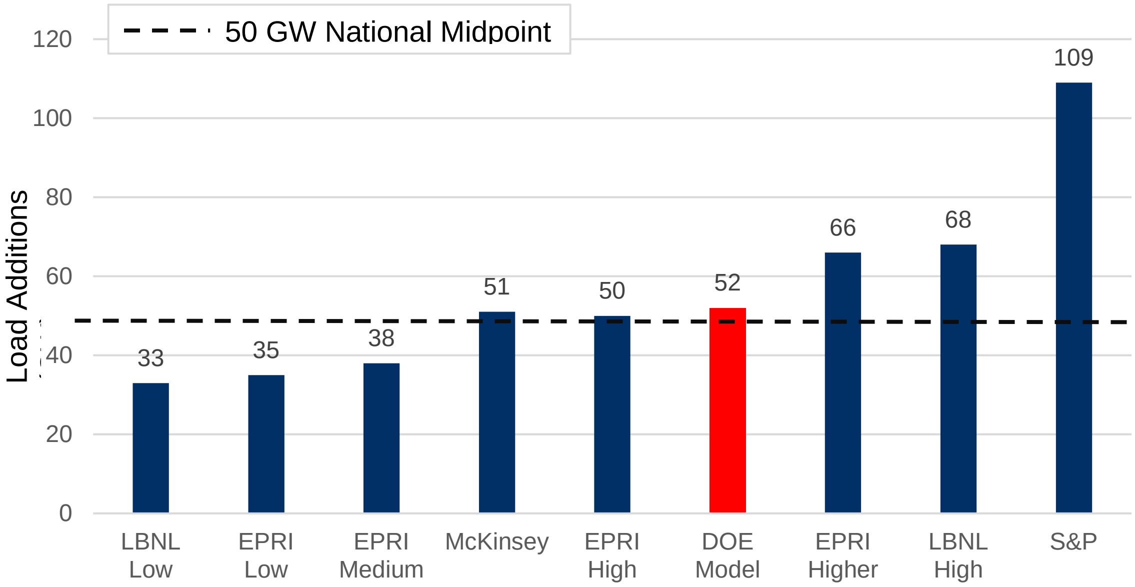

Figure 7. 2024 to 2030 Projected Data Center Load Additions

Figure 2 above displays a benchmark reflecting the median across major studies and aligns with central projections from EPRI and LBNL. Using a single planning midpoint avoids double counting and enables consistent load allocation across national transmission and resource adequacy models.

Data Center Allocation Method

To allocate the 50 GW midpoint regionally, the team used state-level growth ratios from S&P's forecast. These ratios reflect factors such as infrastructure, siting trends, and projected market activity. The modeling team mapped the state-level projections to NERC TPRs, ensuring transparent and repeatable regional allocation. While other methods exist, this approach ensured consistency with the broader modeling framework.

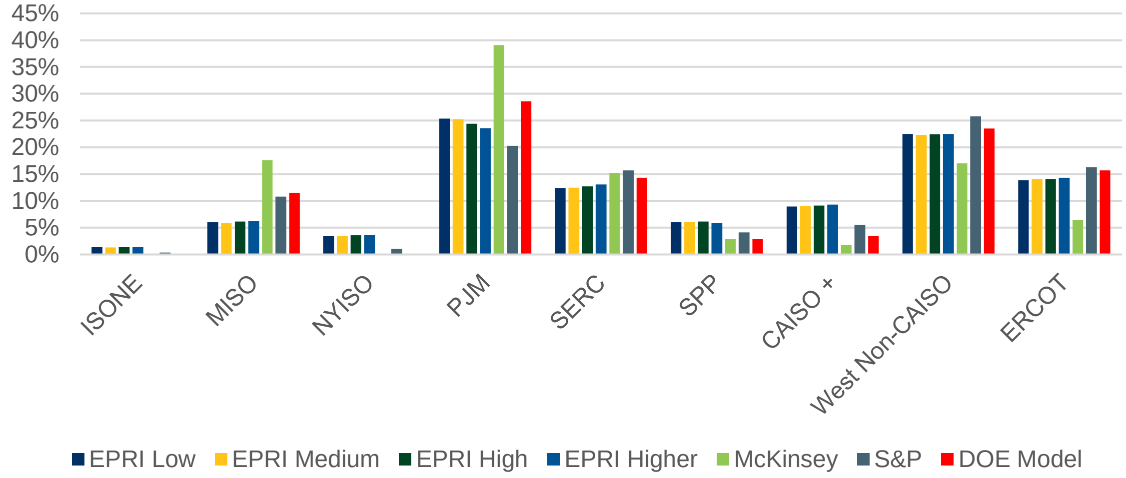

Figure 8. New Data Center Build (% Split by ISO/RTO) (2030 Estimated)

Non-Data Center Load Modeling

The current electricity demand projections were built from NERC data, using historical load (2019–2023) and simulated weather years (2007–2013). These were adjusted based on the EIA's 2022 energy forecast. To estimate 2030 demand, the team interpolated between 2024 and 2033, scaling loads to reflect energy use and seasonal peaks. NERC provided datasets to address anomalies and include behind-the-meter and USE.

Given the rapid emergence of AI/DC loads, additional steps were taken to account for this category of demand. It is difficult to determine how much AI/DC load is already embedded in NERC LTRA forecast, for example, the 2024 LTRA saw more than 50GW increase from 2023, signaling a major shift in utility expectations. To benchmark existing AI/DC contribution, DOE assumed base 2023 AI/DC load equaled the EPRI low-growth case of 166 TWh.

Overall Impact on Projected Peak Load

As a result of the methods applied above, the average year co-incident peak load is projected to grow from a current average peak of 774 GW to 889 GW in 2030. This represents a 15% increase or 2.3% growth rate per year. Excluding the impact of data centers, this would amount to a 51GW increase from 774 GW to 826 GW which represents a 1.1% annual growth rate.

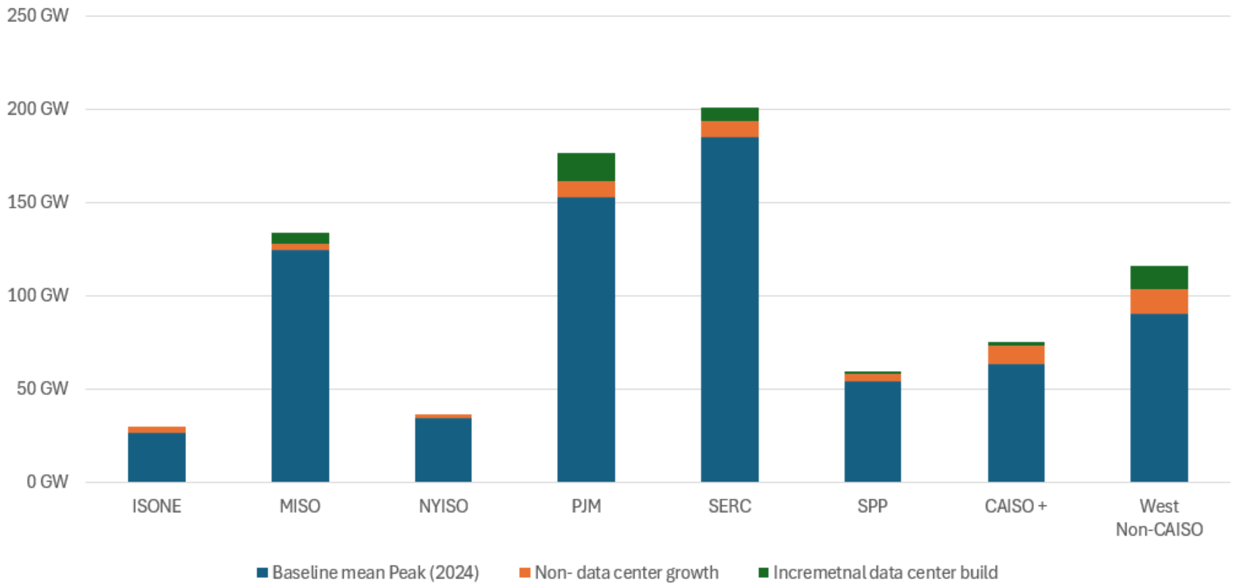

Figure 9. Mean Peak Load by RTO (Current Case vs 2030 Case)

1.4 Transfer Capabilities and Import Export Modeling

The methodology assumes electricity moves between subregions, when conditions start to tighten. Each region has a certain amount of capacity available, and the methodology determines if there is enough to meet the demand. When regions reach a “Tight Margin Level” of 10% of capacity, i.e., if a region’s available capacity is less than 110% of load, it will start transferring from other regions if capacity is available. A scarcity factor is used to determine which regions to transfer from and at what fraction – those with a greater amount of reserve capacity will transfer more. A region is only allowed to export above when it is above the Tight Margin Level.

Total Transfer Capability (TTC) was used and is the sum of the Base Transfer Level and the First Contingency Incremental Transfer Capability. These were derived from scheduled interchange tables or approximated from actual line flows. It should be noted that the TTC does not represent a single line, but rather multiple connections between regions. It is similar to path limits used by many entities but may have different values.

Due to data and privacy limitations, the Canadian power system was not modeled directly as a combination of generation capacity and demand. Instead, actual hourly imports were used from nearly 20 years of historical data, along with recent trends (generally less transfers available during peak hours), to develop daily limits on transfer capabilities. See Appendix B for more details on Canadian transfer limits.

1.5 Perfect Capacity Additions

To understand how much capacity may need to be added to reach approximate reliability targets, we tuned two scenarios by adding hypothetical perfect capacity to reach the reliability threshold based on NUSE.[22] Today, NERC uses a threshold of 0.002% to indicate regions are at high risk of resource adequacy shortfalls. In addition, several system operators, including the Australia Energy Market Operator and Alberta Electric System Operator, are using NUSE thresholds in the range of 0.001% to 0.003%. Several U.S. entities are considering lower thresholds for U.S. power systems in the range of 0.0001% to 0.0002%. [23]

For this analysis, we target NUSE below 0.002% for each region to align with NERC definitions. We iteratively ran the model, hand-tuning the "perfect capacity" to be as small as possible while reaching NUSE values below 0.002% in all regions.[24] As the work was done by hand with a limited number of iterations (15), this should not be considered the minimum possible capacity to accomplish these targets. Further, because the perfect capacity can be located in various places, there would be multiple potential solutions to the problem. These scenarios represent the approximate quantity of perfect capacity each region would require (beyond announced retirements and mature generation additions only) that would lead to Medium or Low risk based on the NERC metrics for USE.

Due to some regions with zero USE, the tuned cases do not reach the same level of adequacy, where the national average is 0.00045% vs. 0.00013%. Due to transmission and siting selection of perfect capacity, there could be many solutions.

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22. We are not using the standard term "expected unserved energy" because we are not running a probabilistic model, so we do not have the full understanding of long-term expectations

23. MISO, "Resource Adequacy Metrics and Criteria Roadmap," December 2024. https://cdn.misoenergy.org/Resource%20Adequacy%20Metrics%20and%20Criteria%20Roadmap667168.pdf.

24. NERC, "Evolving Criteria for a Sustainable Power Grid," July 2024. https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/Evolving_Planning_Criteria_for_a_Sustainable_Power_Grid.pdf.

2 Regional Analysis

This section presents more regional details on resource adequacy according to this analysis. For each of the nine Regional Transmission Organizations (RTOs) and sub-regions, comprehensive summaries are provided of reliability metrics, load assumptions, and composition of generation stacks.

2.1 MISO[25]

In the current system model and the No Plant Closures cases, MISO did not experience shortfall events. MISO's minimum spare capacity in the tightest year was negative, showing that adequacy was achieved by importing power from neighbors. In the Plant Closures case, MISO experienced significant shortfalls, with key reliability metrics exceeding each of the threshold criteria defined for the study.

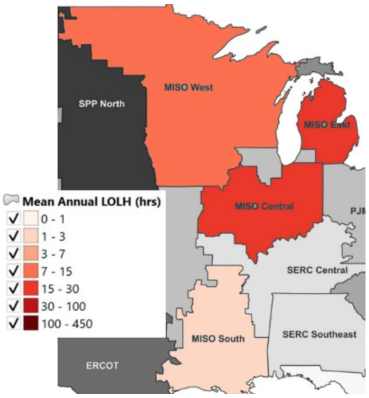

Table 2. Summary of MISO Reliability Metrics

Reliability Metric	Current System	2030 Projection		
		Plant Closures	No Plant Closures	Required Build
AVERAGE OVER 12 WEATHER YEARS				
Average Loss of Load Hours	-	37.8	-	-
Normalized Unserved Energy (%)	-	0.0211	-	-
Unserved Load (MWh)	-	157,599	-	-
WORST WEATHER YEAR				
Max Loss of Load Hours in Single Year	-	124	-	-
Normalized Unserved Load (%)	-	0.0702	-	-
Unserved Load (MWh)	-	524,180	-	-

Load Assumptions

MISO's peak load was roughly 130 GW in the current model and projected to increase to roughly 140 GW by 2030. Approximately 6 GW of this relates to new data centers being installed (12% of U.S. total).

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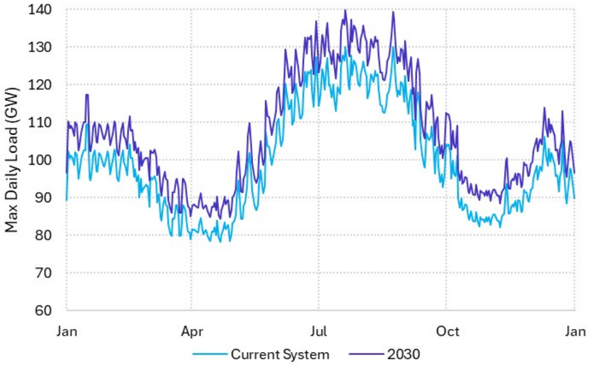
25. Following the initial data collection for this report, MISO issued its 2025 Summer Reliability Assessment. Based on that report, NERC revised evaluations from its 2024 LTRA and reclassified the MISO footprint from being an 'elevated risk' to 'high risk' in the 2028–2031 timeframe, depending on new resource additions/retirements. While DOE's analysis is based on the previously reported figures, DOE is committed to assessing the implications of updated data on overall resource adequacy and providing technical updates on findings, as appropriate.



Subregion	2024	2030
MISO-W	37,913	40,981
MISO-C	35,387	39,243
MISO-S	36,476	38,596
MISO-E	23,167	23,758
Total	**130,136**	**139,846**

Figure 10. MISO Max Daily Load in the Current System versus 2030

Generation Stack

Total installed generating capacity for 2024 was approximately 207 GW.[26] In 2030, 21 GW of new capacity was added leading to 228 GW of capacity in the No Plant Closures case. In the Plant Closures case, 32 GW of capacity was retired such that net retirements in the Plant Closures case were -11 GW, or 196 GW of overall installed capacity on the system.

Subregion	Current System	2030 Plant Closures	2030 No Plant Closures
MISO-W	71,612	67,453	77,605
MISO-C	51,982	47,735	58,823
MISO-S	54,511	52,756	59,710
MISO-E	29,213	28,105	32,255
Total	**207,319**	**196,049**	**228,393**

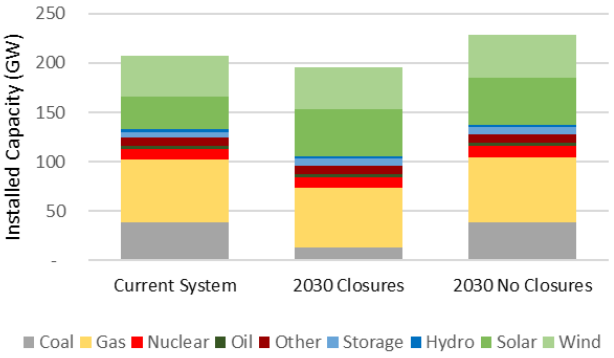


Figure 11. MISO Generation Capacity by Technology and Scenario

MISO's generation mix was comprised primarily of natural gas, coal, wind, and solar. In 2024, natural gas comprised 31% of nameplate, wind comprised 20%, coal 18%, and solar 14%. In 2030, most retirements come from coal and natural gas while additions occur for solar, batteries, and wind. In addition, the model assumed 3 GW of rooftop solar and 8 GW of demand response.

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[26] The total installed capacity numbers reported in this regional analysis section do not reflect the generating capability of all resources during stress conditions.

Table 3. Nameplate Capacity by MISO Subregion and Technology (MW)

	Coal	Gas	Nuclear	Oil	Other	Storage	Hydro	Solar	Wind	Total
2024	**37,914**	**64,194**	**11,127**	**2,867**	**8,717**	**5,427**	**2,533**	**32,826**	**41,715**	**207,319**
MISO-W	12,651	13,608	2,753	1,491	2,613	200	777	8,109	29,411	**71,612**
MISO-C	15,050	10,307	2,169	494	2,211	1,272	769	12,361	7,350	**51,982**
MISO-S	5,493	31,052	5,100	589	2,469	54	845	8,315	596	**54,511**
MISO-E	4,720	9,227	1,105	292	1,424	3,901	143	4,042	4,359	**29,213**
Additions	**0**	**2,535**	**0**	**330**	**0**	**1,929**	**0**	**14,354**	**1,926**	**21,074**
MISO-W	0	537	0	172	0	374	0	3,552	1,358	**5,993**
MISO-C	0	407	0	57	0	934	0	5,103	339	**6,841**
MISO-S	0	1,226	0	68	0	9	0	3,868	27	**5,199**
MISO-E	0	364	0	34	0	611	0	1,831	201	**3,042**
Closures	**(24,913)**	**(6,597)**	**0**	**(324)**	**(140)**	**(16)**	**(83)**	**0**	**(272)**	**(32,345)**
MISO-W	(8,313)	(1,398)	0	(168)	(56)	0	(25)	0	(192)	**(10,152)**
MISO-C	(9,889)	(1,059)	0	(56)	(7)	(3)	(25)	0	(48)	**(11,088)**
MISO-S	(3,609)	(3,191)	0	(67)	(55)	(0)	(28)	0	(4)	**(6,954)**
MISO-E	(3,102)	(948)	0	(33)	(21)	(13)	(5)	0	(28)	**(4,150)**

2.2 ISO-NE

In the current system model and the No Plant Closures case, ISO-NE did not experience shortfall events. The region maintained adequacy throughout the study period through reliance on imports. In the Plant Closures case, ISO-NE still did not exceed any key reliability thresholds, despite moderate retirements. This finding is partly due to the absence of additional AI or data center load growth modeled in the region. Accordingly, no additional perfect capacity was deemed necessary by 2030 to meet the study's reliability standards.

