UNITED STATES DEPARTMENT OF ENERGY

Midcontinent Independent System Operator	Order No. 202-25-3

MOTION TO INTERVENE AND PETITION FOR REHEARING OF THE STATES OF MINNESOTA AND ILLINOIS

Pursuant to section 202 (c) of the Federal Power Act, 16 U.S.C. §§ 824a(c), 825l, the States of Minnesota and Illinois ("the States") move to intervene and petition for rehearing of the Department of Energy's ("DOE") May 23, 2025, Order No. 202-25-3 ("Order," Exhibit 1) directing the Midcontinent Independent System Operator ("MISO") to ensure that the coal-burning J.H. Campbell Plant ("Campbell Plant") in West Olive, Michigan, operated by Consumers Energy, remains available to operate through August 20, 2025, expiring at 00:00h on August 21, 2025.

Pursuant to the Federal Power Act ("the Act") and Department procedures applying it to petitions for rehearing, the States hereby file this timely request for rehearing of DOE's Order. The Order proceeds from a faulty conclusion that an emergency exists for the MISO Regional Transmission Organization ("RTO")—specifically for the summer months of 2025. This Order exceeds DOE's legal authority in several respects. And even if an emergency did exist and DOE had the legal authority to issue an Order, this Order is not rationally related to meet the purported need. It should be rescinded.

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MOTION TO INTERVENE

The States[1] move to intervene in this proceeding and thereby to become a party for purposes of Section 313l of the Act, 16 U.S.C. § 825l. The States have an interest in and are aggrieved by the Order in several ways and seek to intervene and petition for rehearing. *FDR v. R.J. Reynolds Vapor Co.*, 606 U. S. ___ (2025) (slip op., at 3–8) (defining an "adversely affected or aggrieved" party within the APA and without as "anyone even 'arguably within the zone of interests to be protected or regulated by the statute . . . in question.'" (quoting *Association of Data Processing Service Organizations, Inc. v. Camp*, 397 U. S. 150, 153 (1970))).

Factual Background

The utilities in the States are members of MISO, the electric grid operator for the central United States. MISO covers the largest geographical range of any independent system operator ("ISO") in the U.S. The 15 states covered by MISO are: Arkansas, Illinois, Indiana, Iowa, Kentucky, Louisiana, Michigan, Minnesota, Mississippi, Missouri, Montana, North Dakota, South Dakota, Texas, and Wisconsin. As the ISO of the electric grid in this region, MISO manages the flow of electricity across the high-voltage, long-distance power lines. To do so, MISO develops rules so that the wholesale electricity transmission system operates reliably and safely. MISO has described this as being like the "air traffic controller" for the grid in its territory[2], meaning that MISO seeks to resolve power congestion (traffic) issues in real-time through its control room and has processes in place to anticipate and avoid emergencies that could lead to the loss of power.

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[1] *See* Minn. Stat. § 8.01 ("The attorney general shall appear for the state in all causes in the supreme and federal courts wherein the state is directly interested; also in all civil causes of like nature in all other courts of the state whenever, in the attorney general's opinion, the interests of the state require it.).

[2] "Meet MISO," https://www.misoenergy.org/meet-miso/about-miso/industry-foundations/what-we-do/ (last visited June 23, 2025).

On May 23, 2025, the DOE issued an emergency order pursuant to section 202(c) of the Federal Power Act to MISO. *See* Ex. 1; *see also* 16 U.S.C. § 824(c)(1). The Order directs MISO, in coordination with Consumers Energy, the owner of the plant, to ensure that the Campbell Plant in West Olive, Michigan remains available for operation. *Id.* Consumers Energy announced its plan to retire the coal facility in 2021, and MISO approved that plan three years ago, in March 2022.[3]

Adverse Effects

The States will be adversely affected by the emergency order preventing the planned retirement of the Campbell Plant in two primary ways.

First, households and businesses in the States, and the States as consumers in their own right, all will pay higher electricity bills as a result of the Order's imposition of costs and cost-recovery to the States. By ordering the Campbell Plant to take all steps necessary to be available and ordering MISO to take all steps necessary for the Campbell Plant to provide economic dispatch, costs are already being incurred and more costs will continue to be generated. Notably, the age of the units is concerning for costs, and Consumers Energy projected in 2021 that retiring Campbell in 2025 would avoid $365,008,000 in capital expenditures and major maintenance costs.[4] The Order would likely require at least a portion of capital expenditures and major maintenance costs that were not completed in the last four years, which will potentially drive up

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[3] *See* Consumers Energy, "2021 Clean Energy Plan," https://www.consumersenergy.com/-/media/CE/Documents/company/IRP-2021.pdf (last accessed June 23, 2025).

[4] *In the matter of the application of Consumers Energy Company for approval of its integrated resource plan pursuant to MCL 460.6t and for other relief*, MPSC Case No. U-21090, Revised Direct Testimony of Norman J. Kapala on Behalf of Consumers Energy Company at 3 (Oct. 2021).

costs and impact ratepayer bills. This would be in addition to the cost of rehiring operators and obtaining more coal, among other expenses.

Although the precise amount is not yet known, the Order provides that cost recovery is available to Consumers Energy through Federal Energy Regulatory Commission ("FERC") proceedings, which Consumers Energy has already initiated. Consumers Energy filed a petition FERC[5] asking for a process to allocate costs (net of market revenues) across all of MISO Zones 1 through 7 (which includes Minnesota and Illinois). They ask that costs be apportioned according to load, which would assign costs to the States. MISO has already filed its answer indicating its general support for adjusting its tariff to account for Consumers Energy's cost recovery petition, meaning the costs would be charged to the States according to their respective share of load.

Second, the States will suffer environmental harms as a result of the Order. The Campbell Plant is a significant source of particulate matter, nitrogen oxides, sulfur oxides, and carbon dioxide,[6] among other pollutants. By prolonging the operations of the Campbell Plant beyond its planned retirement date, the Order will increase the amount of pollution emitted in the state of Michigan and other MISO States, causing harm to the public health and welfare.[7] Coal-fired power plants also contribute to regional, national, and global greenhouse gas emissions, which cause global climate change. Climate change directly harms the States, imposes significant additional costs on them for responsive actions and resiliency programs, and threatens state climate goals and comply with federal and state air pollution requirements.

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[5] FERC Docket: EL25-90.

[6] *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).

[7] *See* Cross-State Air Pollution Rule (CSAPR) and Clean Air Act § 110.

Minnesota, for example, is experiencing rapid changes including higher winter temperatures and larger, more frequent extreme precipitation events, extreme heat, and drought.[8] Each of Minnesota's top-ten combined warmest and wettest years on record have occurred since 1998, with 2024 standing as the warmest year on record and 2019 the wettest.[9] Minnesota is already suffering from a significant uptick in devastating, large-area extreme rain events, threatening the state with ever greater frequency and intensity.[10] These events damage streets, wastewater facilities, businesses, homes, farms, and natural resources, costing local governments, business owners, and residents millions of dollars in cleanup, repairs, and adaptation expenses.[11] Wildfires are also becoming larger and more frequent, including a rash of devastating fires in the spring of 2025 that consumed more than 32,000 acres and destroyed an estimated 150 structures. The spring of 2024 included heavy precipitation and extreme rainfall events, leading to extensive flooding and federal declarations for large parts of the state.[12] From 1980 to 2024, the annual average for billion-dollar weather and climate disasters in Minnesota is 1.4 events per year, but the annual average from 2020 to 2024 is 4.6 events.[13] The "Lost Winter" of 2023-2024 was the

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[8] Minnesota Climate Trends, *Minnesota Department of Natural Resources* (2023), https://www.dnr.state.mn.us/climate/climate_change_info/climate-trends.html.

[9] *Id.*

[10] *Id.*

[11] *Id.*

[12] "Extreme Rainfall Drenches Northeastern Minnesota," Minnesota Department of Natural Resources, https://www.dnr.state.mn.us/climate/journal/extreme-rainfall-northeast-mn-june-18-2024; "Extreme Rain and Flooding in Southern Minnesota, June 20-22," Minnesota Department of Natural Resources, (August 9, 2024), https://www.dnr.state.mn.us/climate/journal/extreme-rain-flooding-southern-minnesota-june-20-22.html; "Disaster information," Minnesota Department of Public Safety, https://dps.mn.gov/divisions/hsem/em-resources/disaster-information (last visited June 23, 2025).

[13] "Billion Dollar Weather and Climate Disasters, Minnesota Summary, *NOAA National Centers for Environmental Information*, Billion-Dollar Weather and Climate Disasters | Minnesota Summary | National Centers for Environmental Information (NCEI)," https://www.ncei.noaa.gov/access/billions/state-summary/MN.

warmest on record, with temperatures averaging 10.9°F above 1991-2020 averages, greatly harming Minnesota's recreational economy.[14] These impacts will continue, and emissions from the Campbell Plant will contribute to them.

Climate change is affecting Illinois in a number of ways. Illinois' farming industry is vulnerable to cycles of extreme drought and extreme precipitation caused by climate change. In 2023, a severe drought dried up soil throughout the state, with extreme dryness extending down to 20 inches below the surface in some areas.[15] In other years, extreme precipitation has threatened Illinois' agriculture. For instance, January to June of 2013 was the wettest period ever recorded in Illinois, causing widespread flooding in farmland that forced farmers to delay planting and lose revenue.[16] Climate change is also intensifying catastrophic extreme weather events. In 2024, the Illinois State Climatologist recorded strong wind, hail, and tornadoes across all of Illinois' 102 counties and the state logged 142 tornadoes—a new annual record.[17] These storms included a July 15, 2024 "derecho" that produced 100 mile-per-hour winds and 48 separate tornados.[18] In the

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[14] *Id.*

[15] Illinois State Climatologist, Drought Worsens in a Very Dry June (June 30, 2023), https://stateclimatologist.web.illinois.edu/2023/06/30/drought-worsens-in-a-very-dry-june/ (last visited May 23, 2025).

[16] University of Illinois–Institute of Government & Public Affairs, Preparing for Climate Change in Illinois: An Overview of Anticipated Impacts (2015), https://indigo.uic.edu/articles/report/Preparing_for_Climate_Change_in_Illinois_An_Overview_of_Anticipated_Impacts/15078939/1 (last visited May 23, 2025). See also U.S. Dept. of Agriculture Climate Hubs and Great Lakes Research Integrated Science Assessment, Climate Change Impacts on Illinois Agriculture (2022), https://www.climatehubs.usda.gov/sites/default/files/2022_ClimateChangeImpactsOnIllinoisAgriculture.pdf (last visited May 23, 2025).

[17] Tony Briscoe, Lake Michigan Water Levels Rising at Near Record Rate, CHICAGO TRIBUNE (July 12, 2015), https://www.chicagotribune.com/2015/07/12/lake-michigan-water-levels-rising-at-near-record-rate/ (last visited May 23, 2025).

[18] National Weather Service, July 15, 2024 Derecho Produces Widespread Wind Damage and Numerous Tornadoes, available at https://www.weather.gov/lot/2024_07_15_Derecho#:~:text=With%2032%20tornadoes%2C%20t

Chicago area alone, the derecho produced 32 tornados, breaking the previous records set by the July 2014 "double derecho" and March 2023 storm.

PETITION FOR REHEARING

I. Overview and Concise Statement of Error

The challenged Order declares an emergency based on a shortage of electric energy generation when there is no emergency. Even if there were an emergency, the Order imposes several requirements that are inconsistent with and exceed DOE's legal authority. And even if DOE had the authority to impose the requirements, they are not directed to actions that will actually meet the purported emergency.

The Order

The challenged Order is premised on an incomplete recitation of MISO's planned capacity and reserves for the summer of 2025. It notes that MISO "faces potential tight reserve margins during the summer 2025 period." Ex. 1 at 1 (emphasis added). It relies on the North American Electric Reliability Corporation's ("NERC") 2025 Summer Reliability Assessment. Ex. 2. That report does not identify any war, fuel shortage, or natural disaster. *Id*. Rather, it evaluates generation resource and transmission system adequacy as well as energy sufficiency to meet projected summer peak demands and operating reserves. Ex. 2 at 5. Here are NERC's main conclusions regarding MISO:

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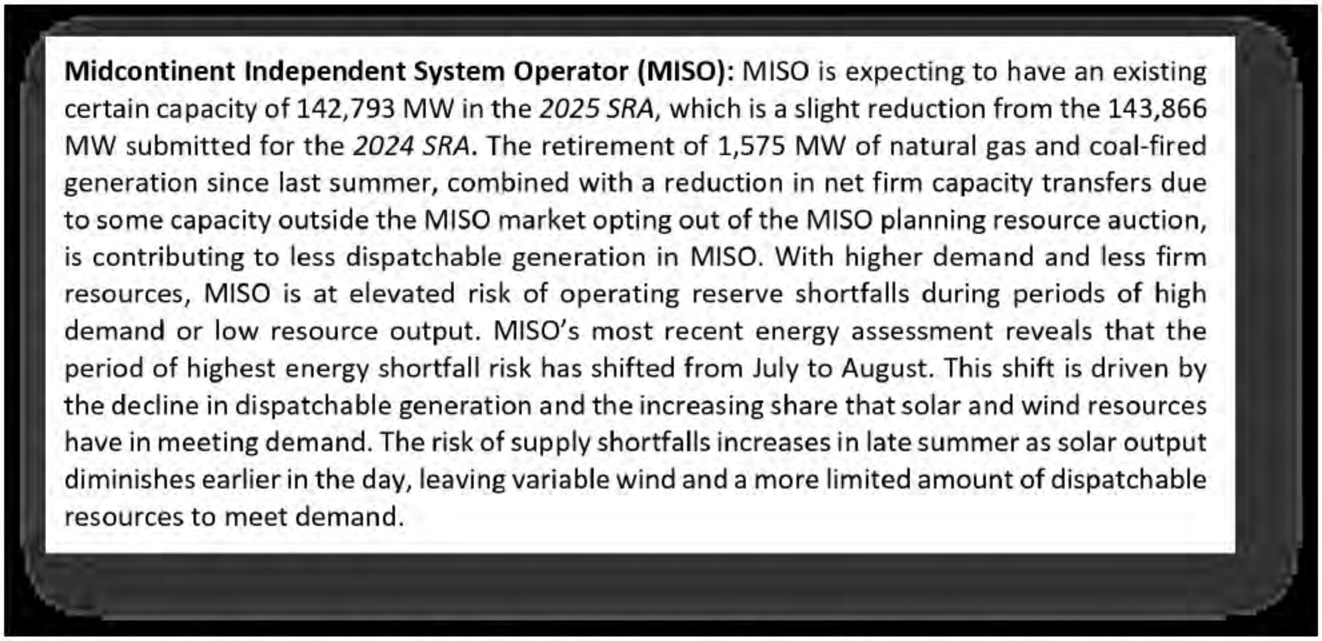
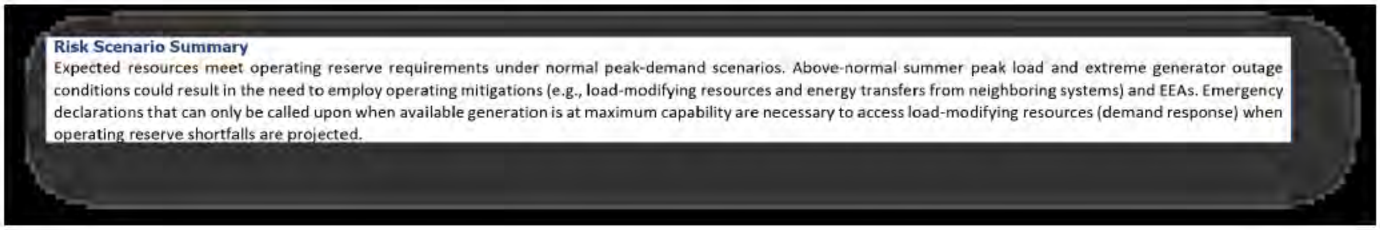
he%20July,March%2031%2C%202023%20tornado%20outbreaks. (last visited May 25, 2025). See also David Struett, Tornado Record Broken with 27 Chicago Area Twisters July 15—Spawned by 'Ring of Fire', WBEZ CHICAGO, available at https://www.wbez.org/weather/2024/07/24/chicago-weather-tornado-record-derecho-july-15 (last accessed May 23, 2025)



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.

Id. at 5. NERC concluded that all areas were projected to have "adequate anticipated resources for normal summer peak load conditions." *Id.* Indeed, the "elevated risk" designation means the probabilistic indices are low but not negligible. *Id.* at 10, Table 1. And further, the MISO-specific "dashboard" concludes that MISO's expected resources meet operating reserve requirements under normal peak-demand scenarios. At worst, operating mitigations "could" be necessary for above-normal summer peak load and extreme generator outage conditions:



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.

Id. at 16.

The Order then describes how the Campbell Plant was scheduled to cease operations on May 31, 2025, and claims that the Campbell Plant's retirement would further decrease available dispatchable generation within MISO's service territory. Ex. 1 at 1. But NERC's analysis already factored in an assumption that the Campbell Plant would be retired and unavailable for the summer of 2025.

The Campbell Plant's retirement was well known to MISO operators and accounted for in their robust resource planning processes described in further detail below. Indeed, the Order acknowledges that the retirement was already factored into MISO's own supply forecasts. *Id*. at 2. MISO's Planning Resource Auction Results for Planning Year 2025-26 ("PRA," Exhibit 3), cited in the Order, confirm adequate margin for a reliable summer season. *Id*.

Nonetheless, the Order determined than an emergency exists, and that "additional dispatch of the Campbell Plant is necessary," Ex. 1 at 2, even though the Campbell Plant was not included in any of the MISO forecasts finding sufficient capacity. It further based its determination "on the insufficiency of dispatchable capacity and anticipated demand" even though MISO had already determined that there was sufficient capacity to meet anticipated demand (Exs. 3-4) and NERC's Summer Reliability Assessment also does not conclude otherwise. Ex. 2 at *passim*. Nonetheless, the Order concludes with several imperatives:

- That Consumers Energy must take steps to ensure that the Campbell Plant is "available to operate." And that MISO "is directed to take every step to employ economic dispatch of the Campbell Plant to minimize cost to ratepayers" Ex. 1 ¶ A.
- That MISO is directed to provide DOE a report "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." Ex. 1 ¶ D.
- That "relevant government authorities" are directed to take such action and make accommodations as may be necessary to effectuate the dispatch and operation of the Campbell Plant if the MISO current tariff provisions "are inapposite." Ex. 1 ¶ E.

- That rate recovery is available pursuant to 16 U.S.C. § 824a(c) (also referred to as section 202(c) of the Federal Power Act). Ex. 1 ¶ G.
- That the Order runs through August 20, 2025. Ex. 1 ¶ H.

DOE's Order issued in error. The Department did not have substantial evidence or engage in reasoned decision-making in declaring the existence of an emergency. It starts from the proposition that there is only a "potential" for insufficient capacity that "could" result in a need for mitigation, which does not present an actual existing or imminent emergency. Plus, section 202(c)'s plain terms limit DOE to actual emergencies—not the potential that emergencies might arise. Section 202(c) is also limited in the type of conduct it allows DOE to order, such as directing the generation, delivery, or transmission of electric energy. This Order, however, requires the Campbell Plant to be available to operate. Ex. 1 ¶ A. Nothing in section 202(c) grants DOE authority to order a plant to remain on standby in case an emergency occurs—especially absent any demonstrated need identified by the utility or grid operator. And even if an emergency did exist and DOE had the legal authority to issue an Order, directing a the Campbell Plant to participate in the bidding market using economic dispatch would not rationally the purported need (because there is no evidence the Campbell Plant can reasonably address any given future emergency need, because emergency responses do not require economic evaluation, and because the Campbell Plant takes so long to ramp up). It should be rescinded.

II. Legal Background

Under section 202(c) of the Federal Power Act, the Commission[19] has authority to issue an order:

> [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. . . .

16 U.S.C. § 824(c)(1). The same subsection states that the Commission may order "temporary connections of facilities" and "generation, delivery, interchange, or transmission of electric energy" that, in the Commission's "judgment will best meet the emergency and serve the public interest." *Id*. The next subsection, 16 U.S.C. § 824(c)(2), establishes that an emergency order must be limited to only those hours necessary to meet the emergency. It states:

> With respect to an order issued under this subsection that may result in a conflict with a requirement of any Federal, State, or local environmental law or regulation, the Commission shall ensure that such order requires generation, delivery, interchange, or transmission of electric energy only during hours necessary to meet

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[19] The "Commission" refers to the Federal Power Commission (FPC), whose powers were transferred in 1977 to either the Secretary of DOE or the Federal Energy Regulatory Commission (FERC). 16 U.S.C. § 796(14); Department of Energy Organization Act, Pub. L. No. 95-91, 91 Stat. 565, 565-613 (1977). This transfer gave FERC the authority over "the interconnection, under section 202(b), of such Act [16 U.S.C. 824a(b)], of facilities for the generation, transmission, and sale of electric energy (*other than emergency interconnection*)." 42 U.S.C. § 7172(a)(1)(B) (emphasis added). However, this transfer also gave DOE "the function of the Federal Power Commission, or of the members, officers, or components thereof" except as provided in subchapter IV of the act. 42 U.S.C. § 7151(b). Because 42 U.S.C. § 7172(a)(1)(B) explicitly excludes emergency interconnection from FERC's authority, the authority over emergency interconnection has historically been delegated to DOE. However, the delegation of this emergency authority to DOE has not been consistently applied. In *Richmond Power & Light v. FERC*, 574 F.2d 610 (1978), a petitioner objected to FERC's (not DOE's) failure to invoke emergency powers under 16 U.S.C. § 824a(c) and order utilities with excess capacity to supply the petitioner with energy. The court did not address whether FERC had the authority to declare an emergency to begin with. *Id*. Thus, whether FERC or DOE has the power to declare an emergency is inconclusive.

> the emergency and serve the public interest, and, to the maximum extent practicable, is consistent with any applicable Federal, State, or local environmental law or regulation and minimizes any adverse environmental impacts.

Id. at § 824(c)(2).

The applicable regulations define "emergency," 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. Actions under this authority are envisioned *as meeting a specific inadequate power supply situation*.

10 C.F.R. § 205.371[20] (emphasis added).

III. Statement of Issues

Issue A: Did DOE have substantial evidence for its declaration of an emergency, and did it exercise reasoned decision-making in declaring that an actual emergency exists?

No. DOE relied on a NERC assessment that identified an elevated risk for <u>potential</u> capacity exceedance <u>if</u> an extreme weather event were to occur**.** Further, DOE failed to consider substantial countervailing evidence, including the MISO States' Integrated Resource Plans and MISO's PRA for the summer of 2025. The Order fails to identify any reasoned basis for concluding an actual emergency exists or is imminent.

Issue B: Section 202(c)(1) allows DOE to issue temporary emergency orders in times of actual extant or impending emergencies such as war, sudden demand for electric energy, shortage of fuel or water, or other similar conditions creating a specific inadequate power supply

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[20] DOE issued 10 C.F.R. §§ 205.370-379 pursuant to the Department of Energy Organization Act's transfer of emergency responsibilities to the Secretary of Energy.

situation. Did DOE exceed this authority where its Order is based on the nonspecific possibility that such a situation might occur over a period of several months?

Yes. An actual "emergency" is a sudden occurrence requiring immediate response action or a concrete need for energy to be produced; conversely, it is not the mere potential that an emergency might occur. 16 U.S.C. § 824a(c); 10 C.F.R. § 205.371. Emergency orders must respond to "a specific inadequate power supply situation." 10 C.F.R. § 205.371. The Order does not address any sudden occurrence needing imminent response, nor does it identify any actual and specific insufficient supply situation. Thus the Order is contrary to law.

Issue C. Section 202(c)(1) allows DOE to issue emergency orders requiring the "generation, delivery, interchange, or transmission of electric energy." Did DOE exceed this authority where its Order requires the Campbell Plant to take steps to be "available" to generate electricity and requires MISO to employ economic dispatch?

Yes. DOE's emergency powers allow it to order the generation, delivery, interchange, or transmission of electric energy. Section 202(c)(1) does not give the DOE the authority to order that a plant be merely available (absent a showing of why that is needed), nor does it give the DOE authority to order MISO to engage in potential economic dispatch. 42 U.S.C. §16432(b). Because it is not confined to the types of actions allowed under section 202(c)(1), the Order is without authority and contrary to law.

Issue D. If DOE issues an order pursuant to 202(c)(1), then 202(c)(2) requires it to set limits on hours of operation and ensure that environmental impact is minimized. Did DOE exceed its authority by invoking section 202(c) to issue an Order that sets no specific hours of operation, places no limits on hours of operation, and adopts no specific requirements to minimize environmental impact?

Yes. The express statutory language requires an emergency order be limited to only those hours necessary to meet the emergency and minimize adverse environmental impacts. 16 U.S.C. § 824a(c)(2). The Order does not establish any limited hours for operation, and at the same time it allows the Campbell Plant to potentially run at any and all hours for the entire 90 days covered bye the Order. It also does not meaningfully take steps to minimize adverse environmental impacts.

Because the Order does not set any specific hours the Campbell Plant must run, allows for unlimited hours for much of the summer, and doesn't meaningfully minimize adverse environmental impacts, the Order violates the requirements of section 202(c)(2). It is without authority and contrary to law.

Issue E: The Federal Power Act reserves resource adequacy planning to the individual states. Did DOE exceed its authority where its Order directly compels a plant slated for retirement to take steps to be available to operate?

Yes. Section 201(a) of the Federal Power Act explicitly provides that federal regulation over generation and transmission is related to matters of interstate commerce and extends "only to those matters which are not subject to regulation by the States." 16 U. S. C. § 824(a). States retain jurisdiction "over facilities used for the generation of electric energy." 16 U.S.C. § 824(b)(1). Because DOE's Order exceeds its authority by contradicting Michigan's resource plans, it is contrary to law.

Issue F: The states retain primary authority for developing and establishing Integrated Resource Plans or Strategic Energy Plans that get factored into MISO's tariffs. The Order directs "relevant governmental authorities" to accommodate the Order. Does this portion of the Order violate the Tenth Amendment, exceed DOE's authority, and impose arbitrary-and-capricious requirements not based on substantial evidence?

Yes, on all fronts. This section of the Order is incomprehensible and unexplained. It violates the Tenth Amendment to the extent it directs state or local officials to carry out the Order. And Section 202(c) does not include authority to order any unit of government to take any particular action. For all of these reasons, the Order is contrary to law.

Issue G: Even if DOE were correct that an emergency exists and that it had the authority to issue the Order, will the Order's requirements rationally meet the emergency?

No. Section 202(c) contemplates emergency orders that are precisely tailored to meet the specific emergency.16 U.S.C. § 824a(c). Emergency generation is not economic dispatch. Plus, the Campbell Plant is high cost and uneconomical, it requires a long time to ramp up, and there is no reason to think it would be used to meet any shortfall if one were to happen given other considerations such as transmission infrastructure. The Order's specific requirement for MISO to take steps to effectuate "economic dispatch" of the Campbell Plant is not rationally related to the emergency it purports to address, so the Order is without substantial evidence and lacks reasoned decision-making.

IV. Description of MISO

MISO is a regional transmission organization (RTO), an independent, non-profit, membership-based organization responsible for optimizing generation and transmission of electricity and ensuring the reliability of the electric power system within its region, consisting of nearly 3,000 generating units.[21] 18 C.F.R. § 35.34(a), (j)(1). MISO administers bulk or wholesale power markets that centrally commit and dispatch power to facilitate least-cost and reliable power production and delivery throughout the region. The wholesale markets within MISO signal and value power needs and identify the most economically efficient way—the least-cost approach where demand for energy equals the cost supplied—to meet them across the system.[22] MISO also works to coordinate generation and transmission of electricity with other RTOs, exporting power at times and at others allowing electricity to be imported to MISO.[23] MISO uses advanced

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[21] MISO, *Fact Sheet* (July 2024), available at https://www.misoenergy.org/meetmiso/media-center/2024/corporate-fact-sheet.

[22] MISO, *Electric Grid 101*, available at https://www.misoenergy.org/meet-miso/grid-operations-basics.

[23] MISO, *Interregional Coordination*, available at https://www.misoenergy.org/planning/interregional-coodination/; see also MISO, Historical Net Scheduled Interchange (NSI), at https://www.misoenergy.org/markets-and-operations/real-time--marketdata/ market-reports/ (data found under "Summary" Market Reports).

modeling and thorough research to coordinate short and long-term planning for the benefit of generating units and consumers.[24]

MISO planned for adequate capacity during the summer of 2025: "As recognized by the Order, MISO's Planning Resource Auction for the 2025-2026 Planning Year demonstrated sufficient capacity for all zones within the MISO Region." Ex. 3 at 2. It reports: "it is important to recognize existing processes have *cleared sufficient electric generating capacity across MISO for the periods of time covered by the Order*." *Id.* (emphasis added). And it goes on to describe its confidence that it has already ensured "sufficient capacity to meet anticipated demand across the MISO Region for the 2025-2026 Planning Year." *Id.*

The long-planned retirement of the Campbell Plant is not an impediment to summer reliability in the MISO region. Since 2010, MISO has experienced the retirement of 30.8 gigawatts (GW) of generation capacity, a large proportion of which (21.9 GW) was coal-fired generating units.[25] That trend is shown below in the bar graph (from MISO's 2023 Transmission Expansion Plan Report[26]), which displays the retired capacity by generation type over time:

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[24] MISO, *Transmission and Generation Planning 101*, available at https://www.misoenergy.org/meet-miso/grid_planning_basics.

[25] *See also* MISO, *Approved Generator Retirements (Public) as of June 28, 2024* ("*Approved Retirements 2024*"), https://www.oasis.oati.com/woa/docs/MISO/MISOdocs/OASIS_Posting_of_Approved_Generator_Retirements_(Public)_2024-06-28.pdf).

[26] MISO, *2023 Transmission Expansion Plan*, available at https://cdn.misoenergy.org/MTEP23%20Executive%20Summary630586.pdf.

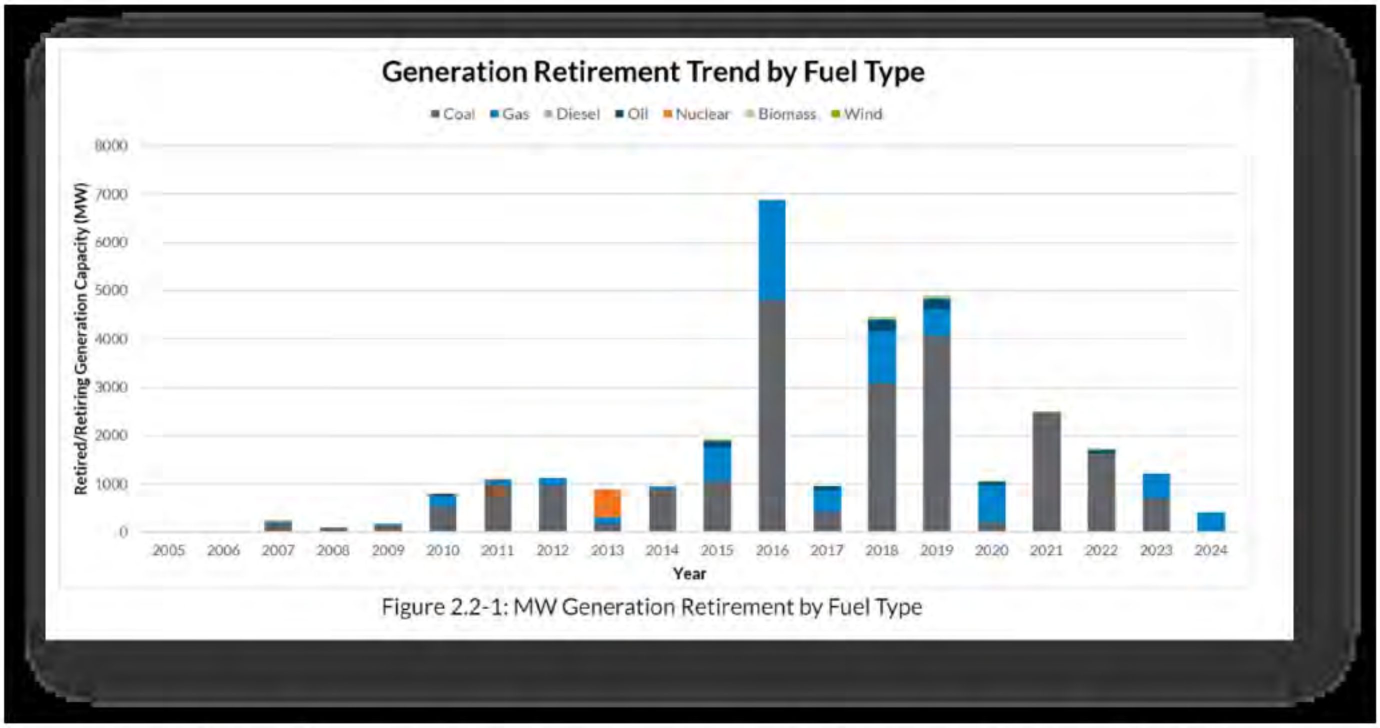

Figure 2.2-1: MW Generation Retirement by Fuel Type

Through use of generation capacity and transmission infrastructure planning, the addition of new capacity—in particular renewables, and the implementation of the other measures discussed above, MISO has been able to absorb these retirements and maintain overall system reliability. *Id.* at 34-35.

V. Argument

A. The Order lacks substantial evidence demonstrating the existence of an actual emergency and DOE failed to engage in reasoned decision-making.

The DOE failed to provide substantial evidence that an unexpected emergency presently exists, as required by 16 U.S.C. § 824a(c)(5). The relevant standard is whether the DOE's determination is supported by substantial evidence. 16 U.S.C. § 824a(c)(5) refers to the possibility of judicial review under 16 U.S.C. § 825l. After an objection has been brought before DOE, the Court may consider it with the understanding that "[t]he finding of the Commission as to the facts, if supported by substantial evidence, shall be conclusive." 16 U.S.C. § 825l. Substantial evidence means "such relevant evidence as a reasonable mind might accept as adequate to support a conclusion." *Duke*

Energy Corp. v. FERC, 892 F.3d 416, 420 (2018). This standard implies deference to an agency's factual determinations. *See, e.g., id*.

While DOE failed to provide substantial evidence of a current and unexpected emergency, the evidence DOE provided, does prove however, that there is currently no energy emergency and will not be an "unexpected emergency" that warrants this Order. MISO is well situated to deliver reliable power throughout its area in the summer of 2025.

In declaring the contrary, DOE relied on a NERC assessment that identified an elevated risk for <u>potential</u> capacity exceedance <u>if</u> an extreme weather event were to occur**.** But the Order makes too much out of too little—the "elevated" category is hardly a call for immediate and unnecessary emergency action. As the NERC assessment points out, MISO expects to have an existing certain capacity of 142,783 MW during the summer—a figure that factored in an assumption that the Campbell Plant would be retired and unavailable for the summer of 2025 and that exceeds both expected demand and the reserve margin[27] anyway. While retirements and fewer suppliers meant that MISO would have fewer firm resources and dispatchable generation, that was no cause for alarm. To the contrary, NERC concluded that all areas were projected to have "adequate anticipated resources for normal summer peak load conditions." *Id*. And nothing in the NERC assessment determined that MISO's interconnection with other RTOs would be insufficient to cover any needs that could arise.

The "elevated risk" category is not tantamount to an emergency. Even though NERC used the term "elevated risk" for the possibility that there could be an operating reserve shortfall, NERC did not apply the "high risk" category to MISO, and did not call for any retired plants to be brought

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[27] MISO PRA, Results for Planning Year 2025-26 at 18 (Corrected May 29, 2025).

back online. Ex. 2. at 5. Moreover, the "elevated risk" designation means the probabilistic indices are low but not negligible. *Id.* at 10, Table 1. And further, the MISO-specific "dashboard" concludes that MISO's expected resources meet operating reserve requirements under normal peak-demand scenarios. At worst, operating mitigations "could" be necessary for above-normal summer peak load and extreme generator outage conditions: *Id.* at 16. The "elevated risk" designation is also far from unusual; it has never required an emergency order before, and the grid has remained stable. MISO has been designated as at "elevated" risk in every NERC Summer Reliability Assessment since NERC initiated the practice of designating regions as "high," elevated," or "normal" risk in 2021.[28] NERC has also designated MISO as "elevated" risk in every Winter Reliability Assessment since 2021. *Id.* Yet no energy shortage has occurred and DOE has never imposed an emergency declaration until now.

Such a declaration is simply unnecessary when considering the bigger picture. DOE clearly erred in its consideration of the evidence, *see Wisconsin Power & Light Co. v. FERC*, 363 F.3d 453, 461 (D.C. Cir. 2004) (an appeals court "must consider . . . 'whether there has been a clear error of judgment.'"), including the contradiction in the Order's citation of MISO's PRA for the summer of 2025 which contrary to the Order actually found sufficient capacity throughout the region. The PRA provides a strong conclusion that supply will be adequate. Ex. 3. The press release announcing the PRA, (Exhibit 4), confirms "adequate resources are available to maintain reliability during the upcoming planning year (June 2025 – May 2026)." Ex. 4. And while "the 2025 auction prices reflect a tightening supply-demand balance during the summer months, there is sufficient capacity throughout the MISO footprint." *Id.* The PRA was based on NERC's standard

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[28] *See* NERC, *Reliability Assessments*, https://www.nerc.com/pa/RAPA/ra/Pages/default.aspx (last visited June 23, 2025).

BAL-502-RF-03 (Exhibit 5), requiring assessment of "one day in ten year" loss of load expectation principles. In short, the NERC standard that MISO applied to conduct the PRA demonstrated that MISO will have sufficient capacity through the summer of 2025. Exs. 3-4. MISO's PRA results show that there will be enough capacity in the summer planning year, and MISO notes that the summer auction price provides a signal to the market to add more capacity for future auction years. DOE appears to have cherry-picked certain phrases from the PRA but does not give it full consideration.

Indeed, in MISO's Answer to the cost-recovery docket dated June 19, 2025, MISO highlights the PRA when it describes its certainty it has planned for adequate capacity: "As recognized by the Order, MISO's Planning Resource Auction for the 2025-2026 Planning Year demonstrated sufficient capacity for all zones within the MISO Region." Ex.10 at 2. It further writes, "it is important to recognize existing processes have cleared sufficient electric generating capacity across MISO for the periods of time covered by the Order." *Id.* (emphasis added). And it goes on to describe its confidence that it has already ensured "sufficient capacity to meet anticipated demand across the MISO Region for the 2025-2026 Planning Year." *Id.* This recent submission undermines DOE's conclusions in the order that MISO faces insufficient capacity.

DOE failed to consider recent comments by MISO's Independent Market Monitor to the Markets Committee of the MISO Board of Directors dispelling NERC's purported concerns. See Exhibit 11. The Independent Market Monitor is charged with ensuring adequate supply markets for the MISO region. He criticized a separate NERC long-term reliability assessment (which has since been revised[29]) that included capacity shortfalls in 2025, noting that NERC's assessment compared the wrong numbers. In doing so, the Independent Market Monitor declared MISO capacity to be "more than adequate," and that he had "no material concerns" over MISO's resource adequacy for the upcoming summer.

DOE also failed to consider MISO's history of strong performance through several extreme weather events including Winter Storms Elliot and Uri, and did not credit MISO's proven track record of engaging in a variety of mechanisms to ensure grid reliability.

DOE further failed to acknowledge that no part of MISO is currently afflicted by any unexpected outage or extreme weather event, and the entire system is running as planned with no outages, unexpected demand, lack of fuel or water, or other such emergencies in place at the time of the order.

Given all of these countervailing considerations, DOE did not have substantial evidence supporting its emergency determination. It did not exercise reasoned decision-making in declaring that an emergency exists. Its Order is arbitrary and capricious.

B. The Order exceeds DOE's authority because it is not limited to a specific inadequate power supply situation as required by Section 202(c) and 10 C.F.R. § 205.371.

An actual "emergency" is a sudden occurrence requiring immediate responsive action; conversely, it is not the mere potential that an emergency might occur. The statute describes the temporary response needed to address a sudden event by its black-letter terms. 16 U.S.C. § 824a(c). And Department regulations define "emergency" to mean an unexpected inadequate supply of

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[29] NERC, *Statement of NERC's Long-term Reliability Assessment*, (June 17, 2025) https://www.nerc.com/news/Pages/Statement-on-NERC%E2%80%99s-2024-Long-Term-Reliability-Assessment.aspx?utm_source=substack&utm_medium=email.

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." 10 C.F.R. § 205.371. Further, emergency orders must meet "a specific inadequate power supply situation," and although emergencies with extended periods of insufficient supply could qualify, the impacted entity is supposed to firm up commitments for supply "so that a continuing emergency order is not needed." *Id*

These requirements have been demonstrated by DOE's historic use of 202(c) authority to address natural disasters and specific capacity crises. The most common reason to invoke Section 202(c) authority has been to address natural disasters like hurricanes, cold weather events, and extreme heat. *See* DOE Order Nos. 202-05-1 & -2 (Sept. 28, 2005) (Hurricane Rita); DOE Order No. 20208-1 (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); DOE Order No. 202-21-1 (Feb. 14, 2021) (Winter Storm Uri); DOE Order No. 202-22-3 (Dec. 23, 2022) (Winter Storm Elliot – Texas ERCOT); DOE Order No. 202-22-4 (Dec. 24, 2022) (Winter Storm Elliot – PJM); DOE Order No. 202-20-2 (Sept. 6, 2020) (extreme heat in California); DOE Order No. 202-21-2 (responding to extreme heat, wildfires and drought in California); DOE Order Nos. 20222-1 & 2 and amendments (same). Indeed, during Winter Storm Elliot, MISO exported power to neighboring regions.[30]

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[30] MISO, *Overview of Winter Storm Elliott December 23, Maximum Generation Event* (Jan. 17, 2023) ("*Winter Storm Elliott Overview*") at 7, https://cdn.misoenergy.org/20230117%20RSC%20Item%2005%20Winter%20Storm%20Elliott%20Preliminary%20Report627535.pdf.

While DOE's emergency powers have occasionally been used to address retirements like the Campbell Plant, it has done so only when requested by the operator or local government and there was a specific need demonstrated for the units to operate due to an unexpected emergency. DOE Order No. 202-05-3 (Dec. 20, 2005) (Mirant to supply Washington D.C. when transmission lines were out of service); DOE Order No. 202-17-1 at 2 (Grand River Energy to operate Unit 1 due to lighting strike to Unit 2 and delay in construction for Unit 3); DOE Order No. 202-17-2 (need to operate Yorktown to avoid imminent risk of load-shedding).

A memorandum by the Congressional Research Service, Exhibit 12, confirms that DOE's use of Section 202(c) to order a plant to be generally available is novel. Ex.12 at 3 (Department engaging in "seemingly new interpretations of the emergency authority").

Courts have also likewise recognized Section 202(c)'s limitation to actual or imminent crises. For example, in *Richmond Power and Light v. FERC*, the D.C. Circuit noted that the statute "speaks of 'temporary' emergencies, epitomized by wartime disturbances, and is aimed at situations in which demand for electricity exceeds supply." 574 F.2d 610, 615 (D.C. Cir. 1978). And in *Otter Tail Power Co. v. Fed. Power Comm'n.*, the Eighth Circuit noted that 202(c) provides authority to "react to a war or national disaster and order immediate interconnection. . . to maintain electrical service during such emergency." 429 F.2d 232, 234 (8th Cir. 1970). In *Otter Tail*, the Eighth Circuit distinguished between an emergency that is likely to occur and one that is actually occurring, concluding that a separate provision, section 202(b) [31] applies to the former, while section 202(c) applies to the latter:

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[31] Section 202(b) refers to 16 U.S.C. § 824a(b), which states "[w]henever the Commission, upon application of any State commission or of any person engaged in the transmission or sale of electric energy, and after notice to each State commission and public utility affected and after opportunity for hearing, finds such action necessary or appropriate in the public interest it may

> On its face, § 202(c) enables the Commission to react to a war or national disaster and order immediate interconnection of the facilities to maintain electrical service during such emergency. . . On the other hand, § 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.

Otter Tail Power Co., 429 F.2d at 234. In that case, a power company challenged the FPC's order issued under § 202(b) of a temporary connection between the power company and a small municipally owned power producer that was "dangerously close to eroding its firm power supply" due to the proximity between the generator load capacities and the peak load demand. *Id.* It claimed that because the ordered connection was temporary, the order could only be issued under section 202(c), and only in emergency conditions. *Id.* The court disagreed that section 202(c) only applies to temporary orders but agreed that a potential crisis in the foreseeable future was not an emergency, making it "just the type of situation to fit into a § 202(b) hearing rather than § 202(c)." *Id.* The caselaw is therefore clear: for DOE to have any authority under section 202(c) the emergency must be actual and not merely a broadly asserted projected risk.

DOE exceeds its authority because the Order does not address any actual emergency or sudden occurrence needing imminent response, and because it has not identified any actual and specific insufficient supply situation. Thus the Order is without authority and contrary to law.

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by order direct a public utility" if the utility would not face an undue burden. The DOE's authority is much more limited in these situations. Further, 42 U.S.C. § 7172(a)(1)(B) vests this power in FERC, not the Secretary.

C. The Order exceeds DOE's authority because it requires actions not listed in Section 202(c)(1).

DOE's power is limited to orders that require connections or the generation, delivery, interchange, or transmission of electric energy. 16 U.S.C. § 824a(c). This authority does not cover mandating general plant <u>availability</u> untethered to meeting any specific need, nor does it allow for <u>potential</u> economic dispatch (which is not an apt solution for an actual emergency anyway—more on this in Section G below). Section 202(c)(1) does not allow for preemptive measures just in case an emergency might occur, and specifically does not allow for the Department to order availability without a specific need to be available.[32] Plus, "Economic dispatch" is not equivalent to the generation of electric energy. Economic dispatch is constrained by statute to mean <u>only</u> the lowest-cost option under the Energy Policy Act of 2005 Section 1234(c). 42 U.S.C. §16432(b). MISO's determination of lowest-cost sources may not result in the Campbell Plant producing *any* generation whatsoever. Thus the Order is without authority and contrary to law.

D. The Order exceeds DOE's authority because it does not set any hours of operation, limit hours of operation, or minimize environmental impact as required by Section 202(c)(3).

The order must be limited to only those hours necessary to meet the emergency. 16 U.S.C. § 824a(c)(2).

The Order addresses only the <u>potential</u> for an emergency, but does not identify a need for the Campbell Plant to generate electricity to meet it. By the same token, the Order does not establish any limited hours or other parameters for the Campbell Plant to follow to ensure it meets

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[32] Of the 19 times the DOE has issued a 202(c)(1) Order, only once, for Mirant in 2005, did it require a plant to supply as-needed additional capacity—but even then it was based on a specific application demonstrating a concrete and specific need. DOE Order No. 202-05-3 (Dec. 20, 2005). That is not the case here.

the purported emergency, only that it be available at all times. Thus the Order is without authority and contrary to law, and allows the Campbell Plant to generate electricity during times there are not even "elevated risks." Allowing a coal plant to generate electricity and pollute beyond the purported emergency needs would increase the environmental impacts that, by law, the Order must strive to minimize. 16 U.S.C. § 824a(c)(2). Thus the Order is without authority and contrary to law.

E. The Order exceeds DOE's authority because Section 201(b)(1) reserves decisions about plant retirements to the states.

Section 201(a) of the Federal Power Act explicitly provides that federal regulation over generation and transmission is related to matters of interstate commerce and extends "only to those matters which are not subject to regulation by the States." 16 U. S. C. § 824(a). Decisions over what plants should be constructed or retired is traditionally subject to state regulation. States retain jurisdiction "over facilities used for the generation of electric energy." 16 U.S.C. § 824(b)(1). "The states are thus authorized to regulate energy production . . . and facilities used for the generation of electric energy" *Coal. for Competitive Elec., Dynergy Inc. v. Zibelman*, 906 F.3d 41, 50 (2d Cir. 2018). What facilities to build, whether they remain feasible, and utility rates are areas governed by the states. *Pac. Gas & Elec. Co. v. State Energy Res. Conservation and Dev. Comm'n*, 461 U.S. 190, 205 (1983).

The energy market is governed by longstanding principles of cooperative federalism encouraged in Section 209(b) of the Federal Power Act—which explicitly declares that the Federal Energy Regulatory Commission may consult with states "regarding the relationship between rate structures, costs, accounts, charges, practices, classifications, and regulations of public utilities subject to the jurisdiction of such State commission and of the Commission.") 16 U.S. Code § 824h(b). Indeed, FERC has embraced these cooperative federalism principles and developed longstanding consultation practices with the states, including through creation of a Joint Federal-State Task Force. Exhibit 8. And more recently, a Federal-State Current Issues Collaborative. Exhibit 9.

Section 103 of the Department of Energy Organization Act is also applicable; it mandates due consideration to state retirement plans and requires, where practicable, consultation with relevant state officials. 42 U.S.C. § 7113.

States are responsible for developing and approving power generation plans, typically through public commissions like the Public Utilities Commission[33] in Minnesota, the Public Service Commission.[34]. These bodies oversee the development of Integrated Resource Plans ("IRPs"), or Strategic Energy Assessments, which are the blueprints for how a utility plans to generate sufficient electric power to meet its expected demand. *E.g.*, Minn. Stat. § 216B.2422 (Minnesota's IRP statute). An IRP can consider and adopt plans with myriad inputs and considerations and impact overall electricity rates, the specific communities or areas where power plants are located, determinations of which power plants might be built or retired and the fuels that they will use, overall electric system reliability (like the likelihood of power outages and how quickly the lights come back on), and the environment.[35] Such processes can be rigorous and commissions will open a docket to publicly vet a proposed plan, receive comments, and make an informed decision that is in the best interest of the states and its ratepayers.[36]

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[33] Minnesota Public Utilities Commission, *Utility Planning*, https://mn.gov/puc/activities/economic-analysis/planning/ (last visited June 23, 2025).
[34] Wis. Stat. Ann. § 196.491 (West).
[35] *Id*.
[36] Minnesota Public Utilities Commission, *Electric Integrated Resource Planning (EILRP)*, https://mn.gov/puc/activities/economic-analysis/planning/irp/ (last visited June 23, 2025).

MISO, in turn, is one of the country's largest regional transmission organizations (RTOs), which were formed to develop transmission systems, trading markets, and attendant procedures.[37] MISO works collaboratively with its member states to ensure resource adequacy throughout its service area.[38] This means that it ensures there is sufficient generation capacity to meet future electricity demands, including forecasting demand growth, assessing existing generation assets, and planning for new generation resources.[39] MISO works with utilities during their development of submissions to state regulators for the IRPs that that the regulators ultimately approve. And MISO then accounts for the final IRPS in its planning and analyses forecasting the balance between load and capacity. MISO also operates a capacity auction where utilities and other load-serving entities can procure the necessary generation capacity to meet projected demand. This incentivizes the development and maintenance of adequate generation resources.[40] MISO works with utilities, local regulators, and other stakeholders to maintain resource adequacy, including through its annual Planning Resource Auction ("PRA"), which procures sufficient resources and allows market participants to buy and sell capacity via an auction. MISO determines the capacity requirements in its region for each season covering the June 1 to May 31 time period.[41]

The Campbell Plant's planned retirement is subject to precisely such state regulation and MISO integration. The plan to retire the plant received intense scrutiny over years before being approved and worked into MISO's projections—all under the auspices of state law including

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[37] FERC, *Energy Primer*, https://www.ferc.gov/sites/default/files/2024-01/24_Energy-Markets-Primer_0117_DIGITAL_0.pdf

[38] MISO, *System Planning*, https://www.misoenergy.org/meet-miso/about-miso/industry-foundations/grid_planning_basics/ (last visited June 23, 2025).

[39] *Id.*

[40] *Id.*

[41] MISO, *Resource Adequacy*, https://www.misoenergy.org/planning/resource-adequacy2/resource-adequacy/#t=10&p=0&s=FileName&sd=desc (last visited June 23, 2025).

Michigan's IRP processes, state regulatory proceedings, state judicial proceedings, and state participation in MISO. *See In re 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). The MPSC approved of Consumers Energy's plan to replace the capacity that the Campbell Plant would have produced with the purchase of a natural gas plant and extension of two units of natural gas peaking plants. *Id.* at *33. The Michigan Court of Appeals affirmed. *Wolverine Power Supply Coop., Inc. v Michigan Public Service Commission (In re Consumers Energy)*; No. 362294, 2023 WL 2620437 (Mich. Ct. App. March 23, 2023).

MISO also reviews planned plant retirements to ensure resource adequacy and grid reliability. Section 38.2.7 of MISO's Open Access Transmission, Energy, and Operating Reserve Markets Tariff requires an operator to provide 26 weeks of advance notice of a planned retirement. MISO then performs a Reliability Study to determine whether the retirement will pose any concern for grid reliability. [42]

Consumers Energy submitted the Attachment Y form to MISO on December 14, 2021, providing notice that it planned to suspend generation at the Campbell Plant by June 1, 2025. MISO approved the Campbell Plant's retirement on March 11, 2022. In making its approval, MISO determined that "the suspension of Campbell Units 1, 2 & 3 would not result in violations of applicable reliability criteria."

DOE did not adequately consult with the state, much less account for or incorporate the findings of MISO in approving Consumer's Energy's Attachment Y submission. Michigan state regulators have primary jurisdiction over IRPs, siting, and cost recovery for utilities operating in

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[42] If MISO does identify a threat to grid reliability if the resource retires, the MISO tariff provides a mechanism to retain that resource until the constraint can be alleviated.

their states including the Campbell Plant. *Zibelman*, 906 F.3d at 50. DOE's failure to consult violates the principles behind FERC and DOT policies to involve the states in light of the statutory reservation of state authority in federal-state regulatory balance, 16 U.S.C. § 824(b)(1). It avoids 209(b) of Federal Power Act regarding federal-state collaboration and upends FERC's historic practice of seeking to develop a robust dialogue between regulators. 16 U.S. Code § 824h(b). And it flouts Section 103 of the Department of Energy Organization Act which requires consultation with relevant state officials—consultation was absolutely "practicable" here given the lack of an imminent emergency and the Order did not give any consideration (much less due consideration) to Michigan's IRP. 42 U.S.C. § 7113.

The Order usurps the State of Michigan's primary rule in resource planning and development; it is contrary to law.

F. The Order impermissibly calls for state governments to assist in its execution.

As discussed in the previous subsection, states retain jurisdiction over facilities used for the generation of electric energy and play a key role in development of MISO's tariff provisions. The Order mandates that to "[t]he 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." Order ¶ E. As applied to state and local authorities, this mandate is unlawful for several reasons.

First, the Order violates the Tenth Amendment by commandeering state and local officials to implement a federal program. *See, e.g.*, *Printz v. United States*, 521 U.S. 898, 933 (1997). While the Order is not specific as to the object or the nature of its direction to "government authorities," vagueness does not erase the constitutional infirmity; it exacerbates it. *Cf. Murphy v. NCAA*, 584

U.S. 453, 469 (2018). All the more so where the Order lacks specific limited hours for operation and environmental conditions as discussed in Section D above.

Second, the Order violates the plain terms of Section 202(c), which does not grant authority to issue any order directing any governmental authority to do anything. 16 U.S.C. § 824a(c)(1). Third, the Order does not explain why directing state officials to act (or refrain from acting) pursuant to the powers reserved to them by the Constitution would help achieve the Order's purposes, and DOE lacked substantial evidence to support such a conclusion.

G. The Order is unreasoned, arbitrary, and capricious because the actions it mandates will not meet the purported emergency.

Section 202(c) contemplates emergency orders that are tailored to the specific emergency—they must "best meet the emergency and serve the public interest." 16 U.S.C. § 824a(c). Even if an emergency did exist and DOE had the legal authority to issue an Order, this Order is not rationally related to address the emergency that the order identifies.

The Order's specific requirement for MISO to take steps to effectuate "economic dispatch" of the Campbell Plant is noteworthy. Economic dispatch is a term of art for the procedure by which MISO selects generators to add electric energy to the grid. It is designed to ensure that the electricity generated matches the demand in its service area in the most cost-effective way. Beyond must-run units, MISO dispatches additional capacity from generators in increasing order of their respective costs, starting with the cheapest sources and moving up to more expensive ones as demand increases. MISO will also consider longer-term forecasts of generation given constraints such as forced outages and to ensure adequate margin. And then MISO monitors the grid in real time and calls upon available capacity as needed the day-ahead or day-of markets.

"Economic dispatch," by definition, is awarded to the lowest-cost option (all else being equal). Exhibit 6. That is because much of the base load planning takes place years or months ahead of time and is comprised of the must-run units. Additional capacity is then called upon in the day-ahead or day-of markets for which additional generation is required:

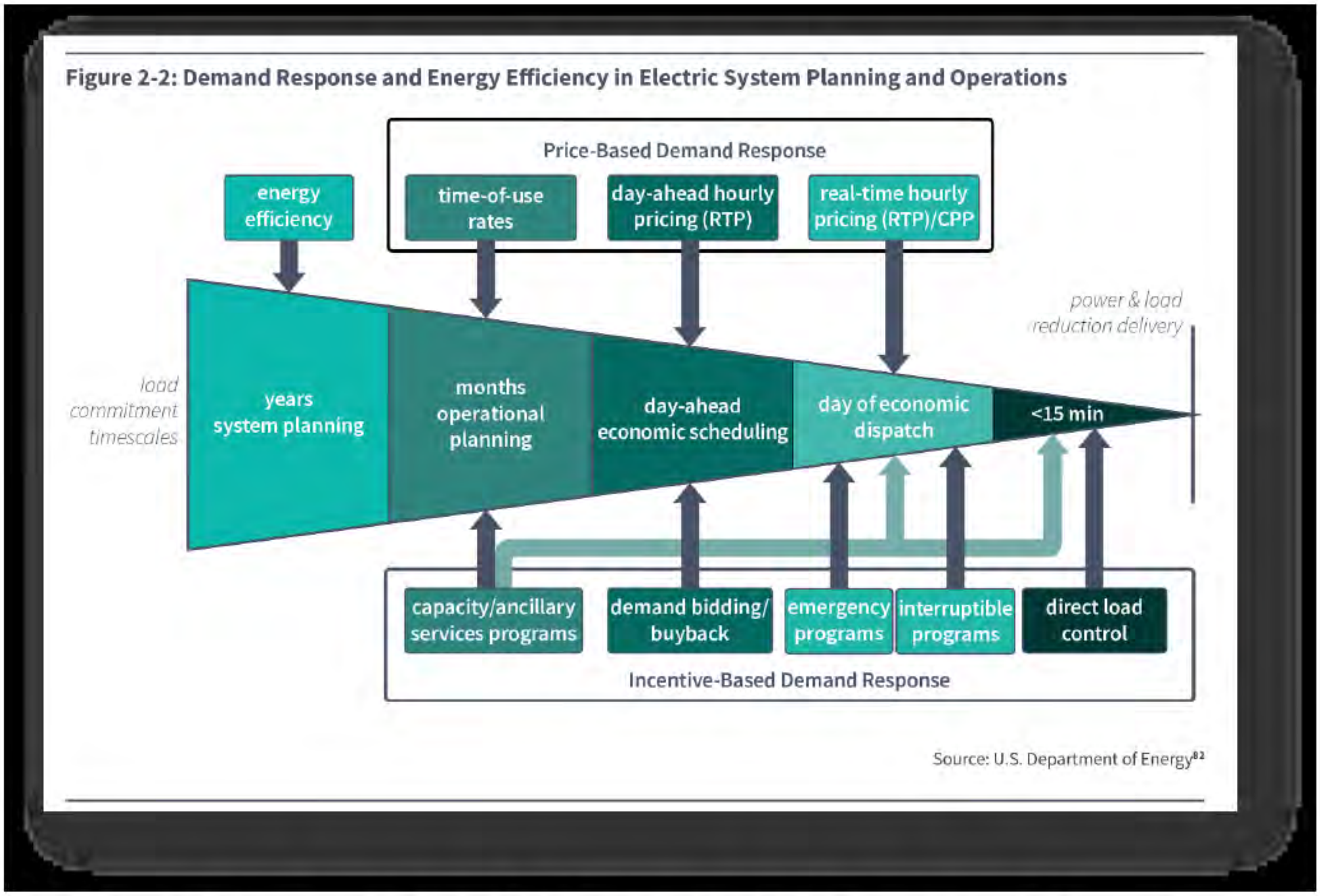

Figure 2-2: Demand Response and Energy Efficiency in Electric System Planning and Operations

Source: U.S. Department of Energy[82]

FERC *Energy Primer*, *supra* n.37 at 43. As explained by DOE's 2007 Report to Congress on economic dispatch, most of the generation available to meet load in real time for economic dispatch is identified and scheduled the day before, based upon the day-ahead load forecast used in the security-constrained unit commitment process. Exhibit 6 at 6. A 2024 report from the Government Accountability Office, Exhibit 13, found that based on 2021 data the vast majority of peaking plants operated on natural gas and oil which can be dispatched in much shorter order; only 3.3 percent of all peakers nationwide burned coal.

Taken together, economic dispatch considers a variety of factors including (1) the cost of generation, (2) the standby condition of the generator, (3) ramp-up time to provide the needed capacity, and (4) whether electric energy can be transmitted to the area of need.

In the context of an emergency, however, plants are generally allowed to run without regard to lowest-cost considerations or bid-submission-and-selection processes. The Order's proposed solution for "economic dispatch" of the Campbell Plant is wholly incompatible with addressing emergency operation (likely because there is no emergency in the first place). In a true emergency, an even uneconomic plants receive cost-of-service payments when they are required to run to alleviate the emergency condition. The RTO does not require the emergency generator to bid into the market and *then* make a determination about whether it will be selected to run as with economic dispatch. Rather, the emergency generator becomes a "price taker" using MISO's "must run" classification. Thus, the order does not use "economic dispatch" in a rational way because an emergency is not addressed with economic dispatch.

Moreover, coal is an expensive fuel type in our current energy mix—indeed the inefficiency of running a coal plant makes it economic in general, and is one of the reasons why this specific Campbell plant was slated for retirement. *See In re Application of Consumers Energy*, No. U-21090, 2022 WL 2915368, at *73.

The Order also does not cite to any evidence that economically dispatching the Campbell Plant will be the appropriate solution for amorphous purported emergency—which is only that a need *might* arise in the future. If, for example, there were a need for additional electricity in North Dakota, it is not likely that there would be sufficient transmission infrastructure across the Great Lakes to deliver electricity from the Campbell Plant to meet that need. And if the need occurs in the day-of or real-time markets, the Campbell Plant will not be able to spool up in time to meet that need, either. That is because it takes over 12 hours to reach peak load. Exhibit 14.[43] And even if there were adequate transmission and lead time, the Campbell Plant still uses an expensive fuel source. If the Campbell Plant's bid is higher than other lower-cost dispatchable alternatives (natural gas, storage, or renewables), then it would not be selected as the most economic resource to meet the need.

Section 202(c)(2) requires the emergency measures to be tailored the actual need; yet here, the Order improperly imposes measures that are not tailored to anything. All the while, the Order imposes costs on the States to maintain an idle plant, adds potentially expensive generation to the mix if it ever were to run, and would generate harmful pollution at the same time. Thus, the Order requiring the Campbell Plant to remain available and for MISO to take steps to use the Campbell Plant for economic dispatch is irrational and arbitrary where the Campbell Plant is unlikely to be a good candidate to serve either economic dispatch or emergency-need functions—especially where it is unclear what need it is supposed to meet in the first place.

Therefore, the Order is not rationally related to meeting the need of the purported emergency that it identifies.

CONCLUSION

For all of the foregoing reasons, the Department should rescind the Order.

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[43] Adapted from U.S. Energy Information Administration submissions according to Forms EIA-860 and EIA923, in which "OVER" indicates ramp-up time exceeding 12 hours. *See* https://www.eia.gov/electricity/data/eia860/; https://www.eia.gov/electricity/data/eia923/.

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Dated: June 23, 2025

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

2025 Summer Reliability Assessment

May 2025

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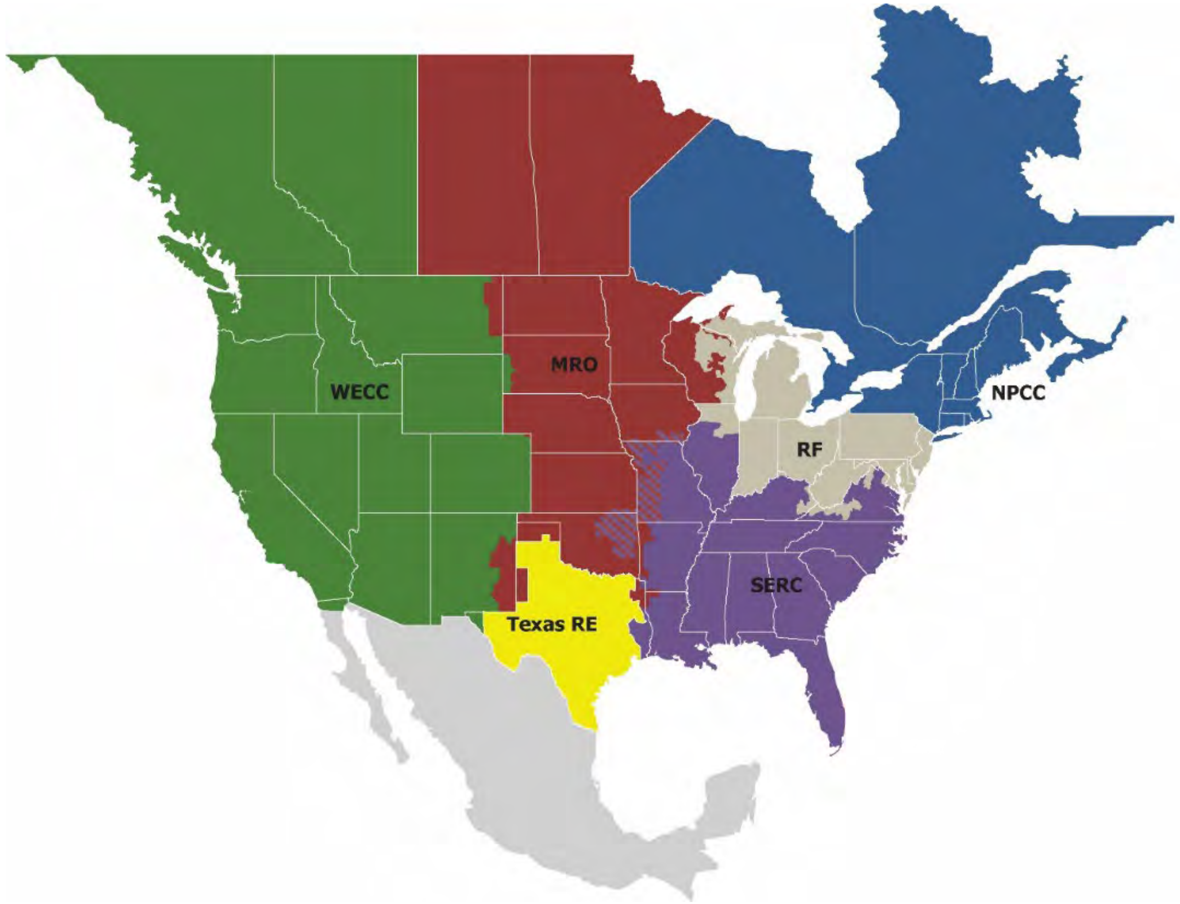
Preface

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

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

The North American BPS is 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.

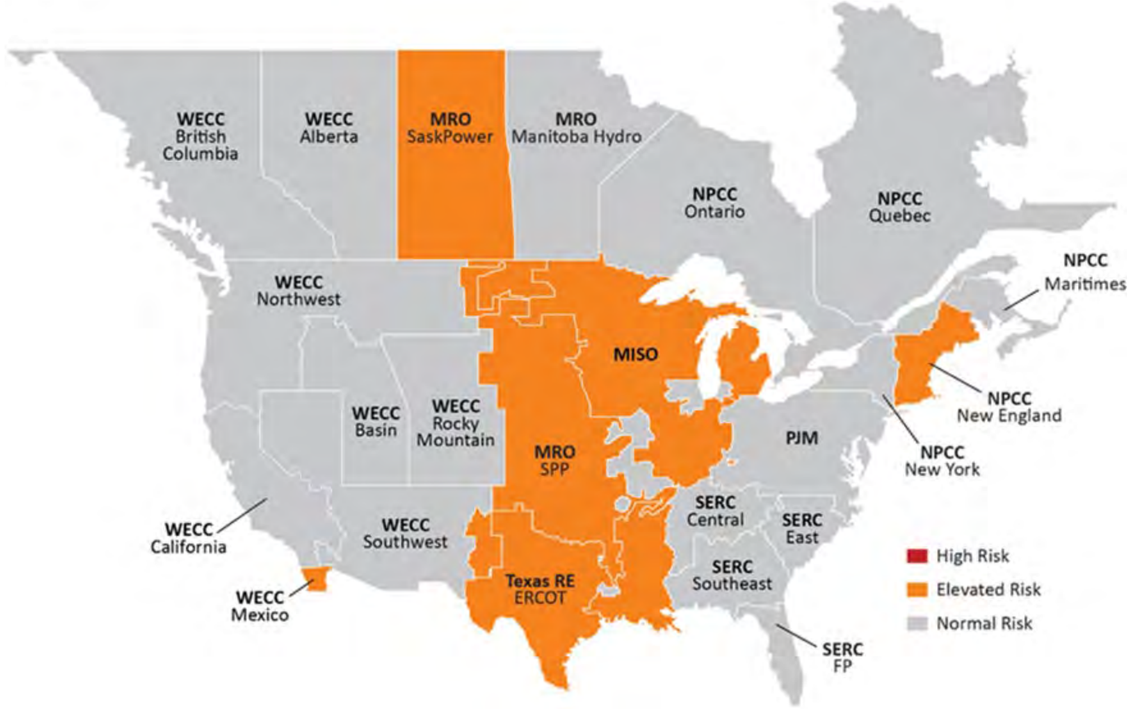

Figure 1: Summer Reliability Risk Area Summary

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.