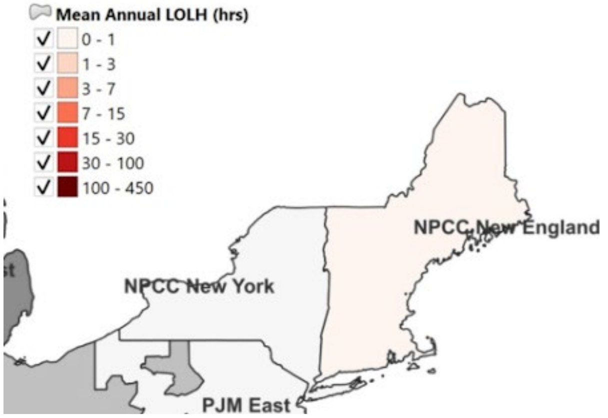
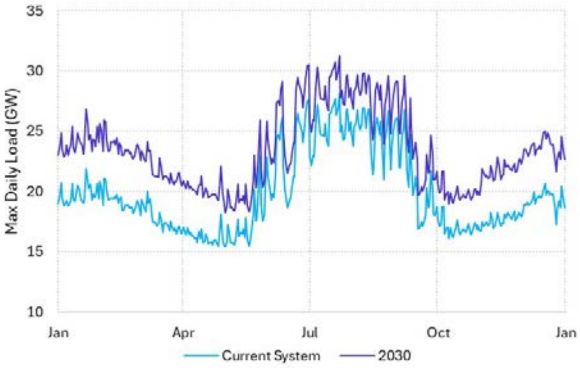


Table 4. Summary of ISO-NE Reliability Metrics

Reliability Metric		2030 Projection		
	Current System	Plant Closures	No Plant Closures	Required Build
AVERAGE OVER 12 WEATHER YEARS				
Average Loss of Load Hours	-	-	-	-
Normalized Unserved Energy (%)	-	-	-	-
Unserved Load (MWh)	-	-	-	-
WORST WEATHER YEAR				
Max Loss of Load Hours in Single Year	-	-	-	-
Normalized Unserved Load (%)	-	-	-	-
Unserved Load (MWh)	-	-	-	-
Max Unserved Load (MW)	-	-	-	-

Load Assumptions

ISO-NE's peak load was roughly 28 GW in the current model and projected to increase to roughly 31 GW by 2030. No additional AI/DCs were projected to be installed.



Subregion	2024	2030
ISO-NE	28,128	31,261
Total	**28,128**	**31,261**

Figure 12. ISO-NE Max Daily Load in the Current System versus 2030

Generation Stack

Total installed generating capacity for 2024 was approximately 40 GW. In 2030, 5.5 GW of new capacity was added leading to 45.5 GW of capacity in the No Plant Closures case. In the Plant Closures case, 2.7 GW of capacity was retired such that net generation change in the Plant Closures case was +11 GW, or 42.8 GW of overall installed capacity on the system.

Subregion	Current System	2030 Plant Closures	2030 No Plant Closures
ISO-NE	39,979	42,845	45,534
Total	**39,979**	**42,845**	**45,534**

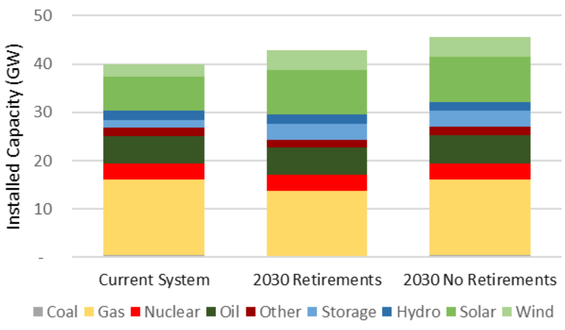


Figure 13. ISO-NE Generation Capacity by Technology and Scenario

ISO-NE's generation mix was comprised primarily of natural gas, solar, oil, and nuclear. In 2024, natural gas comprised 39% of nameplate, solar comprised 17%, oil 14%, and nuclear 8%. In 2030, most retirements come from coal and natural gas while additions occur for solar, storage, and wind. The model assumed nearly 2 GW of rooftop solar and 1.6 GW of energy storage.

Table 5. Nameplate Capacity by ISO-NE Subregion and Technology (MW)

	Coal	Gas	Nuclear	Oil	Other	Storage	Hydro	Solar	Wind	Total
2024	**541**	**15,494**	**3,331**	**5,710**	**1,712**	**1,628**	**1,911**	**7,099**	**2,553**	**39,979**
ISONE	541	15,494	3,331	5,710	1,712	1,628	1,911	7,099	2,553	**39,979**
Additions	**0**	**90**	**0**	**181**	**0**	**1,607**	**0**	**2,183**	**1,495**	**5,555**
ISONE	0	90	0	181	0	1,607	0	2,183	1,495	**5,555**
Closures	**(534)**	**(1,875)**	**0**	**(203)**	**(77)**	**0**	**0**	**0**	**0**	**(2,690)**
ISONE	(534)	(1,875)	0	(203)	(77)	0	0	0	0	**(2,690)**

2.3 NYISO

In both the current system model and the No Plant Closures case, NYISO maintained reliability and did not exceed any shortfall thresholds. Adequacy was preserved through reliance on imports. In the Plant Closures case, NYISO experienced shortfalls but average annual LOLH remaining well below the 2.4-hour threshold and NUSE under the 0.002% standard. The worst weather year produced only 6 hours of lost load and a peak unserved load of 914 MW. Given the modest impact of retirements and no additional AI/data center load modeled, the study concluded that NYISO would not require additional perfect capacity to remain reliable through 2030.

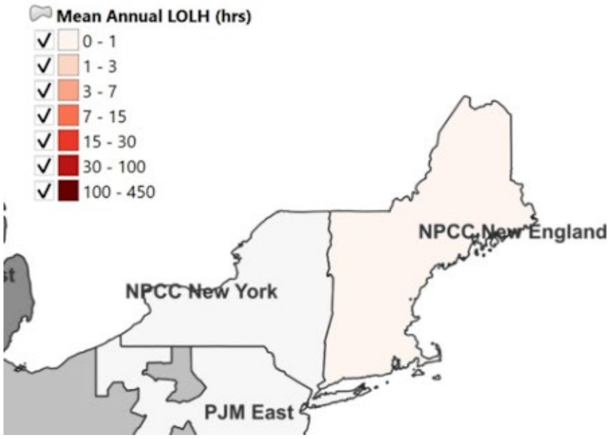
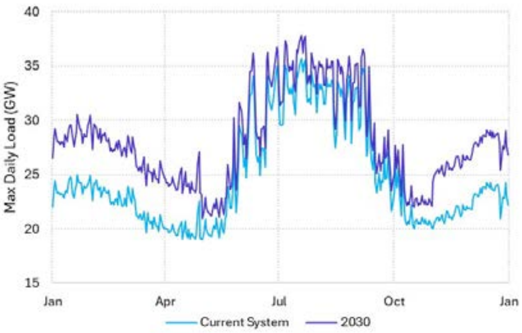


Table 6. Summary of NYISO Reliability Metrics

Reliability Metric	Current System	2030 Projection		
		Plant Closures	No Plant Closures	Required Build
AVERAGE OVER 12 WEATHER YEARS				
Average Loss of Load Hours	0.2	0.5	-	-
Normalized Unserved Energy (%)	0.00001	0.0001	-	-
Unserved Load (MWh)	18	209	-	-
WORST WEATHER YEAR				
Max Loss of Load Hours in Single Year	2	6	-	-
Normalized Unserved Load (%)	0.0001	0.0013	-	-
Unserved Load (MWh)	216	2,505	-	-
Max Unserved Load (MW)	194	914	-	-

Load Assumptions

NYISO's peak load was roughly 36 GW in the current system model and projected to increase to roughly 38 GW by 2030. No additional AI/DCs were projected to be installed.



Subregion	2024	2030
NYISO	35,669	37,844
Total	**35,669**	**37,844**

Figure 14. NYISO Max Daily Load in the Current System versus 2030

Generation Stack

Total installed generating capacity for 2024 was approximately 46 GW. In 2030, 5.5 GW of new capacity was added leading to 51 GW of capacity in the No Plant Closures case. In the Plant Closures case, 1 GW of capacity was retired such that net generation in the Plant Closures case was +4 GW, or 50 GW of overall installed capacity on the system.

Subregion	Current System	2030 Plant Closures	2030 No Plant Closures
NYISO	45,924	50,396	51,444
Total	**45,924**	**50,396**	**51,444**

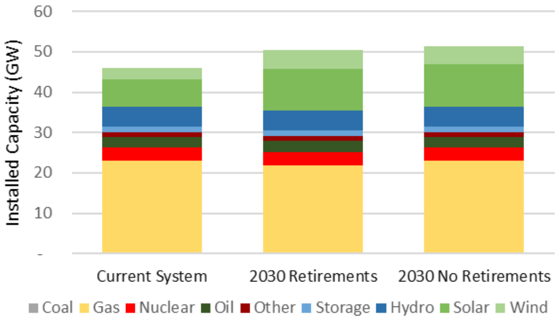


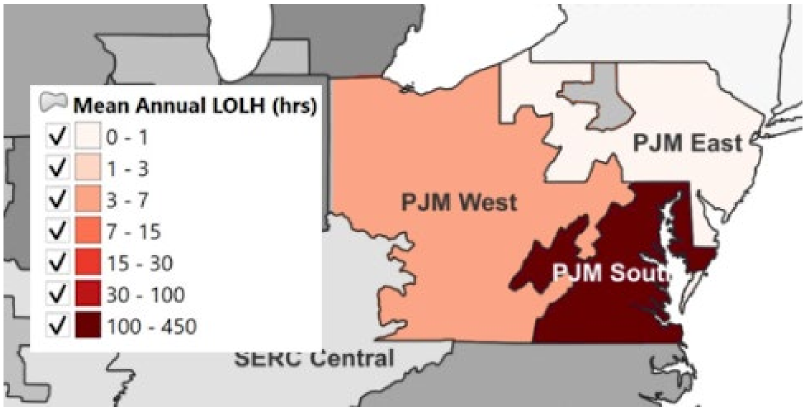
Figure 15. NYISO Generation Capacity by Technology and Scenario

NYISO's generation mix was comprised primarily of natural gas, solar, and hydro. In 2024, natural gas comprised 50% of total nameplate generation, solar comprised 14%, and hydro 11%. In 2030, most retirements come from natural gas while additions occur for solar and wind. The model assumed 6 GW of rooftop solar and nearly 1 GW of demand response.

Table 7. Nameplate Capacity by NYISO Subregion and Technology (MW)

	Coal	Gas	Nuclear	Oil	Other	Storage	Hydro	Solar	Wind	Total
2024	**0**	**22,937**	**3,330**	**2,631**	**1,194**	**1,460**	**4,915**	**6,749**	**2,706**	**45,924**
NYISO	0	22,937	3,330	2,631	1,194	1,460	4,915	6,749	2,706	**45,924**
Additions	**0**	**0**	**0**	**15**	**0**	**0**	**0**	**3,604**	**1,902**	**5,521**
NYISO	0	0	0	15	0	0	0	3,604	1,902	**5,521**
Closures	**0**	**(1,030)**	**0**	**(19)**	**0**	**0**	**0**	**0**	**0**	**(1,049)**
NYISO	0	(1,030)	0	(19)	0	0	0	0	0	**(1,049)**

2.4 PJM



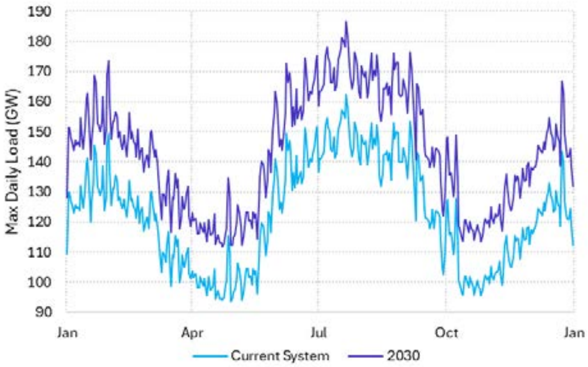
In the current system model, PJM experienced shortfalls, but they were below the required threshold. In the No Plant Closures case, shortfalls increased dramatically, with 214 average annual LOLH and peak unserved load reaching 17,620 MW, indicating growing strain even without retirements. In the Plant Closures case, reliability metrics worsened significantly, with annual LOLH surging to over 430 hours per year and NUSE reaching 0.1473%—over 70 times the accepted threshold. During the worst weather year, 1,052 hours of load were shed. To restore reliability, the study found that PJM would require 10,500 MW of additional perfect capacity by 2030.

Table 8. Summary of PJM Reliability Metrics

Reliability Metric		2030 Projection		
	Current System	Plant Closures	No Plant Closures	Required Build
AVERAGE OVER 12 WEATHER YEARS				
Average Loss of Load Hours	2.4	430.3	213.7	1.4
Normalized Unserved Energy (%)	0.0008	0.1473	0.0657	0.0003
Unserved Load (MWh)	6,891	1,453,513	647,893	2,536
WORST WEATHER YEAR				
Max Loss of Load Hours in Single Year	29	1,052	644	17
Normalized Unserved Load (%)	0.0100	0.4580	0.2703	0.0031
Unserved Load (MWh)	82,687	1,453,513	647,893	2,536
Max Unserved Load (MW)	4,975	21,335	17,620	4,162

Load Assumptions

PJM's peak load was roughly 162 GW in the current system model and projected to increase to roughly 187 GW by 2030. Approximately 15 GW of this relates to new AI/DC being installed (29% of U.S. total), primarily in PJM-S.



Subregion	2024	2030
PJM-W	81,541	92,378
PJM-S	39,904	51,151
PJM-E	41,003	43,118
Total	**162,269**	**186,627**

Figure 16. PJM Max Daily Load in the Current System versus 2030

Generation Stack

Total installed generating capacity for 2024 was approximately 215 GW. In 2030, 39 GW of new capacity was added leading to 254 GW of capacity in the No Plant Closures case. In the Plant Closures case, 17 GW of capacity was retired such that net generation in the Plant Closures case was +22 GW, or 237 GW of overall nameplate capacity on the system.

Subregion	Current System	2030 Plant Closures	2030 No Plant Closures
PJM-W	114,467	123,100	135,810
PJM-S	39,951	48,850	50,667
PJM-E	60,221	64,848	67,027
Total	**214,638**	**236,798**	**253,504**

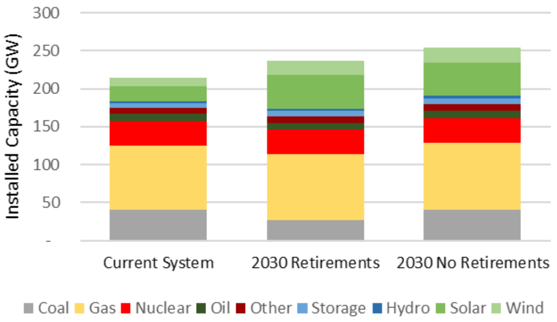


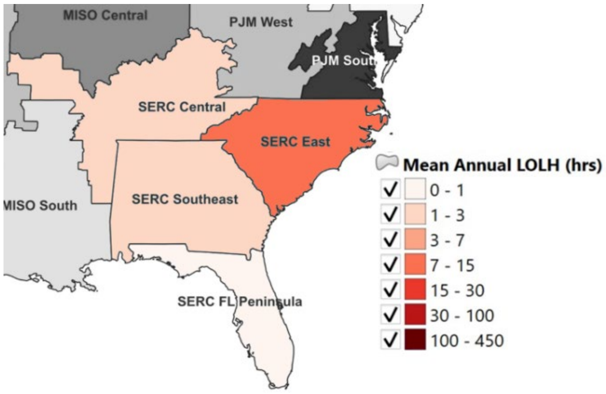
Figure 17. PJM Generation Capacity by Technology and Scenario

PJM's generation mix was comprised primarily of natural gas, coal, and nuclear. In 2024, natural gas comprised 39% of nameplate, coal comprised 19%, and nuclear 15%. In 2030, most retirements come from coal and some natural gas and oil while significant additions occur for solar plus lesser additions of wind, storage, and natural gas. The model assumed 9 GW of rooftop solar and 7 GW of demand response.

Table 9. Nameplate Capacity by PJM Subregion and Technology (MW)

	Coal	Gas	Nuclear	Oil	Other	Storage	Hydro	Solar	Wind	Total
2024	**39,915**	**84,381**	**32,535**	**9,875**	**8,248**	**5,400**	**3,071**	**19,495**	**11,718**	**214,638**
PJM-W	34,917	39,056	16,557	1,933	3,926	383	1,252	6,379	10,065	**114,467**
PJM-S	2,391	15,038	5,288	3,985	2,303	3,085	1,070	6,430	360	**39,951**
PJM-E	2,608	30,287	10,690	3,956	2,019	1,932	749	6,686	1,294	**60,221**
Additions	**0**	**4,499**	**0**	**32**	**317**	**1,938**	**0**	**24,991**	**7,089**	**38,866**
PJM-W	0	2,082	0	6	135	855	0	12,176	6,089	**21,343**
PJM-S	0	802	0	13	102	726	0	8,856	218	**10,717**
PJM-E	0	1,615	0	13	81	357	0	3,958	783	**6,806**
Closures	**(13,253)**	**(1,652)**	**0**	**(1,790)**	**(11)**	**0**	**0**	**0**	**0**	**(16,706)**
PJM-W	(11,593)	(765)	0	(350)	(1)	0	0	0	0	**(12,710)**
PJM-S	(794)	(294)	0	(722)	(6)	0	0	0	0	**(1,817)**
PJM-E	(866)	(593)	0	(717)	(3)	0	0	0	0	**(2,179)**

2.5 SERC



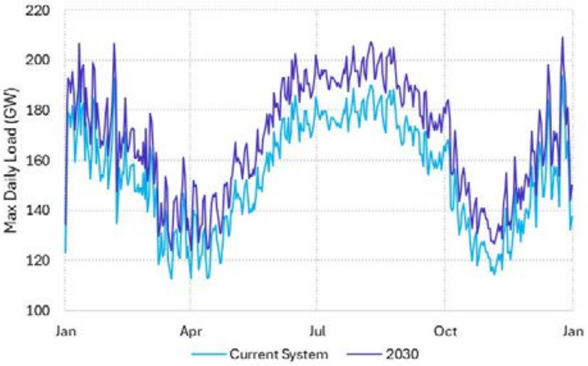
In the current system model and the No Plant Closures case, SERC maintained overall adequacy, though some subregions—particularly SERC-East—faced emerging winter reliability risks. In the Plant Closures case, shortfalls became more severe, with SERC-East experiencing increased unserved energy and loss of load hours during extreme cold events, including 42 hours of outages in a single winter storm. The analysis identified that planned retirements, combined with rising winter load from electrification, would stress the system. To restore reliability in SERC-East, the study found that 500 MW of additional perfect capacity would be needed by 2030. Other SERC subregions performed adequately, but continued monitoring is warranted due to shifting seasonal peaks and fuel supply vulnerabilities.