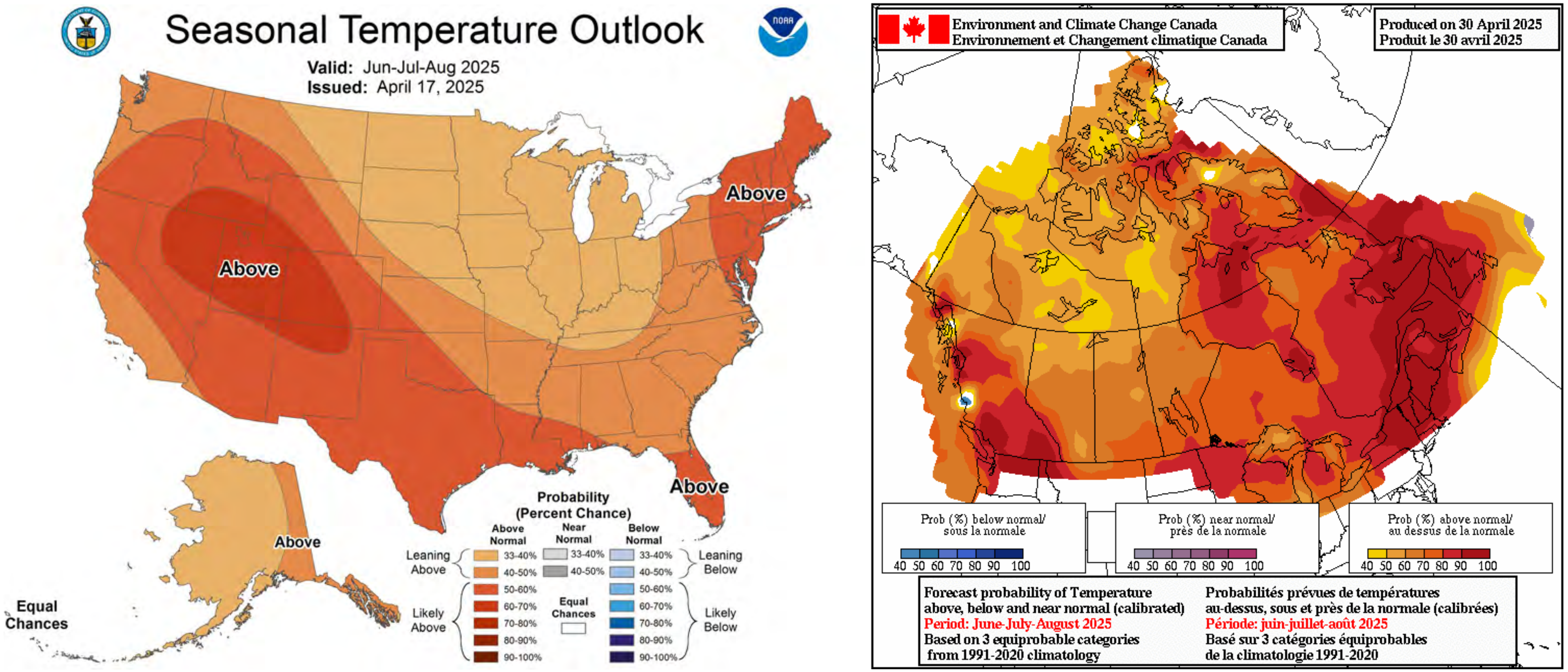

Figure 2: United States and Canada Summer Temperature Outlook[10]

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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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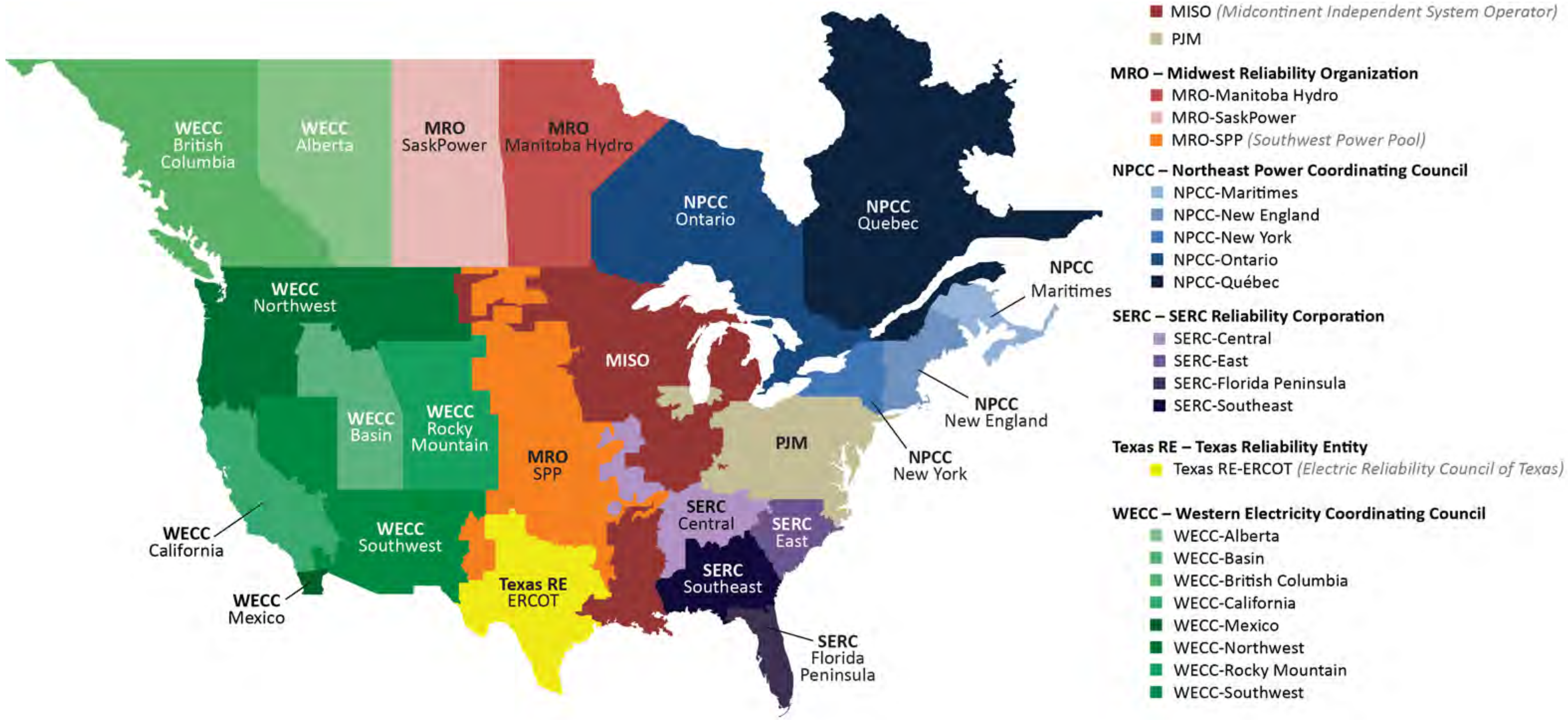
[11] PY 2025–2026 LOLE Study Report

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.

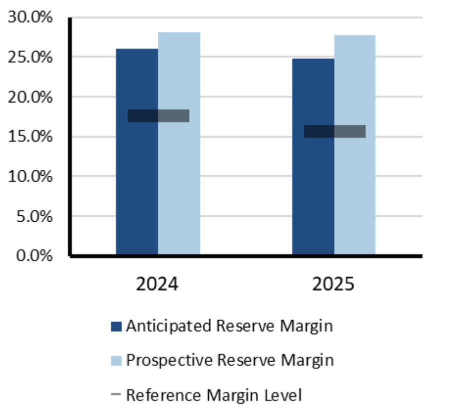
Highlights

- 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.

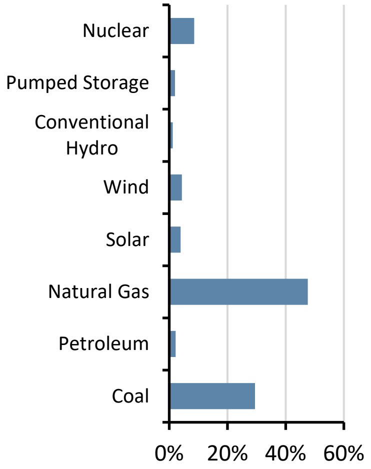
Risk Scenario Summary

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.

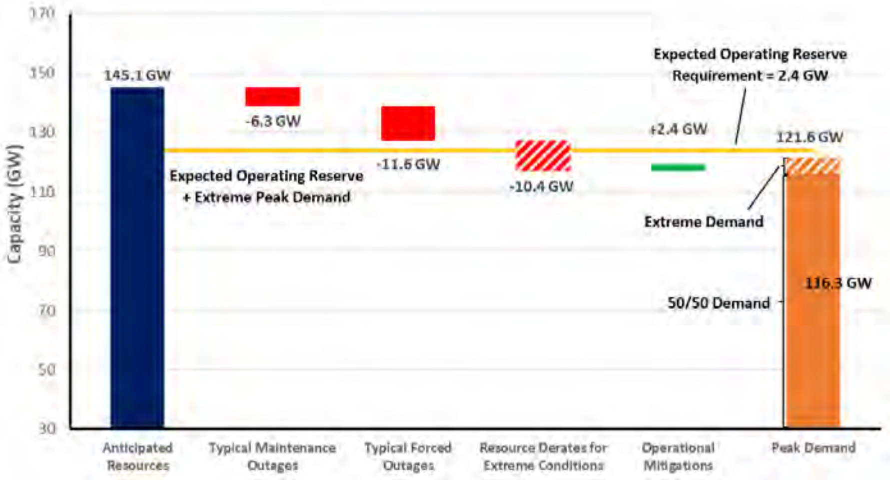
On-Peak Reserve Margin



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.

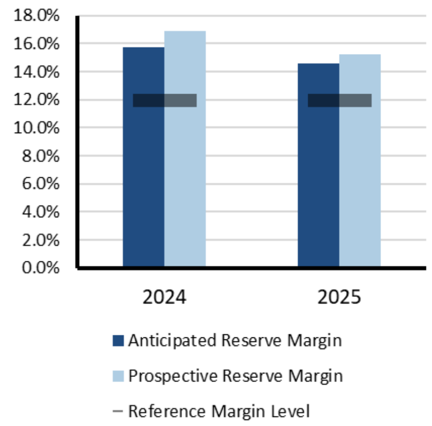
Highlights

- 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.

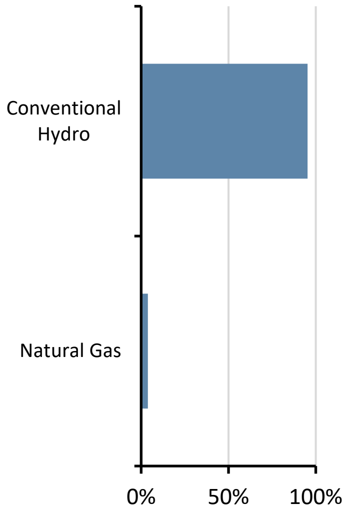
Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed scenarios.

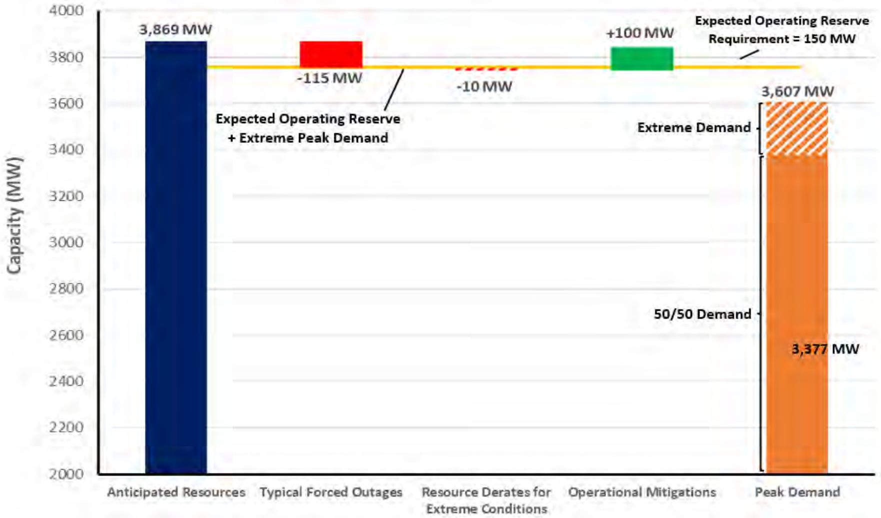
On-Peak Reserve Margin



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.

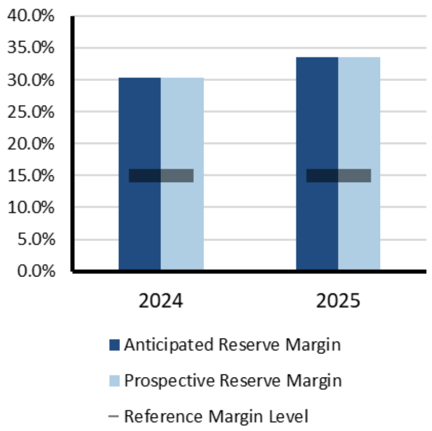
Highlights

- 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.

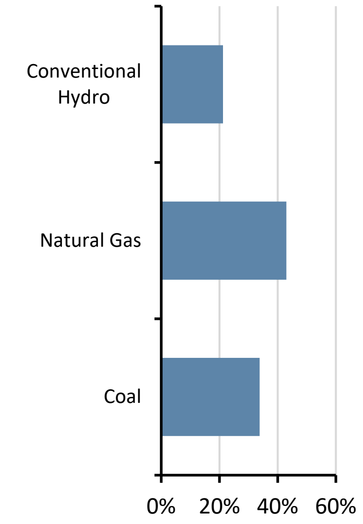
Risk Scenario Summary

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.

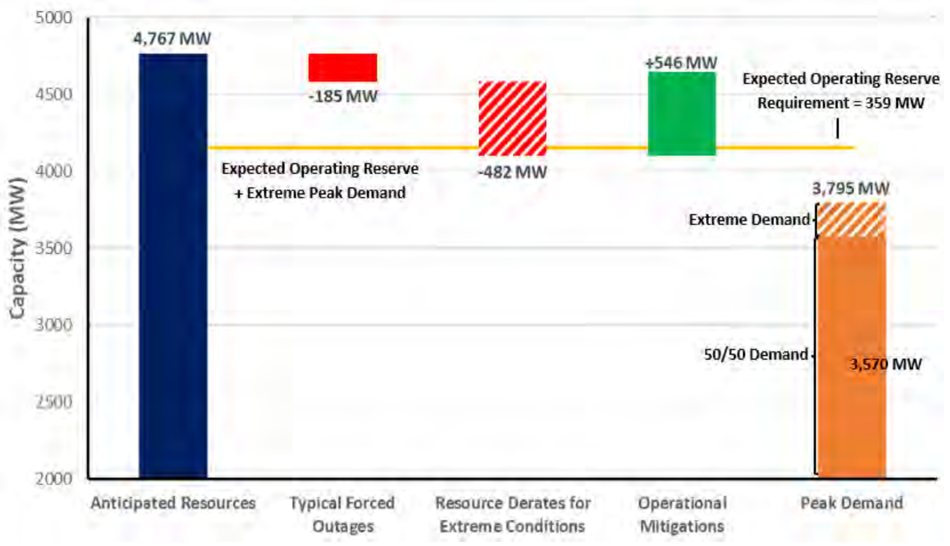
On-Peak Reserve Margin



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.

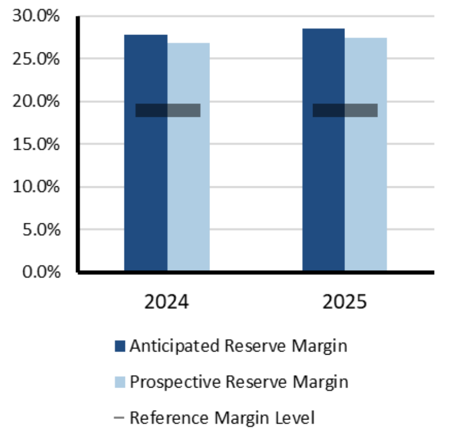
Highlights

- 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.

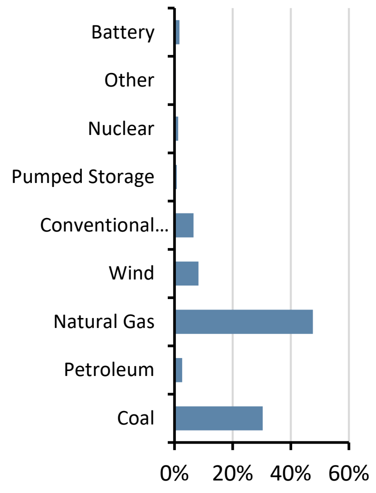
Risk Scenario Summary

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.

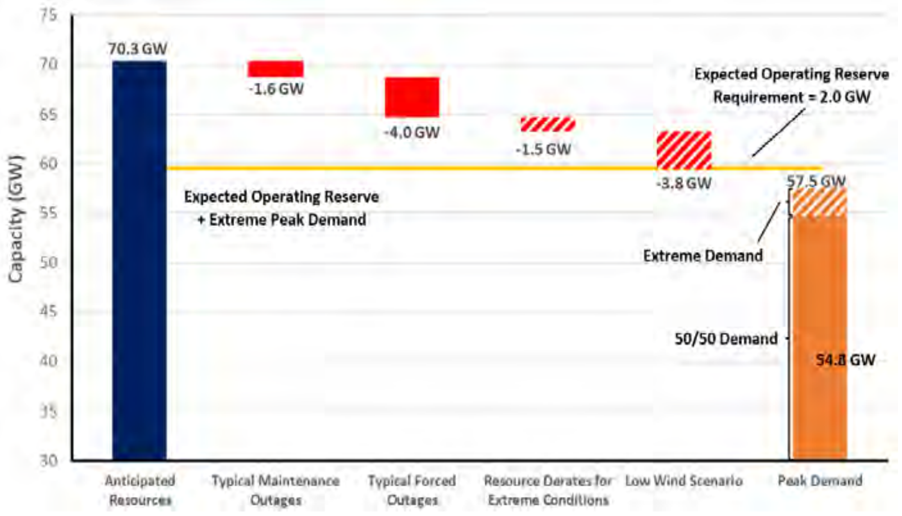
On-Peak Reserve Margin



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.

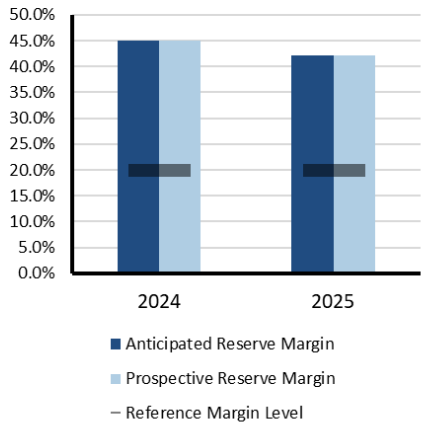
Highlights

- 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.

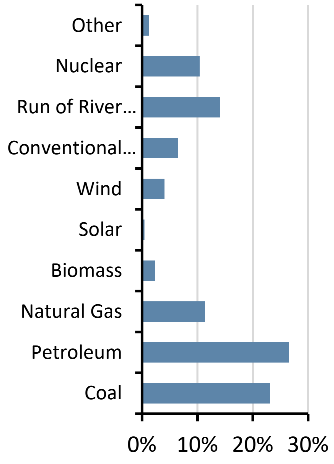
Risk Scenario Summary

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.

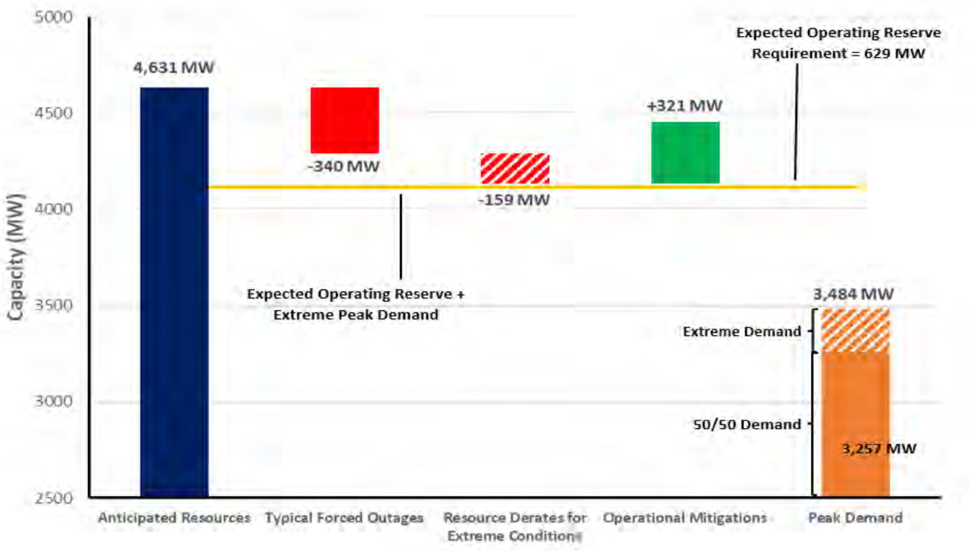
On-Peak Reserve Margin



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 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.

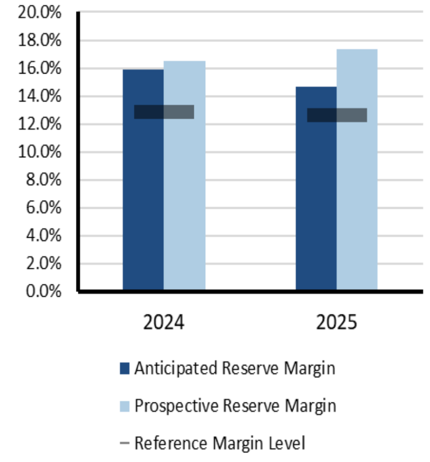
Highlights

- 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.

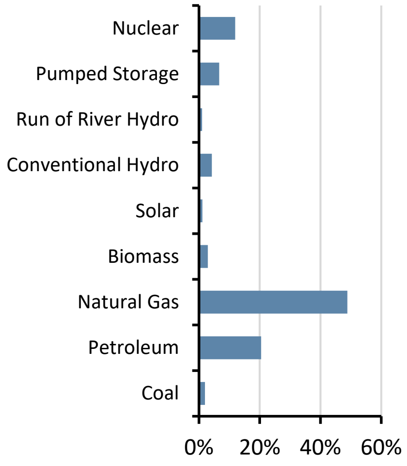
Risk Scenario Summary

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.

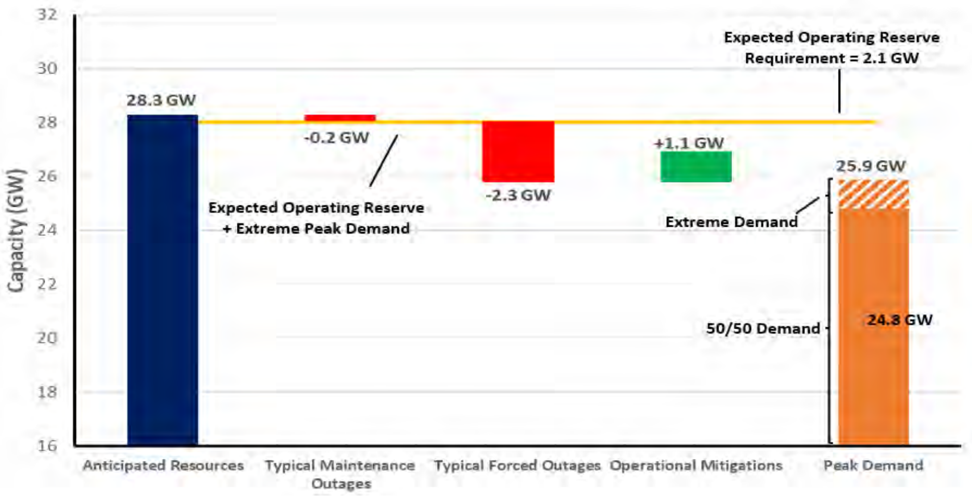
On-Peak Reserve Margin



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: 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

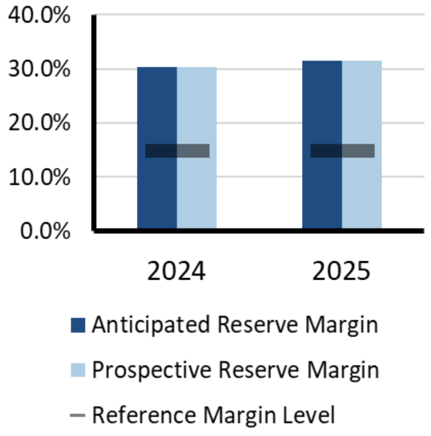
NPCC-New York

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.

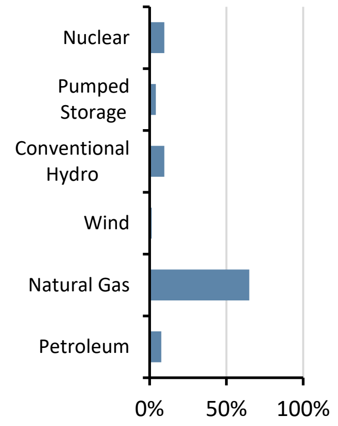
On-Peak Reserve Margin



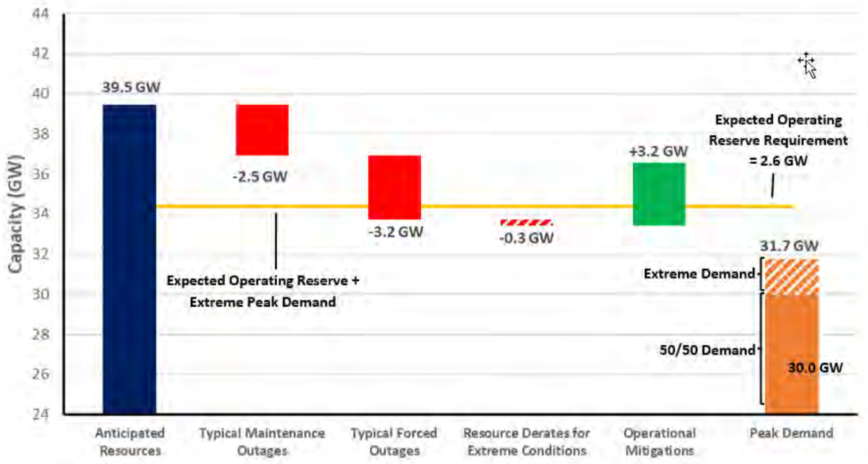
Risk Scenario Summary

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.

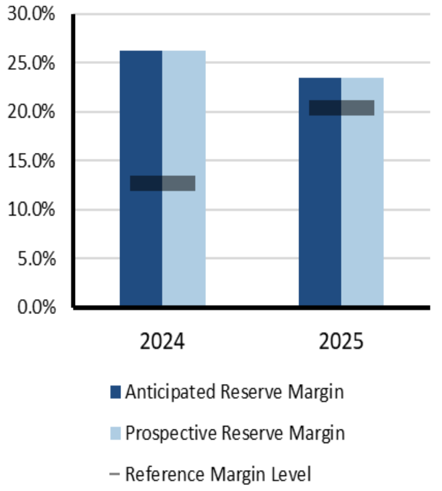
Highlights

- 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."

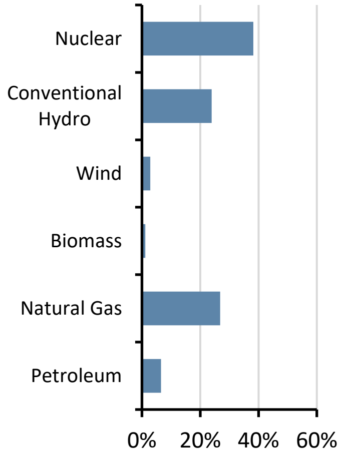
Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed scenarios.

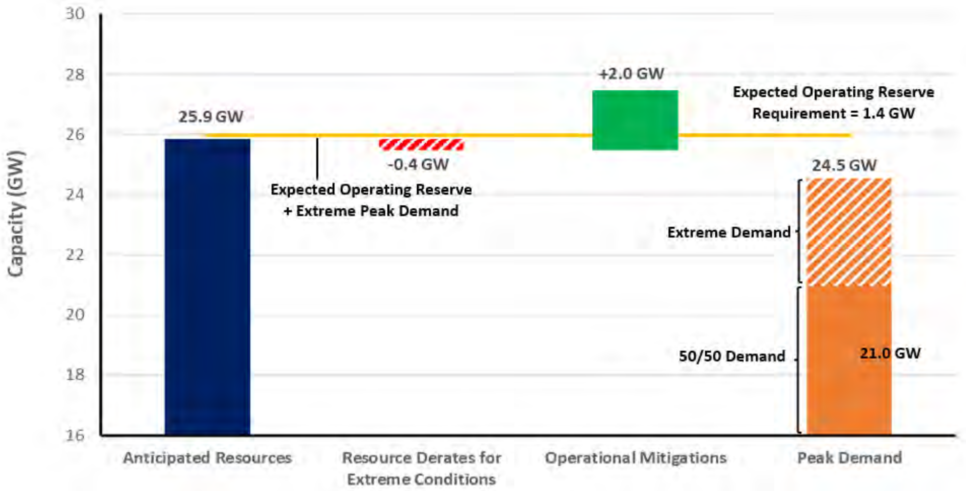
On-Peak Reserve Margin



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 forecast) and highest weather-adjusted daily demand based on 31 years of demand history, and extreme weather represents a 97/3 distribution of probabilistically modelled data

Extreme Derates: Derived from weather-adjusted temperature rating of thermal units and adjustments to expected hydro production for low water conditions

Operational Mitigations: The operational procedures used to mitigate extreme conditions total approximately 2,010 MW for the On-Peak Risk Scenario, consisting of imports, public appeals, and voltage reductions. Public appeals and voltage reductions were not included in the 2024 On-Peak Risk Scenario.

NPCC-Québec

The Québec assessment area (province of Québec) is a winter-peaking NPCC area that covers 595,391 square miles with a population of 8 million. Québec is one of the four Interconnections in North America; it has ties to Ontario, New York, New England, and the Maritimes consisting of either high-voltage direct current ties, radial generation, or load to and from neighboring systems.

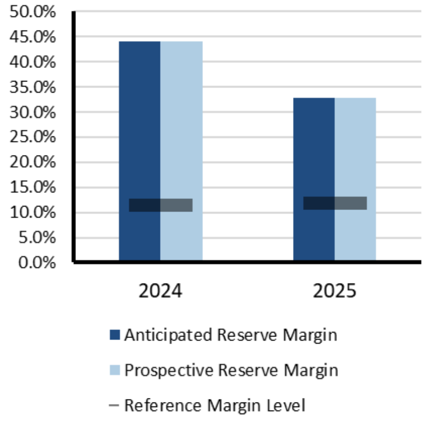
Highlights

- The Québec area forecasted summer peak demand is 23,283 MW during the week beginning August 3, 2025, with a forecasted net margin of 5,698 MW (24.5%).
- Resource adequacy issues are not expected this summer.
- The Québec area expects to be able to assist other areas.
- Modeling was made more precise this year with the inclusion of summer demand-response programs, dispatchable demand-side management (DSM), and weekly modeling of the reserve requirements and bottled generation.

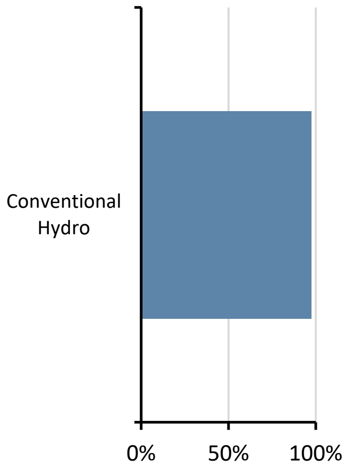
Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed scenarios.

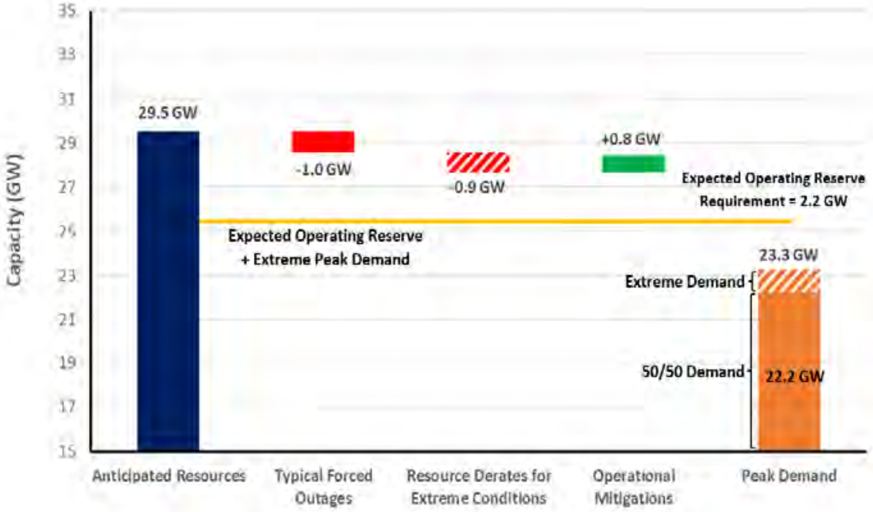
On-Peak Reserve Margin



On-Peak Fuel Mix



2025 Summer Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenario: Net internal demand (50/50) and (90/10) demand forecast

Operational mitigations: An operational procedure used to mitigate extreme conditions and not already included in margins is the depletion of some operating reserves by 750 MW.

PJM

PJM Interconnection is a regional transmission organization that coordinates the movement of wholesale electricity in all or parts of Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, West Virginia, and the District of Columbia. PJM serves 65 million customers and covers 369,089 square miles. PJM is a BA, PC, Transmission Planner, Resource Planner, Interchange Authority, TOP, Transmission Service Provider, and RC.

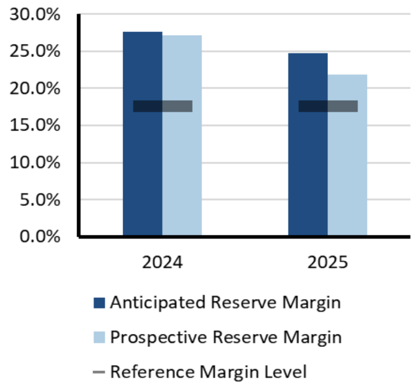
Highlights

- PJM is forecasting 27% installed reserves (including expected committed demand response), which is above the target installed reserve margin of 17.7% necessary to meet the 1-day-in-10-years LOLE criterion.
- During extreme high temperatures that can cause record demand, PJM anticipates the need for demand-response resources to help reduce load at times this summer.

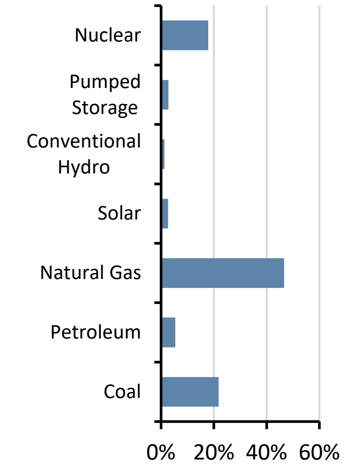
Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed scenarios.

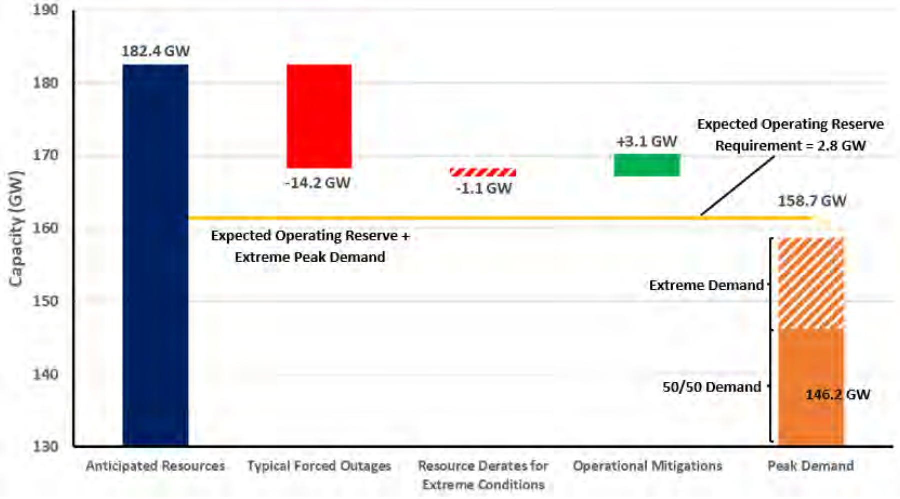
On-Peak Reserve Margin



On-Peak Fuel Mix



2025 Summer Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: Net internal demand (50/50) and (90/10) demand forecast

Forced Outages: Based on historical data and trending

Extreme Derates: Accounts for reduced thermal capacity contributions due to performance in extreme conditions

Operational Mitigations: A total of 3 GW based on operational/emergency procedures

SERC-Central

SERC-Central is an assessment area within the SERC Regional Entity. SERC-Central includes all of Tennessee and portions of Georgia, Alabama, Mississippi, Missouri, and Kentucky. Historically a summer-peaking area, SERC-Central is beginning to have higher peak demand forecasts in winter. SERC is one of the six companies across North America that are responsible for the work under Federal Energy Regulatory Commission (FERC)-approved delegation agreements with NERC. SERC-Central is specifically responsible for the reliability and security of the electric grid across the Southeastern and Central areas of the United States. This area covers approximately 630,000 square miles and serves a population of more than 91 million. The SERC Regional Entity includes 36 BAs, 28 planning entities, and 6 RCs.

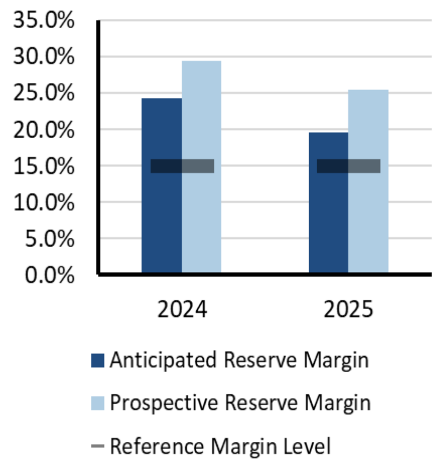
Highlights

- SERC-Central saw a sizable increase in its reserves last summer, but coal retirements this summer will result in SERC-Central having lower reserves.
- SERC-Central's anticipated resources meet operating reserve requirements under the expected conditions and under the summer risk period scenario.
- The probabilistic analysis metrics indicate adequate energy resources for the area.
- Entities perform resource studies to ensure resource adequacy to meet the summer peak demand and maintain the reliability of the system.
- Members of SERC-Central actively participate in the SERC working groups to perform coordinated studies and develop mitigating actions for any potential or emerging reliability impacts on transmission and resource adequacy.

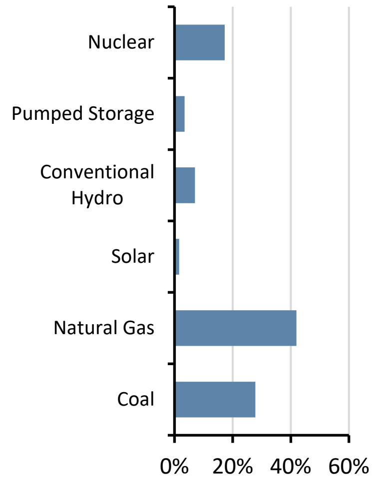
Risk Scenario Summary

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.

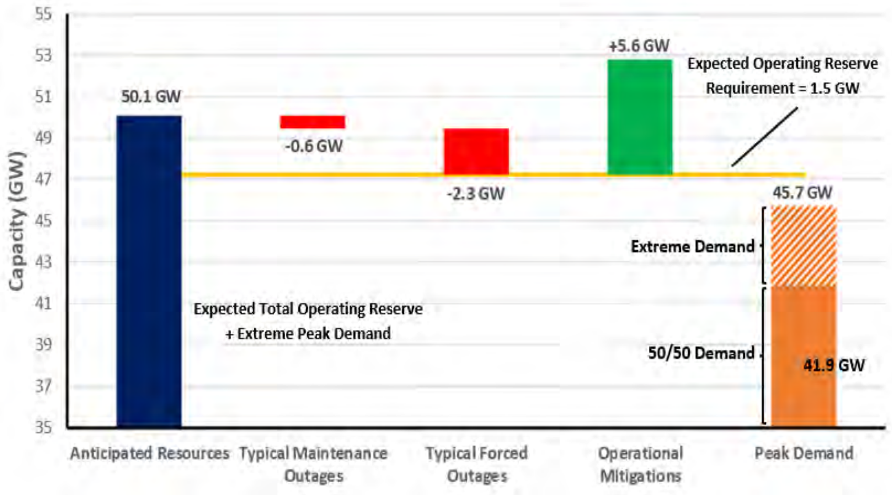
On-Peak Reserve Margin



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: 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.

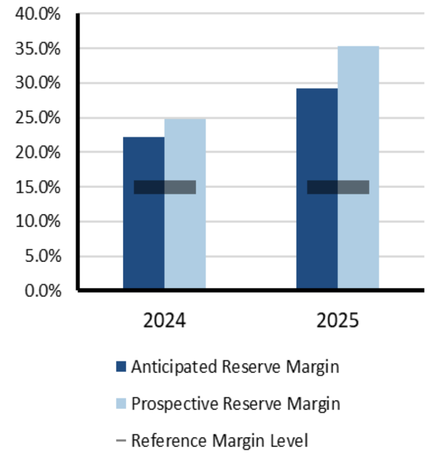
Highlights

- 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.

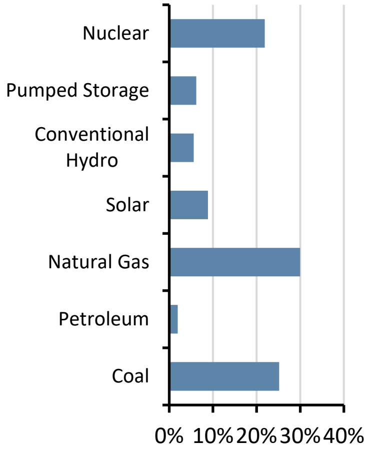
Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed scenarios.

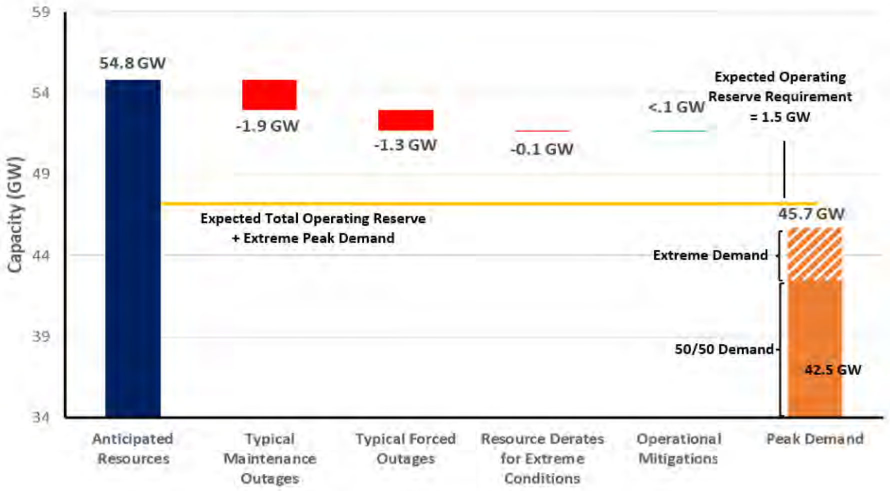
On-Peak Reserve Margin



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

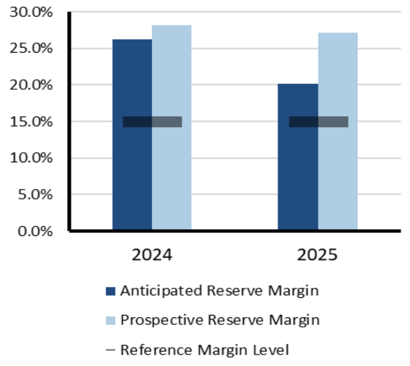
SERC-Florida Peninsula

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.

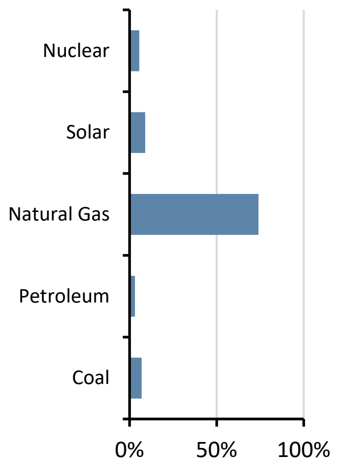
On-Peak Reserve Margin



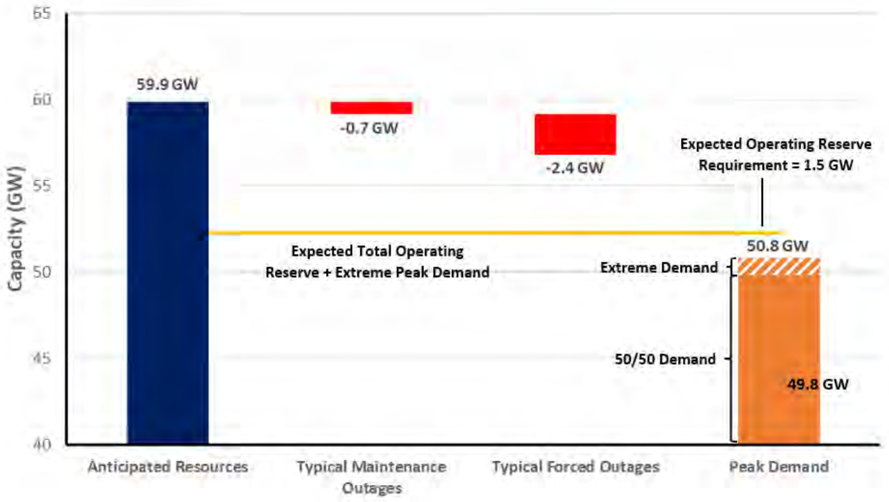
Risk Scenario Summary

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.

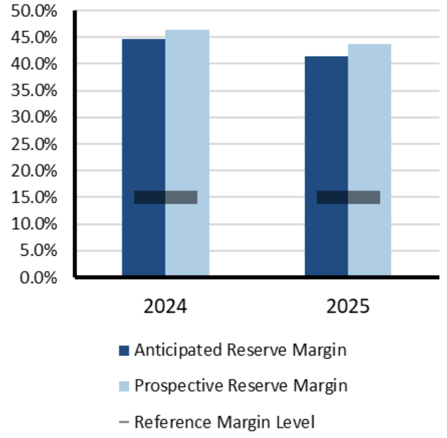
Highlights

- 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.

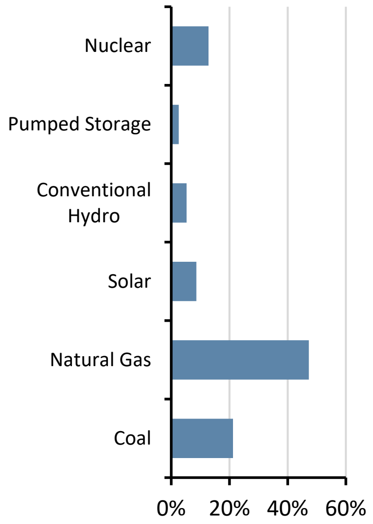
Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed scenarios.

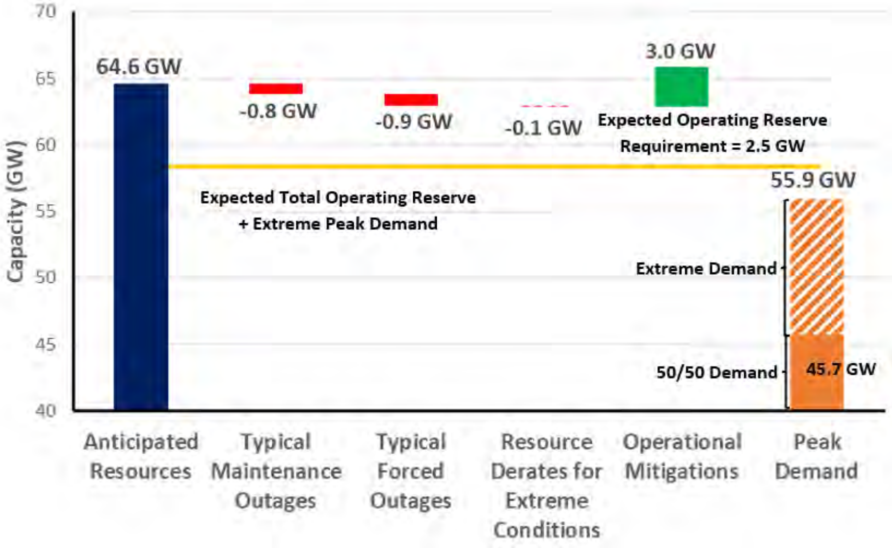
On-Peak Reserve Margin



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.

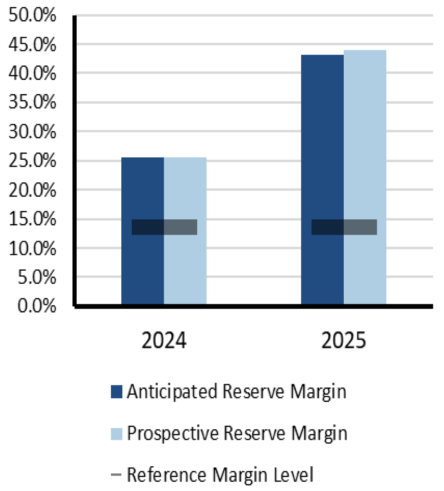
Highlights

- 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.

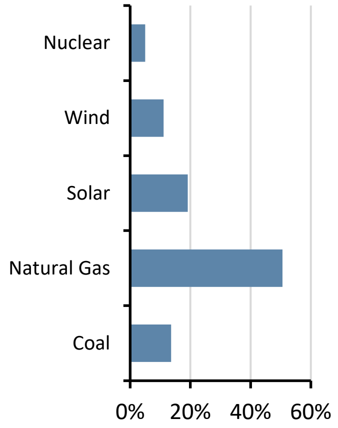
Risk Scenario Summary

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.

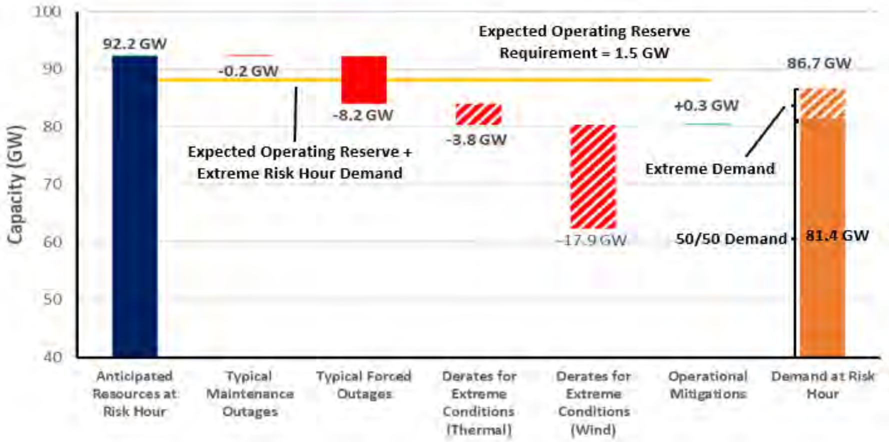
On-Peak Reserve Margin



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.

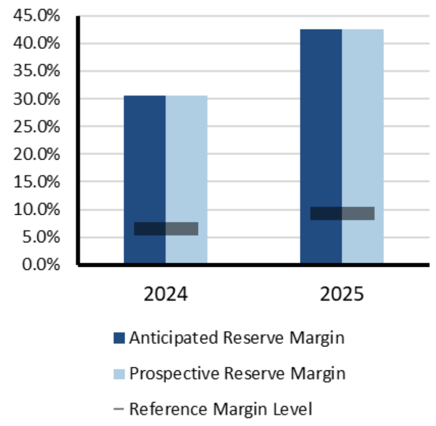
Highlights

- 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.

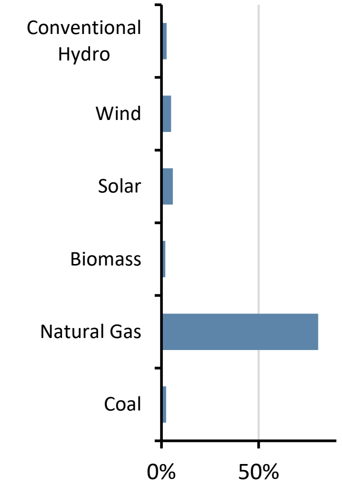
Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed scenarios.

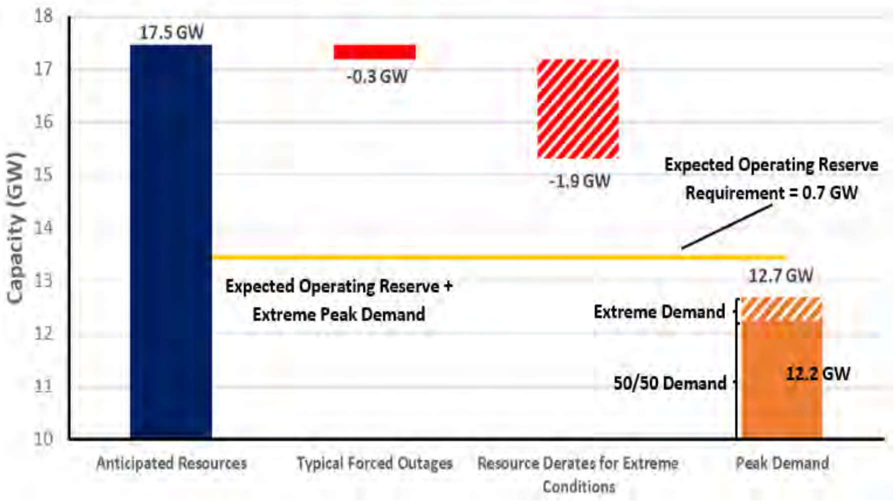
On-Peak Reserve Margin



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

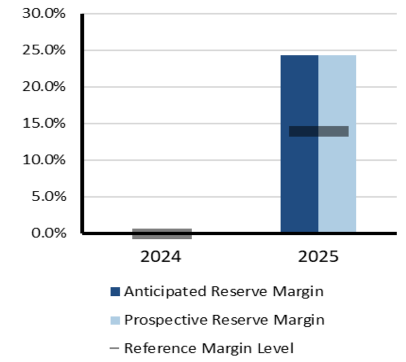
- Total internal expected demand has increased 8% and demand response has increased almost 28% for a net internal demand increase of 7.2%.
- Reserve margins are not anticipated to fall below the reference margin (14%) for the upcoming summer; an early July peak is expected at around 3:00 p.m.
- During 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

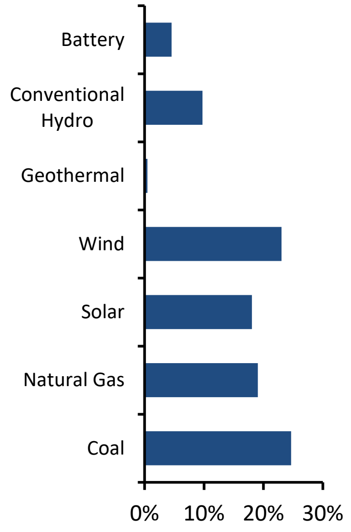
Expected resources meet operating reserve requirements under the assessed scenarios with imports.

On-Peak Reserve Margin

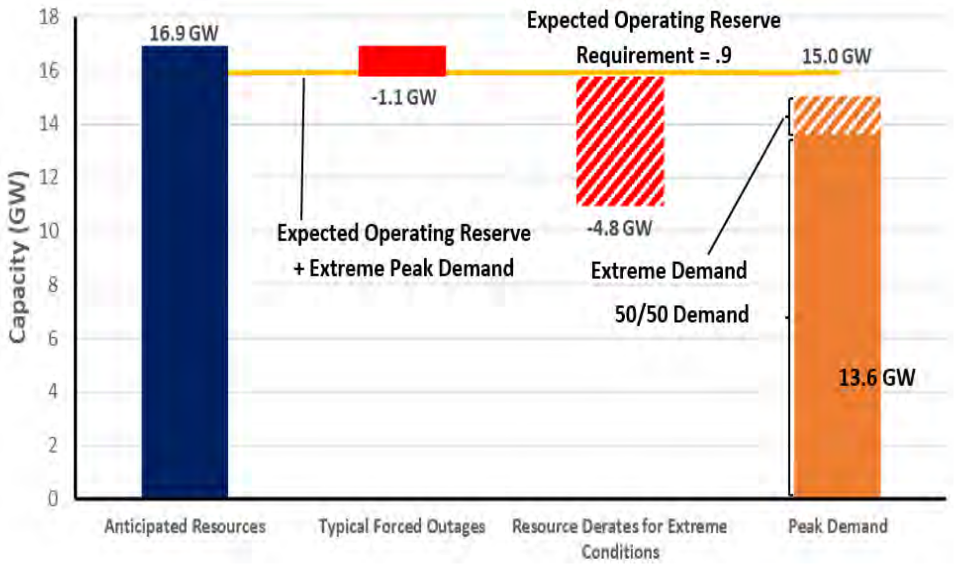
(Note: year comparison not available)



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.

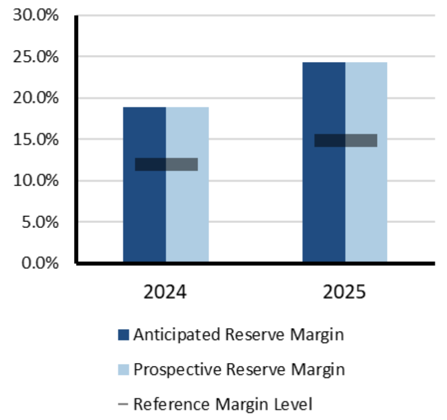
Highlights

- 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.

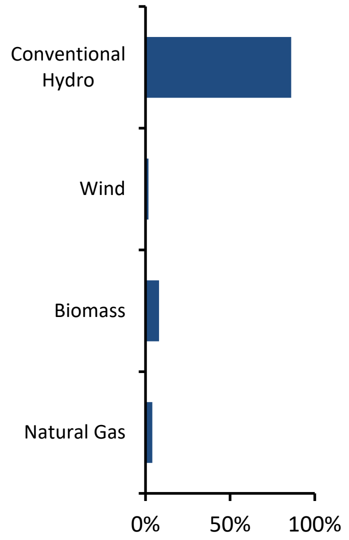
Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed scenarios.

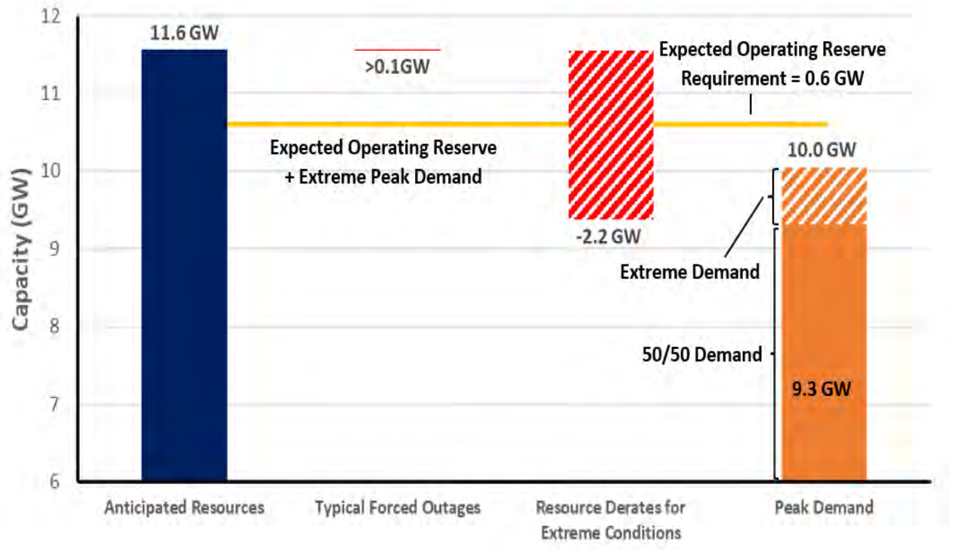
On-Peak Reserve Margin



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

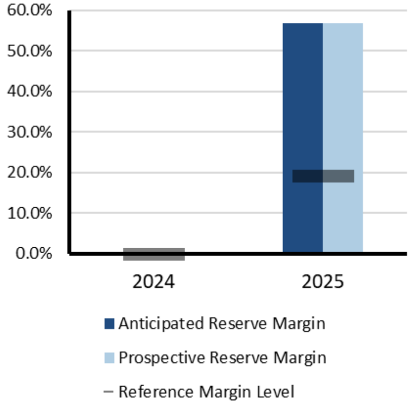
- Demand response is down 8.6% since last summer, existing-certain capacity is up 5.8%, and Tier 1 planned capacity is up 41.2% for a net increase in anticipated resources of 9%; anticipated and prospective reserve margins are up by 11.4%. The peak hour is still forecasted for early September around 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

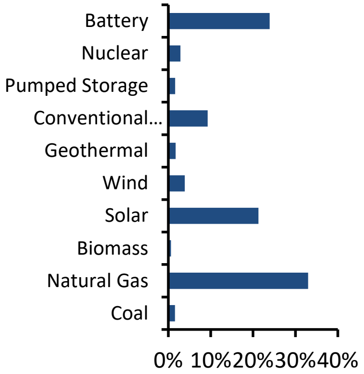
Expected resources meet operating reserve requirements under assessed scenarios, and a probabilistic assessment of normal and extreme resource/demand scenarios reveals neither EUE nor LOLH.

On-Peak Reserve Margin

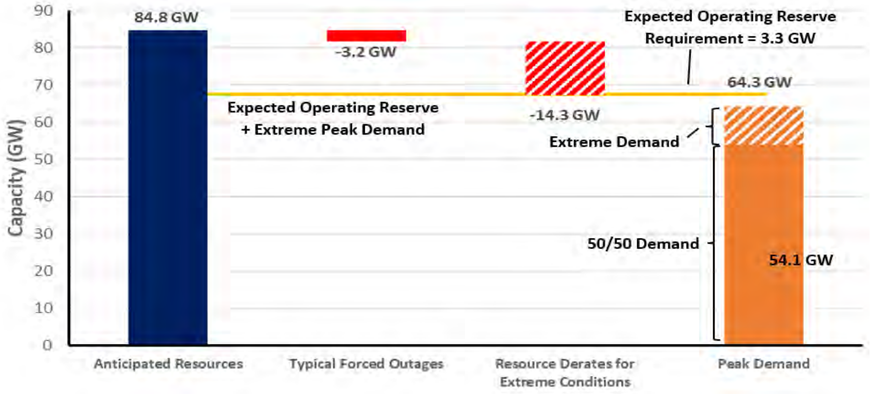
(Note: year comparison not available)



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

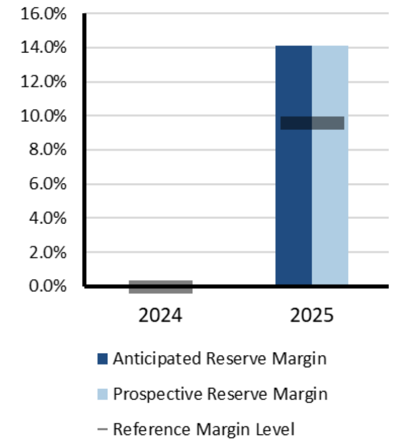
WECC-Mexico is a summer-peaking assessment area in the Western Interconnection that includes the northern portion of the Mexican state of Baja California, which has a population of 3.8 million people and includes CENACE. It has 1,568 miles of transmission. WECC is responsible for coordinating and promoting 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.

On-Peak Reserve Margin

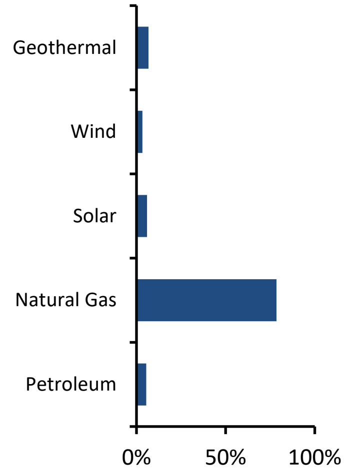
(Note: year comparison not available)



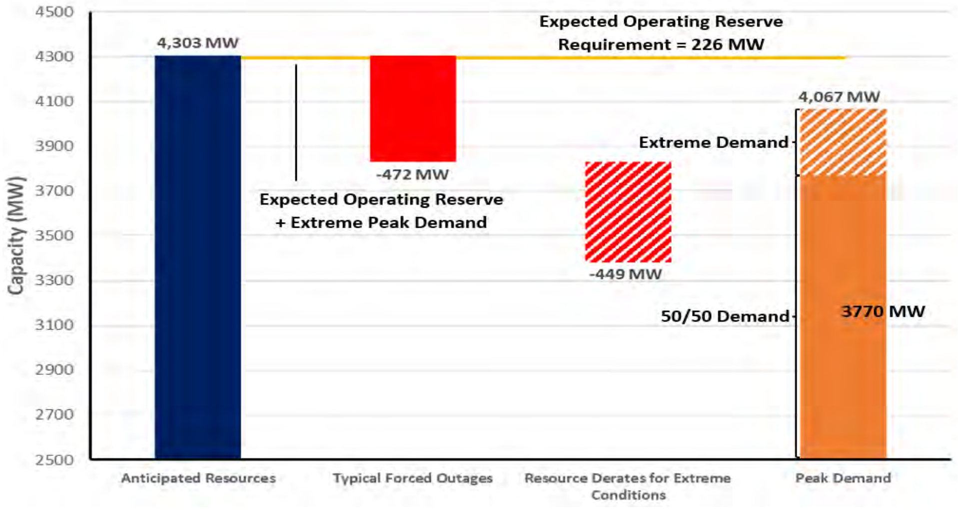
Risk Scenario Summary

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 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.*

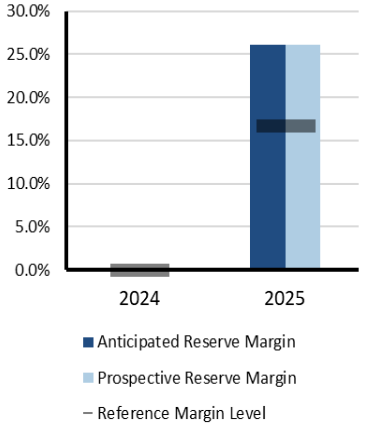
Highlights

- 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

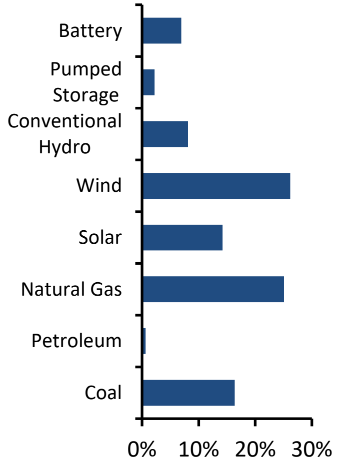
Expected resources meet operating reserve requirements under assessed scenarios with imports.

On-Peak Reserve Margin

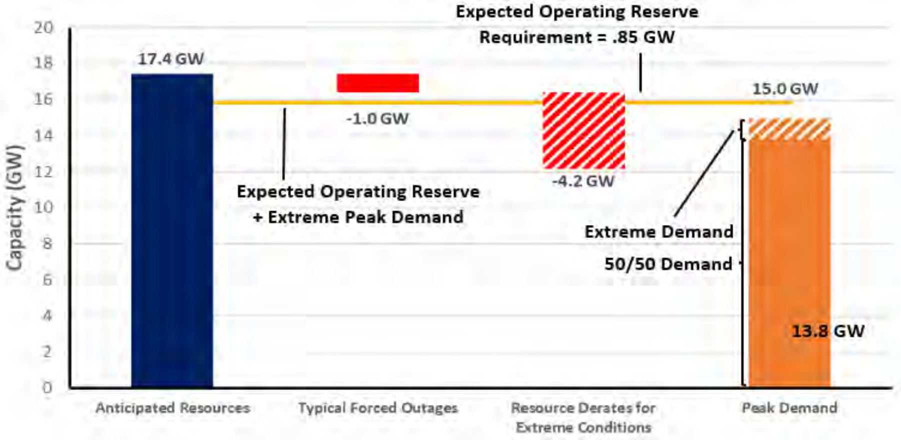


(Note: year comparison not available)

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

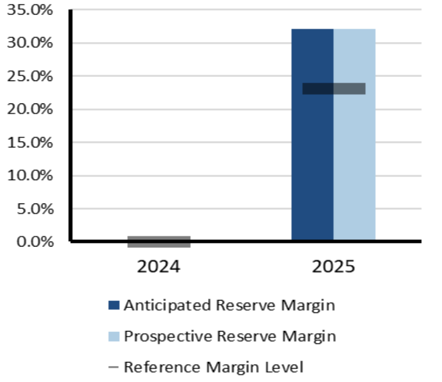
- The reserve margins (existing-certain 29% and anticipated and prospective 32%) are not anticipated to fall below the reference margin (23%) for the upcoming summer. An extreme summer peak load may be around 32,740 MW.
- Typical forced outages are forecast to be 771 MW, with derates for thermal under 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

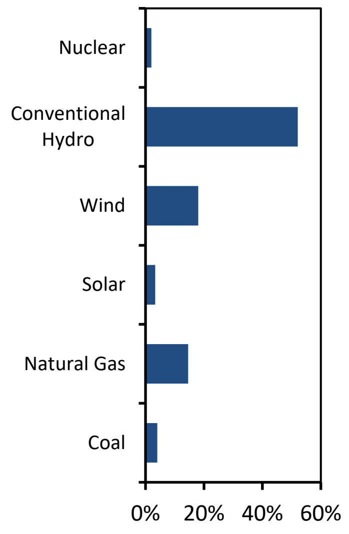
Expected resources meet operating reserve requirements under assessed scenarios with imports.

On-Peak Reserve Margin

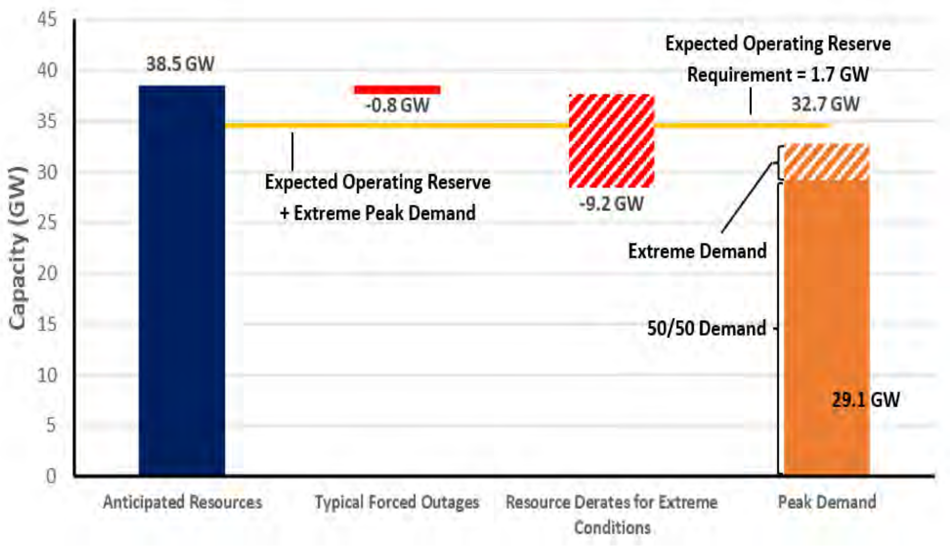
(Note: year comparison not available)



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

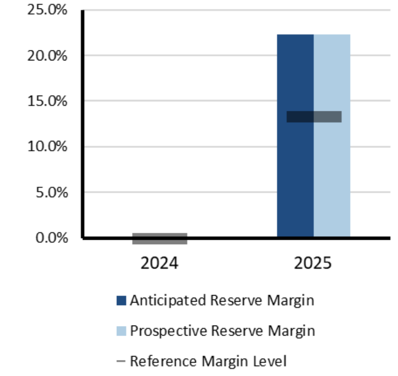
- Anticipated Reserve Margins for the summer are 22%, exceeding the Reference Margin Level for reliability calculated by WECC.
- WECC's probabilistic analysis indicates that the area is not expected to encounter LOLH or EUE under a range of demand and resource conditions.
- The peak hour is expected 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

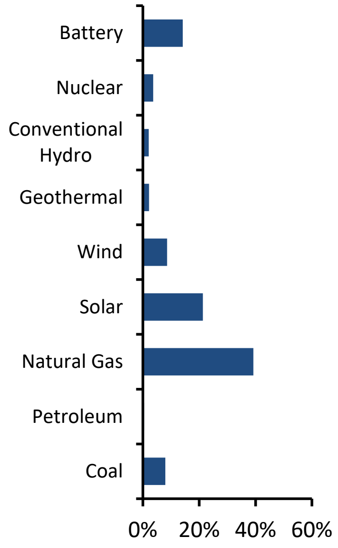
Expected resources meet operating reserve requirements under assessed scenarios with imports.

On-Peak Reserve Margin

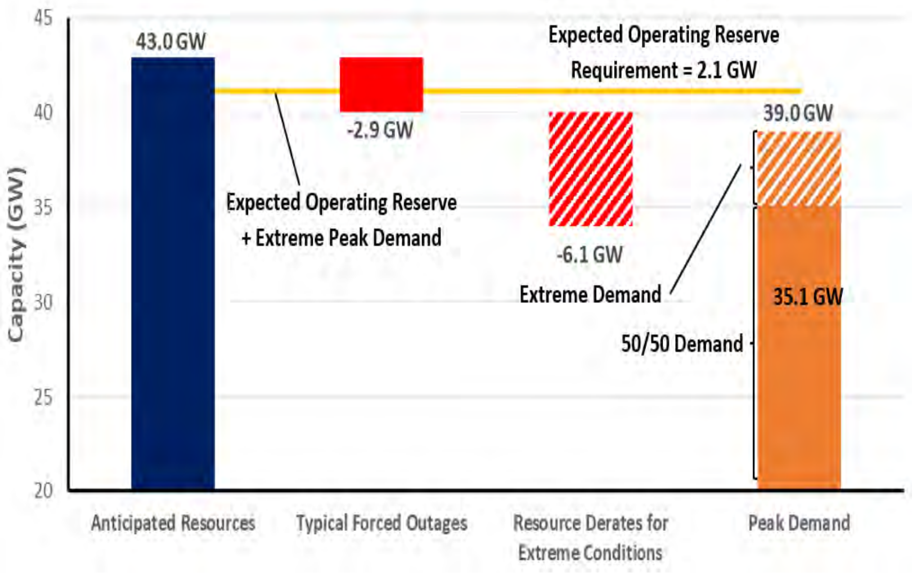
(Note: year comparison not available)



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**.