Table 10. Summary of SERC Reliability Metrics

Reliability Metric	Current System	2030 Projection		
		Plant Closures	No Plant Closures	Required Build
AVERAGE OVER 12 WEATHER YEARS				
Average Loss of Load Hours	0.3	8.1	1.2	0.8
Normalized Unserved Energy (%)	0.0001	0.0041	0.0004	0.0002
Unserved Load (MWh)	489	44,514	3,748	2,373
WORST WEATHER YEAR				
Max Loss of Load Hours in Single Year	4	42	14	10
Normalized Unserved Load (%)	0.0006	0.0428	0.0042	0.0026
Unserved Load (MWh)	5,683	465,392	44,977	2,373
Max Unserved Load (MW)	2,373	19,381	6,359	5,859

Load Assumptions

SERC's peak load was roughly 193 GW in the current system model and projected to increase to roughly 209 GW by 2030. Approximately 7.5 GW of this relates to new AI/DCs being installed (14% of U.S. total).



Subregion	2024	2030
SERC-C	50,787	52,153
SERC-SE	48,235	54,174
SERC-FL	58,882	62,572
SERC-E	51,693	56,313
Total	**193,654**	**209,269**

Figure 18. SERC Max Daily Load in the Current System versus 2030

Generation Stack

Total installed generating capacity for 2024 was approximately 254 GW. In 2030, 26 GW of new capacity was added leading to 279 GW of capacity in the No Plant Closures case. In the Plant Closures case, 19 GW of capacity was retired such that net generation change in the Plant Closures case was +7 GW, or 260 GW of overall installed capacity on the system.

Subregion	Current System	2030 Plant Closures	2030 No Plant Closures
SERC-C	53,978	54,014	59,660
SERC-SE	67,073	64,768	69,478
SERC-FL	72,714	83,127	86,173
SERC-E	59,914	58,513	63,973
Total	**253,680**	**260,423**	**279,285**

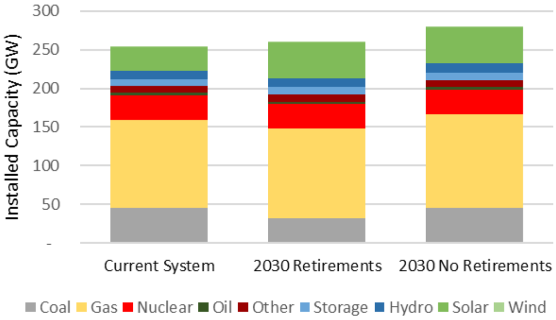


Figure 19. SERC Generation Capacity by Technology and Scenario

SERC's generation mix was comprised primarily of natural gas, coal, nuclear, and solar. In 2024, natural gas comprised 45% of nameplate, coal comprised 18%, nuclear 12%, and solar 11%. In 2030, most retirements come from coal and natural gas while additions occur for solar and some storage. The model assumed 3 GW of rooftop solar and 8 GW of demand response.

Table 11. Nameplate Capacity by SERC Subregion and Technology (MW)

	Coal	Gas	Nuclear	Oil	Other	Storage	Hydro	Solar	Wind	Total
2024	**45,747**	**113,334**	**31,702**	**4,063**	**8,779**	**7,469**	**11,425**	**30,180**	**982**	**253,680**
SERC-C	13,348	20,127	8,280	148	1,887	1,884	4,995	2,328	982	**53,978**
SERC-SE	13,275	29,866	8,018	915	2,493	1,662	3,260	7,584	0	**67,073**
SERC-FL	4,346	47,002	3,502	1,957	3,198	538	0	12,172	0	**72,714**
SERC-E	14,777	16,340	11,902	1,044	1,202	3,384	3,170	8,096	0	**59,914**
Additions	**0**	**6,898**	**0**	**0**	**381**	**2,254**	**0**	**16,073**	**0**	**25,606**
SERC-C	0	4,831	0	0	0	80	0	771	0	**5,682**
SERC-SE	0	906	0	0	19	0	0	3,135	0	**4,059**
SERC-FL	0	1,161	0	0	218	1,670	0	10,410	0	**13,459**
SERC-E	0	0	0	0	144	504	0	1,757	0	**2,405**
Closures	**(14,075)**	**(4,115)**	**0**	**(672)**	**0**	**0**	**0**	**0**	**0**	**(18,862)**
SERC-C	(4,465)	(1,181)	0	0	0	0	0	0	0	**(5,646)**
SERC-SE	(5,160)	(124)	0	(176)	0	0	0	0	0	**(5,460)**
SERC-FL	(1,495)	(1,071)	0	(480)	0	0	0	0	0	**(3,046)**
SERC-E	(2,955)	(1,739)	0	(16)	0	0	0	0	0	**(4,710)**

2.6 SPP

In the current system model, SPP experienced shortfalls, but they were below the required threshold. Adequacy was preserved through reliance on imports. In the No Plant Closures case, SPP experienced persistent reliability challenges, with average annual LOLH reaching approximately 48 hours per year and peak hourly shortfalls affecting up to 19% of demand. In the Plant Closures case, system conditions deteriorated further, with unserved energy and outage hours increasing substantially. These shortfalls were concentrated in the northern subregion, which lacks the firm generation and import capacity needed to meet peak winter demand. The analysis determined that 1,500 MW of additional perfect capacity would be needed in SPP by 2030 to restore reliability.

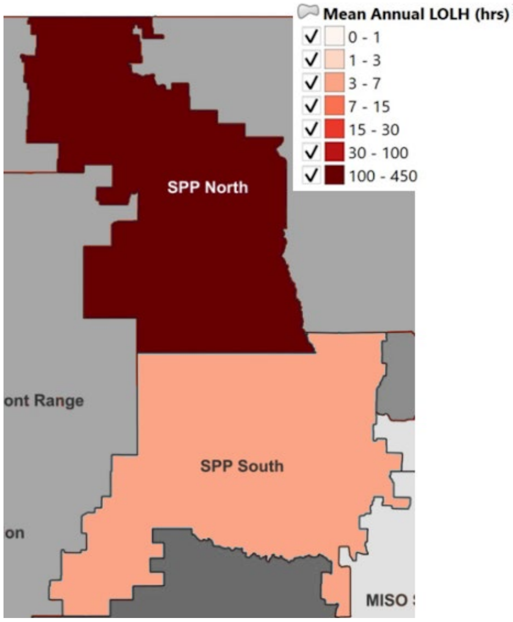
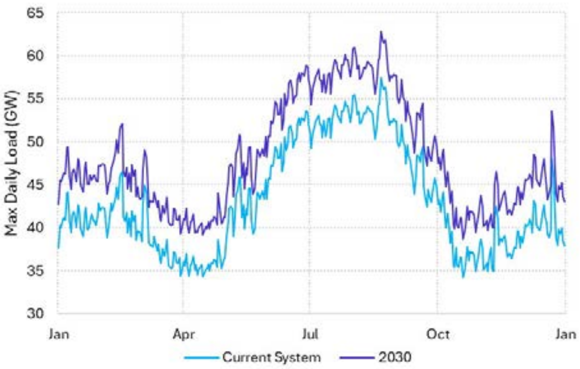


Table 12. Summary of SPP Reliability Metrics

Reliability Metric		2030 Projection		
	Current System	Plant Closures	No Plant Closures	Required Build
AVERAGE OVER 12 WEATHER YEARS				
Average Loss of Load Hours	1.7	379.6	47.8	2.4
Normalized Unserved Energy (%)	0.0002	0.0911	0.0081	0.0002
Unserved Load (MWh)	541	313,797	27,697	803
WORST WEATHER YEAR				
Max Loss of Load Hours in Single Year	20	556	186	26
Normalized Unserved Load (%)	0.0022	0.2629	0.0475	0.0027
Unserved Load (MWh)	6,492	907,518	163,775	9,433
Max Unserved Load (MW)	606	13,263	2,432	762

Load Assumptions

SPP's peak load was roughly 57 GW in the current system model and projected to increase to roughly 63 GW by 2030. Approximately 1.5 GW of this relates to new AI/DCs being installed (3% of U.S. total).



Subregion	2024	2030
SPP-N	12,668	14,676
SPP-S	44,898	48,337
Total	**57,449**	**62,891**

Figure 20. SPP Max Daily Load in the Current System versus 2030

Generation Stack

Total installed generating capacity for 2024 was 95 GW. In 2030, 15 GW of new capacity was added leading to 110 GW of capacity in the No Plant Closures case. In the Plant Closures case, 7 GW of capacity was retired such that net generation change in the 2030 Plant Closures case was +8 GW, or 103 GW of overall installed capacity on the system.

Subregion	Current System	2030 Plant Closures	2030 No Plant Closures
SPP-N	20,065	20,679	22,385
SPP-S	75,078	82,451	88,064
Total	**95,142**	**103,130**	**110,449**

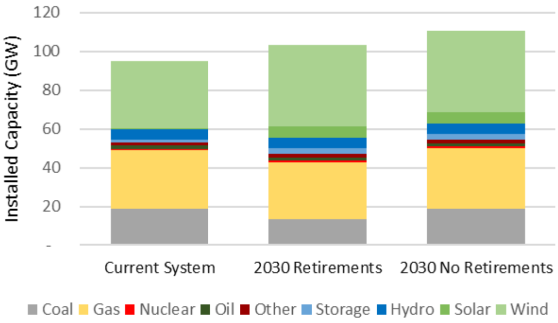


Figure 21. SPP Generation Capacity by Technology and Scenario

SPP's generation mix was comprised primarily of wind, natural gas, and coal. In 2024, wind comprised 36% of nameplate, natural gas comprised 32%, and coal 20%. In the 2030 case, most retirements come from coal and natural gas while additions occur for wind, solar, storage, and natural gas. The model assumed almost no rooftop solar and 1.3 GW of demand response.

Table 13. Nameplate Capacity by SPP Subregion and Technology (MW)

	Coal	Gas	Nuclear	Oil	Other	Storage	Hydro	Solar	Wind	Total
2024	**18,919**	**30,003**	**769**	**1,626**	**1,718**	**1,522**	**5,123**	**774**	**34,689**	**95,142**
SPP-N	5,089	3,467	304	504	519	8	3,041	91	7,041	**20,065**
SPP-S	13,829	26,536	465	1,121	1,199	1,514	2,082	683	27,649	**75,078**
Additions	**0**	**1,094**	**0**	**7**	**462**	**1,390**	**0**	**5,288**	**7,066**	**15,306**
SPP-N	0	126	0	2	114	11	0	633	1,434	**2,320**
SPP-S	0	968	0	5	348	1,379	0	4,655	5,632	**12,987**
Closures	**(5,530)**	**(1,732)**	**0**	**(56)**	**0**	**0**	**0**	**0**	**0**	**(7,318)**
SPP-N	(1,488)	(200)	0	(17)	0	0	0	0	0	**(1,705)**
SPP-S	(4,042)	(1,532)	0	(39)	0	0	0	0	0	**(5,613)**

2.7 CAISO+

In the current system and No Plant Closures cases, CAISO+ did not experience major reliability issues, though adequacy was often maintained through significant imports during tight conditions. In the Plant Closures case, however, the region faced substantial shortfalls, particularly during summer evening hours when solar output declines. Average LOLH reached 7 hours per year, and the worst-case year showed load shed events affecting up to 31% of demand. The NUSE exceeded reliability thresholds, signaling the system's vulnerability to high load and low renewable output periods.

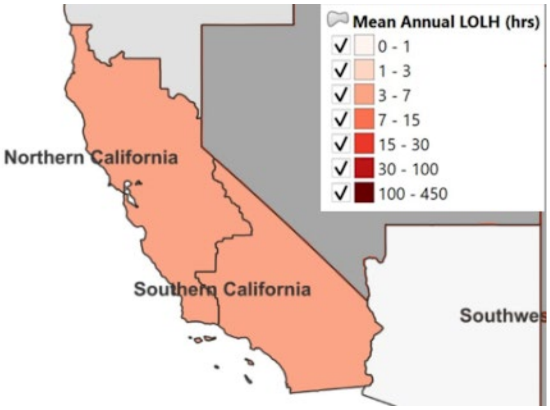
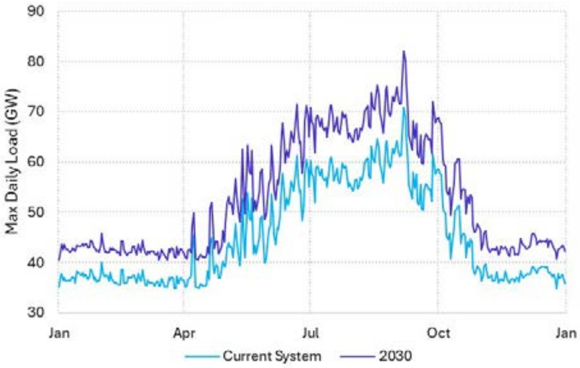


Table 14. Summary of CAISO+ Reliability Metrics

Reliability Metric	Current System	2030 Projection Plant Closures	2030 Projection No Plant Closures	2030 Projection Required Build
AVERAGE OVER 12 WEATHER YEARS				
Average Loss of Load Hours	-	6.8	-	-
Normalized Unserved Energy (%)	-	0.0062	-	-
Unserved Load (MWh)	-	23,488	-	-
WORST WEATHER YEAR				
Max Loss of Load Hours in Single Year	-	21	-	-
Normalized Unserved Load (%)	-	0.0195	-	-
Unserved Load (MWh)	-	73,462	-	-
Max Unserved Load (MW)	-	12,391	-	-

Load Assumptions

CAISO+'s peak load was roughly 79 GW in the current system model and projected to increase to roughly 82 GW by 2030. Approximately 2 GW of this relates to new AI/DCs being installed (4% of U.S. total).



Subregion	2024	2030
CALI-N	29,366	34,066
CALI-S	41,986	48,666
Total	**70,815**	**82,146**

Figure 22. CAISO+ Max Daily Load in the Current System versus 2030

Generation Stack

Total installed generating capacity for 2024 was approximately 117 GW. In 2030, 14 GW of new capacity was added leading to 131 GW of capacity in the No Plant Closures case. In the Plant Closures case, 8 GW of capacity was retired such that net closures in the Plant Closures case were +6 GW, or 123 GW of overall installed capacity on the system.

Subregion	Current System	2030 Plant Closures	2030 No Plant Closures
CALI-N	47,059	48,897	52,501
CALI-S	69,866	74,041	78,308
Total	**116,925**	**122,938**	**130,809**

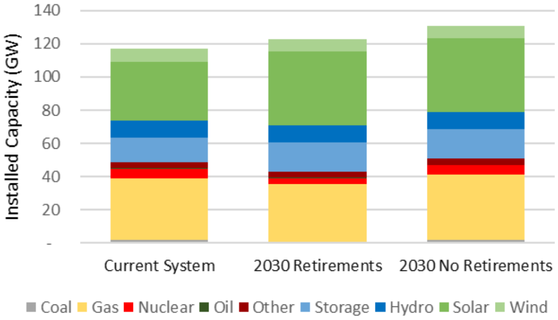


Figure 23. CAISO+ Generation Capacity by Technology and Scenario

CAISO+'s generation mix was comprised primarily of natural gas, solar, storage, and hydro. In 2024, natural gas comprised 32% of nameplate, solar comprised 31%, storage 13%, and hydro 9%. In 2030, most retirements come from coal, natural gas, and nuclear while additions occur for solar and storage. The model assumed 10 GW of rooftop solar and less than 1 GW of demand response.

Table 15. Nameplate Capacity by CAISO+ Subregion and Technology (MW)

	Coal	Gas	Nuclear	Oil	Other	Storage	Hydro	Solar	Wind	Total
2024	**1,816**	**37,434**	**5,582**	**185**	**3,594**	**14,670**	**10,211**	**35,661**	**7,773**	**116,925**
CALI-N	0	12,942	5,582	165	1,872	4,639	8,727	11,759	1,373	**47,059**
CALI-S	1,816	24,492	0	20	1,722	10,031	1,483	23,902	6,400	**69,866**
Additions	**0**	**2,126**	**0**	**0**	**92**	**3,161**	**0**	**8,507**	**0**	**13,885**
CALI-N	0	735	0	0	44	757	0	3,906	0	**5,442**
CALI-S	0	1,391	0	0	48	2,404	0	4,600	0	**8,442**
Closures	**(1,800)**	**(3,771)**	**(2,300)**	**0**	**0**	**0**	**0**	**0**	**0**	**(7,871)**
CALI-N	0	(1,304)	(2,300)	0	0	0	0	0	0	**(3,604)**
CALI-S	(1,800)	(2,467)	0	0	0	0	0	0	0	**(4,267)**

2.8 West Non-CAISO

In both the current system and No Plant Closures cases, the West Non-CAISO region maintained adequacy on average. In the Plant Closures case, the region's reliability declined, with annual LOLH increasing and peak shortfalls in the worst year affecting up to 20% of hourly load in some subregions. While overall NUSE normalized unserved energy remained just above the 0.002% threshold, specific areas, especially those with limited local resources and constrained transmission, exceeded acceptable risk levels. These reliability gaps were primarily driven by increasing reliance on variable energy resources without sufficient firm generation.