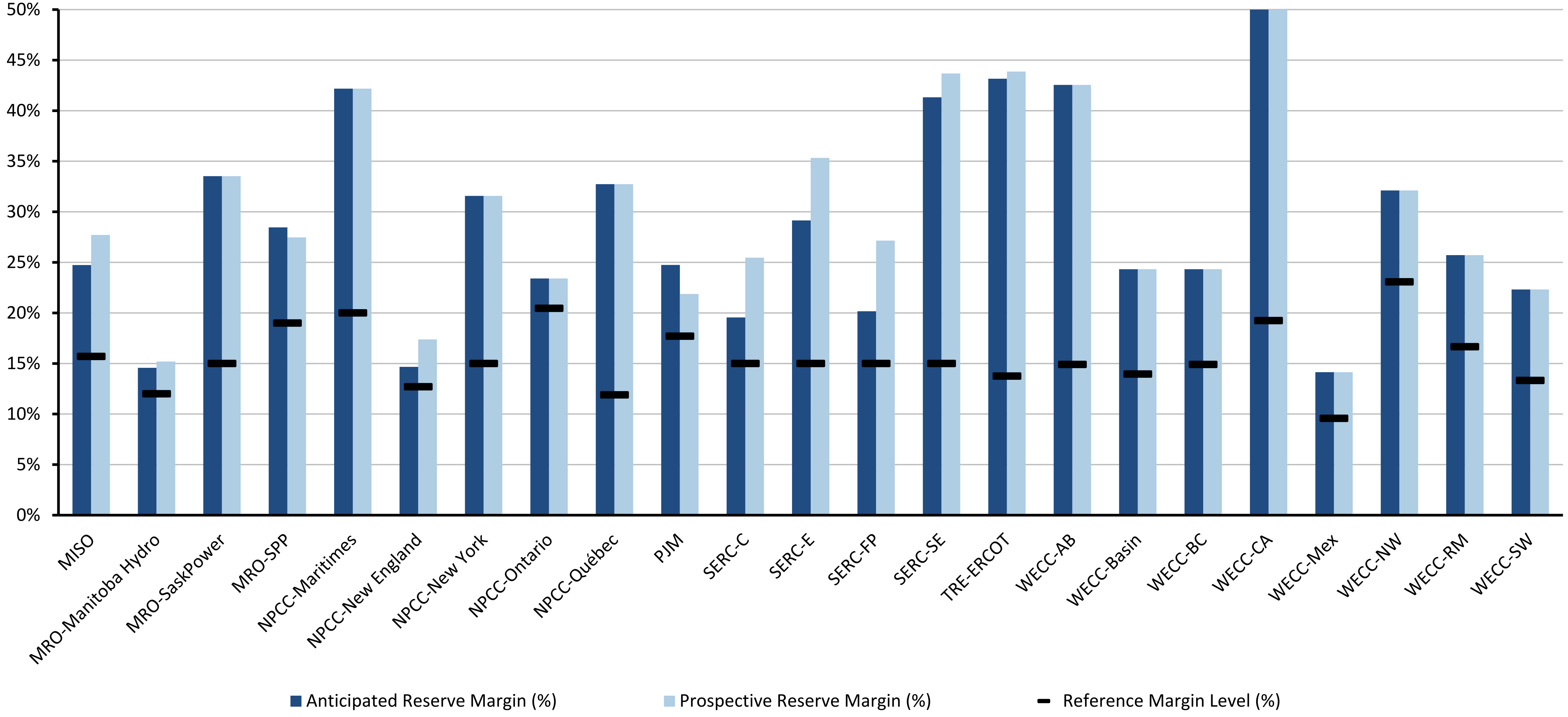

Figure 4: Summer 2025 Anticipated/Prospective Reserve Margins Compared to Reference Margin Level

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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.

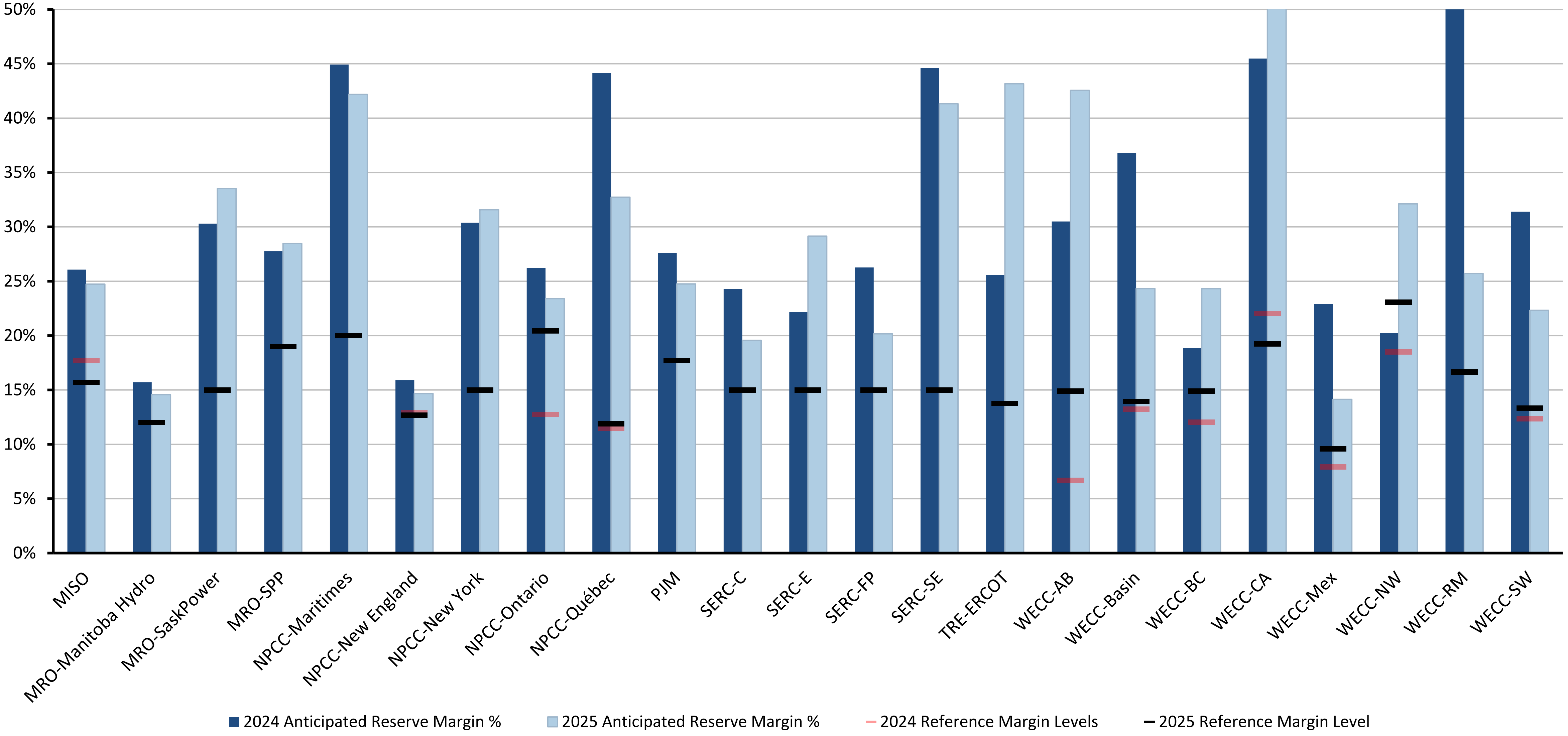

Figure 5: Summer 2024 and Summer 2025 Anticipated Reserve Margins Year-to-Year Change

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.

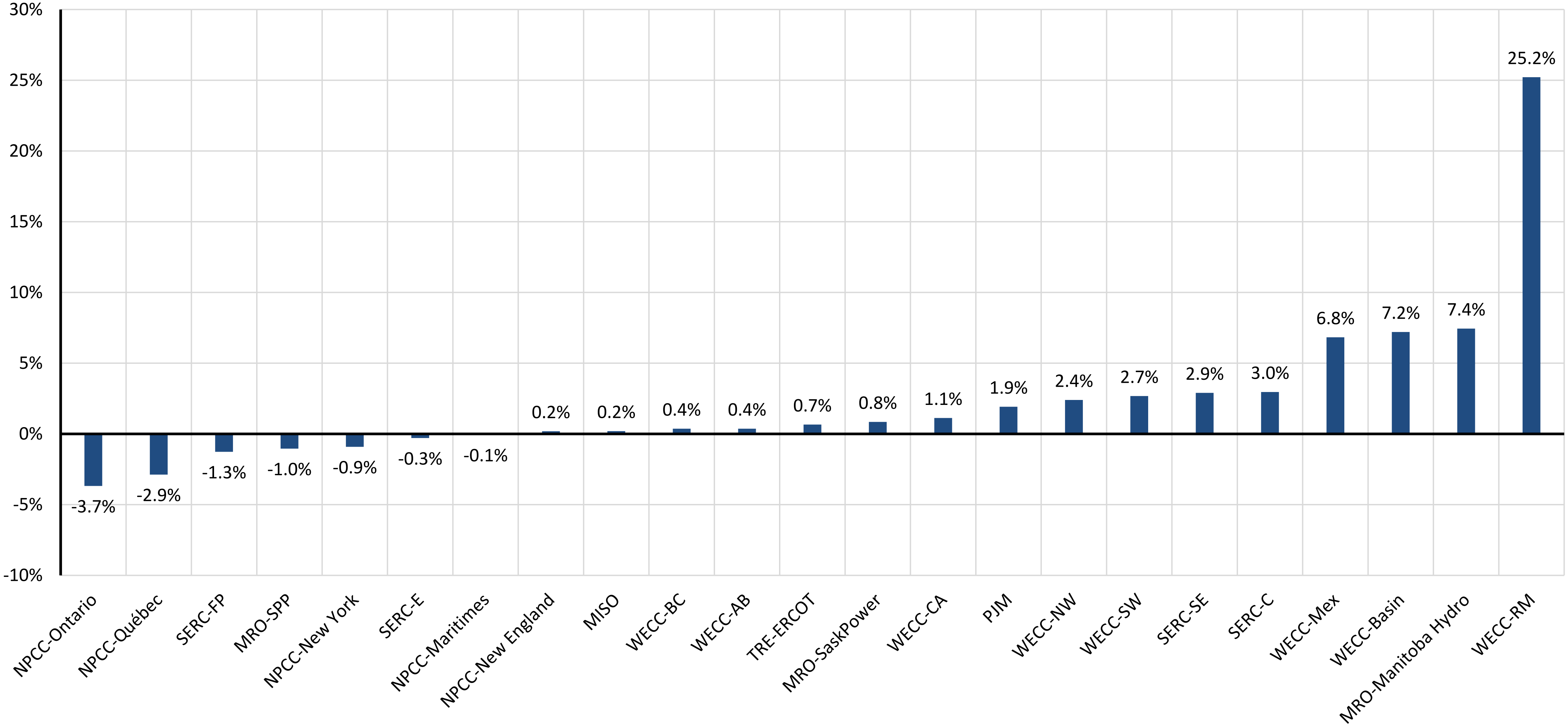

Figure 6: Changes in Net Internal Demand—Summer 2024 Forecast Compared to Summer 2025 Forecast

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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

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.

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…

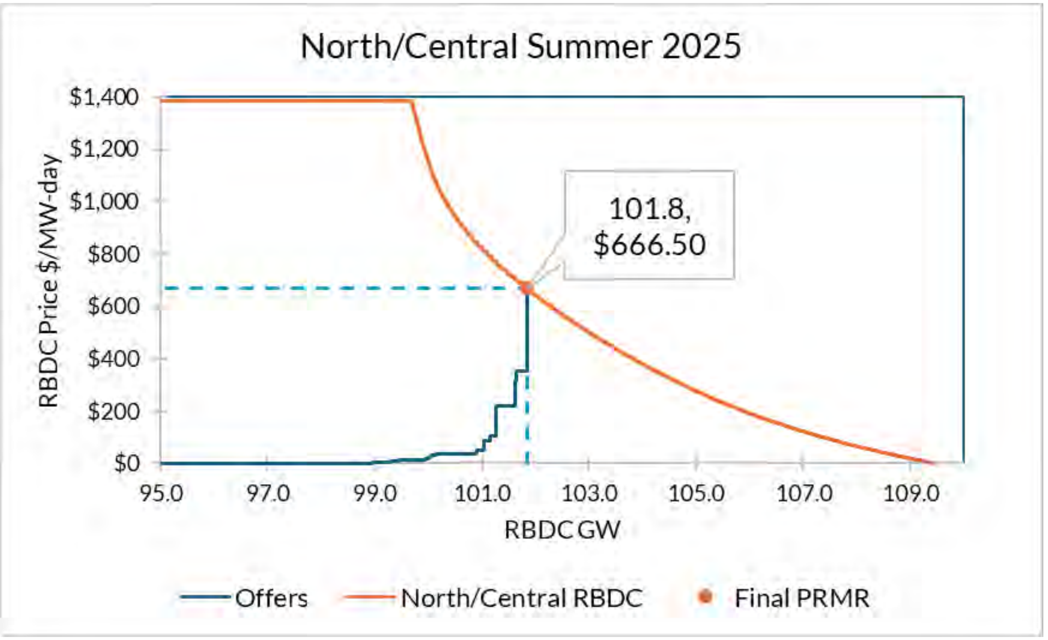
- Delivers competitive prices aligned with seasonal risks and tightening surplus
    - Prioritizes summer availability, the system's highest-risk season (based on 1-in-10 LOLE)
- Values incremental capacity above and below the LOLE target based on its reliability
    - Clears capacity above target Planning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

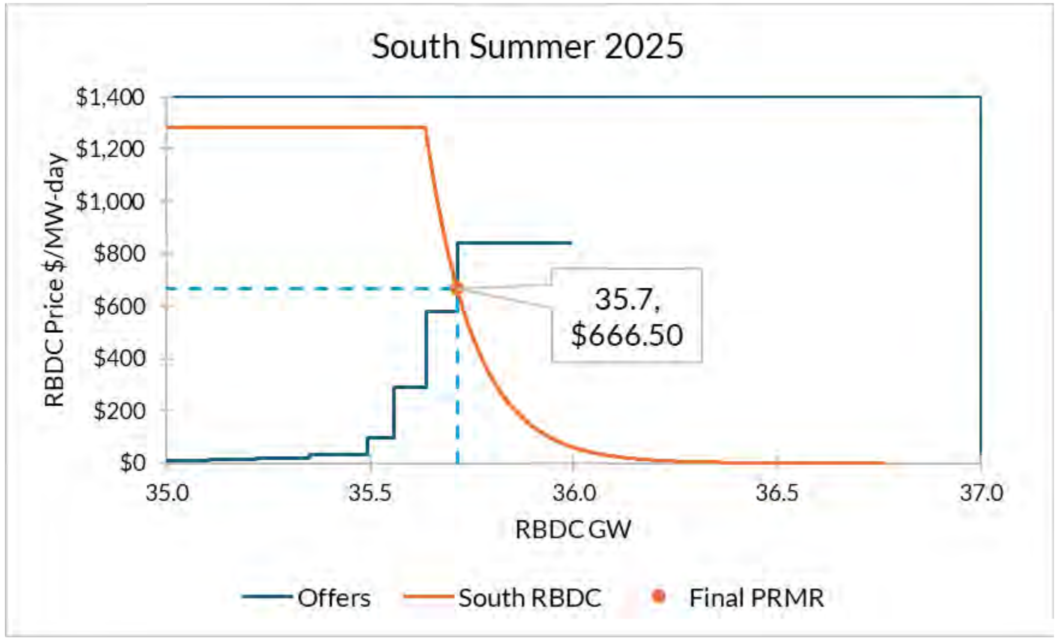
Why it Matters

- 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



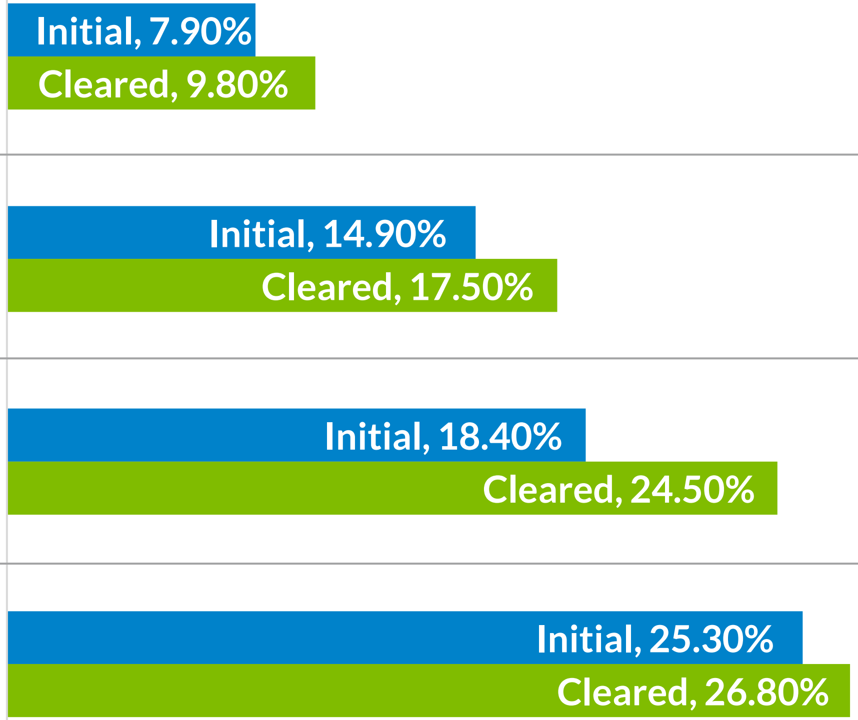


- Summer clearing of $666.50 reflects highest reliability risk and reducing surplus capacity year-over-year
    - Surplus capacity in the summer has reduced from approximately 6.5 GW in 2023, to 4.6 GW in 2024, to 2.6 GW in 2025
- Incremental capacity cleared beyond the target Planning Reserve Margin 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



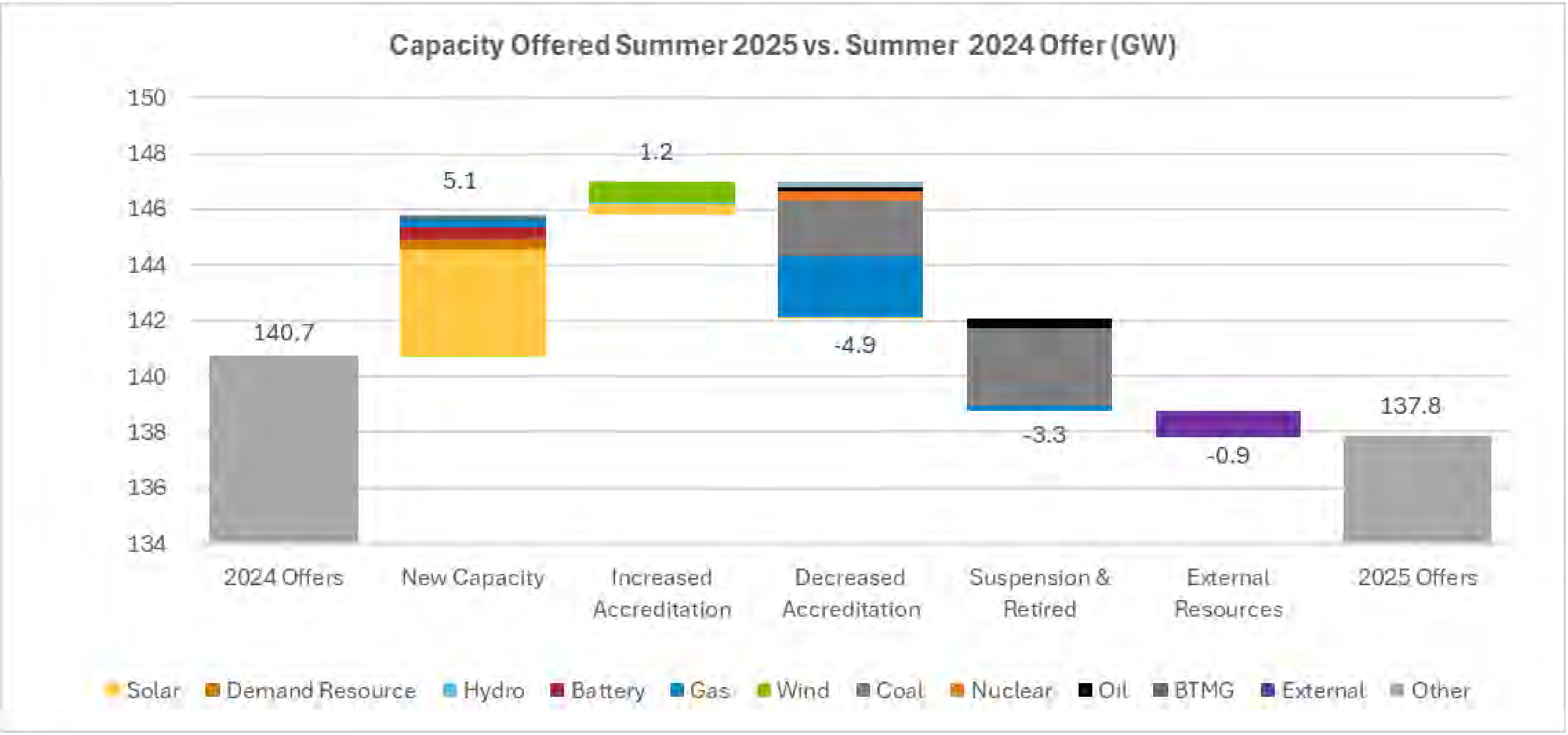
	2025 Planning Resource Auction Initial Target vs. Final Cleared	Additional Reliability	Auction Clearing Price
Summer	Initial, 7.90% Cleared, 9.80%	+1.9%	$666.50
Fall	Initial, 14.90% Cleared, 17.50%	+2.6%	$91.60 N/C $74.09 S
Winter	Initial, 18.40% Cleared, 24.50%	+6.1%	$33.20
Spring	Initial, 25.30% Cleared,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

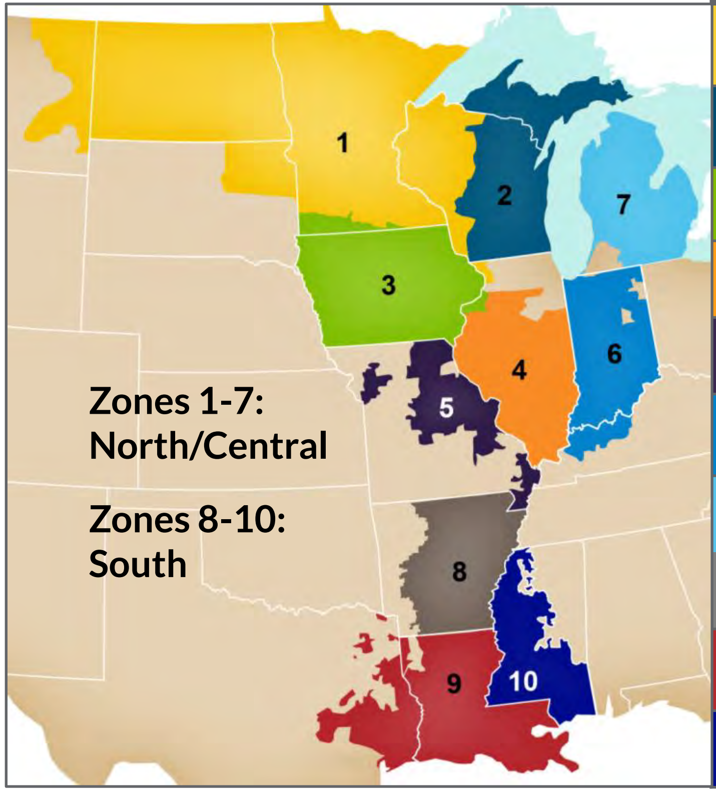
Table of Contents

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



Zones 1-7: North/Central

Zones 8-10: South

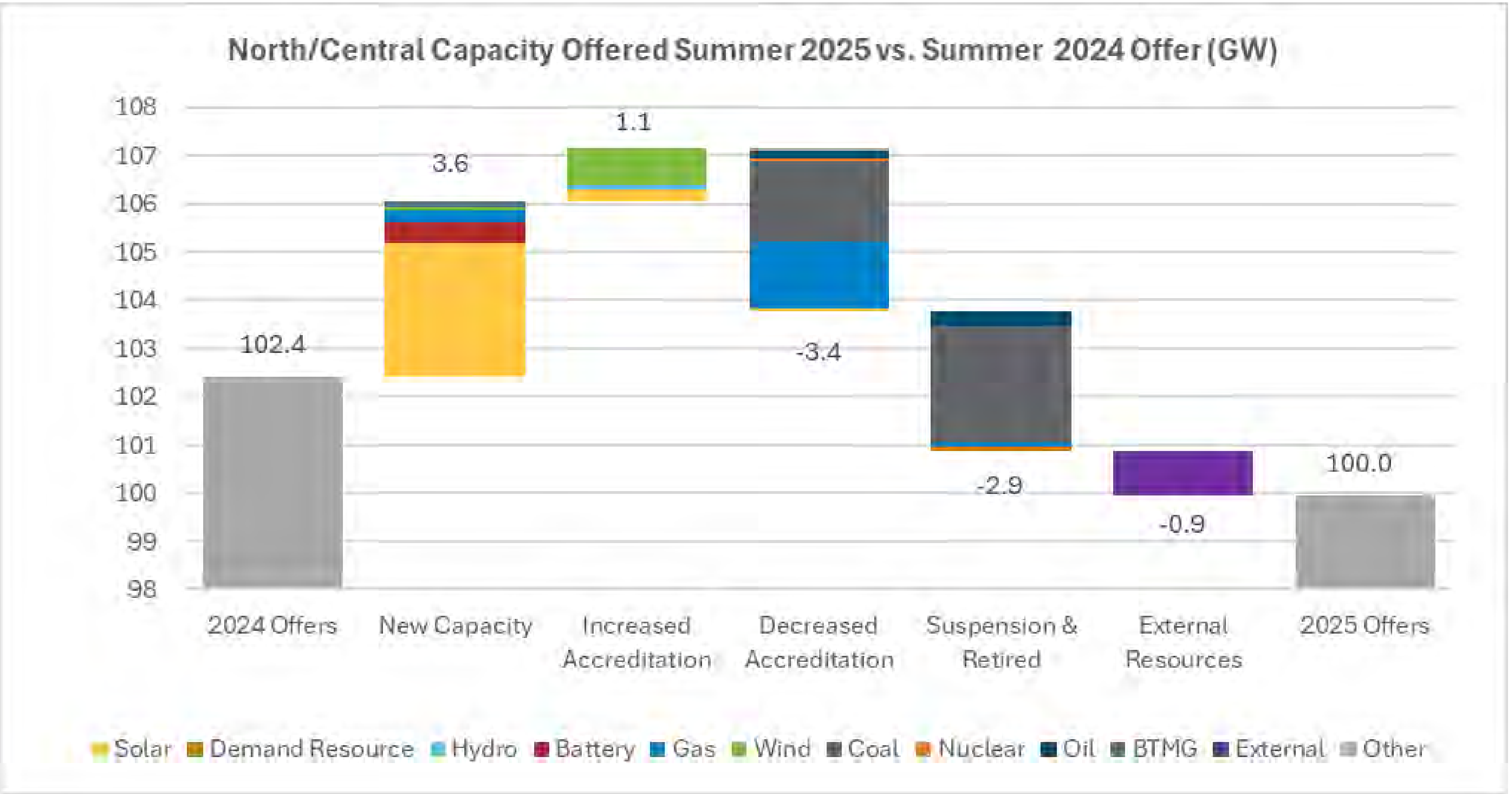
2025 PRA Results

	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)

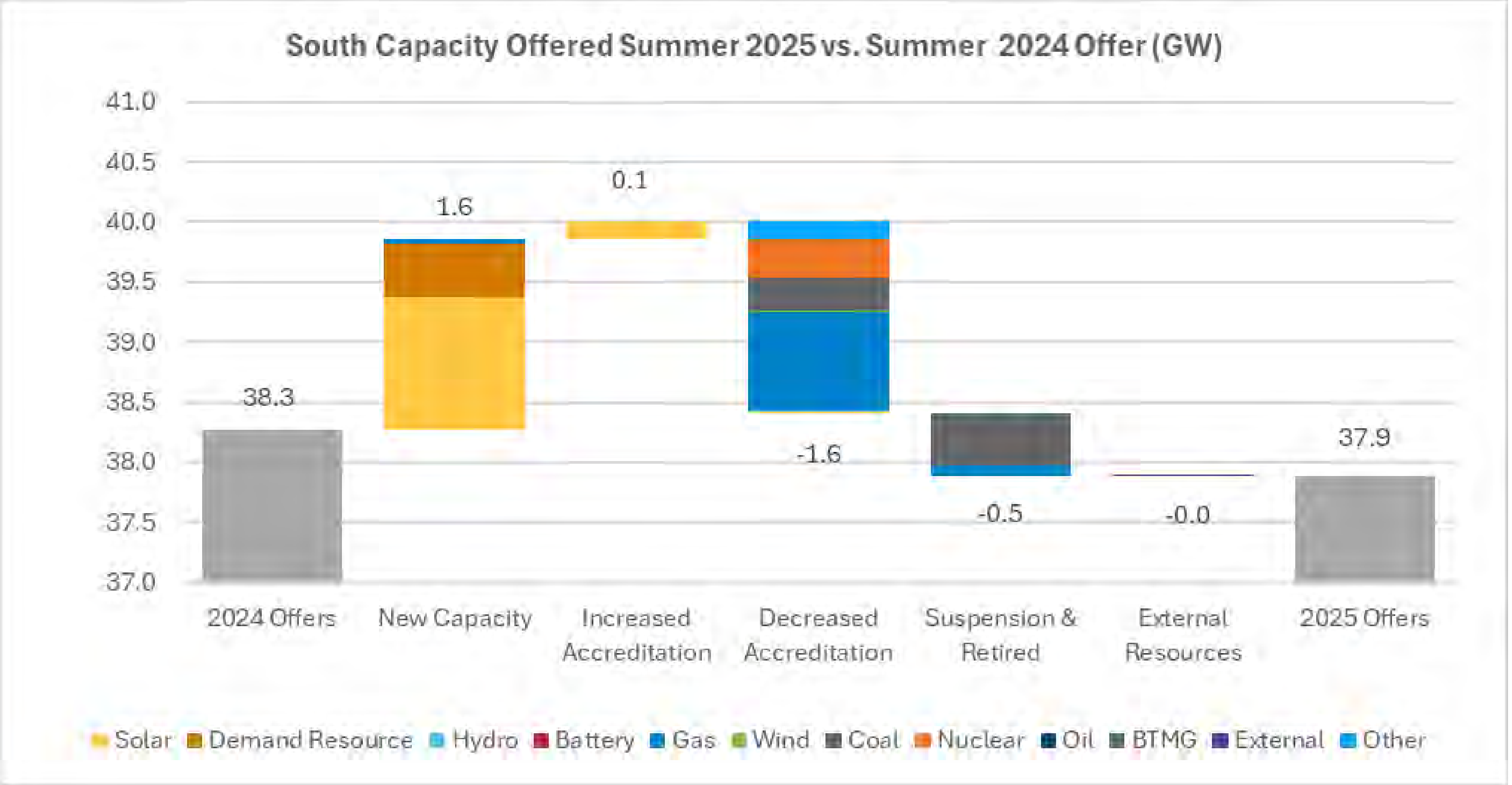
05/29/2025: MISO Planning Resource Auction for Planning Year 2025/26 Results Posting

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



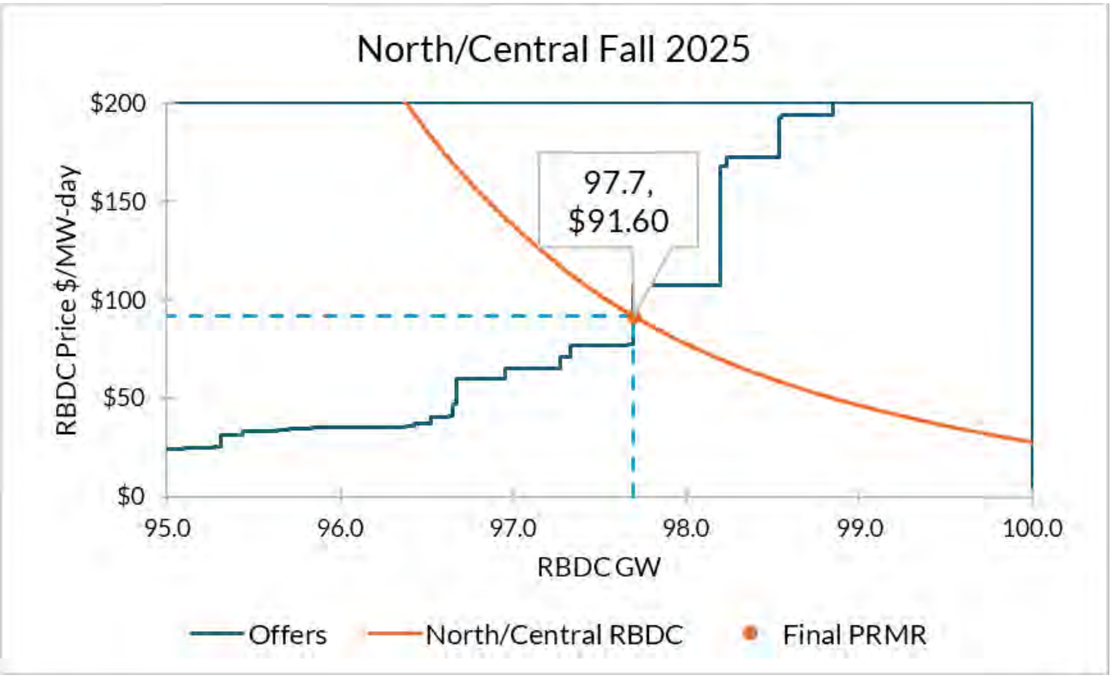
BTMG: Behind the Meter Generation | *Capacity indicated is offered accredited value*

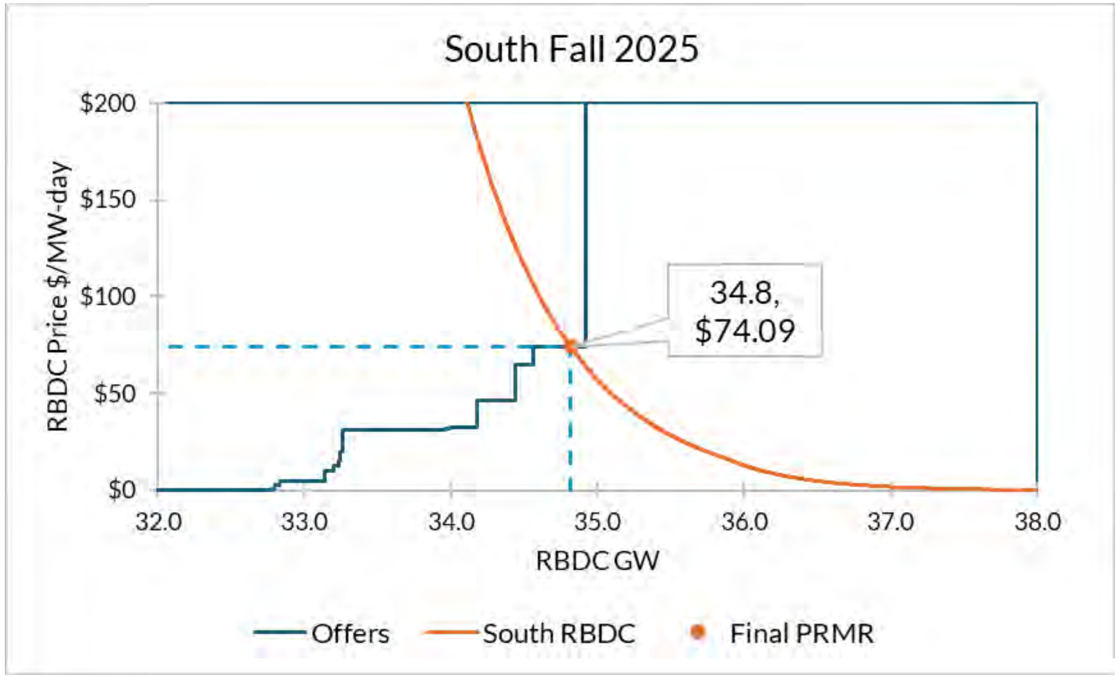
For the South, new capacity additions nearly offset the negative impacts of decreased accreditation, suspensions/retirements



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

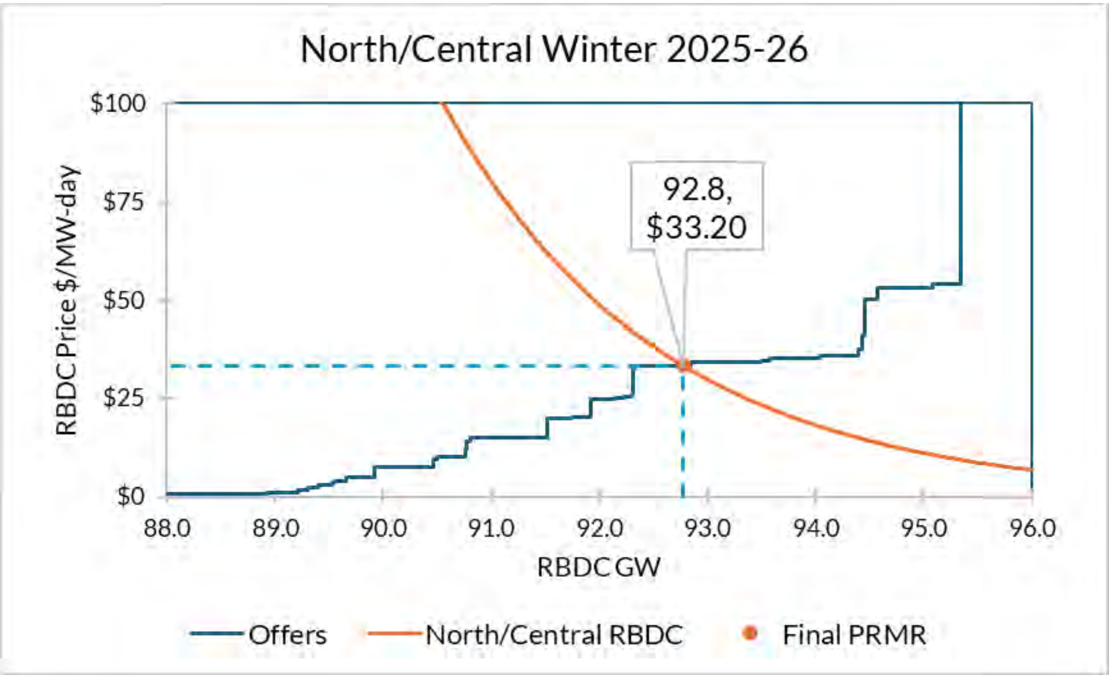
Fall 2025 Reliability-Based Demand Curve, Offer Curves and Auction Clearing Prices

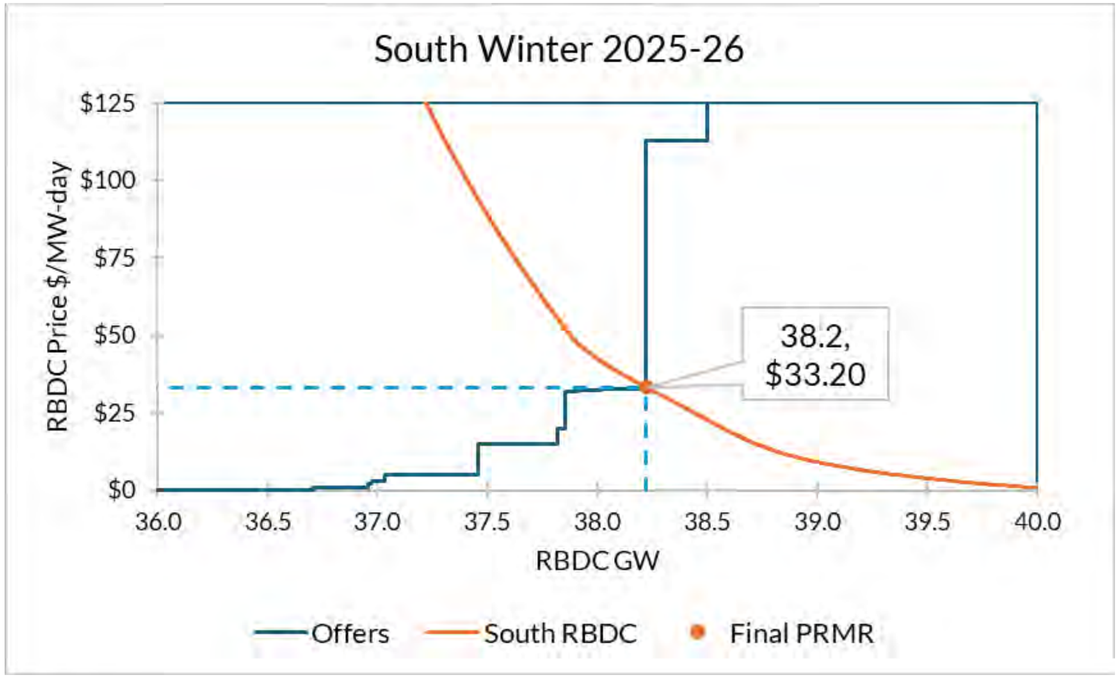




- Subregional RBDCs are determining clearing for both subregions
- Subregional Power Balance Constraint (SRPBC), South to North, is binding resulting in price separation between North/Central and South subregions in Fall season
  - ACP for North subregion is $91.60, and $74.09 South subregion
  - A marginal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

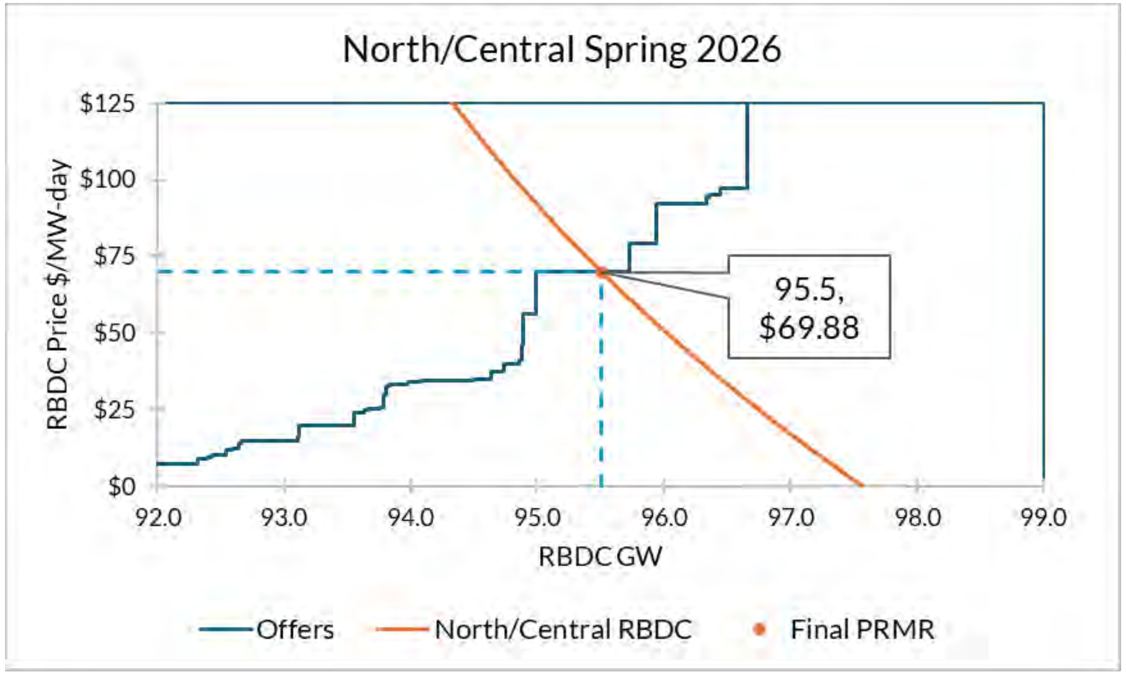
Winter 2025/26 Reliability-Based Demand Curve, Offer Curves and Auction Clearing Prices

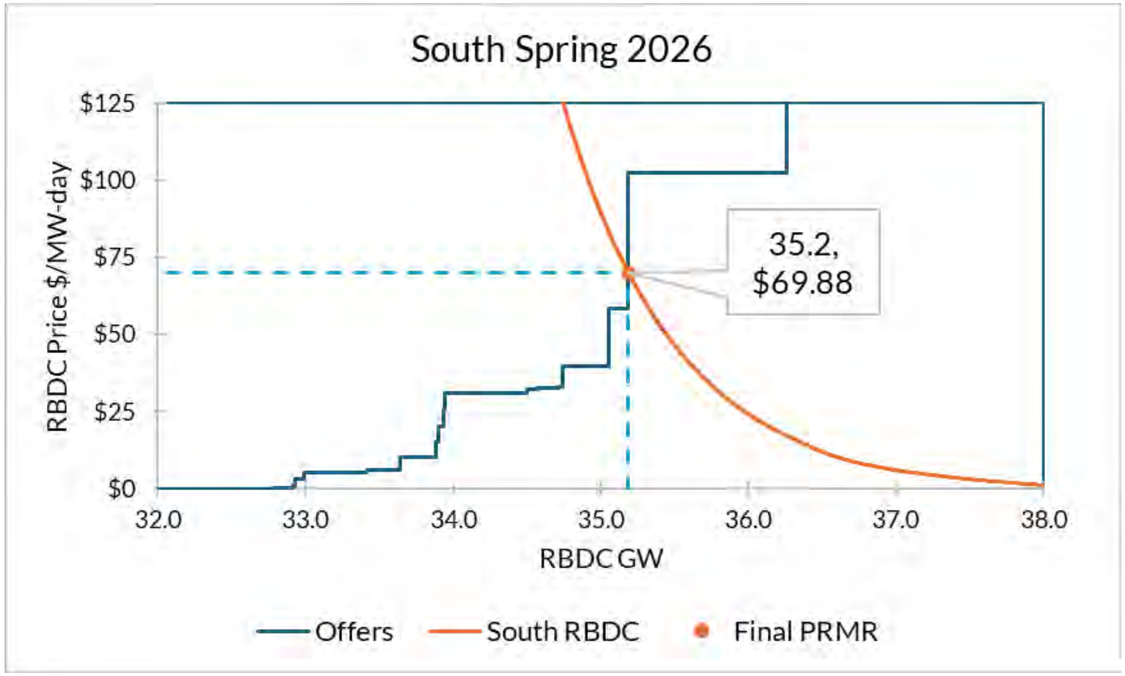

North/Central Winter 2025-26


South Winter 2025-26

- 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.

Fall 2025 PRA Results by Zone

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

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

Winter 2025/26 PRA Results by Zone

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

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

Spring 2026 PRA Results by Zone

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

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

Summer Supply Offered and Cleared Comparison Trend

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

ZRC: Zonal Resource Credit

Fall Supply Offered and Cleared Comparison Trend

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

ZRC: Zonal Resource Credit

Winter Supply Offered and Cleared Comparison Trend

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

ZRC: Zonal Resource Credit

Spring Supply Offered and Cleared Comparison Trend

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

ZRC: Zonal Resource Credit

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

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

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

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

ERZ: External Resource Zones

Historical Summer Auction Clearing Price Comparison

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

- Auction Clearing Prices shown in $/MW-Day

ERZ: External Resource Zones

Fall Auction Clearing Price Comparison

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

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

ERZ: External Resource Zones

Winter Auction Clearing Price Comparison

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

- Auction Clearing Prices shown in $/MW-Day

ERZ: External Resource Zones

Spring Auction Clearing Price Comparison

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

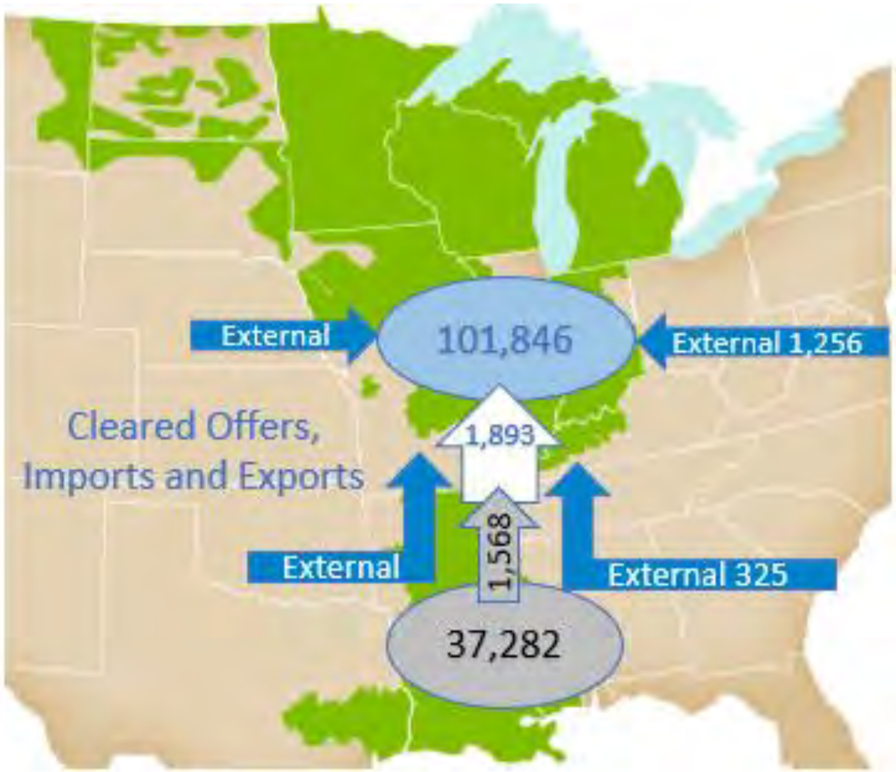
- Auction Clearing Prices shown in $/MW-Day

ERZ: External Resource Zones

Summer 2025 Capacity

Offered Capacity & Final PRMR (MW)

Cleared Capacity, Imports & Exports (MW)



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

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

Fall 2025 Capacity

Offered Capacity & Final PRMR (MW)

Cleared Capacity, Imports & Exports (MW)

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

Winter 2025/26 Capacity

Offered Capacity & Final PRMR (MW)

Cleared Capacity, Imports & Exports (MW)

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

Spring 2026 Capacity

Offered Capacity & Final PRMR (MW)

Offers and PRMR

Offers
96,094

Final PRMR
95,511

External Offers
1,220

Offers
38,424

Final PRMR
35,189

External Offers
323

Cleared Capacity, Imports & Exports (MW)

Cleared Offers, Imports and Exports

External

95,511

External 1,150

1,288

965

External

External 323

36,154

PRMR: Planning Reserve Margin Requirement

Offers includes Fixed Resource Adequacy Plan (FRAP), Self-scheduled and price sensitive offers

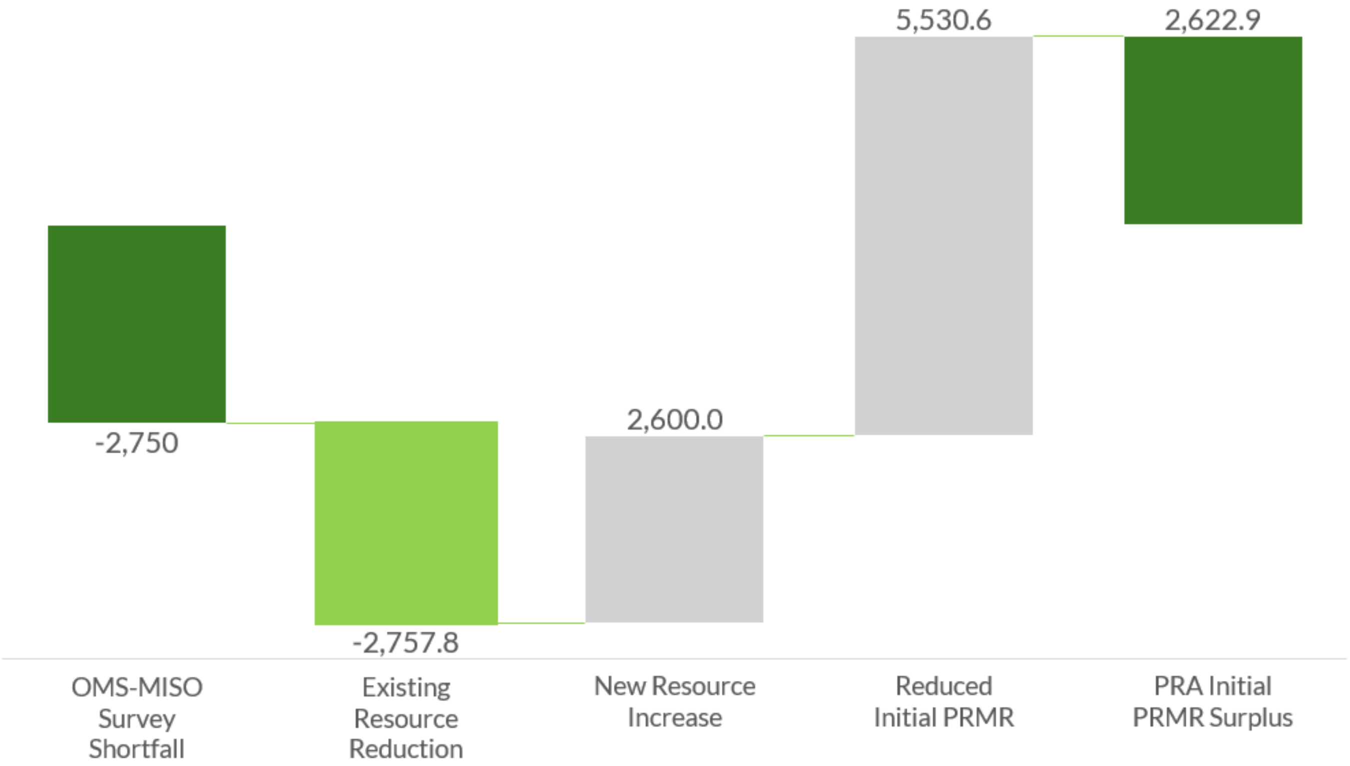
05/29/2025: MISO Planning Resource Auction for Planning Year 2025/26 Results Posting

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

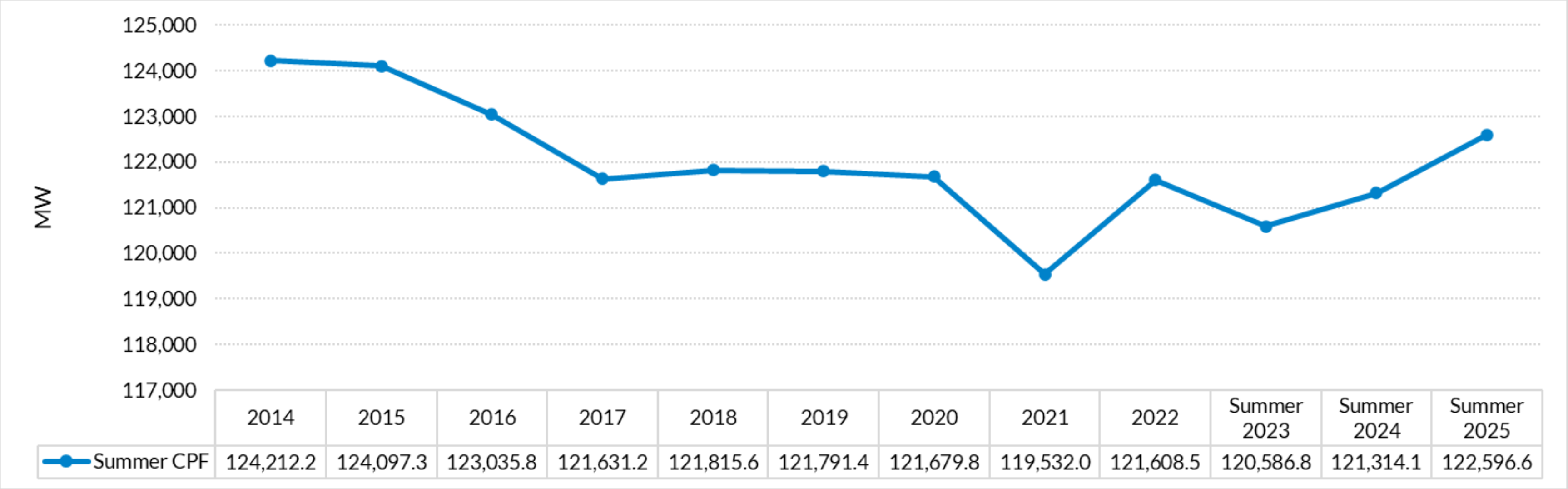
2024 OMS-MISO Survey Projection vs. 2025 PRA Actual PRMR Surplus (MW)



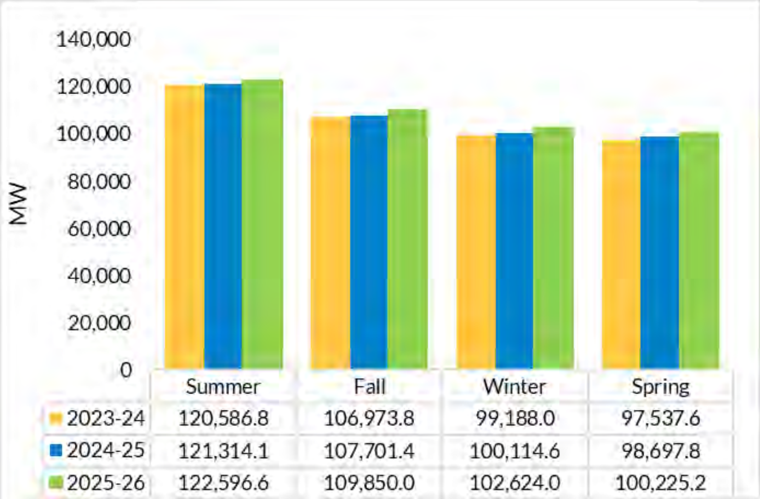
**PRA Shortfall/Surplus relative to Initial PRMR | PRMR: Planning Reserve Margin Requirement*

Coincident Peak Forecast

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



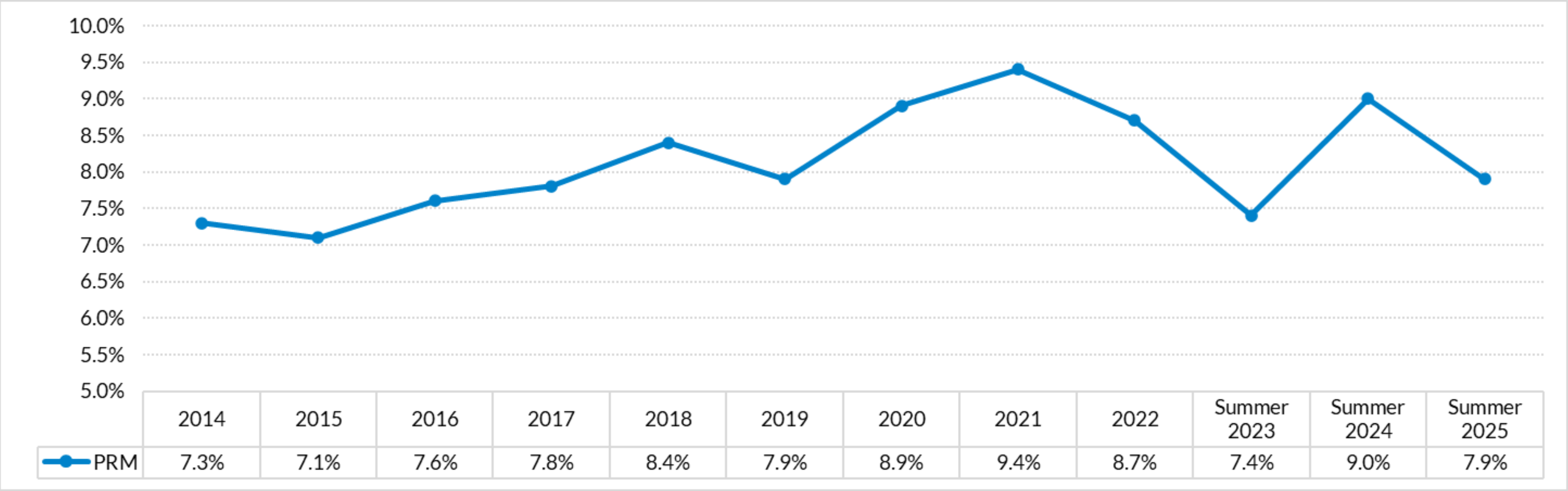
	2014	2015	2016	2017	2018	2019	2020	2021	2022	Summer 2023	Summer 2024	Summer 2025
Summer CPF	124,212.2	124,097.3	123,035.8	121,631.2	121,815.6	121,791.4	121,679.8	119,532.0	121,608.5	120,586.8	121,314.1	122,596.6



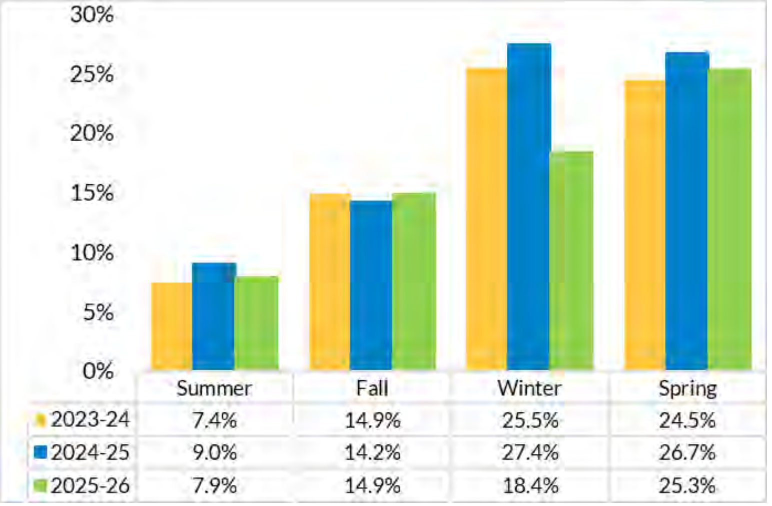
	Summer	Fall	Winter	Spring
🟨 2023-24	120,586.8	106,973.8	99,188.0	97,537.6
🟦 2024-25	121,314.1	107,701.4	100,114.6	98,697.8
🟩 2025-26	122,596.6	109,850.0	102,624.0	100,225.2

PRMR: Planning Reserve Margin Requirement

Planning Reserve Margin (%)

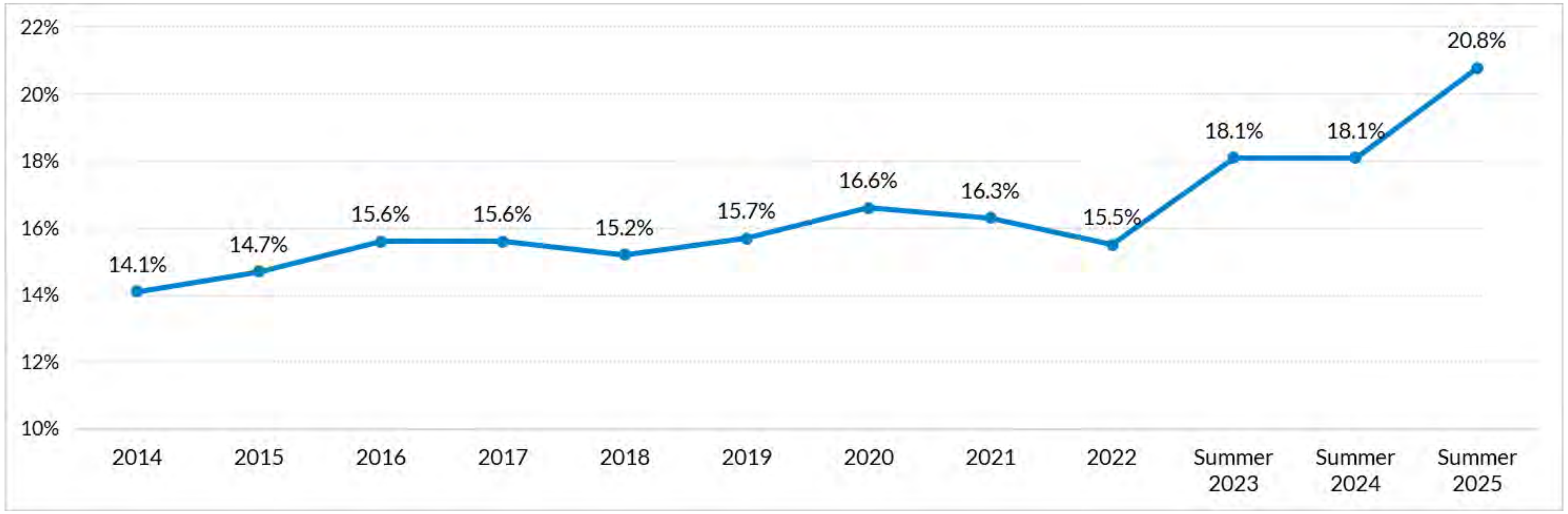


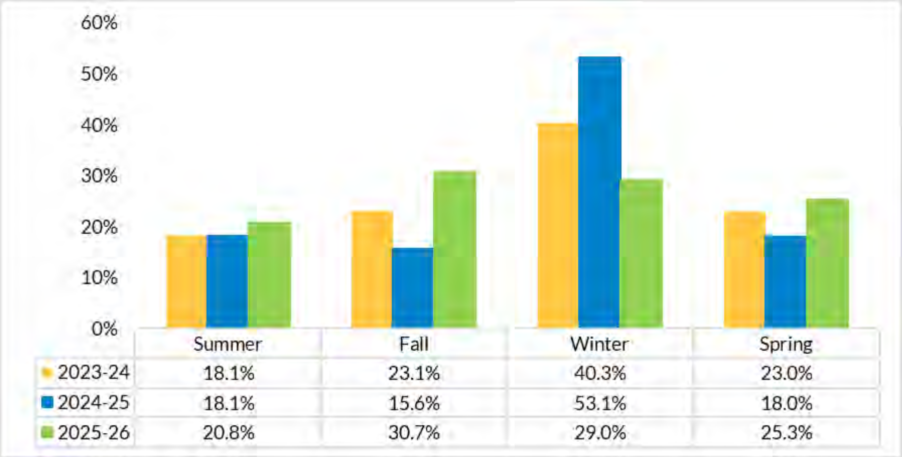
	2014	2015	2016	2017	2018	2019	2020	2021	2022	Summer 2023	Summer 2024	Summer 2025
PRM	7.3%	7.1%	7.6%	7.8%	8.4%	7.9%	8.9%	9.4%	8.7%	7.4%	9.0%	7.9%



	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 (%)



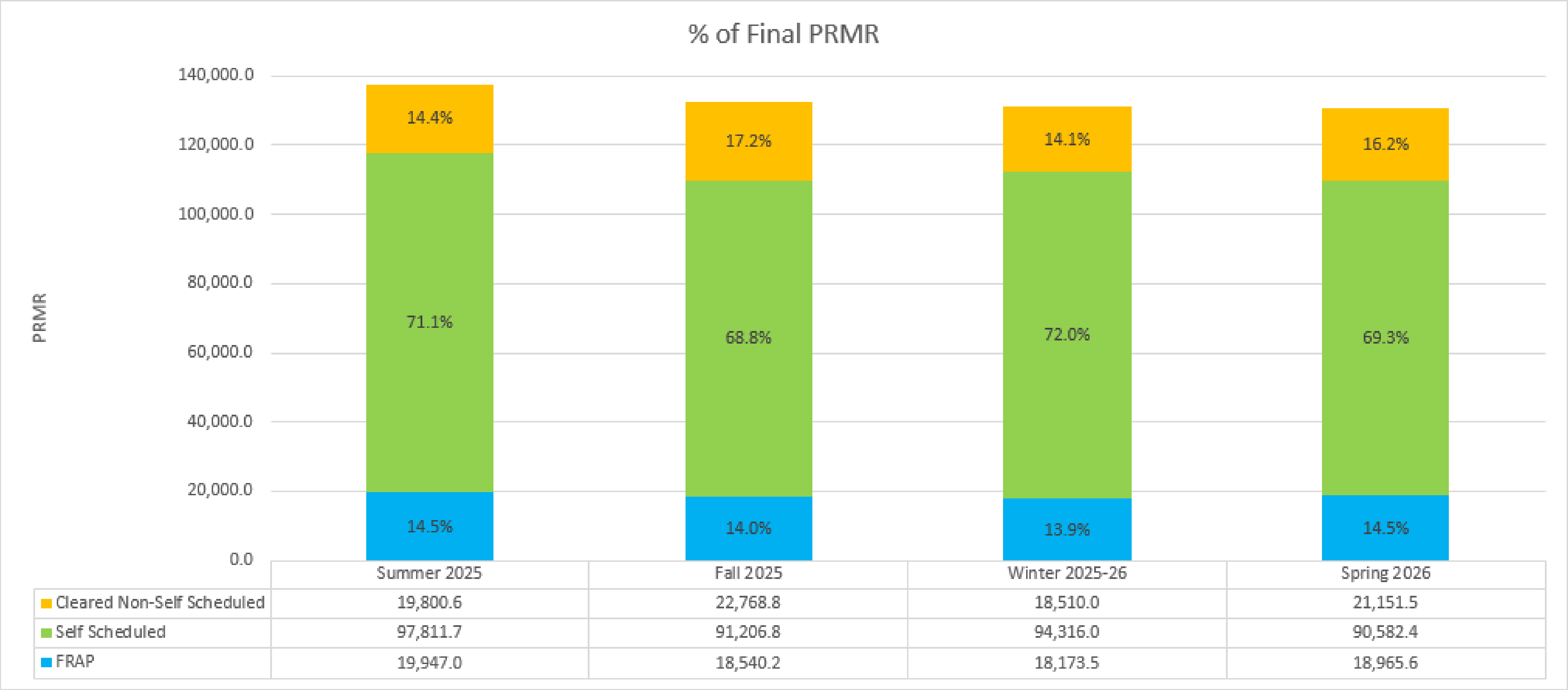


	Summer	Fall	Winter	Spring
🟨 2023-24	18.1%	23.1%	40.3%	23.0%
🟦 2024-25	18.1%	15.6%	53.1%	18.0%
🟩 2025-26	20.8%	30.7%	29.0%	25.3%

- 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

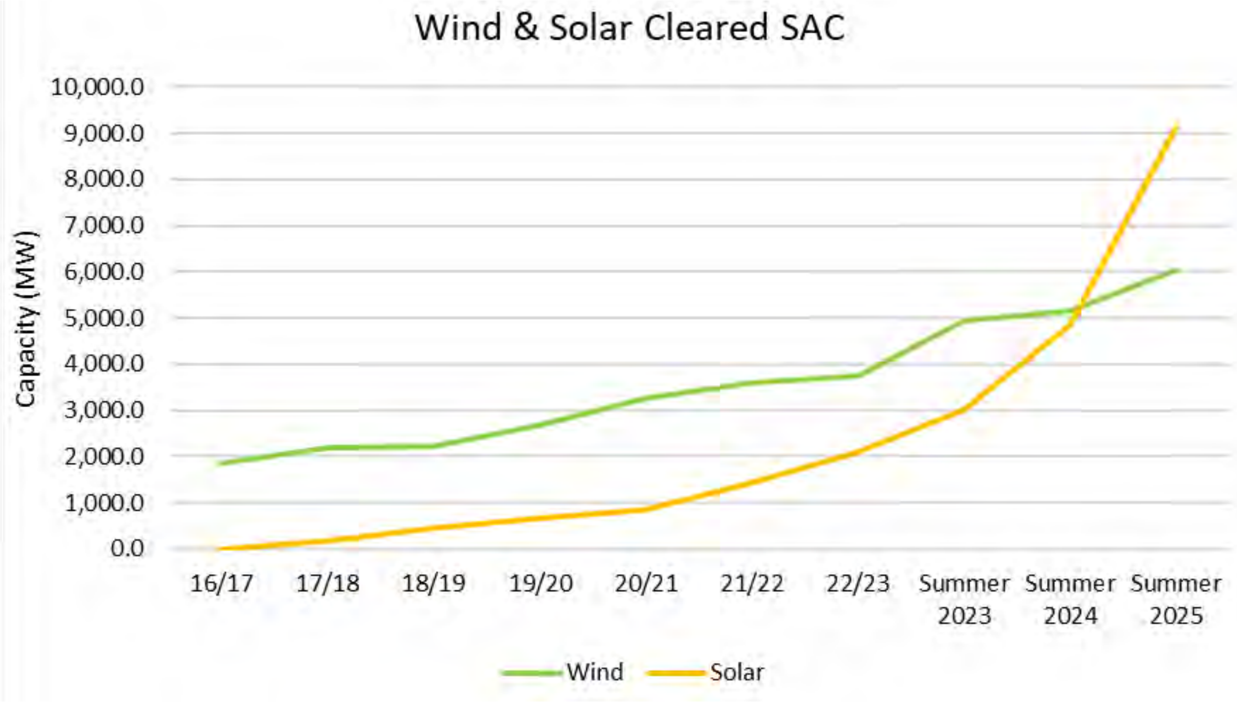


	Summer 2025	Fall 2025	Winter 2025-26	Spring 2026
🟨 Cleared Non-Self Scheduled	19,800.6	22,768.8	18,510.0	21,151.5
🟩 Self Scheduled	97,811.7	91,206.8	94,316.0	90,582.4
🟦 FRAP	19,947.0	18,540.2	18,173.5	18,965.6