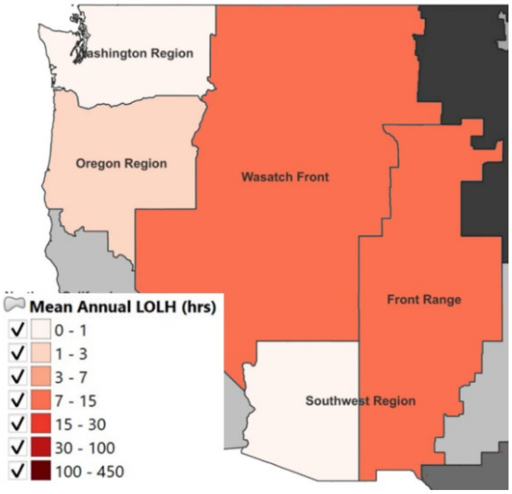
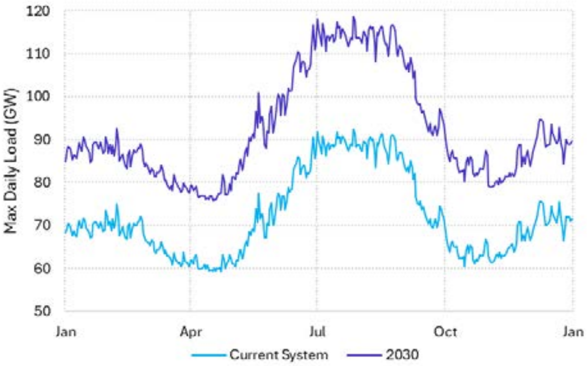


Table 16. Summary of West Non-CAISO Reliability Metrics

Reliability Metric		2030 Projection		
	Current System	Plant Closures	No Plant Closures	Required Build
AVERAGE OVER 12 WEATHER YEARS				
Average Loss of Load Hours	-	17.8	-	-
Normalized Unserved Energy (%)	-	0.0032	-	-
Unserved Load (MWh)	-	21,785	-	-
WORST WEATHER YEAR				
Max Loss of Load Hours in Single Year	-	47	-	-
Normalized Unserved Load (%)	-	0.0098	-	-
Unserved Load (MWh)	-	66,248	-	-
Max Unserved Load (MW)	-	5,071	-	-

Load Assumptions

West Non-CAISO's peak load was roughly 92 GW in the current system model and projected to increase to roughly 119 GW by 2030. Approximately 12 GW of this relates to new AI/DCs being installed (24% of U.S. total).



Subregion	2024	2030
WASHINGTON	20,756	23,187
OREGON	11,337	16,080
SOUTHWEST	23,388	30,169
WASATCH	27,161	35,440
FRONT R	20,119	24,996
Total	**92,448**	**118,657**

Figure 24. West Non-CAISO Max Daily Load in the Current System versus 2030

Generation Stack

Total installed generating capacity for 2024 was 178 GW. In 2030, 29 GW of new capacity was added leading to 207 GW of capacity in the No Plant Closures case. In the Plant Closures case, 13 GW of capacity was retired such that net generation change in the Plant Closures case was 16 GW, or 193 GW of overall installed capacity on the system.

Subregion	Current System	2030 Plant Closures	2030 No Plant Closures
WASHINGTON	35,207	36,588	37,573
OREGON	19,068	21,689	22,081
SOUTHWEST	42,335	47,022	49,158
WASATCH	42,746	45,175	50,251
FRONT R	38,572	43,011	47,844
Total	**177,929**	**193,485**	**206,908**

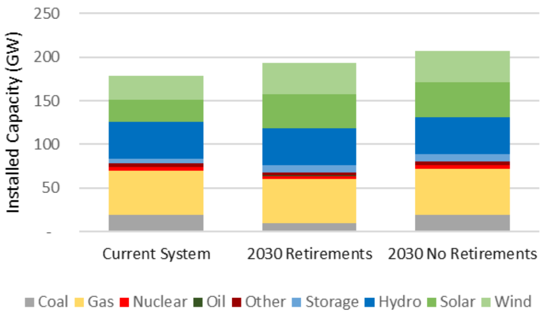


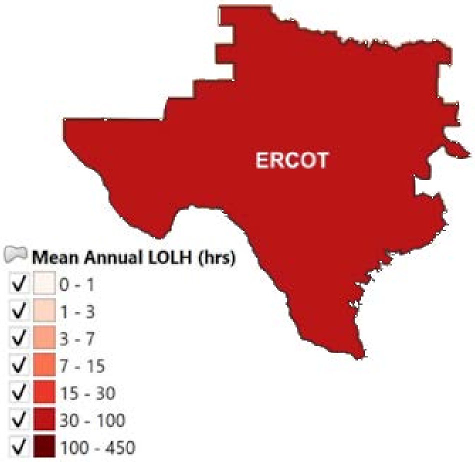
Figure 25. West Non-CAISO Generation Capacity by Technology and Scenario

West Non-CAISO's generation mix was comprised primarily of natural gas, hydro, wind, solar, and coal. In 2024, natural gas comprised 28% of nameplate, hydro comprised 24%, wind 15%, solar 13%, and coal 11%. In 2030, most retirements come from coal and natural gas while additions occur for solar, wind, storage, and natural gas. The model assumed 6 GW of rooftop solar and over 1 GW of demand response.

Table 17. Nameplate Capacity by West Non-CAISO Subregion and Technology (MW)

	Coal	Gas	Nuclear	Oil	Other	Storage	Hydro	Solar	Wind	Total
2024	**19,850**	**49,969**	**3,820**	**644**	**4,114**	**5,104**	**42,476**	**24,652**	**27,298**	**177,929**
WASHINGTON	560	3,919	1,096	17	595	489	24,402	1,438	2,690	**35,207**
OREGON	0	3,915	0	6	456	482	8,253	2,517	3,440	**19,068**
SOUTHWEST	4,842	17,985	2,724	323	1,316	2,349	1,019	8,093	3,685	**42,335**
WASATCH	7,033	14,061	0	87	1,433	1,194	7,587	7,299	4,052	**42,746**
FRONT R	7,415	10,089	0	211	314	590	1,215	5,306	13,432	**38,572**
Additions	**0**	**2,320**	**0**	**1**	**8**	**2,932**	**0**	**14,759**	**8,959**	**28,979**
WASHINGTON	0	246	0	0	0	109	0	1,059	952	**2,366**
OREGON	0	246	0	0	0	150	0	1,399	1,218	**3,013**
SOUTHWEST	0	309	0	0	0	2,338	0	3,578	599	**6,823**
WASATCH	0	884	0	0	7	233	0	4,946	1,435	**7,505**
FRONT R	0	634	0	0	0	102	0	3,779	4,756	**9,271**
Closures	**(9,673)**	**(2,540)**	**0**	**(6)**	**(311)**	**(170)**	**(627)**	**0**	**(95)**	**(13,422)**
WASHINGTON	(317)	(195)	0	(0)	(66)	(28)	(369)	0	(11)	**(986)**
OREGON	0	(195)	0	(0)	(58)	0	(125)	0	(14)	**(392)**
SOUTHWEST	(1,185)	(951)	0	0	0	0	0	0	0	**(2,136)**
WASATCH	(3,978)	(699)	0	(2)	(178)	(89)	(115)	0	(16)	**(5,077)**
FRONT R	(4,194)	(501)	0	(4)	(8)	(53)	(18)	0	(54)	**(4,832)**

2.9 ERCOT



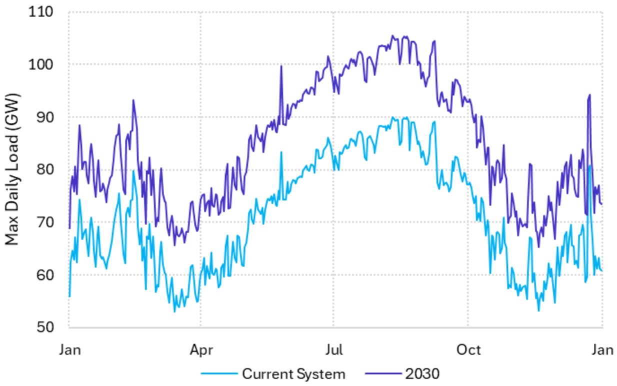
In the current system model, ERCOT exceeded reliability thresholds, with 3.8 annual Loss of Load Hours and a NUSE of 0.0032%, indicating stress even before future retirements and load growth. In the No Plant Closures case, conditions worsened as average LOLH rose to 20 hours per year and the worst-case year reached 101 hours, driven by data center growth and limited dispatchable additions. The Plant Closures case intensified these risks, with average annual LOLH rising to 45 hours per year and unserved load reaching 0.066%. Peak shortfalls reached 27% of demand, with outages concentrated in winter when generation is most vulnerable. To meet reliability targets, ERCOT would require 10,500 MW of additional perfect capacity by 2030.

Table 18. Summary of ERCOT Reliability Metrics

Reliability Metric		2030 Projection		
	Current System	Plant Closures	No Plant Closures	Required Build
AVERAGE OVER 12 WEATHER YEARS				
Average Loss of Load Hours	3.8	45.0	20.3	1.0
Normalized Unserved Energy (%)	0.0032	0.0658	0.0284	0.0008
Unserved Load (MWh)	15,378	397,352	171,493	4,899
WORST WEATHER YEAR				
Max Loss of Load Hours in Single Year	30	149	101	12
Normalized Unserved Load (%)	0.0286	0.02895	0.01820	0.0098
Unserved Load (MWh)	136,309	1,741,003	1,093,560	58,787
Max Unserved Load (MW)	10,115	27,156	23,105	8,202

Load Assumptions

ERCOT's peak load was roughly 90 GW in the current system model and projected to increase to roughly 105 GW by 2030. Approximately 8 GW of this relates to new data centers being installed (62% of U.S. total).



Subregion	2024	2030
ERCOT	90,075	105,485
Total	**90,075**	**105,485**

Figure 26. ERCOT Max Daily Load in the Current System versus 2030

Generation Stack

Total installed generating capacity for 2024 was 157 GW. In 2030, 55 GW of new capacity was added leading to 213 GW of capacity in the No Plant Closures case. In the Plant Closures case, 4 GW of capacity was retired such that net generation change in the Plant Closures case was +51 GW, or 208 GW of overall nameplate capacity on the system.

Subregion	Current System	2030 Plant Closures	2030 No Plant Closures
ERCOT	157,490	208,894	212,916
Total	**157,490**	**208,894**	**212,916**

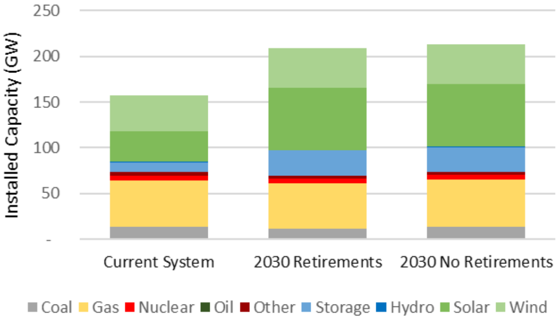


Figure 27. ERCOT Generation Capacity by Technology and Scenario

ERCOT's generation mix was comprised primarily of natural gas, wind, and solar. In 2024, natural gas comprised 32% of nameplate, wind comprised 25%, and solar 22%. In 2030, most retirements come from coal and natural gas while additions occur for solar, storage, and wind. The model assumed 2.5 GW of rooftop solar and 3.5 GW of demand response.

Table 19. Nameplate Capacity for ERCOT and by Technology (MW)

	Coal	Gas	Nuclear	Oil	Other	Storage	Hydro	Solar	Wind	Total
2024	**13,568**	**50,889**	**4,973**	**10**	**3,627**	**10,720**	**583**	**33,589**	**39,532**	**157,490**
ERCOT	13,568	50,889	4,973	10	3,627	10,720	583	33,589	39,532	**157,490**
Additions	**0**	**569**	**0**	**0**	**0**	**16,538**	**0**	**34,681**	**3,638**	**55,426**
ERCOT	0	569	0	0	0	16,538	0	34,681	3,638	**55,426**
Closures	**(2,000)**	**(2,022)**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**(4,022)**
ERCOT	(2,000)	(2,022)	0	0	0	0	0	0	0	**(4,022)**

Appendix A - Generation Calibration and Forecast

The study team started with the grid model from the NERC ITCS, which was published in 2024 with reference to NERC 2023 LTRA capacity.[27] This zonal ITCS model serves as the starting point for the network topology (covering 23 U.S regions), transmission capacity between zones, and general modeling assumptions. The resource mix and retirements in the ITCS model were updated for this study to reflect the various 2030 scenarios discussed previously. Prior to developing the 2030 scenarios, the study team also updated the 2024 ITCS model to ensure consistency in the current model assumptions.

2024 Resource Mix

Because there were noted changes in assumed capacity additions between the 2023 and 2024 LTRAs[28], the ITCS model was updated with the 2024 LTRA data, provided directly by NERC to the study team. The 2024 LTRA dataset, reported at the NERC assessment area level—which is more aggregated in some areas than the ITCS regional structure (covering 13 U.S. regions; see Figure A.1)—includes both existing resource capacities[29] and Tier 1, 2, and 3 planned additions for each year from 2024 to 2033. As explained below, to incorporate this data into the ITCS model, a mapping process was developed to disaggregate generation capacities from the NERC assessment areas to the more granular ITCS regions by technology type. To preserve the daily or monthly adjustments to generator availability for certain categories (wind, solar, hybrid, hydropower, batteries, and other) by using the ITCS methods, the nameplate LTRA capacity was used. For all other categories (mostly thermal generators), summer and winter on-peak capacity contributions were used.

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[27] NERC, "Interregional Transfer Capability Study (ITCS)." https://www.nerc.com/pa/RAPA/Documents/ITCS_Final_Report.pdf.

[28] NERC, "2024 Long-Term Reliability Assessment," December, 2024, 24. https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_Long%20Term%20Reliability%20Assessment_2024.pdf.

[29] Capacities are reported for both winter and summer seasonal ratings, along with nameplate values.

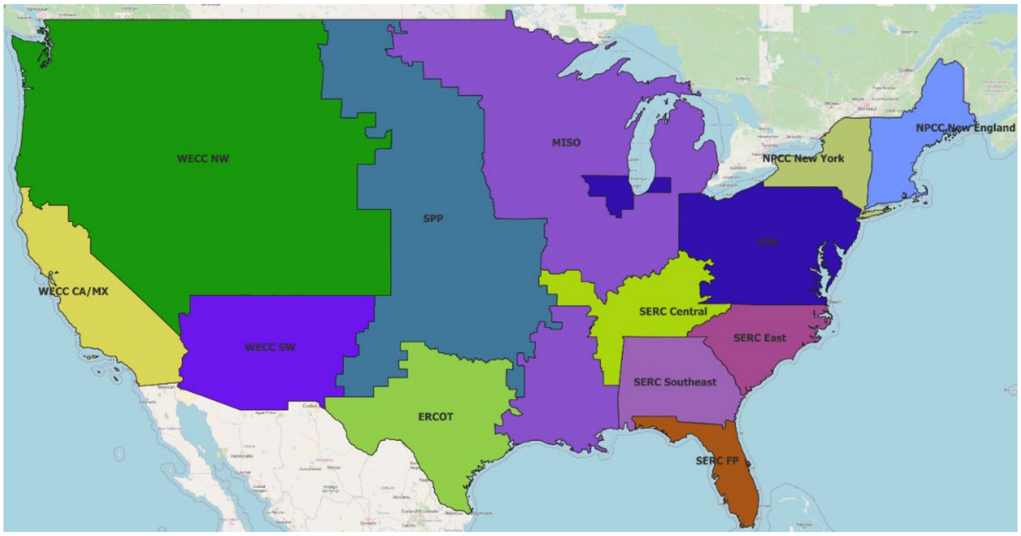

Figure A.1. NERC assessment areas.

To disaggregate generation capacity from the NERC assessment areas to the ITCS regions, EIA 860 plant-level data were used to tabulate the generation capacity for each ITCS region and NERC assessment area. The geographical boundaries for the NERC assessment areas and the ITCS regions were constructed based on ReEDS zones.[30] Disaggregation fractions were then calculated by technology type using the combined existing capacity and planned additions through 2030 from EIA 860 data as of December 2024. Specifically, to compute each fraction, an ITCS region's total (existing plus planned) capacity was divided by the corresponding total capacity across all ITCS regions within the same mapped NERC assessment area and fuel type group:

$$Fraction_{rf} = \frac{Capacity_{rf}}{\sum_{r' \in ITCS(R)} Capacity_{r'f}} \qquad \text{(Equation.1)}$$

Where $Capacity_{rf}$ is the capacity of fuel type f in ITCS region r and $ITCS(R)$ is the set of all ITCS regions mapped to the same NERC assessment area R. The denominator is the total capacity of that fuel type across all ITCS regions mapped to R.

Note that in cases where NERC assessment areas align one-to-one with ITCS regions, no mapping was required. Table A.1 summarizes which areas exhibited a direct one-to-one matching and which required disaggregation (1-to-many) or aggregation (many-to-one) to align with the ITCS regional structure.

An exception to this general approach is the case of the Front Range ITCS region, which geographically spans across two NERC assessment areas—WECC-NW and WECC-SW—resulting in two-to-one mapping. For this case, a separate allocation method was used: Plant-level data from EIA 860 were analyzed to determine the proportion of Front Range capacity located in each NERC area. These proportions were then used to derive custom weighting factors for allocating capacities from both WECC-NW and WECC-SW into the Front Range region.

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[30] NREL, "Regional Energy Development System," https://www.nrel.gov/analysis/reeds/.

Table A.1. Mapping of NERC assessment areas to ITCS regions.

NERC Area	ITCS Region	Match
ERCOT	ERCOT	1 to 1
NPCC-New England	NPCC-New England	1 to 1
NPCC-New York	NPCC-New York	1 to 1
SERC-C	SERC-C	1 to 1
SERC-E	SERC-E	1 to 1
SERC-FP	SERC-FP	1 to 1
SERC-SE	SERC-SE	1 to 1
WECC-SW	Southwest Region	1 to 1
MISO	MISO Central	1 to 4
MISO	MISO East	
MISO	MISO South	
MISO	MISO West	
SPP	SPP North	1 to 2
SPP	SPP South	
WECC-CAMX	Southern California	1 to 2
WECC-CAMX	Northern California	
WECC-NW	Oregon Region	1 to 3
WECC-NW	Washington Region	
WECC-NW	Wasatch Front	
WECC-NW	Front Range	2 to 1
WECC-SW	Front Range	

Table A.2 and Figure A.2 show the same combined capacities by ITCS region and NERC planning region, respectively.