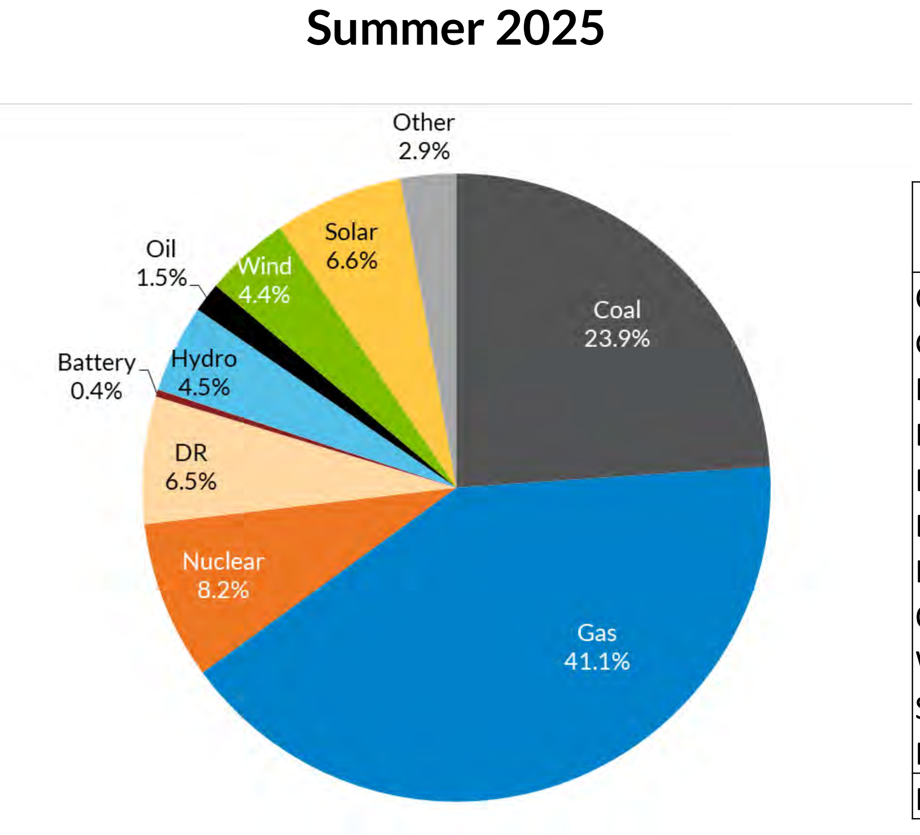
PRMR: Planning Reserve Margin Requirement

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)

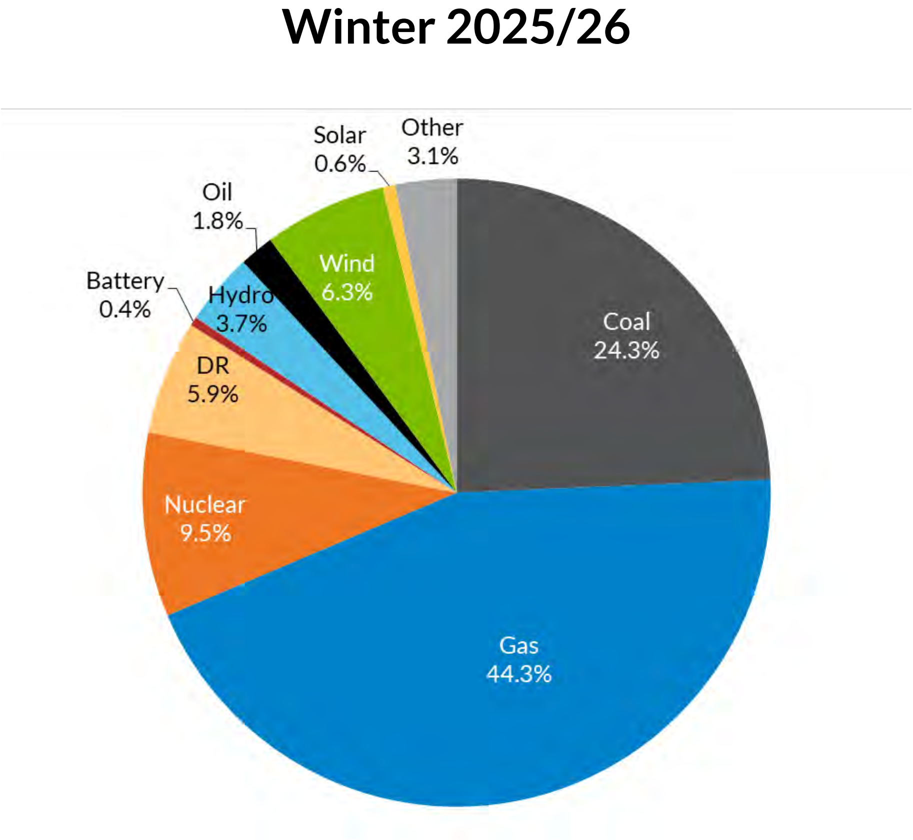


Winter final PRMR is 6.6 GW (4.8%) lower than the summer with fewer solar resources to meet final PRMR in the winter versus the summer



MISO-wide

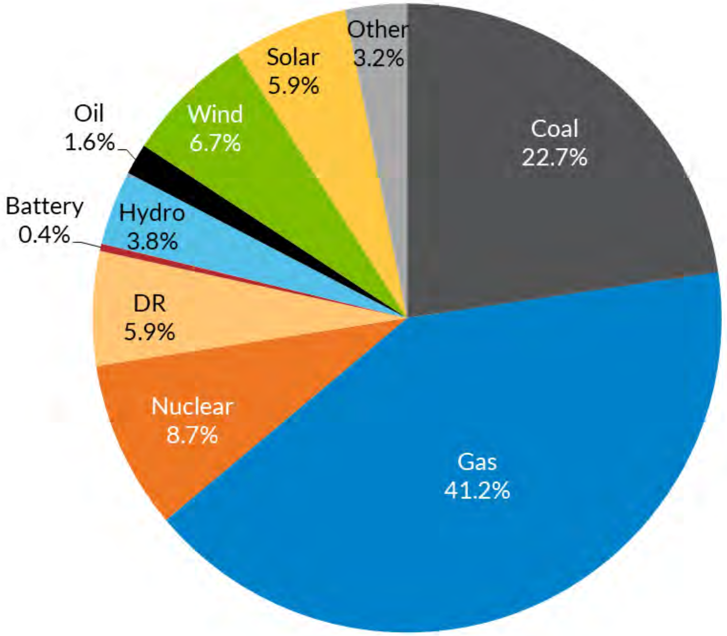
Cleared ZRC	Summer 2025	Winter 2025/26	Difference
Coal	32,909.6	31,887.2	1,022.4
Gas	56,470.0	57,990.5	-1,520.5
Nuclear	11,232.1	12,416.7	-1,184.6
DR	9,004.4	7,698.3	1,306.1
Battery	499.2	588.5	-89.3
EE	27.6	32.9	-5.3
Hydro	6,231.3	4,823.7	1,407.6
Oil	2,088.8	2,315.7	-226.9
Wind	6,039.1	8,282.9	-2,243.8
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



PRMR: Planning Reserve Margin Requirement

Fall 2025 and Spring 2026 - Cleared ZRCs and Final PRMR

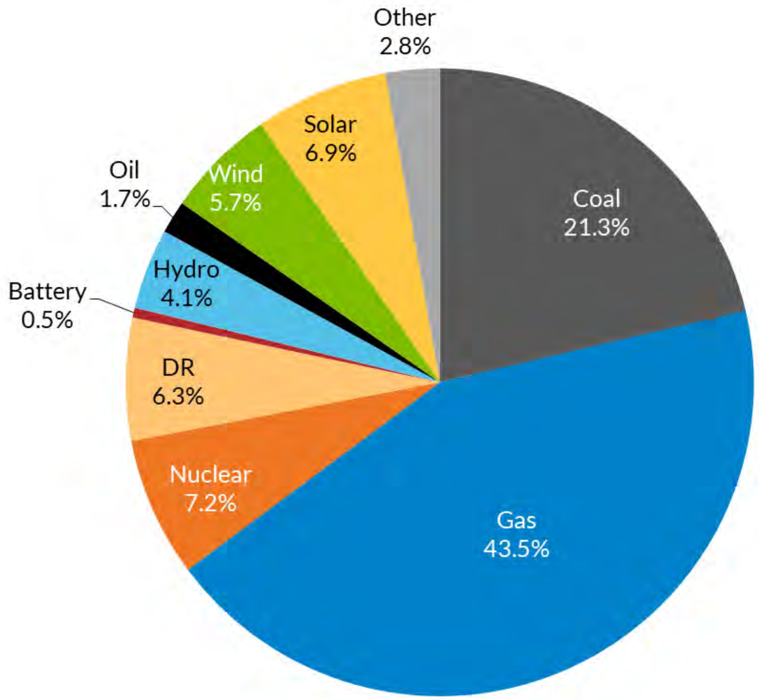
Fall 2025



MISO-Wide

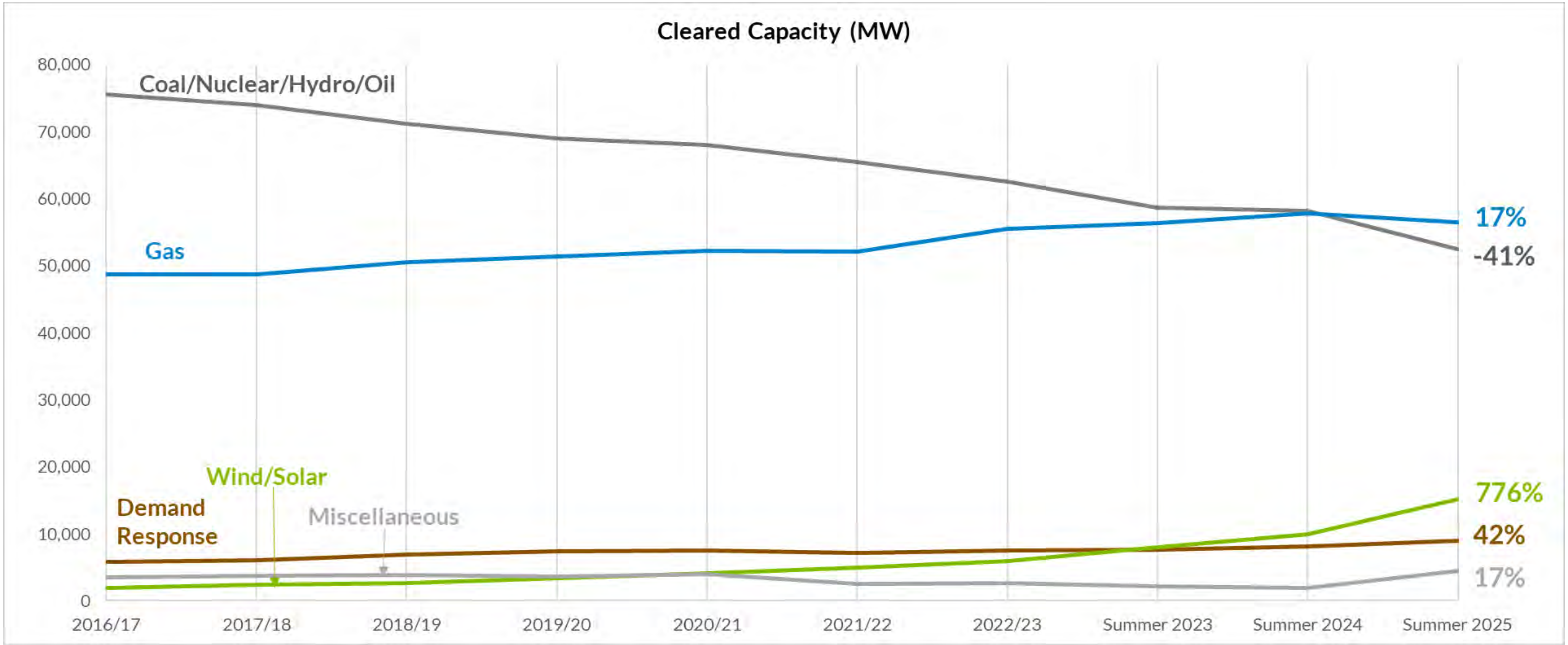
Cleared ZRC	Fall 2025	Spring 2026
Coal	30,038.9	27,886.8
Gas	54,636.4	56,820.7
Nuclear	11,482.1	9,405.4
DR	7,767.8	8,240.5
Battery	497.9	663.3
EE	28.1	30.5
Hydro	5,047.4	5,415.8
Oil	2,123.8	2,190.4
Wind	8,864.8	7,438.0
Solar	7,843.8	8,975.1
Misc	4,184.8	3,633.0
PRMR	132,515.8	130,699.5

Spring 2026

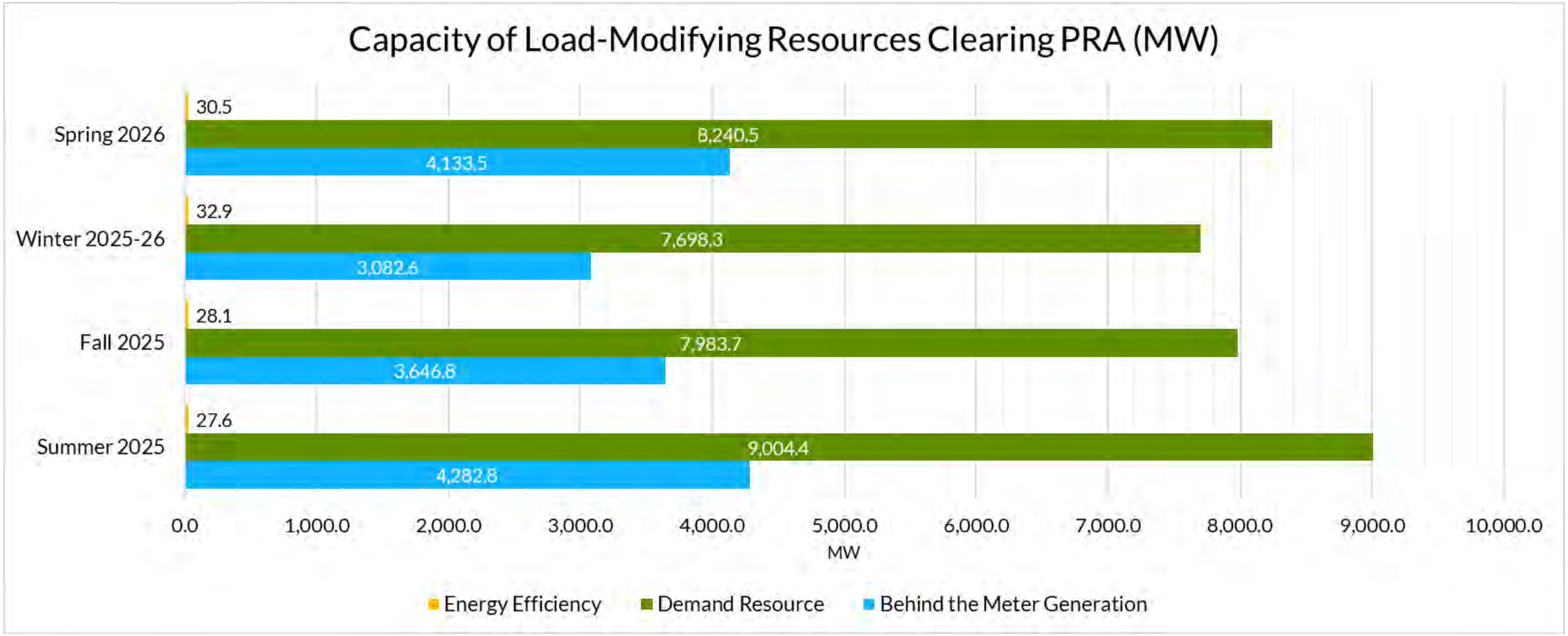


PRMR: Planning Reserve Margin Requirement

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



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https://help.misoenergy.org/

MISO’s Planning Resource Auction indicates sufficient resources

Improved pricing signal more accurately highlights reliability risk

For Immediate Release

April 28, 2025

Media Contact

Brandon Morris

CARMEL, Ind. — Today, MISO released the 2025 Planning Resource Auction (PRA) results indicating adequate resources are available to maintain reliability during the upcoming planning year (June 2025 – May 2026). While the 2025 auction prices reflect a tightening supply-demand balance during the summer months, there is sufficient capacity throughout the MISO footprint.

This is the first year MISO utilized a Reliability-Based Demand Curve (RBDC), which introduces a reliability-focused pricing structure that more accurately reflects the increasing value of accredited capacity as the system approaches minimum resource adequacy targets.

“MISO's market reforms continue to assist in providing pricing signals that improve market efficiency and enhance reliability across the footprint,” said Aubrey Johnson, MISO’s vice president of system planning and competitive transmission. ““We developed the RBDC through extensive collaboration with the Organization of MISO states, our stakeholders and our Independent Market Monitor to ensure this proactive approach helps meet the future needs of our evolving fleet.”

The seasonal Auction Clearing Prices are:

- Summer (June, July and August) $666.50/MW-day
- Fall (September, October and November)
    - $91.60/MW-day for the North/Central subregion
    - $74.09/MW-day for the South subregion
- Winter (December, January and February) $33.20/MW-day
- Spring (March, April and May) $69.88/MW-day
- Annualized, the prices are $217/MW-day for the North/Central region and $212 for the South region.

The majority of MISO's Load Serving Entities (LSEs) either self-supply or secure the capacity they need before the auction. Those that enter the auction to procure capacity must pay the Auction Clearing Price and those holding excess capacity sell it at the same clearing price. The impact on consumer costs will vary and depends on factors such as the size of any capacity shortfall and the terms of wholesale power purchase agreements or state-regulated retail rates.

"This year's results underscore MISO's proactive Market Redefinition efforts to enhance resource availability as outlined in the Reliability Imperative." Johnson continues. "MISO, our states and our stakeholders continue to make progress responding to the resource adequacy challenges we face, and these results offer valuable insights to allow members to maximize their existing resources and plan for the ongoing energy transition."

MISO's Independent Market Monitor has reviewed and agreed with the offers and results of the 2025 PRA. MISO will host the 2025 Planning Resource Auction Results meeting April, 29 at 10 a.m. ET.

##

MEDIA CONTACT:
Brandon D. Morris

About MISO

Midcontinent Independent System Operator (MISO) is an independent, not-for-profit organization that delivers safe, cost-effective electric power across 15 U.S. states and the Canadian province of Manitoba. 45 million people depend on MISO to generate and transmit the right amount of electricity every minute of every day. MISO is committed to reliable, nondiscriminatory operation of the bulk power transmission system and collaborating with all stakeholders to create cost-effective and innovative solutions for our changing industry. MISO operates one of the world's largest energy markets with more than $40 billion in annual gross market energy transactions.

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A. Introduction

1. Title: **Planning Resource Adequacy Analysis, Assessment and Documentation**

2. Number: **BAL-502-RF-03**

3. Purpose: To establish common criteria, based on "one day in ten year" loss of Load expectation principles, for the analysis, assessment and documentation of Resource Adequacy for Load in the ReliabilityFirst Corporation (RF) region

4. Applicability

4.1 Functional Entities

4.1.1 Planning Coordinator

5. Effective Date:

5.1 BAL-502-RF-03 shall become effective on the first day of the first calendar quarter that is after the date that this standard is approved by applicable regulatory authorities or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect.

B. Requirements and Measures

R1 The Planning Coordinator shall perform and document a Resource Adequacy analysis annually. The Resource Adequacy analysis shall *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*:

1.1 Calculate a planning reserve margin that will result in the sum of the probabilities for loss of Load for the integrated peak hour for all days of each planning year[1] analyzed (per R1.2) being equal to 0.1. (This is comparable to a "one day in 10 year" criterion).

1.1.1 The utilization of Direct Control Load Management or curtailment of Interruptible Demand shall not contribute to the loss of Load probability.

1.1.2 The planning reserve margin developed from R1.1 shall be expressed as a percentage of the median[2] forecast peak Net Internal Demand (planning reserve margin).

1.2 Be performed or verified separately for each of the following planning years:

---

[1] The annual period over which the LOLE is measured, and the resulting resource requirements are established (June 1st through the following May 31st).

[2] The median forecast is expected to have a 50% probability of being too high and 50% probability of being too low (50:50).

1.2.1 Perform an analysis for Year One.

1.2.2 Perform an analysis or verification at a minimum for one year in the 2 through 5 year period and at a minimum one year in the 6 though 10 year period.

1.2.2.1 If the analysis is verified, the verification must be supported by current or past studies for the same planning year.

1.3 Include the following subject matter and documentation of its use:

1.3.1 Load forecast characteristics:

1.3.1.1 Median (50:50) forecast peak Load.

1.3.1.2 Load forecast uncertainty (reflects variability in the Load forecast due to weather and regional economic forecasts).

1.3.1.3 Load diversity.

1.3.1.4 Seasonal Load variations.

1.3.1.5 Daily demand modeling assumptions (firm, interruptible).

1.3.1.6 Contractual arrangements concerning curtailable/Interruptible Demand.

1.3.2 Resource characteristics:

1.3.2.1 Historic resource performance and any projected changes

1.3.2.2 Seasonal resource ratings

1.3.2.3 Modeling assumptions of firm capacity purchases from and sales to entities outside the Planning Coordinator area.

1.3.2.4 Resource planned outage schedules, deratings, and retirements.

1.3.2.5 Modeling assumptions of intermittent and energy limited resource such as wind and cogeneration.

1.3.2.6 Criteria for including planned resource additions in the analysis

1.3.3 Transmission limitations that prevent the delivery of generation reserves

1.3.3.1 Criteria for including planned Transmission Facility additions in the analysis

1.3.4 Assistance from other interconnected systems including multi-area assessment considering Transmission limitations into the study area.

1.4 Consider the following resource availability characteristics and document how and why they were included in the analysis or why they were not included:

1.4.1 Availability and deliverability of fuel.

1.4.2 Common mode outages that affect resource availability

1.4.3 Environmental or regulatory restrictions of resource availability.

1.4.4 Any other demand (Load) response programs not included in R1.3.1.

1.4.5 Sensitivity to resource outage rates.

1.4.6 Impacts of extreme weather/drought conditions that affect unit availability.

1.4.7 Modeling assumptions for emergency operation procedures used to make reserves available.

1.4.8 Market resources not committed to serving Load (uncommitted resources) within the Planning Coordinator area.

1.5 Consider Transmission maintenance outage schedules and document how and why they were included in the Resource Adequacy analysis or why they were not included

1.6 Document that capacity resources are appropriately accounted for in its Resource Adequacy analysis

1.7 Document that all Load in the Planning Coordinator area is accounted for in its Resource Adequacy analysis

M1 Each Planning Coordinator shall possess the documentation that a valid Resource Adequacy analysis was performed or verified in accordance with R1

R2 The Planning Coordinator shall annually document the projected Load and resource capability, for each area or Transmission constrained sub-area identified in the Resource Adequacy analysis *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*.

2.1 This documentation shall cover each of the years in Year One through ten.

2.2 This documentation shall include the Planning Reserve margin calculated per requirement R1.1 for each of the three years in the analysis.

2.3 The documentation as specified per requirement R2.1 and R2.2 shall be publicly posted no later than 30 calendar days prior to the beginning of Year One.

M2 Each Planning Coordinator shall possess the documentation of its projected Load and resource capability, for each area or Transmission constrained sub-area identified in the Resource Adequacy analysis on an annual basis in accordance with R2.

R3 The Planning Coordinator shall identify any gaps between the needed amount of planning reserves defined in Requirement R1, Part 1.1 and the projected planning reserves documented in Requirement R2 *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*.

M3 Each Planning Coordinator shall possess the documentation identifying any gaps between the needed amounts of planning reserves and projected planning reserves in accordance with R3.

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

As defined in the NERC Rules of Procedure, "Compliance Enforcement Authority" means NERC or the Regional Entity in their respective roles of monitoring and enforcing compliance with the NERC Reliability Standards.

1.2. Evidence Retention

The following evidence retention periods identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the Compliance Enforcement Authority may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit.

The Applicable Entity shall keep data or evidence to show compliance with Requirements R1 through R3, and Measures M1 through M3 from the most current and prior two years.

If an Applicable Entity is found non-compliant, it shall keep information related to the non-compliance until mitigation is complete and approved, or for the time specified above, whichever is longer.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

1.3. Compliance Monitoring and Assessment Processes

Compliance Audit
Self-Certification
Spot Checking

Compliance Investigation
Self-Reporting
Complaint

1.4. Additional Compliance Information

None

Table of Compliance Elements

R #	Time Horizon	VRF	VIOLATION SEVERITY LEVEL			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	Long-term Planning	Medium	The Planning Coordinator Resource Adequacy analysis failed to consider 1 or 2 of the Resource availability characteristics subcomponents under Requirement R1, Part 1.4 and documentation of how and why they were included in the analysis or why they were not included **OR** The Planning Coordinator Resource Adequacy analysis failed to consider Transmission maintenance outage schedules and document how and why they were included in the analysis or why they were not included per Requirement R1, Part 1.5	The Planning Coordinator Resource Adequacy analysis failed to express the planning reserve margin developed from Requirement R1, Part 1.1 as a percentage of the net Median forecast peak Load per Requirement R1, Part 1.1.2 **OR** The Planning Coordinator Resource Adequacy analysis failed to include 1 of the Load forecast Characteristics subcomponents under Requirement R1, Part 1.3.1 and documentation of its use **OR**	The Planning Coordinator Resource Adequacy analysis failed to be performed or verified separately for individual years of Year One through Year Ten per Requirement R1, Part 1.2 **OR** The Planning Coordinator failed to perform an analysis or verification for one year in the 2 through 5 year period or one year in the 6 though 10 year period or both per Requirement R1, Part 1.2.2 **OR** The Planning Coordinator Resource Adequacy analysis failed to include 2 or	The Planning Coordinator failed to perform and document a Resource Adequacy analysis annually per R1. **OR** The Planning Coordinator Resource Adequacy analysis failed to calculate a Planning reserve margin that will result in the sum of the probabilities for loss of Load for the integrated peak hour for all days of each planning year analyzed for each planning period being equal to 0.1 per Requirement R1, Part 1.1 **OR**

				The Planning Coordinator Resource Adequacy analysis failed to include 1 of the Resource Characteristics subcomponents under Requirement R1, Part 1.3.2 and documentation of its use **Or** The Planning Coordinator Resource Adequacy analysis failed to document that all Load in the Planning Coordinator area is accounted for in its Resource Adequacy analysis per Requirement R1, Part 1.7	more of the Load forecast Characteristics subcomponents under Requirement R1, Part 1.3.1 and documentation of their use **OR** The Planning Coordinator Resource Adequacy analysis failed to include 2 or more of the Resource Characteristics subcomponents under Requirement R1, Part 1.3.2 and documentation of their use **OR** The Planning Coordinator Resource Adequacy analysis failed to include Transmission limitations and documentation of its use	The Planning Coordinator failed to perform an analysis for Year One per Requirement R1, Part 1.2.1

					per Requirement R1, Part 1.3.3 **OR** The Planning Coordinator Resource Adequacy analysis failed to include assistance from other interconnected systems and documentation of its use per Requirement R1, Part 1.3.4 **OR** The Planning Coordinator Resource Adequacy analysis failed to consider 3 or more Resource availability characteristics subcomponents under Requirement R1, Part 1.4 and documentation of how and why they were included in the analysis or why they were not included	

					OR The Planning Coordinator Resource Adequacy analysis failed to document that capacity resources are appropriately accounted for in its Resource Adequacy analysis per Requirement R1, Part 1.6	
R2	Long-term Planning	Lower	The Planning Coordinator failed to publicly post the documents as specified per requirement Requirement R2, Part 2.1 and Requirement R2, Part 2.2 later than 30 calendar days prior to the beginning of Year One per Requirement R2, Part 2.3	The Planning Coordinator failed to document the projected Load and resource capability, for each area or Transmission constrained sub-area identified in the Resource Adequacy analysis for one of the years in the 2 through 10 year period per Requirement R2, Part 2.1. **OR** The Planning Coordinator failed to document the Planning	The Planning Coordinator failed to document the projected Load and resource capability, for each area or Transmission constrained sub-area identified in the Resource Adequacy analysis for year 1 of the 10 year period per Requirement R2, Part 2.1. **OR** The Planning Coordinator failed to document the projected Load and resource	The Planning Coordinator failed to document the projected Load and resource capability, for each area or Transmission constrained sub-area identified in the Resource Adequacy analysis per Requirement R2, Part 2.

				Reserve margin calculated per requirement R1.1 for each of the three years in the analysis per Requirement R2, Part 2.2.	capability, for each area or Transmission constrained sub-area identified in the Resource Adequacy analysis for two or more of the years in the 2 through 10 year period per Requirement R2, Part 2.1.	
R3	Long-term Planning	Lower	None	None	None	The Planning Coordinator failed to identify any gaps between the needed amount of planning reserves and the projected planning reserves, per R3

D. Regional Variances

None

E. Interpretations

None

F. Associated Documents

None

Version History

Version	Date	Action	Change Tracking
BAL-502-RFC-02	12/04/08	ReliabilityFirst Board Approved	
BAL-502-RFC-02	08/05/09	NERC BoT Approved	
BAL-502-RFC-02	03/17/11	FERC Approved	
BAL-502-RFC-03	06/01/17	ReliabilityFirst Board Approved	
BAL-502-RF-03	08/10/17	NERC BOT Approved	
BAL-502-RF-03	10/16/17	FERC Approved	

ECONOMIC DISPATCH

OF

ELECTRIC GENERATION CAPACITY

A REPORT TO CONGRESS AND THE STATES PURSUANT TO SECTIONS 1234 AND 1832 OF THE ENERGY POLICY ACT OF 2005

United States Department of Energy

February 2007

ECONOMIC DISPATCH

OF

ELECTRIC GENERATION CAPACITY

A REPORT TO CONGRESS AND THE STATES
PURSUANT TO SECTIONS 1234 AND 1832
OF THE
ENERGY POLICY ACT OF 2005

Sections 1234 and 1832 of the Energy Policy Act of 2005 (EPAct)[1] direct the U.S. Department of Energy (the Department, or DOE) to:

1) Study the procedures currently used by electric utilities to perform economic dispatch;
2) Identify possible revisions to those procedures to improve the ability of non-utility generation resources to offer their output for sale for the purpose of inclusion in economic dispatch; and
3) Study the potential benefits to residential, commercial and industrial electricity consumers nationally and in each State if economic dispatch procedures were revised to improve the ability of non-utility generation resources to offer their output for inclusion in economic dispatch.

EPAct defines "economic dispatch" to mean "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." [EPAct 2005, Sec. 1234 (b)] On November 7, 2005, the Department submitted a report to Congress in fulfillment of this requirement, *The Value of Economic Dispatch*.[2] The Act also requires the Secretary of Energy to submit a yearly report to Congress and the States "on the results of the study conducted under subsection (a), including recommendations to Congress and the States for any suggested legislative or regulatory changes." [EPAct 2005, Sec. 1234 (c)]

This report responds to the latter requirement, as the first annual study following up on the initial economic dispatch report to Congress and the States. It concludes that while the value of economic dispatch to promote reliability and efficiency of generation resources remains unchanged, national or state policy with respect to economic dispatch has changed very little since November 7, 2005. Accordingly, it does not appear that the practice of economic dispatch has undergone significant change.

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[1] The two sections have identical language. Hereafter in this report, citations will be to section 1234.

[2] This report, issued by the Department of Energy on November 7, 2005, can be found at http://www.oe.energy.gov/epa_sec1234.htm .

Review of the Department of Energy's 2005 Economic Dispatch Report

Security-constrained economic dispatch is an area-wide optimization process designed to meet electricity demand at the lowest cost, given the operational and reliability limitations of the area's generation fleet and transmission system. DOE's 2005 report found that security-constrained economic dispatch benefits electricity consumers by systematically increasing the use of the most efficient generation units (and demand-side resources, where available). This can lead to:

> … better fuel utilization, lower fuel usage, and reduced air emissions than would result from using less efficient generation. As the geographic and electrical scope integrated under unified economic dispatch increases, additional cost savings result from pooled operating reserves, which allow an area to meet loads reliably using less total generation capacity than would be needed otherwise. Economic dispatch requires operators to pay close attention to system conditions and to maintain secure grid operation, thus increasing operational reliability without increasing costs. Economic dispatch methods are also flexible enough to incorporate policy goals such as promoting fuel diversity or respecting demand as well as supply resources. Over the long term, economic dispatch can encourage new investment in generation as well as in transmission expansion and upgrades that enhance both reliability and cost savings.[3]

The initial report found that there have been many studies of the savings from various aspects of economic dispatch, but the studies do not provide consistent estimates of the benefits and effectiveness of economic dispatch. Compiling the results of an extensive survey of the electric industry's use of economic dispatch, the report found that all of the regional grid operators (Regional Transmission Operators and Independent System Operators), and the utilities in the third of the nation outside grid operator footprints use economic dispatch to manage and dispatch their generation units. At the same time, although regional grid operators and utilities observe the basic principles of security-constrained economic dispatch, the details of dispatch execution and the constraints placed around dispatch operations vary widely. The report concluded that there is room to improve economic dispatch practices to reduce the total cost of electricity and increase grid reliability. It did not attempt, however, to estimate the magnitude of such potential improvements.

Review of the FERC-State Economic Dispatch Joint Board Recommendations and Outcomes

Section 1298 of EPAct directed the Federal Energy Regulatory Commission (FERC) to convene regional joint boards with state regulators to:

> … consider issues relevant to what constitutes "security constrained economic dispatch" and how such a mode of operating an electric energy system affects or

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[3] *Ibid.* at 3-4.

> enhances the reliability and affordability of service to customers in the region concerned and to make recommendations to the Commission regarding such issues.[4]

On September 30, 2005, FERC issued an order convening joint boards in each of four designated regions (Northeast, PJM-MISO, South and West). The boards met over a period of several months and submitted regional reports to FERC, which compiled those reports with additional commentary in a submittal to Congress on July 31, 2006.[5]

The analysis and conclusions about economic dispatch varied significantly across the four regions. However, no joint board recommended any material changes to the way that economic dispatch is conducted within its region. FERC's report summarizes:

> … Regions where centralized dispatch predominates (PJM-MISO, Northeast) did not propose changing the basic dispatch or pricing mechanisms, and regions where individual utility dispatch predominates (South, West) did not propose new initiatives for greater centralization of the dispatch. In regions with existing RTOs, there were a number of recommendations for specific improvements within the existing centralized dispatch framework, but no new proposals for fundamental changes in the way the RTOs operate the dispatch. In regions where individual utility dispatch predominates, the boards were open to voluntary changes to aspects of the existing dispatch, or continued industry pursuit of regional dispatch on a voluntary basis, as long as these initiatives could be demonstrated to provide benefits to customers and gain appropriate state and federal approvals. However, these boards did not call for any specific initiatives and opposed any form of mandated modification.[6]

Since the FERC joint board report contains an excellent summary of the joint boards' concerns and conclusions, the present report addresses only the specific, affirmative recommendations offered by the various joint boards:

- The Northeast Joint Board recommended broadening the application of economic dispatch through greater coordination between the NYISO and ISO-NE, consideration of possible coordination with other areas, meetings with stakeholders on such coordination, examination of the possibility of coordination with other areas, and preparation of a report by NYISO and ISO-NE to FERC describing their seams elimination plans. That report had not been filed when this report was written.

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[4] EPAct, Section 1298.

[5] Federal Energy Regulatory Commission, "Security Constrained Economic Dispatch: Definition, Practices, Issues and Recommendations – A Report to Congress Regarding the Recommendations of Regional Joint Boards For the Study of Economic Dispatch Pursuant to Section 223 of the Federal Power Act as Added by Section 1298 of the Energy Policy Act of 2005," July 31, 2006, at http://www.ferc.gov/industries/electric/indus-act/joint-boards/final-cong-rpt.pdf .

[6] *Ibid.* at 10.

- The PJM-MISO Joint Board recommended examining the cost and feasibility of consolidating MISO and PJM economic dispatch and expanding further to include areas not currently under RTO-managed dispatch, subject to cost-effectiveness and applicable state laws. They also recommended continued improvements to the seams coordination between the two RTOs. This work is ongoing.
- The Western Joint Board recommended the conduct of studies to determine the potential of better dispatch coordination across larger sections of the region, particularly to improve the dispatch of renewables and to coordinate import and export scheduling.
- The Northeast Joint Board recommended that the RTOs improve data transparency by making bid data available more quickly to market participants.
- The PJM-MISO Joint Board asserted the need for continued RTO independence and objectivity in the conduct of economic dispatch.
- The PJM-MISO Joint Board recommended continued attention by the RTOs and state regulators to enable greater demand response participation in economic dispatch. PJM now allows demand response resources to bid into its real-time energy markets.
- Similarly, the Western Joint Board recommended broadening the definition of security-constrained economic dispatch to include policies such as demand response that affect dispatch beyond purely economic and security considerations.
- The PJM-MISO Joint Board recommended that the RTOs establish a clear benchmark to assess the effectiveness of economic dispatch at achieving reliability and cost-effectiveness objectives.
- The Western Joint Board recommended against conducting a more detailed study of utility economic dispatch methods (as suggested in the Department's 2005 report), on the grounds that such a review was not likely to add value.
- The Southern and Western Joint Boards considered the DOE recommendation concerning the standardization of non-utility generator-to-buyer contract terms, and concluded that this was worth pursuing on the condition that the results maintain flexibility and be applied regionally rather than nationally. However, no organization or agency has pursued this recommendation.
- The Northeast Joint Board recommended that FERC request the ISO-RTO Council to identify best practices for future improvements in economic dispatch tools. However, to date FERC has not issued a request of this nature.