Table A.2. Existing and Tier 1 capacities by NERC assessment area (in MW) in 2024.

2024 Exsting + Tier 1			Coal	NG	Nuclear	Oil	Biomass	Geo	Other	Pumped Storage	Battery	Hydro	Solar	Wind	DR	DGPV	Total
EAST	**Total**		**143,035**	**330,342**	**82,793**	**26,771**	**3,624**	**-**	**991**	**19,607**	**3,298**	**28,980**	**72,757**	**94,364**	**25,753**	**24,367**	**856,682**
	ISONE	**Total**	541	15,494	3,331	5,710	818	-	233	1,571	57	1,911	3,386	2,553	661	3,713	39,979
	MISO	**Total**	**37,914**	**64,194**	**11,127**	**2,867**	**613**	**-**	**329**	**4,396**	**1,031**	**2,533**	**29,777**	**41,715**	**7,775**	**3,049**	**207,319**
		MISO-W	12,651	13,608	2,753	1,491	244	-	2	-	200	777	7,368	29,411	2,367	741	71,612
		MISO-C	15,050	10,307	2,169	494	32	-	152	773	499	769	10,587	7,350	2,026	1,774	51,982
		MISO-S	5,493	31,052	5,100	589	243	-	117	49	5	845	8,024	596	2,109	291	54,511
		MISO-E	4,720	9,227	1,105	292	94	-	57	3,574	327	143	3,799	4,359	1,273	243	29,213
	NYISO	**Total**	-	22,937	3,330	2,631	334	-	-	1,400	60	4,915	1,039	2,706	860	5,710	45,924
	PJM	**Total**	**39,915**	**84,381**	**32,535**	**9,875**	**851**	**-**	**-**	**5,062**	**338**	**3,071**	**10,892**	**11,718**	**7,397**	**8,603**	**214,638**
		PJM-W	34,917	39,056	16,557	1,933	112	-	-	234	149	1,252	5,780	10,065	3,814	599	114,467
		PJM-S	2,391	15,038	5,288	3,985	479	-	-	2,958	127	1,070	3,932	360	1,824	2,498	39,951
		PJM-E	2,608	30,287	10,690	3,956	260	-	-	1,870	62	749	1,180	1,294	1,759	5,506	60,221
	SERC	**Total**	**45,747**	**113,334**	**31,702**	**4,063**	**989**	**-**	**83**	**6,701**	**768**	**11,425**	**26,959**	**982**	**7,707**	**3,221**	**253,680**
		SERC-C	13,348	20,127	8,280	148	36	-	-	1,784	100	4,995	2,308	982	1,851	20	53,978
		SERC-SE	13,275	29,866	8,018	915	424	-	-	1,548	115	3,260	7,267	-	2,069	317	67,073
		SERC-FL	4,346	47,002	3,502	1,957	310	-	83	-	538	-	10,121	-	2,804	2,051	72,714
		SERC-E	14,777	16,340	11,902	1,044	219	-	-	3,369	15	3,170	7,263	-	983	833	59,914
	SPP	**Total**	**18,919**	**30,003**	**769**	**1,626**	**20**	**-**	**345**	**477**	**1,044**	**5,123**	**703**	**34,689**	**1,353**	**71**	**95,142**
		SPP-N	5,089	3,467	304	504	1	-	185	-	8	3,041	84	7,041	333	7	20,065
		SPP-S	13,829	26,536	465	1,121	19	-	160	477	1,037	2,082	619	27,649	1,020	64	75,078
ERCOT	**Total**		**13,568**	**50,889**	**4,973**	**10**	**163**	**-**	**-**	**-**	**10,720**	**583**	**31,058**	**39,532**	**3,464**	**2,531**	**157,490**
	ERCOT	**Total**	13,568	50,889	4,973	10	163	-	-	-	10,720	583	31,058	39,532	3,464	2,531	157,490
WEST	**Total**		**21,666**	**87,403**	**9,403**	**829**	**1,565**	**4,093**	**106**	**4,536**	**15,238**	**52,687**	**44,042**	**35,071**	**1,944**	**16,271**	**294,854**
	CAISO+	**Total**	**1,816**	**37,434**	**5,582**	**185**	**726**	**2,004**	**35**	**3,514**	**11,156**	**10,211**	**25,614**	**7,773**	**829**	**10,047**	**116,925**
		CALI-N	-	12,942	5,582	165	465	1,049	9	1,967	2,672	8,727	6,723	1,373	349	5,036	47,059
		CALI-S	1,816	24,492	-	20	261	955	26	1,547	8,484	1,483	18,891	6,400	480	5,011	69,866
	Non-CA WECC	**Total**	**19,850**	**49,969**	**3,820**	**644**	**839**	**2,089**	**71**	**1,022**	**4,082**	**42,476**	**18,428**	**27,298**	**1,115**	**6,224**	**177,929**
		WA	560	3,919	1,096	17	352	-	-	140	350	24,402	1,052	2,690	243	386	35,207
		OR	-	3,915	-	6	293	21	-	-	482	8,253	2,145	3,440	141	372	19,068
		SOUTHWEST	4,842	17,985	2,724	323	102	1,047	-	176	2,173	1,019	5,641	3,685	168	2,452	42,335
		WASATCH	7,033	14,061	-	87	56	1,011	61	444	750	7,587	5,625	4,052	305	1,674	42,746
		FRONT R	7,415	10,089	-	211	36	10	10	262	328	1,215	3,966	13,432	258	1,340	38,572
		Total	**178,268**	**468,635**	**97,169**	**27,610**	**5,353**	**4,093**	**1,096**	**24,144**	**29,256**	**82,249**	**147,856**	**168,966**	**31,161**	**43,169**	**1,309,026**

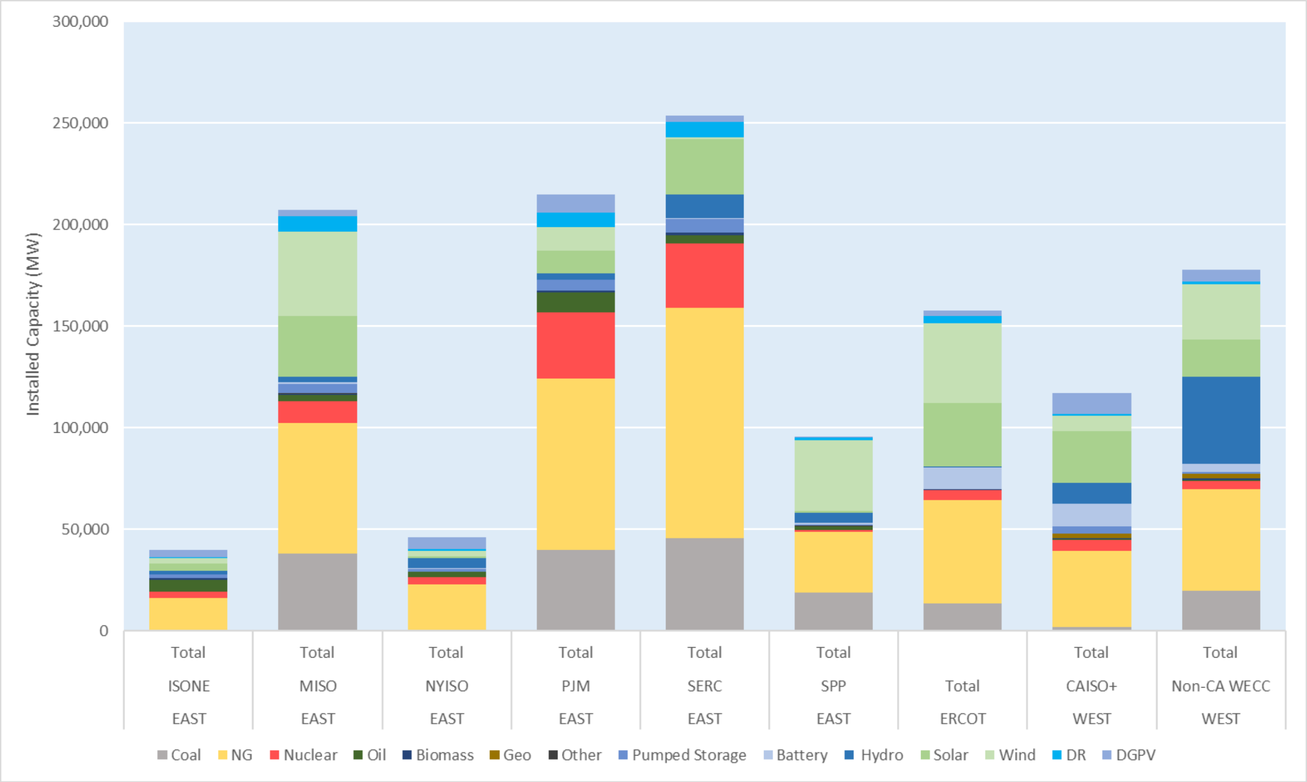

Figure A.2. Existing and Tier 1 capacities by NERC assessment area in 2024.

Forecasting 2030 Resource Mixes

To develop the 2030 ITCS generation portfolio, the study team added new capacity builds and removed planned retirements.

(i) *Tier 1*: Assumes that only projects considered very mature in the development pipeline—such as those with signed interconnection agreements—will be built. This results in minimal capacity additions beyond 2026. The data are based on projects designated as Tier 1 in the 2024 LTRA data for the year 2030.

Retirements

To project which units will retire by 2030, the study team primarily used the LTRA 2024 data and cross-checked it with EIA data. The assessment areas were disaggregated to ITCS zones based on the ratios of projected retirements in EIA 860 data. The three scenarios modeled are as follows:

(i) *Announced*: Assumes that in addition to confirmed retirements, generators that have publicly announced retirement plans but have not formally notified system operators have also begun the retirement process. This is based on data from the 2024 LTRA, which were collected by the NERC team from sources like news announcements, public disclosures, etc.

(ii) *None*: Assumes that there are no retirements between 2024 and 2030 for comparison. Delaying or canceling some near-term retirements may not be feasible, but this case can help determine how much retirements contribute to resource adequacy challenges in regions where rapid AI and data center growth is expected.

Generation Stack for Each Scenario

Finally, when summing all potential future changes, the team arrived at a generation stack for each of the various scenarios to be studied. The first figure provides a visual comparison of all the cases, which vary from 1,309 GW to 1,519 GW total generation capacity for the entire continental United States, to enable the exploration of a range of potential generation futures. The tables below provide breakdowns by ITCS region and by resource type.

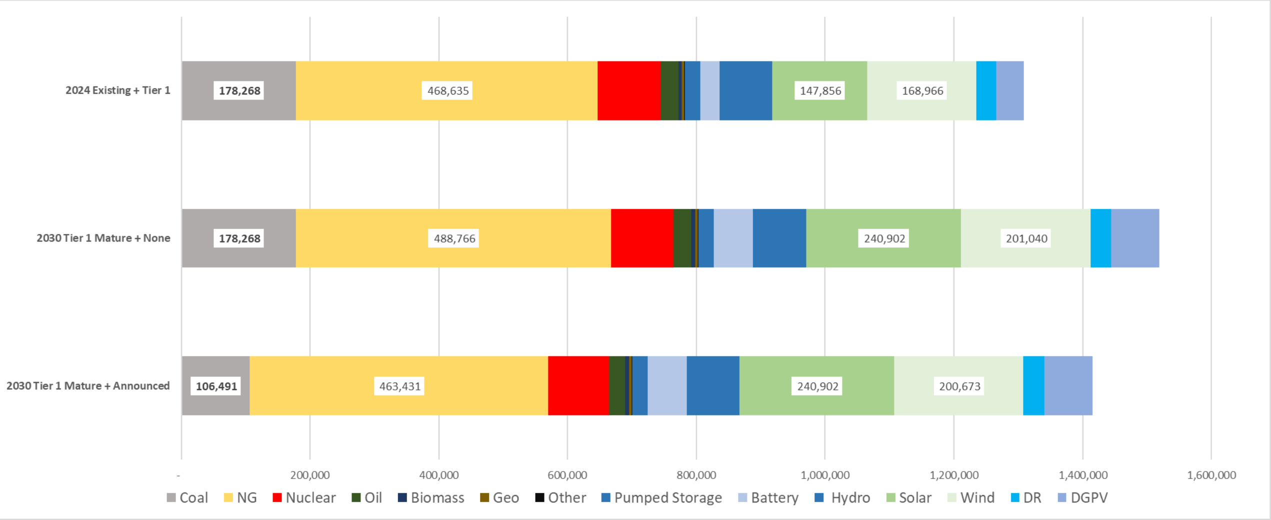

Figure A.9. Comparison of 2030 generation stacks for the various scenarios.

Table A.4. 2030 generation stack for Tier 1 mature + announced retirements.

2030 Tier 1 Mature + Announced			Coal	NG	Nuclear	Oil	Biomass	Geo	Other	Pumped Storage	Battery	Hydro	Solar	Wind	DR	DGPV	Total
EAST	**Total**		**84,730**	**328,457**	**82,793**	**24,272**	**3,473**	**-**	**991**	**19,591**	**12,415**	**28,897**	**126,849**	**113,568**	**26,837**	**36,768**	**889,641**
	ISONE	**Total**	7	13,708	3,331	5,687	741	-	233	1,571	1,664	1,911	3,676	4,048	661	5,606	42,845
	MISO	**Total**	**13,001**	**60,132**	**11,127**	**2,873**	**473**	**-**	**329**	**4,380**	**2,960**	**2,450**	**44,132**	**43,369**	**7,775**	**3,049**	**196,049**
		MISO-W	4,338	12,747	2,753	1,494	188	-	2	-	574	751	10,920	30,577	2,367	741	67,453
		MISO-C	5,161	9,655	2,169	495	25	-	152	770	1,433	743	15,690	7,642	2,026	1,774	47,735
		MISO-S	1,883	29,087	5,100	591	187	-	117	49	14	817	11,892	619	2,109	291	52,756
		MISO-E	1,619	8,643	1,105	293	72	-	57	3,561	938	138	5,630	4,531	1,273	243	28,105
	NYISO	**Total**	-	21,907	3,330	2,628	334	-	-	1,400	60	4,915	1,159	4,608	860	9,194	50,396
	PJM	**Total**	**26,662**	**87,228**	**32,535**	**8,117**	**917**	**-**	**-**	**5,062**	**2,276**	**3,071**	**33,530**	**18,807**	**7,638**	**10,955**	**236,798**
		PJM-W	23,323	40,373	16,557	1,589	120	-	-	234	1,004	1,252	17,793	16,153	3,939	762	123,100
		PJM-S	1,597	15,546	5,288	3,276	516	-	-	2,958	853	1,070	12,105	577	1,883	3,181	48,850
		PJM-E	1,742	31,309	10,690	3,252	280	-	-	1,870	419	749	3,632	2,076	1,816	7,012	64,848
	SERC	**Total**	**31,672**	**116,117**	**31,702**	**3,391**	**989**	**-**	**83**	**6,701**	**3,021**	**11,425**	**38,360**	**982**	**8,088**	**7,893**	**260,423**
		SERC-C	8,883	23,777	8,280	148	36	-	-	1,784	180	4,995	3,070	982	1,851	29	54,014
		SERC-SE	10,321	28,127	8,018	899	424	-	-	1,548	618	3,260	9,024	-	2,213	317	64,768
		SERC-FL	2,851	47,092	3,502	1,477	310	-	83	-	2,208	-	16,717	-	3,022	5,865	83,127
		SERC-E	9,617	17,122	11,902	868	219	-	-	3,369	15	3,170	9,549	-	1,002	1,682	58,513
	SPP	**Total**	**13,389**	**29,365**	**769**	**1,576**	**20**	**-**	**345**	**477**	**2,434**	**5,123**	**5,991**	**41,755**	**1,815**	**71**	**103,130**
		SPP-N	3,602	3,394	304	489	1	-	185	-	18	3,041	717	8,475	447	7	20,679
		SPP-S	9,787	25,971	465	1,087	19	-	160	477	2,416	2,082	5,274	33,280	1,368	64	82,451
ERCOT	**Total**		**11,568**	**49,436**	**4,973**	**10**	**163**	**-**	**-**	**-**	**27,258**	**583**	**62,406**	**43,169**	**3,464**	**5,864**	**208,894**
	ERCOT	**Total**	11,568	49,436	4,973	10	163	-	-	-	27,258	583	62,406	43,169	3,464	5,864	208,894
WEST	**Total**		**10,193**	**85,538**	**7,103**	**823**	**1,427**	**3,983**	**106**	**4,366**	**21,330**	**52,060**	**51,648**	**43,935**	**1,981**	**31,931**	**316,424**
	CAISO+	**Total**	**16**	**35,789**	**3,282**	**185**	**726**	**2,059**	**35**	**3,514**	**14,316**	**10,211**	**27,112**	**7,773**	**866**	**17,055**	**122,938**
		CALI-N	-	12,373	3,282	165	465	1,078	9	1,967	3,429	8,727	7,116	1,373	364	8,549	48,897
		CALI-S	16	23,416	-	20	261	982	26	1,547	10,887	1,483	19,996	6,400	501	8,506	74,041
	Non-CA WECC	**Total**	**10,177**	**49,749**	**3,820**	**639**	**701**	**1,924**	**71**	**852**	**7,014**	**41,849**	**24,536**	**36,162**	**1,115**	**14,876**	**193,485**
		WA	243	3,971	1,096	16	286	-	-	111	459	24,033	1,404	3,631	243	1,092	36,588
		OR	-	3,967	-	6	238	18	-	-	632	8,128	2,865	4,644	141	1,051	21,689
		SOUTHWEST	3,657	17,343	2,724	323	102	1,047	-	176	4,511	1,019	7,460	4,284	168	4,211	47,022
		WASATCH	3,055	14,247	-	86	45	850	61	355	983	7,472	7,512	5,470	305	4,733	45,175
		FRONT R	3,221	10,222	-	208	30	8	10	209	430	1,197	5,296	18,133	258	3,789	43,011
		Total	**106,491**	**463,431**	**94,869**	**25,106**	**5,063**	**3,983**	**1,096**	**23,958**	**61,003**	**81,539**	**240,902**	**200,673**	**32,282**	**74,563**	**1,414,959**

Table A.5. 2030 generation stack for Tier 1 mature + no retirements.

2030 Tier 1 Mature + No Retirements			Coal	NG	Nuclear	Oil	Biomass	Geo	Other	Pumped Storage	Battery	Hydro	Solar	Wind	DR	DGPV	Total
EAST	**Total**		**143,035**	**345,459**	**82,793**	**27,336**	**3,701**	**-**	**991**	**19,607**	**12,415**	**28,980**	**126,849**	**113,840**	**26,837**	**36,768**	**968,610**
	ISONE	**Total**	541	15,584	3,331	5,891	818	-	233	1,571	1,664	1,911	3,676	4,048	661	5,606	45,534
	MISO	**Total**	**37,914**	**66,729**	**11,127**	**3,197**	**613**	**-**	**329**	**4,396**	**2,960**	**2,533**	**44,132**	**43,641**	**7,775**	**3,049**	**228,393**
		MISO-W	12,651	14,145	2,753	1,662	244	-	2	-	574	777	10,920	30,768	2,367	741	77,605
		MISO-C	15,050	10,714	2,169	551	32	-	152	773	1,433	769	15,690	7,690	2,026	1,774	58,823
		MISO-S	5,493	32,278	5,100	657	243	-	117	49	14	845	11,892	623	2,109	291	59,710
		MISO-E	4,720	9,592	1,105	326	94	-	57	3,574	938	143	5,630	4,560	1,273	243	32,255
	NYISO	**Total**	-	22,937	3,330	2,646	334	-	-	1,400	60	4,915	1,159	4,608	860	9,194	51,444
	PJM	**Total**	**39,915**	**88,880**	**32,535**	**9,907**	**928**	**-**	**-**	**5,062**	**2,276**	**3,071**	**33,530**	**18,807**	**7,638**	**10,955**	**253,504**
		PJM-W	34,917	41,138	16,557	1,939	122	-	-	234	1,004	1,252	17,793	16,153	3,939	762	135,810
		PJM-S	2,391	15,840	5,288	3,998	522	-	-	2,958	853	1,070	12,105	577	1,883	3,181	50,667
		PJM-E	2,608	31,902	10,690	3,969	284	-	-	1,870	419	749	3,632	2,076	1,816	7,012	67,027
	SERC	**Total**	**45,747**	**120,232**	**31,702**	**4,063**	**989**	**-**	**83**	**6,701**	**3,021**	**11,425**	**38,360**	**982**	**8,088**	**7,893**	**279,285**
		SERC-C	13,348	24,958	8,280	148	36	-	-	1,784	180	4,995	3,070	982	1,851	29	59,660
		SERC-SE	13,275	29,866	8,018	915	424	-	-	1,548	618	3,260	9,024	-	2,213	317	69,478
		SERC-FL	4,346	48,163	3,502	1,957	310	-	83	-	2,208	-	16,717	-	3,022	5,865	86,173
		SERC-E	14,777	17,246	11,902	1,044	219	-	-	3,369	15	3,170	9,549	-	1,002	1,682	63,973
	SPP	**Total**	**18,919**	**31,098**	**769**	**1,632**	**20**	**-**	**345**	**477**	**2,434**	**5,123**	**5,991**	**41,755**	**1,815**	**71**	**110,449**
		SPP-N	5,089	3,594	304	506	1	-	185	-	18	3,041	717	8,475	447	7	22,385
		SPP-S	13,829	27,504	465	1,126	19	-	160	477	2,416	2,082	5,274	33,280	1,368	64	88,064
ERCOT	**Total**		**13,568**	**51,458**	**4,973**	**10**	**163**	**-**	**-**	**-**	**27,258**	**583**	**62,406**	**43,169**	**3,464**	**5,864**	**212,916**
	ERCOT	**Total**	13,568	51,458	4,973	10	163	-	-	-	27,258	583	62,406	43,169	3,464	5,864	212,916
WEST	**Total**		**21,666**	**91,849**	**9,403**	**829**	**1,565**	**4,156**	**106**	**4,536**	**21,330**	**52,687**	**51,648**	**44,030**	**1,981**	**31,931**	**337,717**
	CAISO+	**Total**	**1,816**	**39,560**	**5,582**	**185**	**726**	**2,059**	**35**	**3,514**	**14,316**	**10,211**	**27,112**	**7,773**	**866**	**17,055**	**130,809**
		CALI-N	-	13,677	5,582	165	465	1,078	9	1,967	3,429	8,727	7,116	1,373	364	8,549	52,501
		CALI-S	1,816	25,883	-	20	261	982	26	1,547	10,887	1,483	19,996	6,400	501	8,506	78,308
	Non-CA WECC	**Total**	**19,850**	**52,289**	**3,820**	**645**	**839**	**2,097**	**71**	**1,022**	**7,014**	**42,476**	**24,536**	**36,257**	**1,115**	**14,876**	**206,908**
		WA	560	4,166	1,096	17	352	-	-	140	459	24,402	1,404	3,642	243	1,092	37,573
		OR	-	4,161	-	6	293	22	-	-	632	8,253	2,865	4,658	141	1,051	22,081
		SOUTHWEST	4,842	18,294	2,724	323	102	1,047	-	176	4,511	1,019	7,460	4,284	168	4,211	49,158
		WASATCH	7,033	14,945	-	88	56	1,018	61	444	983	7,587	7,512	5,486	305	4,733	50,251
		FRONT R	7,415	10,723	-	212	36	10	10	262	430	1,215	5,296	18,187	258	3,789	47,844
		Total	**178,268**	**488,766**	**97,169**	**28,175**	**5,429**	**4,156**	**1,096**	**24,144**	**61,003**	**82,249**	**240,902**	**201,040**	**32,282**	**74,563**	**1,519,243**

Appendix B - Representing Canadian Transfer Limits

Introduction

The reliability and stability of cross-border electricity interconnections between the United States and Canada are critical to ensuring continuous power delivery amid evolving demands and variable supply conditions. In recent years, increased integration of wind and solar generation, coupled with extreme weather events, has introduced significant uncertainties in regional power flows.

This report describes the development and implementation of a machine learning (ML)-based model designed to project the maximum daily energy transfer (MaxFlow) across major United States–Canada interfaces, such as BPA–BC Hydro and NYISO–Ontario. Leveraging 15 years of high-resolution load and generation data, summarizing it into key daily statistics, and training a robust eXtreme Gradient Boosting (XGBoost) regressor can allow data-driven predictions to be captured with quantified uncertainty.

The project team provided percentile-based forecasts—25, 50, and 75 percent—to support both conservative and strategic planning. The conservative methodology (25 percent) was used for this report to ensure availability when needed.

The subsequent sections detail the methodology used for data processing and feature engineering, the architecture and training of the predictive model, and the validation metrics and feature importance analyses used. Future enhancements could include incorporating weather patterns, neighboring-region dynamics, and fuel-specific generation profiles to further strengthen predictive performance and support grid resilience.

Methodology

This section describes the ML approach used to build the MaxFlow prediction model.

Dataset Collection and Preparation

Data were collected for hourly and derived daily load and generation over a 15-year period (2010–2024), comprising 8,760 hourly observations annually. Hourly interconnection flow rates were collected for the same years across all major United States–Canada interfaces.[1–17]

Underlying Hypothesis

The team hypothesized that the MaxFlow between interconnected regions is critically influenced by regional load and generation extrema (maximum and minimum) and their variability. These statistics reflect grid stress conditions, influencing interregional energy flow. Additionally, nonlinear interactions due to imbalances in adjacent regions further affect energy transfer dynamics.

Regression Model

The XGBoost regression model was chosen because of its ability to capture complex, nonlinear relationships, regularization capability to prevent overfitting, high speed and performance, fast convergence, built-in handling of missing data, and ease of confidence interval approximation.

XGBoost builds many small decision trees, one after another. Each new tree learns to correct the mistakes of the previous ensemble by focusing on which predictions had the greatest error. Instead of creating one large, complex tree, it combines many simpler trees—each making a modest adjustment—so that, together, they capture nonlinear patterns and interactions. Regularization (penalties for tree size and leaf adjustments) prevents overfitting, and a “learning rate” scales each tree’s contribution so that improvements are made gradually. The final prediction is simply the sum of all those small corrections.

Model Training, Validation, and Assessment

Figure B.1 shows the data analysis and prediction process, which ties together seven stages—from raw CSV loading through outlier filtering, feature engineering, projecting to 2030, rebuilding 2030 features, training an XGBoost model, and finally making and evaluating the 2030 flow forecasts with quantiles. Each stage feeds into the next, ensuring that the features used for training mirror exactly those that will be available for future (2030) predictions.

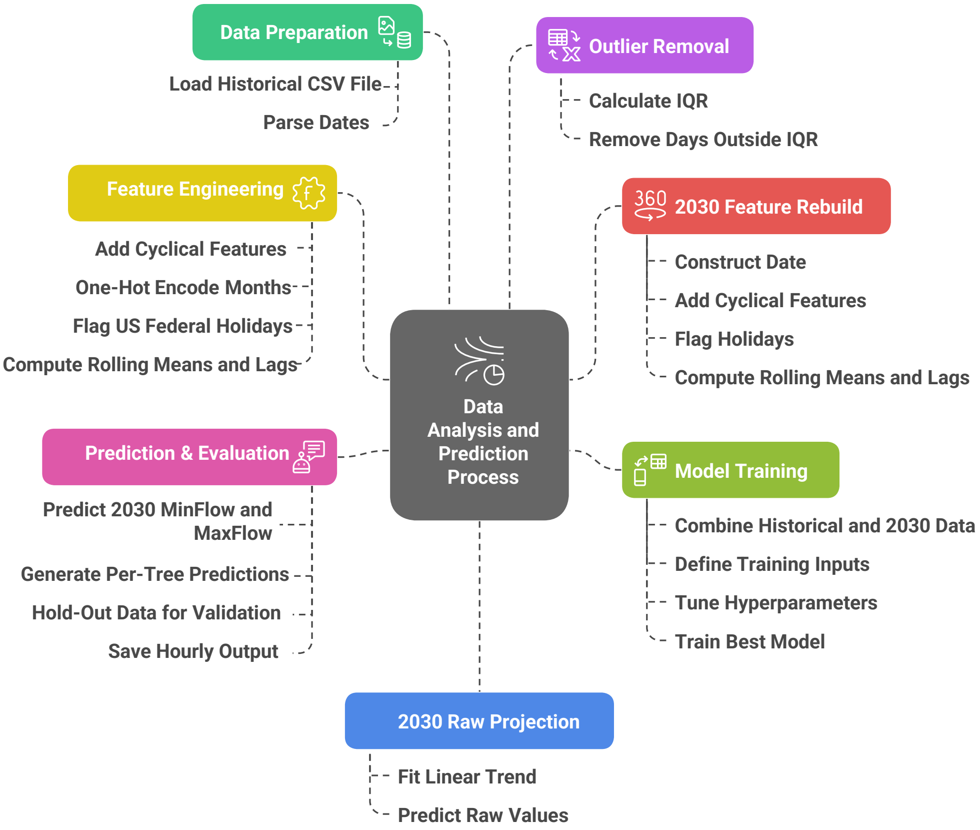

Figure B.1. Data analysis and prediction process.

Example Feature Importance for Predicting MaxFlow from Ontario to NYISO

The trained ML/XGBoost model can be used for predicting the desired year’s MaxFlow. In addition, feature importance analysis can be added to assess the contribution of each variable.

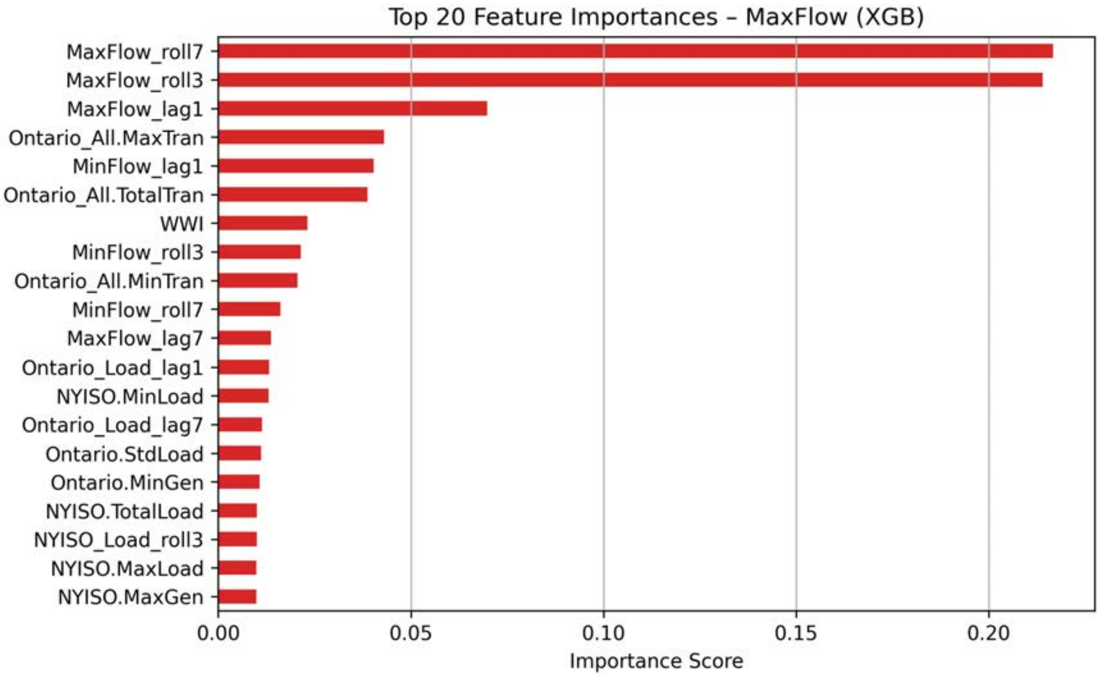

Figure B.2. Feature importance for predicting the hourly maximum energy transfer (MaxFlow) between NYISO and Ontario. XGB = eXtreme Gradient Boosting.

The feature importance plot shows that MaxFlow rolling/lagging features and Ontario_All.MaxTran are the dominant predictors of MaxFlow, meaning temporal patterns and Ontario's peak transfer capacity strongly influence interregional flow limits. Weather-related variables (WWI, e.g., temperature, humidity, etc.) and Ontario_All.TotalTran also rank highly. The 2030 MaxFlow prediction plot shows seasonal fluctuations, with higher values early and late in the year. The red shaded area represents a 95 percent confidence interval for the predictions.

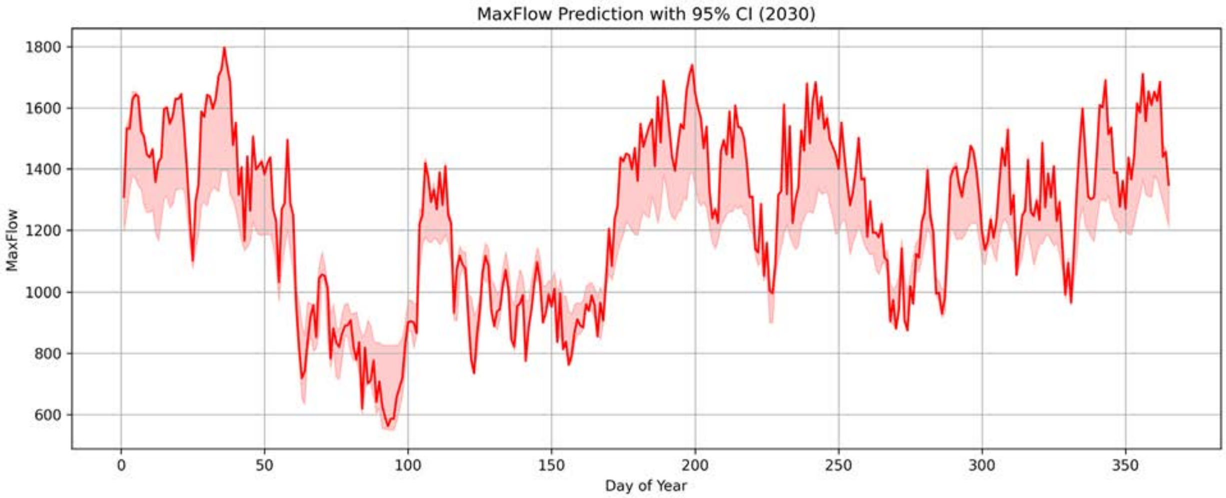

Figure B.3. Projected 2030 daily maximum energy transfer (MaxFlow) with 95 percent confidence interval (CI).

Model Performance

Validating model performance on unseen data is essential to ensure the model's reliability and generalizability. The following evaluation examines how well the XGBoost model predicts minimum energy transfer (MinFlow) and MaxFlow on the validation split, highlighting strengths and areas for improvement.

Rigorous performance evaluation is a fundamental step in any ML workflow. From quantifying error metrics (root mean square error and mean absolute error) and goodness-of-fit (R^2) on both training and validation splits, it is possible to identify overfitting, assess generalization, and guide model refinement. Table B.1 shows XGBoost model performance for the Ontario–NYISO transfer limit.

Table B.1. eXtreme Gradient Boosting model performance for the Ontario–NYISO transfer limit.

Metric	Value	Explanation
MinFlow RMSE (Train)	69.2528	Root mean square error (RMSE) on training data for minimum energy transfer (MinFlow)
MinFlow R^2 (Train)	0.9651	R^2 on training data for MinFlow (higher → better fit)
MinFlow RMSE (Validation)	163.6642	RMSE on held-out data for MinFlow
MinFlow R^2 (Validation)	0.8073	R^2 on held-out data for MinFlow (higher → better generalization)
MaxFlow RMSE (Train)	114.4234	RMSE on training data for maximum energy transfer (MaxFlow)
MaxFlow R^2 (Train)	0.8838	R^2 on training data for MaxFlow (higher → better fit)
MaxFlow RMSE (Validation)	144.9614	RMSE on held-out data for MaxFlow
MaxFlow R^2 (Validation)	0.8178	R^2 on held-out data for MaxFlow (higher → better generalization)

Overall, the XGBoost model delivers excellent in-sample as well as out-of-sample accuracy. Similar outputs are available for each transfer limit.

Maximum flow predictions: Ontario to New York

Ontario and NYISO are connected through multiple high-voltage interconnections, which collectively provide a total transfer capability of up to 2,500 MW, subject to individual tie-line limits. Table B.2 outlines the data sources, preparation process, and assumptions used in creating datasets for the prediction models.

Table B.2. Ontario to New York transmission flow data and assumptions overview.

	Description
Data source	https://www.ieso.ca/power-data/data-directory
Data preparation	IESO public hourly inter-tie schedule flow data can be accessed for the years spanning from 2002 to 2023.
Assumptions	Positive flow indicates that Ontario is exporting to NY, and negative flow indicates that Ontario is importing from NY.

Figure B.4 illustrates the historical monthly MaxFlow for Ontario from 2007 through 2024, alongside 2030 projected quartile scenarios (Q1, Q2, and Q3). Analyzing these trends helps assess future reliability and facilitates capacity planning under varying conditions.

Historical monthly peaks (2007–2023) reveal a clear seasonal cycle for ONT–NYISO transfers: flows typically increase in late winter/early spring (February–April) and again in late fall/early winter (November–December). Over 16 years, the average spring peaks hovered around 1,700–1,900 MW, with occasional spikes above 2,200 MW. The 2030 forecast for Q1, Q2, and Q3 aligns with this pattern, predicting a springtime peak near 1,800 MW, a summer trough around 1,400 MW, and a modest late-summer uptick near 1,500 MW.

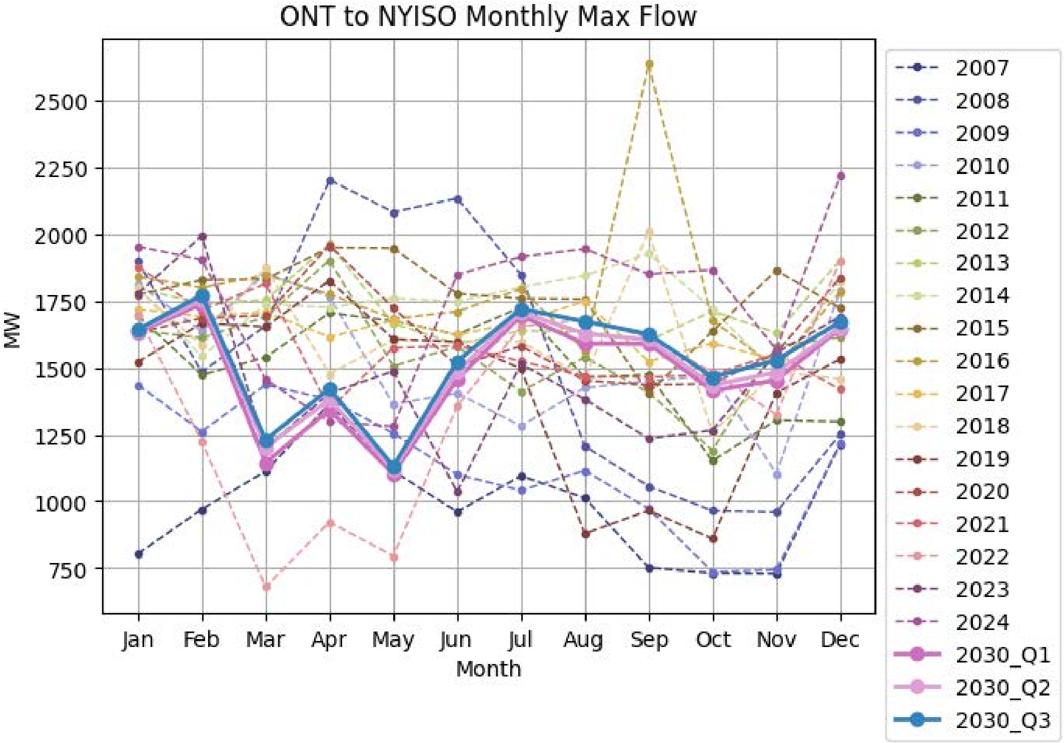

Figure B.4. Monthly maximum energy transfer between Ontario (ONT) and New York (NYISO).

The team used robust validation metrics to justify these results. When trained on daily data from the 2010–2024 period—incorporating projected 2030 loads, seasonal flags, and holiday effects—the XGBoost model achieved $R^2 > 0.80$ and a root mean square error below 150 MW on an unseen 20 percent hold-out dataset. Moreover, the 95 percent confidence intervals for monthly maxima were narrow (approximately ±150 MW), demonstrating low predictive uncertainty. A comparison of predicted maxima with historical extremes revealed that 2030 forecasts consistently fell within (or slightly above) the previous window of variability, implying realistic demand-driven behavior. In summary, the close alignment with historical peaks, strong cross-validated performance, and tight confidence bands collectively validate the results.

Discussion

The reason that the team used ML/XGBoost to approximate the 2030 transfer profiles was to ensure that there would be no violations or inconsistencies between transfer limits, load, and generation. The 15 years of data used were sufficient for having the models learn historical relationships and project them forward to 2030 to capture the underlying trends in load, generation, and their interactions. The use of such an extensive dataset justifies using ML to establish consistent transfer profiles.

However, in some regions, like Ontario to NYISO, the available data encompassed a shorter time period, and the relationships were only partially captured because of a lack of neighboring-region data. In such cases, it was necessary to incorporate additional predictors, such as rolling and lag features from the transfer limits. Although the direct use of transfer limit data to project future transfer limits would typically be avoided, these engineered features help improve predictions when data coverage is sparse and the model's goodness-of-fit is low.

In all cases, the ML models ensured that these historical relationships were not violated, maintaining internal consistency among load, generation, and transfer limits. Overall, the team relied on ML when long-term data were available for training and projecting load and generation profiles. Rolling and lag features were used to reinforce the model when data availability was limited, but always with the goal of upholding consistent physical relationships in the 2030 projections.

Supplementary Plots for Additional Transfers

This section presents figures and tables showing results and source data information for each transfer listed below:

(iii) Pacific Northwest to British Columbia

(iv) Alberta to Montana

(v) Manitoba to MISO West

(vi) Ontario to MISO West

(vii) Ontario to MISO East

(viii) Ontario to New York

(ix) Hydro-Quebec to New York

(x) Hydro-Quebec to New England

(xi) New Brunswick to New England

The figures show the daily MaxFlow for each transfer that was considered in this analysis.

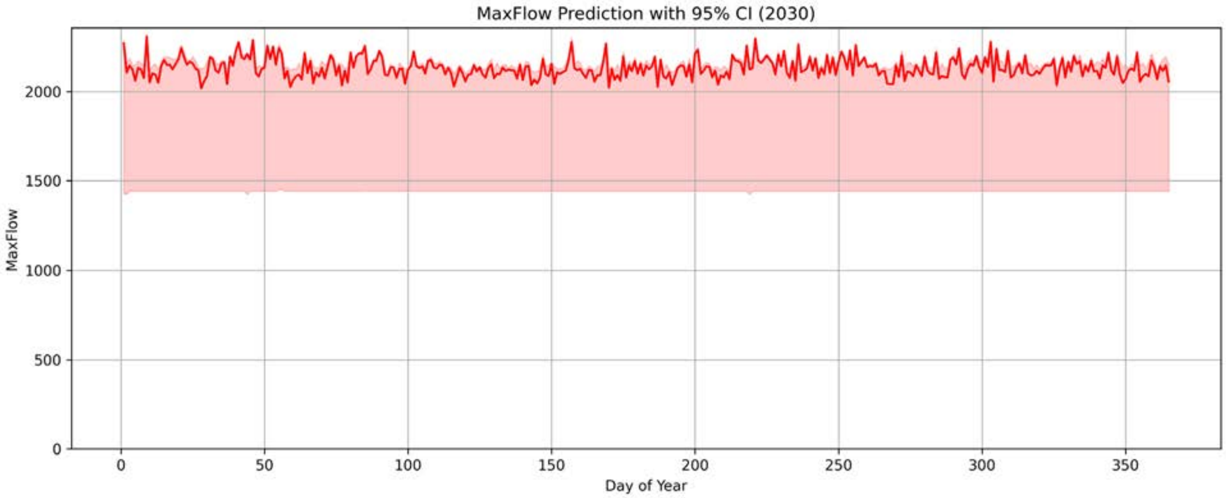

Figure B.5. Projected 2030 daily maximum energy transfer (MaxFlow) with 95 percent confidence interval (CI) between British Columbia and the Pacific Northwest.

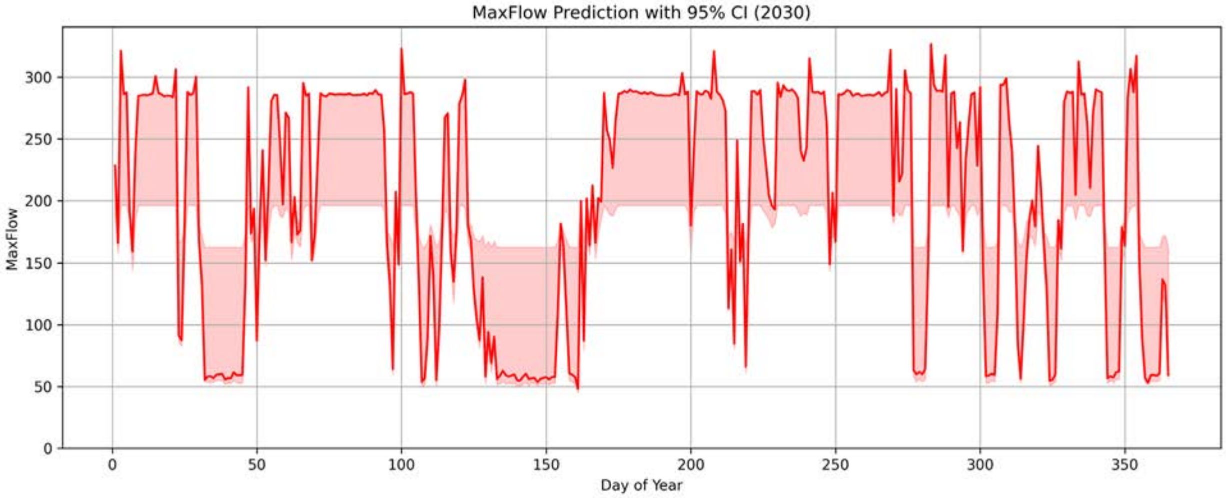

Figure B.6. Projected 2030 daily maximum energy transfer (MaxFlow) with 95 percent confidence interval (CI) between AESO and Montana.

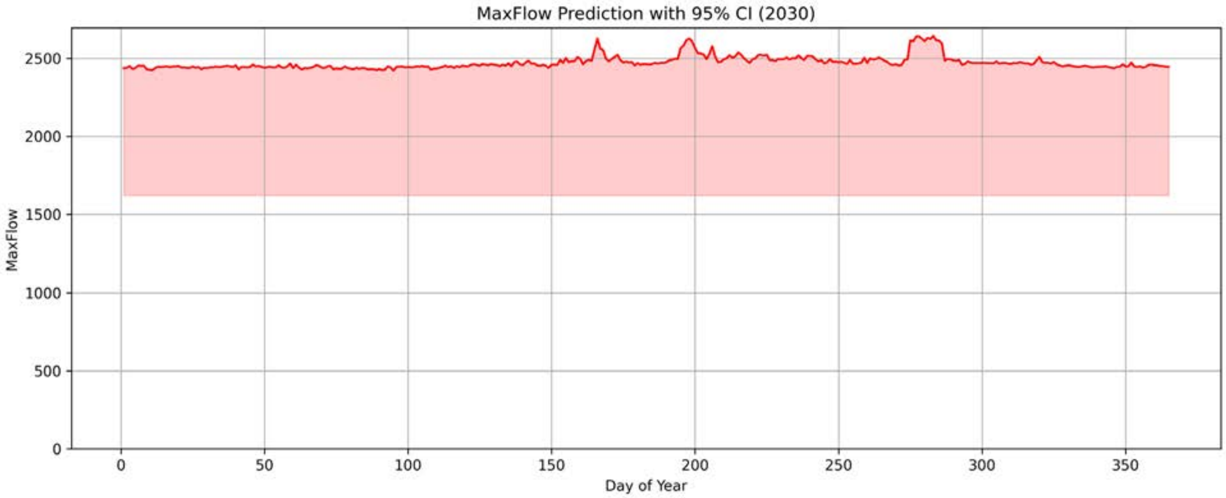

Figure B.7. Projected 2030 maximum energy transfer (MaxFlow) with 95 percent confidence interval (CI) between Manitoba and MISO.

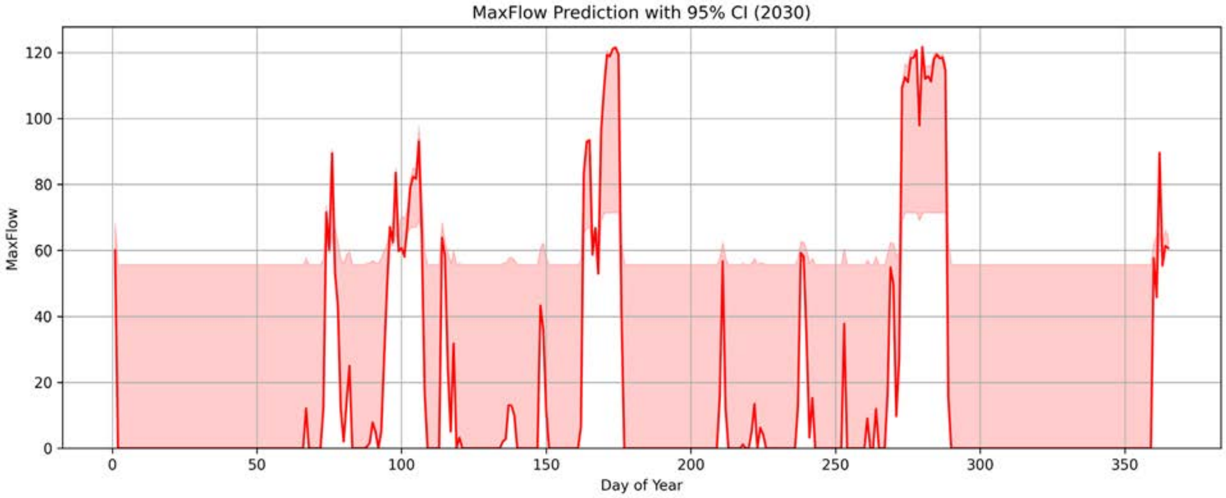

Figure B.8. Projected 2030 daily maximum energy transfer (MaxFlow) with 95 percent confidence interval (CI) between Ontario and MISO West.

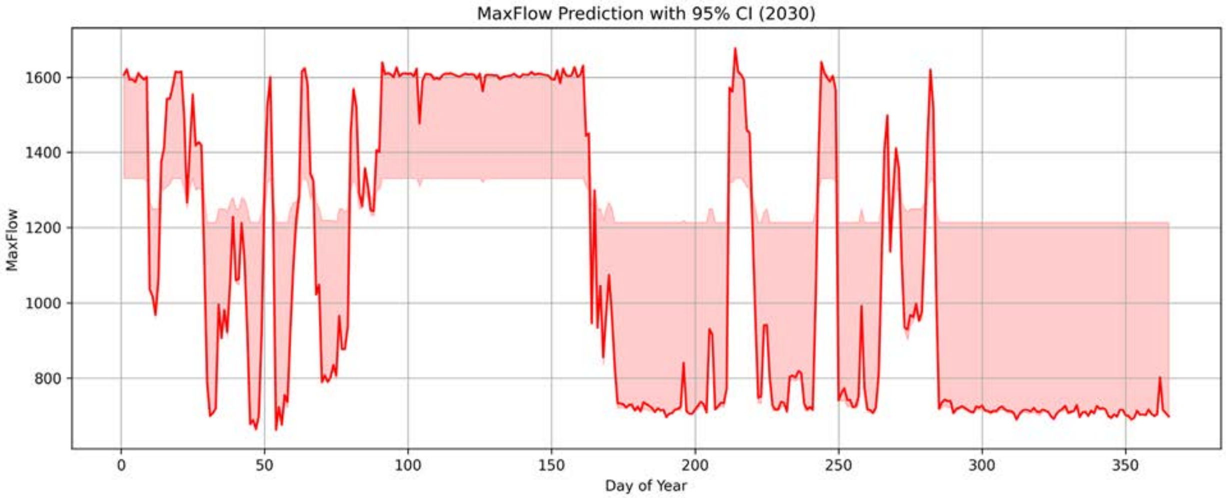

Figure B.9. Projected 2030 daily maximum energy transfer (MaxFlow) with 95 percent confidence interval (CI) between Ontario and MISO East.

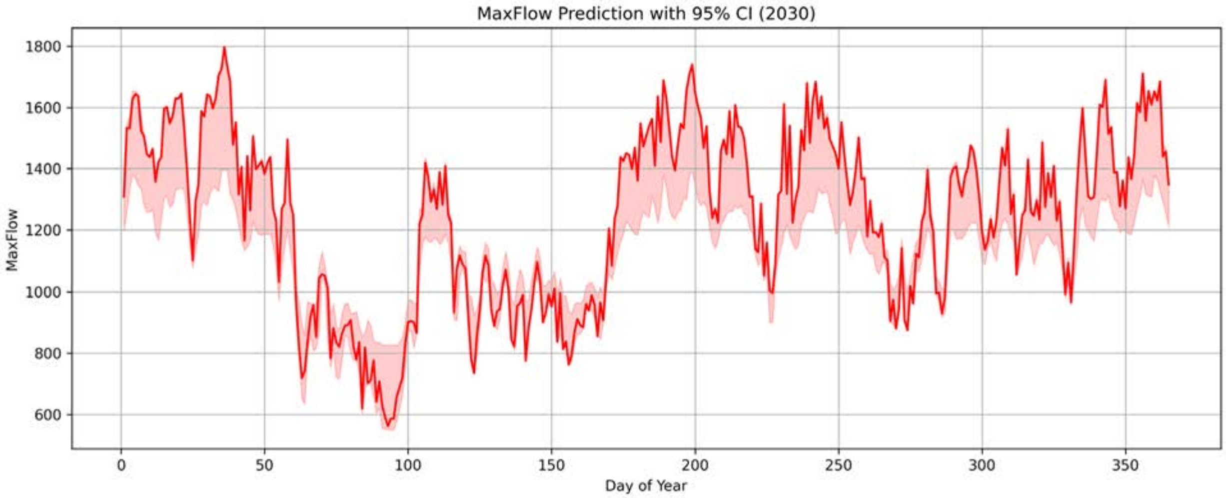

Figure B.10. Projected 2030 daily maximum energy transfer (MaxFlow) with 95 percent confidence interval (CI) between Ontario and New York.

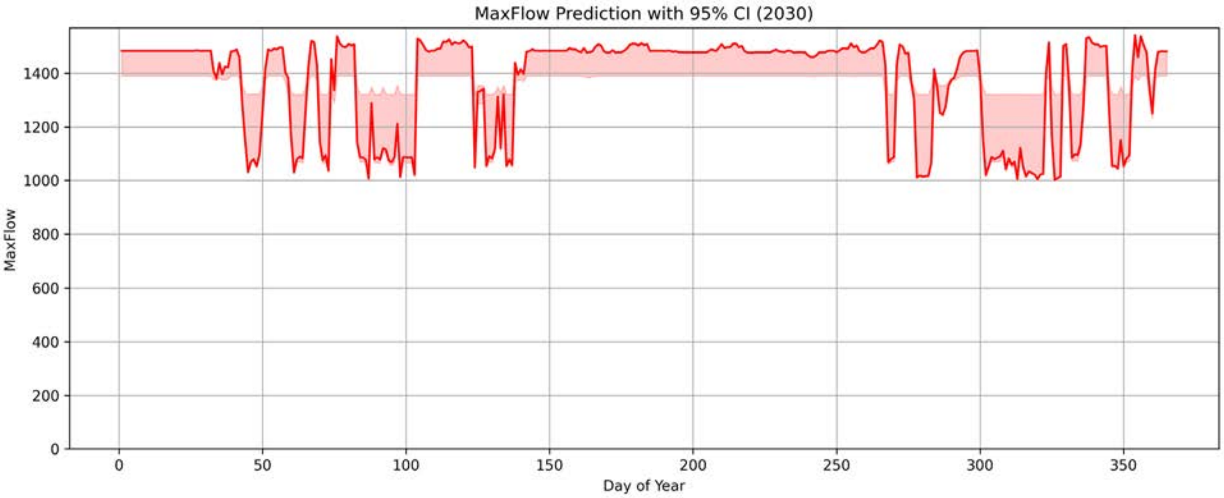

Figure B.11. Projected 2030 daily maximum energy transfer (MaxFlow) with 95 percent confidence interval (CI) between Quebec and New York.

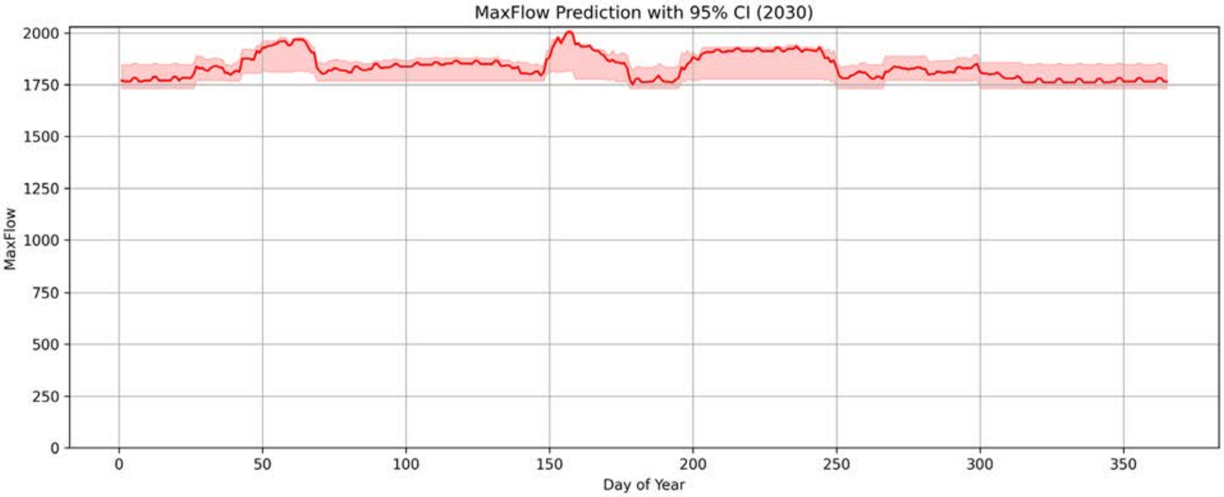

Figure B.12. Projected 2030 daily maximum energy transfer (MaxFlow) with 95 percent confidence interval (CI) between Quebec and New England.

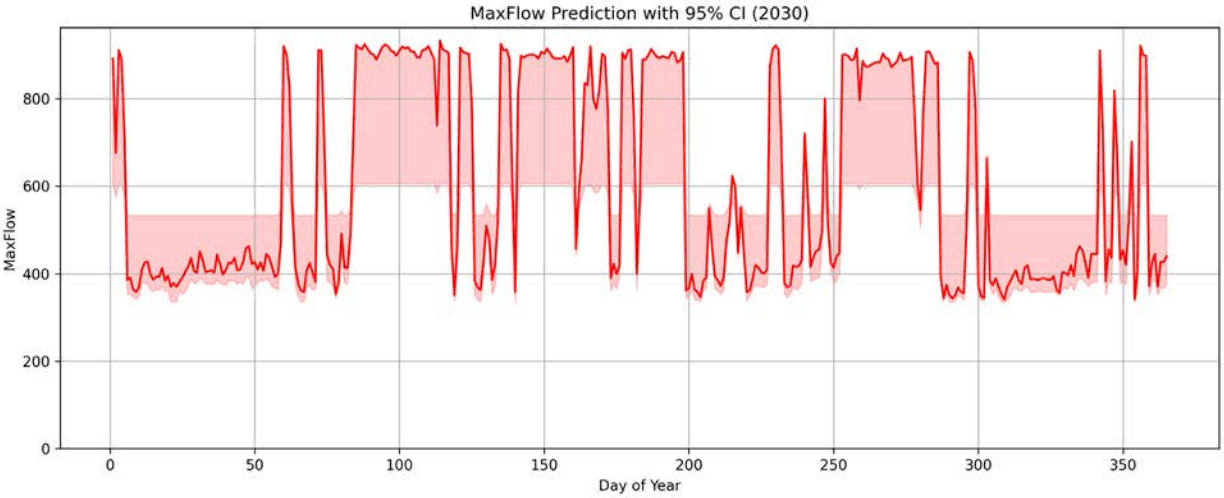

Figure B.13. Projected 2030 daily maximum energy transfer (MaxFlow) with 95 percent confidence interval (CI) between New Brunswick and New England.

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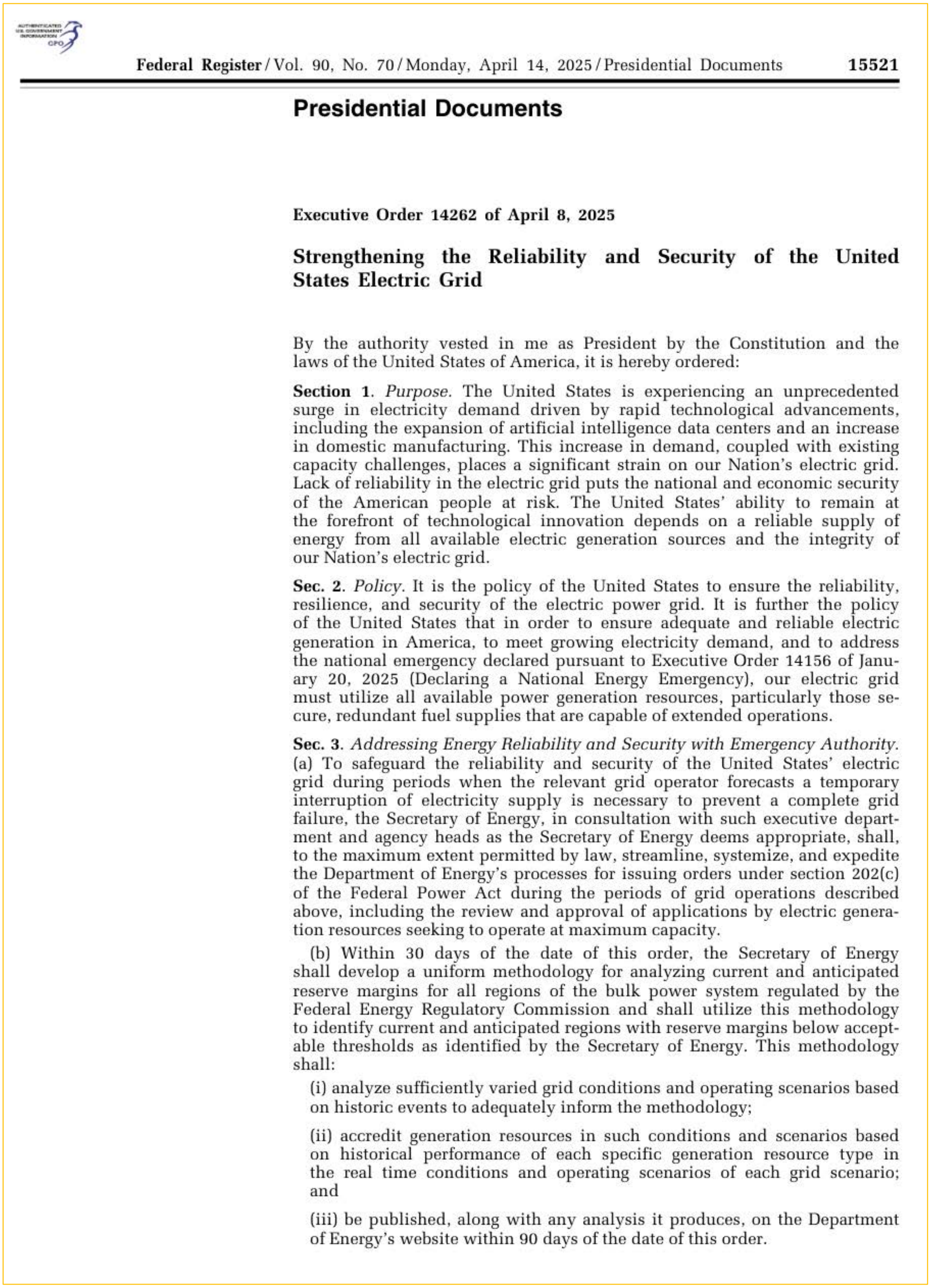

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Presidential Documents

Executive Order 14262 of April 8, 2025

Strengthening the Reliability and Security of the United States Electric Grid

By the authority vested in me as President by the Constitution and the laws of the United States of America, it is hereby ordered:

Section 1. *Purpose*. The United States is experiencing an unprecedented surge in electricity demand driven by rapid technological advancements, including the expansion of artificial intelligence data centers and an increase in domestic manufacturing. This increase in demand, coupled with existing capacity challenges, places a significant strain on our Nation's electric grid. Lack of reliability in the electric grid puts the national and economic security of the American people at risk. The United States' ability to remain at the forefront of technological innovation depends on a reliable supply of energy from all available electric generation sources and the integrity of our Nation's electric grid.

Sec. 2. *Policy*. It is the policy of the United States to ensure the reliability, resilience, and security of the electric power grid. It is further the policy of the United States that in order to ensure adequate and reliable electric generation in America, to meet growing electricity demand, and to address the national emergency declared pursuant to Executive Order 14156 of January 20, 2025 (Declaring a National Energy Emergency), our electric grid must utilize all available power generation resources, particularly those secure, redundant fuel supplies that are capable of extended operations.

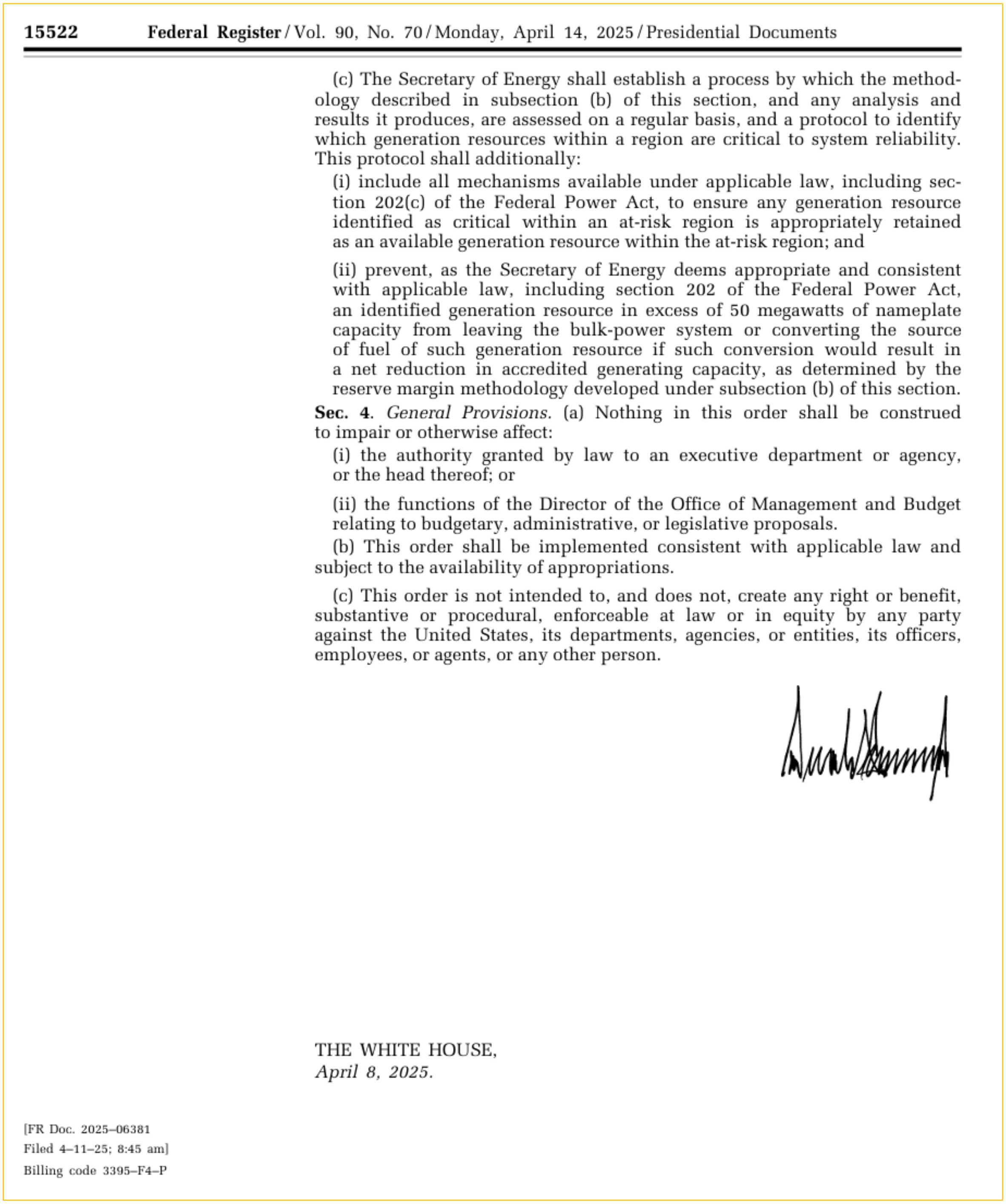
Sec. 3. *Addressing Energy Reliability and Security with Emergency Authority*. (a) To safeguard the reliability and security of the United States' electric grid during periods when the relevant grid operator forecasts a temporary interruption of electricity supply is necessary to prevent a complete grid failure, the Secretary of Energy, in consultation with such executive department and agency heads as the Secretary of Energy deems appropriate, shall, to the maximum extent permitted by law, streamline, systemize, and expedite the Department of Energy's processes for issuing orders under section 202(c) of the Federal Power Act during the periods of grid operations described above, including the review and approval of applications by electric generation resources seeking to operate at maximum capacity.

(b) Within 30 days of the date of this order, the Secretary of Energy shall develop a uniform methodology for analyzing current and anticipated reserve margins for all regions of the bulk power system regulated by the Federal Energy Regulatory Commission and shall utilize this methodology to identify current and anticipated regions with reserve margins below acceptable thresholds as identified by the Secretary of Energy. This methodology shall:

(i) analyze sufficiently varied grid conditions and operating scenarios based on historic events to adequately inform the methodology;

(ii) accredit generation resources in such conditions and scenarios based on historical performance of each specific generation resource type in the real time conditions and operating scenarios of each grid scenario; and

(iii) be published, along with any analysis it produces, on the Department of Energy's website within 90 days of the date of this order.



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(c) The Secretary of Energy shall establish a process by which the methodology described in subsection (b) of this section, and any analysis and results it produces, are assessed on a regular basis, and a protocol to identify which generation resources within a region are critical to system reliability. This protocol shall additionally:

(i) include all mechanisms available under applicable law, including section 202(c) of the Federal Power Act, to ensure any generation resource identified as critical within an at-risk region is appropriately retained as an available generation resource within the at-risk region; and

(ii) prevent, as the Secretary of Energy deems appropriate and consistent with applicable law, including section 202 of the Federal Power Act, an identified generation resource in excess of 50 megawatts of nameplate capacity from leaving the bulk-power system or converting the source of fuel of such generation resource if such conversion would result in a net reduction in accredited generating capacity, as determined by the reserve margin methodology developed under subsection (b) of this section.

Sec. 4. *General Provisions.* (a) Nothing in this order shall be construed to impair or otherwise affect:

(i) the authority granted by law to an executive department or agency, or the head thereof; or

(ii) the functions of the Director of the Office of Management and Budget relating to budgetary, administrative, or legislative proposals.

(b) This order shall be implemented consistent with applicable law and subject to the availability of appropriations.

(c) This order is not intended to, and does not, create any right or benefit, substantive or procedural, enforceable at law or in equity by any party against the United States, its departments, agencies, or entities, its officers, employees, or agents, or any other person.

THE WHITE HOUSE,
April 8, 2025.

[FR Doc. 2025–06381
Filed 4–11–25; 8:45 am]
Billing code 3395–F4–P

Available at (accessed on 5/27/2025):
https://www.federalregister.gov/documents/2025/04/14/2025-06381/strengthening-the-reliability-and-security-of-the-united-states-electric-grid

U.S. DEPARTMENT
of ENERGY

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energy.gov/topics/reliability

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