Other Activities and Issues Related to Economic Dispatch

FERC Reform of Open Access Transmission Tariff

The Commission recently issued Order 890, in which it revised its *pro forma* Open Access Transmission Tariff, under which transmission operators offer transmission service for all bulk power sellers and buyers.[7] A common theme within FERC's reform effort, supported by many

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[7] FERC Order No. 890, "Preventing Undue Discrimination and Preference in Transmission Service," February 16, 2007, RM05-17-000 and RM05-25-000.

comments in response to FERC's Notice of Inquiry on OATT reform,[8] was that greater transparency in grid conditions, operations, and planning would enable many transmission customers – producers and purchasers – to participate more effectively in the wholesale electric market.

While many of the subjects covered by Order 890 do not address economic dispatch directly, the order will affect the ways that generation resources (including independent power producers) are treated under economic dispatch, whether conducted by a vertically integrated utility or an independent grid operator. The principal changes required by the order include:

- A requirement that public utilities work through the North American Electric Reliability Corporation (NERC) to develop consistent methodologies for calculating Available Transfer Capability (ATC) and to publish those methodologies. Calculating and publishing ATC is one of the "most critical functions under the *pro forma* OATT because it determines whether transmission customers can access alternative power supplies," the Commission said.[9]
- Each transmission provider's planning process must meet nine specified planning principles: coordination, openness, transparency, information exchange, comparability, dispute resolution, regional coordination, economic planning studies, and cost allocation.
- The rule reforms the pricing of energy and generator imbalances to require charges to be related to the cost of correcting the imbalance, to encourage efficient scheduling behavior and to exempt intermittent generators, such as wind power producers, from higher imbalance charges in recognition of the special circumstances presented by such resources.
- The Commission adopted a conditional firm component to long-term point-to-point transmission service addressing situations in which firm service can be provided for most, but not all, hours of the requested time period. The rule also reforms the existing requirements for redispatch service to ensure that the requirements are of greater use to transmission customers and more consistent with reliable planning and operation of an area's system.

Load forecasting

As noted in the Department's November 2005 Economic Dispatch Report, improving the quality and accuracy of load forecasting would improve the reliability and cost-minimization outcomes of economic dispatch. This is because most of the units available to meet load in real time were identified and scheduled the day before, based upon the day-ahead load forecast used in the security-constrained unit commitment process. While the cost of over-estimating load (in which case the load prediction is notably lower than actual) is relatively low and primarily financial (because money and fuel was expended to make a generator available although it was not fully

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[8] Federal Energy Regulatory Commission, "Preventing Undue Discrimination and Preference in Transmission Services," Notice of Inquiry, September 16, 2005, and comments, found at http://www.ferc.gov/industries/electric/indus-act/oatt-reform.asp .

[9] Federal Energy Regulatory Commission, news release regarding Order 890, February 15, 2007.

utilized), significantly under-estimating load can compromise reliability and cause sharp short-term increases in real-time wholesale market prices.

The importance of accurate load forecasting was demonstrated recently by the heat wave that occurred across most of the nation in July, 2006, the second hottest July on record in the United States. Due to the combination of the heat wave and a strong economy, total energy production in July 2006 was 4.3 percent higher than that in July 2005.[10] The California ISO, for example, reported that energy demand experienced within its control area on July 21 and 22 broke all previous records, demonstrating "tremendous growth in the demand for electricity – the amount of growth [not] forecasted to appear [until] five years from now."[11] Further, demand in California continued to rise on following days and was prevented from exceeding the area's production capacity only through the combination of aggressive customer conservation efforts and the loss of hundreds of distribution transformers which failed in the heat, removing significant additional load from the grid. A similar but less protracted disruption in electric service occurred in Texas on April 17-18, 2006.[12] Although long-term load forecasting is subject to many uncertainties, improvements in near-term load forecasting could lead to greater cost savings as well as improved reliability.

Private Sector Initiatives

The largest geographic and electric systems integrated under security-constrained economic dispatch are operated by RTOs and ISOs. Those grid operators have made specific changes to their economic dispatch efforts, including coordination of market operations, congestion management and redispatch between PJM and MISO, and co-optimization of resource prices across multiple markets by ISO-New England.

Commercial software vendors continue to work to improve the quality and scope of the tools used for security-constrained unit commitment and security-constrained economic dispatch. Because RTOs manage significantly greater resource fleets than traditional utilities – for instance, PJM handles over 150 gigawatts of resources spanning 30,000 "buses,"[13] while traditional utilities might dispatch across 5,000 buses – the scope of dispatch calculations has raised new computational challenges. At the same time, software developers are developing new algorithms to solve large-scale security-constrained unit commitment (SCUC) and security-constrained economic dispatch (SCED) problems, using new techniques such as temporal coupling and mixed integer programming to improve modeling of specific resource types and

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[10] Energy Information Administration," Monthly Flash Estimates of Electric Power Data", September 19, 2006, Data for July 2006.

[11] California ISO, "Conservation Works! More Conservation Needed as Peak Demand Skyrockets to Critical Peak Monday," July 23, 2006.

[12] See http://www.nbc5i.com/news/8794207/detail.html?rss=dfw&psp=news and other local news sources.

[13] The term "bus" is used in the electricity industry to refer to a node in an electrical transmission network where one or more elements are connected together.

optimize multiple complex power flows simultaneously.[14] Demands from the software vendors' most challenging customers -- large grid operators such as the NYISO, ISO-NE and PJM -- are driving and supporting such vendor initiatives.

Conclusions

Other than some responses to the FERC-State Joint Board studies, few significant changes were made in 2006 in the policies and practices for economic dispatch in the United States electric grid. More significant changes are likely to result, however, from the industry's implementation of FERC's Order 890. Although the order was issued in mid-February 2007, the rulemaking process was initiated in September 2005, and full implementation of the order will take many months.

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[14] E-mail from Avnaesh Jayantilal, Director Market Management Systems, Areva T&D, Redmond WA, October 13, 2006.

175 FERC ¶ 61,224
UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Before Commissioners: Richard Glick, Chairman;
James P. Danly, Allison Clements,
and Mark C. Christie.

Joint Federal-State Task Force on Electric Transmission Docket No. AD21-15-000

ORDER ESTABLISHING TASK FORCE AND SOLICITING NOMINATIONS

(Issued June 17, 2021)

1. Section 209(b) of the Federal Power Act (FPA) authorizes the Federal Energy Regulatory Commission (the Commission or FERC) to confer with state commissions "regarding the relationship between rate structures, costs, accounts, charges, practices, classifications, and regulations of public utilities subject to the jurisdiction" of such state commissions and FERC, including through joint hearings.[1] Pursuant to that authority, in this order, we establish a Joint Federal-State Task Force on Electric Transmission (Task Force); solicit nominations for state commission representation on the Task Force; set forth preliminary details of the Task Force; and identify topics for the Task Force to consider.

I. Task Force

2. Pursuant to section 209(b) of the FPA, we hereby establish the Task Force to conduct joint hearings on the transmission-related topics outlined below. Developing new transmission infrastructure implicates a host of different issues, including how to plan and pay for these facilities. Federal and state regulators each have authority over transmission-related issues, meaning that transmission developers must successfully navigate different federal and state regulatory processes. In addition, the development of new transmission infrastructure often affects numerous different priorities of federal and state regulators (e.g., reliability, customer protection, environmental considerations). As a result, the area is ripe for greater federal-state coordination and cooperation. We

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[1] 16 U.S.C. § 824h(b).

believe that a formal structure to jointly explore transmission-related issues is important in order to secure the benefits that transmission can provide and is in the public interest.[2]

3. The Task Force will be comprised of all FERC Commissioners as well as representatives from 10 state commissions. State commission representatives will serve one-year terms from the date of appointment by FERC and in no event will serve on the Task Force for more than three consecutive terms. State commission representatives will sit in an advisory capacity. We request that the National Association of Regulatory Utility Commissioners (NARUC) submit nominations to the Commission, in this docket, for the 10 state commission representatives no later than 30 days from the date of this order. We further request that two state commission representatives originate from each NARUC region,[3] recognizing that transmission-related issues may be viewed differently not only within, but also among different parts of the country. Although we solicit 10 nominations for state commission representatives on the Task Force, all state commissions will be invited to suggest agenda topics for public meetings of the Task Force and to submit comments before and after on the topics being discussed at such meetings. In addition, in the future, the Task Force may convene regional meetings with opportunity for participation by all state commissions in the region. Staff from FERC, NARUC, and the state commissions of state commission representatives will be appointed to support the work of the Task Force.

4. The Task Force will convene for multiple formal meetings annually, with FERC issuing orders fixing the time and place and agenda for each meeting, after consulting with all Task Force members and considering suggestions from state commissions. Meetings will be open to the public for listening and observing and on the record. We expect the initial public meeting of the Task Force to be held during the Fall 2021. The Task Force will expire three years after the first public meeting but may be extended for an additional period of time prior to its expiration by agreement of both FERC and NARUC.

5. The Task Force has the authority to examine the issues identified below, including soliciting oral and written input from interested parties. The Task Force may make

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[2] *See* 18 C.F.R. § 385.1301(b) (2020) (suggesting FERC or any state commission "will freely suggest cooperation with respect to any proceeding or matter affecting any public utility . . . subject to the jurisdiction of the Commission and of a State commission, and concerning which it is believed that cooperation will be in the public interest"); *see also id.* § 385.1305(c) (stating that FERC or any state commission "should feel free to suggest or request a joint . . . hearing at any time").

[3] *See* Nat'l Ass'n of Regul. Util. Comm'rs, https://www.naruc.org/meetings-and-events/regionals/ (last visited June 2, 2021) (identifying five regional associations).

recommendations to FERC on potential modifications to FERC's regulations, present recommendations at a monthly FERC open meeting, and develop a record to be incorporated into FERC and/or state commission proceedings.

II. Issue Statement

6. The Task Force will focus on topics related to efficiently and fairly planning and paying for transmission, including transmission to facilitate generator interconnection, that provides benefits from a federal and state perspective. Topics that the Task Force may consider include the following:

- Identifying barriers that inhibit planning and development of optimal transmission necessary to achieve federal and state policy goals, as well as potential solutions to those barriers;

- Exploring potential bases for one or more states to use FERC-jurisdictional transmission planning processes to advance their policy goals, including multi-state goals;

- Exploring opportunities for states to voluntarily coordinate in order to identify, plan, and develop regional transmission solutions;

- Reviewing FERC rules and regulations regarding planning and cost allocation of transmission projects and potentially identifying recommendations for reforms;

- Examining barriers to the efficient and expeditious interconnection of new resources through the FERC-jurisdictional interconnection processes, as well as potential solutions to those barriers; and

- Discussing mechanisms to ensure that transmission investment is cost effective, including approaches to enhance transparency and improve oversight of transmission investment including, potentially, through enhanced federal-state coordination.

III. Next Steps

7. After receiving nominations from NARUC, due within 30 days of the date of this order, for the 10 state commission representatives, we will issue a subsequent order, listing members of the Task Force and their roles and fixing the time and place for the first public meeting. At least two weeks prior to the first public meeting, we will issue an order with an agenda, developed in collaboration with Task Force members and in consideration of suggestions from state commissions.

By the Commission. Commissioner Chatterjee is not participating.

(S E A L)

Kimberly D. Bose,
Secretary.

NEWS RELEASES

FERC, NARUC Establish Federal-State Current Issues Collaborative

March 21, 2024
Items E-5
Docket Nos. AD21-15, AD24-7

FERC voted today to establish a new Federal-State Current Issues Collaborative to build on nearly three years of successful transmission-related task force discussions with state utility regulators and expand their efforts to energy sector issues where there are relevant jurisdictional connections or potential regulatory gaps.

The new Collaborative, formed in conjunction with the National Association of Regulatory Utility Commissioners (NARUC), expands on the last three years of work of the Joint Federal-State Task Force on Transmission. The Collaborative will provide a venue for federal and state regulators to share perspectives, improve understanding and, where appropriate, identify potential solutions regarding challenges and coordination on matters that affect specific state and federal regulatory jurisdictions. Potential topics include exploring where best to coordinate between state and federal regulators on issues ranging from electric reliability and resource adequacy to natural gas-electric coordination, wholesale and retail markets, new technologies and innovations, and infrastructure.

> "The past three years of our Task Force work have proven just how important it is for FERC and state regulators to meet and expand our shared perspectives on important electricity sector matters that we all grapple with on a daily basis," FERC Chairman Willie Phillips said. "I look forward to this expanded collaboration with our state colleagues."

"The role of state utility commissioners is increasingly more challenging and consequential to the quality of life, safety and economic health of this nation. Ensuring the reliability of the grid as the energy sector evolves at a rapid pace is crucial," said NARUC President Julie Fedorchak. "We appreciate the opportunity to continue these dialogues with FERC on matters at the cross-section of state and federal jurisdictions, which ultimately affect the well-being of our society."

"Transmission planning, siting and cost allocation are growing issues in some portions of our nation that are presenting challenges for state and federal regulators alike," said North Carolina Commissioner Kim Duffley, who represented the states as the co-chair of the task force. “I greatly appreciate the opportunity to have served with my fellow regulators on the task force, as the process allowed for meaningful dialogue and assisted in providing a clearer understanding of regional differences. The states look forward to seeing the beneficial results of our conversations and working with our federal partners on other significant federal-state issues.”

The Joint Federal-State Task Force on Electric Transmission, established in 2021, had its final meeting in February 2024. Since its first meeting in November 2021, the Task Force addressed numerous transmission-related topics, including regional transmission planning and cost allocation, generator interconnection, interregional transmission, oversight of transmission costs, physical security, grid enhancing technologies and siting.

The Federal-State Issues Collaborative will convene its first meeting this fall; it will expire in the fall of 2027. The Collaborative structure will be similar to that of the Task Force: It will be comprised of all sitting FERC Commissioners and representatives from 10 state commissions to be nominated by NARUC, with two state nominees from each NARUC region. State members will serve one-year terms.

R24-12

Contact Information

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This page was last updated on March 21, 2024

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Consumers Energy Company	)	
	)	**Docket No. EL25-90-000**
v.	)	
	)	
Midcontinent Independent System Operator, Inc.	)	

ANSWER OF THE
MIDCONTINENT INDEPENDENT SYSTEM OPERATOR, INC.

The Midcontinent Independent System Operator, Inc. ("MISO" or "Respondent") submits[1] this Answer to the Complaint of Consumers Energy Company ("Consumers Energy" or "Complainant"). Consumers Energy filed the Complaint in response to an order issued by the U.S. Secretary of Energy pursuant to Federal Power Act ("FPA") section 202(c) and section 201(b) of the Department of Energy Authorization Act.[2] The DOE Order determined "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[.]"[3] To address that emergency, the DOE Order directs MISO and Consumers Energy to take all measures necessary to ensure that the J.H. Campbell coal-fired power plant in West Olive, MI ("Campbell Plant") is available to operate.[4] Consumers Energy's Complaint requests that MISO's Open Access Transmission, Energy and Operating Reserve Markets Tariff ("Tariff") be revised to permit

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[1] *See* Rules 206 and 213 of the Rules of Practice and Procedure of the Federal Energy Regulatory Commission ("FERC" or "Commission"), 18 C.F.R. § 385.206(f) (2025); 18 C.F.R. § 385.213 (2025).

[2] U.S. Department of Energy, Order No. 202-25-3, at 2 (May 23, 2025) ("DOE Order").

[3] DOE Order at 1.

[4] DOE Order at 2.

recovery of costs incurred incident to the DOE Order, and provides draft Tariff language for the Commission's review.

As recognized by the Order, MISO's Planning Resource Auction for the 2025-2026 Planning Year demonstrated sufficient capacity for all zones within the MISO Region.[5] While MISO does not intend to contest, within the context of this docket, the characterization within the Order that an emergency exists "due to a shortage of electric energy . . . [or] a shortage of facilities," it is important to recognize existing processes have cleared sufficient electric generating capacity across MISO for the periods of time covered by the Order. The clearing of sufficient capacity to meet anticipated demand across the MISO Region for the 2025-2026 Planning Year reflects the diligent efforts of MISO's members, Market Participants, Relevant Electric Retail Regulatory Authorities (RERRA) and the Federal Energy Regulatory Commission (FERC) to establish policies and processes that address both immediate, and future capacity requirements. MISO continues to work with these parties in the context of anticipated growing demand for electricity, planned electric generating facility retirements, and an evolving mix of new electric generating resources to refine processes that address the challenges ahead. MISO is confident that these collaborative efforts do not require further intervention and will help ensure the region continues to procure sufficient capacity to meet demand.

MISO acknowledges that the DOE Order directs Consumers Energy "to file with the Federal Energy Regulatory Commission Tariff revisions or waivers necessary to effectuate this order."[6] MISO also acknowledges that the DOE Order provides that "[r]ate recovery is available pursuant to 16 U.S.C. § 824a(c)."[7] MISO supports the addition of a cost recovery schedule to the

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[5] Department of Energy Order No. 202-25-3 (May 23, 2025) at p. 2.

[6] DOE Order at 3.

[7] DOE Order at 3.

Tariff, subject to the reservations noted below, and believes that a Commission finding that such a mechanism be incorporated in the Tariff would further compliance with the DOE Order by both Consumers and MISO.

I. BACKGROUND

The Secretary of Energy issued the DOE Order on May 23, 2025.[8] The DOE Order identifies an "emergency situation" in the MISO region and states that MISO "faces potential tight reserve margins during the summer 2025 period, particularly during periods of high demand or low generation resource output."[9] The DOE Order notes that the Campbell Plant is scheduled to cease operations on May 31, 2025," and concludes that the Campbell Plant's retirement "would further decrease available dispatchable generation within MISO's service territory[.]"[10] The DOE Order states that, although MISO and Consumers Energy incorporated the Campbell Plant's planned retirement into their supply forecasts and acquired a 1,200 MW natural gas plant in Covert, MI, the North American Electric Reliability Corporation's ("NERC") analysis still anticipates an "elevated risk of operating reserve shortfalls."[11] The DOE Order concludes that "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)."[12]

The DOE Order directs MISO and Consumers Energy to "take all measures necessary to ensure that the Campbell Plant is available to operate."[13] MISO is "directed to take every step to employ economic dispatch of the Campbell Plant to minimize cost to ratepayers" and "to provide the [DOE] with information concerning the measures it has taken and is planning to take to ensure

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[8] DOE Order at 3.
[9] DOE Order at 1.
[10] DOE Order at 1.
[11] DOE Order at 2.
[12] DOE Order at 3.
[13] DOE Order at 2.

the operational availability and economic dispatch of the Campbell Plant consistent with the public interest."[14] MISO notes that it is working closely with Consumers and the other owners of the Campbell Plant to ensure the plant is available to operate in compliance with the DOE Order.

The DOE Order states that, to "[t]he 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."[15] The Order further provides that "Consumers [Energy] is directed to file with the Federal Energy Regulatory Commission Tariff revisions or waivers necessary to effectuate this order."[16] The DOE Order states that "[r]ate recovery is available pursuant to 16 U.S.C. § 824a(c)."[17]

II. ANSWER

A. The Tariff Does Not Currently Include a Mechanism to Allow Cost Recovery Pursuant to the DOE Order.

Consumers Energy observes that there is no MISO Tariff provision that would permit Consumers Energy's costs of complying with the DOE Order to be allocated to Load Serving Entities ("LSEs") in MISO's northern and central zones, and that MISO does not have the unilateral authority to offer Consumers Energy a section 202(c) rate agreement.[18] MISO agrees. MISO acknowledges that its Tariff does not currently include a mechanism to allow the cost recovery contemplated by the DOE Order. As discussed below, MISO does not oppose the addition of a cost recovery schedule to its Tariff that would allow Consumers Energy to recover its costs as contemplated by the DOE Order.

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[14] DOE Order at 2-3.

[15] DOE Order at 3.

[16] DOE Order at 3.

[17] DOE Order at 3.

[18] Complaint at 18.

B. MISO Does Not Oppose the Addition of a Cost Recovery Schedule for the Recovery of These Costs, and Will File a Cost Recovery Schedule to the Extent Directed by the Commission.

MISO does not oppose the addition of a cost recovery schedule that would permit Consumers Energy to recover the costs incurred as a result of its efforts to comply the DOE Order. MISO will file such a schedule if directed by the Commission.

C. MISO Reserves Its Right to Modify or Otherwise Change the Cost Recovery Allocation Formula, As Necessary, to Account for Existing Tariff Requirements or Changes.

MISO reserves the right to modify, adjust, or otherwise change the cost recovery allocation formula proposed by Consumers, should it be necessary, to account for existing Tariff requirements and to include other clarifications as may be appropriate.

III. ADMISSIONS AND DENIALS; AFFIRMATIVE DEFENSES

MISO denies all allegations in the Complaint not specifically and expressly admitted herein.[19]

IV. COMMUNICATIONS

All notices and communications with respect to this proceeding should be directed to:

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[19] 18 C.F.R. § 385.213(c)(2)(i)-(ii).

V. CONCLUSION

WHEREFORE, MISO respectfully requests that the Commission accept this answer.

Respectfully submitted,

/s/ Timothy Caister
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Regulatory Affairs
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Counsel for Midcontinent Independent System Operator, Inc.

CERTIFICATE OF SERVICE

I hereby certify that I have on this day e-served a copy of this document upon all parties listed on the official service list compiled by the Secretary in the above-captioned proceeding, in accordance with the requirements of Rule 2010 of the Commission's Rules of Practice and Procedure (18 C.F.R. § 385.2010).

Dated this 19th day of June, 2025 in Carmel, Indiana.

/s/ Adriana Rodriguez
Adriana Rodriguez
Midcontinent Independent
System Operator, Inc.

Dated: June 19, 2025

MISO IMM Blasts NERC Long-term Assessment, Says RTO in Good RA Spot

By Amanda Durish Cook

MINNEAPOLIS — MISO Independent Market Monitor David Patton called NERC's Long-Term Reliability Assessment inaccurate for labeling MISO a high-risk area and said he believes MISO is in a good reliability position.

"We find that it is completely inaccurate. MISO should not be colored in red," Patton said at a June 10 Markets Committee meeting of the MISO Board of Directors.

Patton faulted NERC for apparently conflating installed capacity with unforced capacity in the assessment's totals. He said NERC tallied unforced capacity values for MISO when calculating a margin that it ultimately compared to an installed capacity requirement. He said the blunder lowered the footprint's capacity sums on paper by more than 10 GW.

"I don't frankly understand how they did this," Patton said. "They basically presented an apples and oranges assessment."

NERC's Long-Term Reliability Assessment predicted MISO could be confronted with capacity shortfalls in 2025. It assumed the RTO would have 132.2 GW in generating capacity, or 124.4 GW after factoring in all retirement announcements. (See *NERC Warns Challenges 'Mounting' in Coming Decade*.)

Ahead of summer, MISO reported it has 143.1 GW in offered capacity available to it to meet a likely 123-GW annual peak. (See *MISO Prepping for Likely 123-GW Summer 2025 Peak*.) Altogether, the RTO has 203 GW of installed capacity.

Patton said NERC's lapse is influencing national policy, evidenced by the Department of Energy's directive to keep Consumers Energy's 1.4-GW J.H. Campbell coal plant in Michigan operating over the summer. (See *Consumers Energy Seeking Compensation for Keeping Campbell Open*.) He said NERC's projection could bleed into other rule changes.

"That sort of initiative can lead to FERC ordering market changes that are unnecessary," Patton said.

Patton also said MISO overstated load predictions used in NERC's assessment by submitting non-coincident peak forecasts instead of coincident peaks, raising its load requirements and lowering the calculated capacity margin.

Patton said of the four RTO markets he monitors, "I would say MISO is most reliable of the four."

"It seems like a combination of errors that seems correctable here, but there isn't a path for correction," MISO Director Barbara Krumsiek said.

Patton said he hopes NERC will rectify its methods that inform the long-term assessment by the next December report. He said he has reached out to NERC and committed to working with the regulatory authority on its approach.

Michelle Bloodworth, CEO of coal lobby organization America's Power, questioned whether it was appropriate for the MISO Market Monitor to question a "credible institution" such as NERC. She said she believed MISO's "elevated risk" status under the assessment was apt.

Bloodworth praised the DOE's actions to keep J.H. Campbell available for a little while longer. She noted that Cleco's 568-MW Big Cajun II Unit 1 shuttered March 31 due to a settlement decree; she said having the coal plant online at the time might have helped matters during MISO's load shedding orders in the New Orleans area on May 25. (See *NOLA City Council Puts Entergy, MISO in Hot Seat over Outages*.)

At the same meeting, MISO said it likely will manage higher-than-normal temperatures paired with drought over the summer.

"If you're dry and have a pervasive heatwave going on, it can compound challenges in the operating room," MISO Executive Director of Market Operations JT Smith said.

Smith said a doubled-in-size solar fleet also likely will test MISO's ramp and regulation capabilities in its ancillary market. He said MISO operators could be managing unavailable resources and higher-than-expected load throughout summer.

Why This Matters

MISO IMM David Patton panned the RTO's precarious standing in NERC's Long-Term Reliability Assessment. He waved away resource adequacy concerns and said NERC botched a margin-to-capacity requirement comparison, apparently mixing up unforced capacity and installed capacity.

As part of a five-year update, Vice President of Operations Renuka Chatterjee said MISO finds itself in the most "dynamic and demanding" operating environment it ever has. She cited steeper evening ramps and mounting long-duration outages, forecasting challenges and stability risks.

MISO entered summer June 1 with a $666.50/MW-day capacity price, signifying the premium the RTO has put on new capacity. (See *MISO Summer Capacity Prices Shoot to $666.50 in 2025/26 Auction*.)

Carrie Milton, of the IMM staff, said if generation operators had held off on powering down about 1.6 GW until September, it would have lowered capacity prices to $472/MW-day in the summer.

But Milton said the Campbell plant is not factored into MISO's clearing prices and isn't necessary for reliability during the season. She said MISO's auction already returned a better than one-day-in-10-years standard without the large coal plant.

"We are more than adequate," Patton said. He repeated that he has "no material concerns" over MISO's resource adequacy for the upcoming summer.

Patton said factoring in imports and typical planned and forced outages, MISO has a comfortable, 12.2% reserve margin. ■

Congressional Research Service
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Federal Power Act: The Department of Energy’s Emergency Authority

June 12, 2025

Congressional Research Service
https://crsreports.congress.gov
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Contacts

Section 202(c) of the Federal Power Act (16 U.S.C. §824a(c)) grants the Secretary of Energy certain authorities over the temporary operation of the electricity system during emergencies. Actions by the Trump Administration have highlighted this authority and raised questions about its future implementation. This report provides a brief history of the emergency authorities and discusses current issues.

History of Section 202(c)

The Federal Power Act was enacted in 1935 and included emergency authority language. At the time, federal oversight of the electricity system was conducted by the Federal Power Commission (FPC). Now, the Federal Energy Regulatory Commission (FERC) has most responsibilities for electricity system oversight—but not for emergencies. The emergency authority was transferred to the Secretary of Energy when the Department of Energy (DOE) was established by the Department of Energy Organization Act (P.L. 95-91) in 1977. Hereinafter, the emergency authority is described as residing with DOE.

Section 202(c) provides DOE broad discretion to require almost any change to the operation of the U.S. electricity system on a temporary basis. Specifically, DOE may "require by order such temporary connections of facilities and such generation, delivery, interchange, or transmission of electric energy as in its judgment will best meet the emergency and serve the public interest."

DOE may execute this authority during war or at any other time it "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." This report focuses on the authority as used during emergencies, not war, and it focuses on DOE's authority—it does not discuss other energy emergency authorities.[1]

In 2015, Congress amended Section 202(c) to specify how the emergency authority should interact with environmental requirements for power plants. In practice, the amendments prioritize electric reliability over environmental outcomes, essentially by providing a waiver of federal, state, or local environmental laws and regulations during times of emergencies.

This waiver has limitations. First, DOE emergency orders that may result in conflicts with environmental requirements may be issued only for 90-day periods. They may be renewed for additional 90-day periods as long as DOE deems these renewals necessary to meet the emergency.

Second, if an emergency order would result in a violation of a federal, state, or local environmental law or regulation, DOE must ensure the order is in effect "only during hours necessary to meet the emergency and serve the public interest." Lastly, DOE must "to the maximum extent practicable" ensure the order is consistent with environmental laws or regulations and "minimizes any adverse environmental impacts."

DOE Implementation

DOE's regulations for implementing its emergency authority were finalized in 1981.[2] The regulations define terms, including "emergency," and specify requirements for requesting an emergency order.

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[1] For example, in the 1970s, Congress passed several laws granting the President certain authorities to respond to energy shortages at the time. A discussion of those laws is beyond the scope of this report.

[2] 10 C.F.R. §§205.370-205.379.

The Section 202(c) emergency authority is focused primarily on short-term situations—though, as shown below, DOE has exercised this authority in situations of varying duration. DOE's regulations emphasize the short-term nature of "emergencies" in this context. In the 1981 rulemaking, DOE explained,

> The DOE does not intend these regulations to replace prudent utility planning and system expansion. This intent has been reinforced in the final rule by expanding the 'Definition of Emergency' to indicate that, while a utility may rely upon these regulations for assistance during a period of unexpected inadequate supply of electricity, it must solve long-term problems itself.[3]

DOE and FPC have used the emergency authority several dozen times since 1935 in response to different kinds of emergencies.

DOE's website contains information on use of the emergency authority from 2000.[4] From 2000 through May 2025, DOE used its emergency authority in response to 19 events. Eleven events were weather-related and included hurricanes, heat waves, and winter storms. Some events prompted multiple emergency orders, either because more than one utility experienced emergency conditions (e.g., Winter Storm Elliot in 2022) or because the initial emergency order was extended (e.g., the California energy crisis of 2000-2001).

Details on the use of the Section 202(c) emergency authority prior to 2000 are not available in a single DOE repository; they are therefore more difficult to comprehensively compile. According to one compilation, the emergency authority was used 29 times prior to 2000; 22 of these occasions were in association with World War II.[5]

The duration of emergency orders under Section 202(c) has varied; some have lasted just a few hours, while others have been extended to cover events lasting more than a year. Among the orders listed on DOE's website, the shortest order CRS identified occurred in response to a heat wave in Texas in September 2023. DOE granted an emergency order in this case for four hours on each of two days to respond to the highest levels of expected electricity demand.[6] The order allowed one coal-fired unit and 16 natural gas-fired units to operate in violation of limits on sulfur dioxide, nitrogen oxide, mercury, carbon monoxide, and wastewater during those hours, if required to maintain reliability.

In the longest event CRS identified, DOE granted multiple renewals to a request to allow two coal-fired units in Virginia to continue operating, as needed for reliability, in violation of mercury emissions limitations while a transmission facility was constructed. Emergency orders in response to that event were in effect from June 16, 2017, to March 8, 2019.[7]

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[3] Department of Energy (DOE), Economic Regulatory Administration, "Emergency Interconnection of Electric Facilities and the Transfer of Electricity to Alleviate an Emergency Shortage of Electric Power" (final rule), 46 *Federal Register* 39985, August 6, 1981, https://archives.federalregister.gov/issue_slice/1981/8/6/39984-39991.pdf#page=2.

[4] See DOE, "DOE's Use of Federal Power Act Emergency Authority," https://www.energy.gov/ceser/does-use-federal-power-act-emergency-authority; and DOE, "DOE's Use of Federal Power Act Emergency Authority – Archived," https://www.energy.gov/ceser/does-use-federal-power-act-emergency-authority-archived.

[5] Benjamin Rolsma, "The New Reliability Override," *Connecticut Law Review*, vol. 57, no. 3 (May 2025).

[6] Additional information is available at DOE, "Federal Power Act Section 202(c): ERCOT September 2023," https://www.energy.gov/ceser/federal-power-act-section-202c-ercot-september-2023.

[7] Additional information is available at DOE, "Federal Power Act Section 202(c) – PJM Interconnection & Dominion Energy Virginia, 2017," June 19, 2017, https://www.energy.gov/oe/articles/federal-power-act-section-202c-pjm-interconnection-dominion-energy-virginia-2017.

Trump Administration Actions

On April 8, 2025, President Trump issued Executive Order (E.O.) 14262, "Strengthening the Reliability and Security of the United States Electric Grid."[8] E.O. 14262 directs DOE to "streamline, systemize, and expedite" its processes for issuing emergency orders when "the relevant grid operator forecasts a temporary interruption of electricity supply is necessary to prevent a complete grid failure." A blackout is an example of a temporary interruption of electricity supply.

The E.O. additionally directs DOE to develop a protocol to identify generation resources that are critical to system reliability. The protocol must "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." Further, the protocol must prevent, "as the Secretary of Energy deems appropriate and consistent with applicable law," identified resources from "leaving the bulk-power system" or converting fuels in such a way that reduces their accredited capacity. An example of fuel conversion that could reduce accredited capacity is replacing a coal-fired power plant with a solar farm.

The language of the E.O. is nonspecific regarding the duration of any DOE action to retain resources or prevent them from leaving the bulk-power system. The E.O. language could be interpreted to mean DOE should take long-term action (i.e., lasting multiple years) or indefinite action. Emergency orders issued in response to multiyear events would be unusual, though not unprecedented, applications of DOE's Section 202(c) authority. It is unclear the extent to which limits to the authority might exist through judicial review or other avenues if DOE chose to issue long-term or indefinite emergency orders.

DOE issued emergency orders for three separate events in May 2025, all involving seemingly new interpretations of the emergency authority. One event is anticipated electricity supply shortages in Puerto Rico in summer 2025.[9] One of the DOE emergency orders pertaining to Puerto Rico directs the local utility to conduct vegetation management (e.g., shrub clearing) around specified transmission lines on the island.[10] No other emergency order issued from 2000 to the present has addressed vegetation management.

The other events involve elevated risk of supply shortages in parts of the Midwest and Eastern United States this summer. DOE ordered a delay in retirement plans for a coal-fired power plant in Michigan and a natural gas/oil dual-fired power plant in Pennsylvania.[11] Unlike in the cases of other emergency orders issued since 2000, the grid operators in these cases had not requested the delayed retirements. Moreover, neither had identified reliability risks specifically associated with

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[8] Executive Order 14262 of April 8, 2025, "Strengthening the Reliability and Security of the United States Electric Grid," 90 *Federal Register* 15521-15522, April 14, 2025, https://www.federalregister.gov/documents/2025/04/14/2025-06381/strengthening-the-reliability-and-security-of-the-united-states-electric-grid.

[9] For background on Puerto Rico's electricity system, see CRS In Focus IF12913, *Electric Reliability and Resiliency in Puerto Rico*, by Corrie E. Clark.

[10] Secretary of Energy Chris Wright, *Order No. 202-25-2*, May 16, 2025, https://www.energy.gov/sites/default/files/2025-05/PREPA%20202%28c%29%20Emergency%20Measures%20Transmission.pdf.

[11] Secretary of Energy Chris Wright, *Order No. 202-25-3*, May 23, 2025, https://www.energy.gov/sites/default/files/2025-05/Midcontinent%20Independent%20System%20Operator%20%28MISO%29%20202%28c%29%20Order_1.pdf; and Secretary of Energy Chris Wright, *Order No. 202-25-4*, May 30, 2025, https://www.energy.gov/sites/default/files/2025-05/Federal%20Power%20Act%20Section%20202%28c%29%20PJM%20Interconnection.pdf.

the retirement of the power plants in question at the time they approved those retirements. One of the affected grid operators, PJM, issued a supportive statement following the emergency order.[12]

Issues for Congress

E.O. 14262 does not specify how DOE should streamline its processes for issuing emergency orders. Congress could evaluate whether DOE's existing regulations require streamlining and, if Congress determines they do, could provide policy direction and set a timeline for updating the regulations. Congress could also leave it to DOE's discretion as to when and how to update its regulations.

Congress could weigh DOE action in this space against other priorities for the department, given that updating processes for issuing emergency orders could divert DOE resources from other activities. On the one hand, brownouts or blackouts due to insufficient electricity supplies are relatively rare in the United States. Grid operators have their own processes in place for managing the grid during times of supply shortages and, historically, DOE emergency orders have rarely been requested. On the other hand, many observers anticipate electricity demand to increase in the coming years faster than new supply can be brought online. If these trends continue, brownouts or blackouts could become more common, potentially increasing DOE's use of its emergency authority or Congress's interest in addressing emergency situations for electricity supply.

Regarding the statutory authority itself, Congress could consider whether amendments to Section 202(c) of the Federal Power Act are appropriate. The language has remained unchanged since 1935, potentially reflecting Congress's continued view over this time period that the original authorization is appropriate. Nonetheless, the U.S. electricity system has changed in many ways since 1935, and Congress might choose to consider reevaluating the authority.

One potential aspect for congressional consideration is the duration of DOE emergency orders, especially in relation to critical resources identified pursuant to E.O. 14262. Under current law, and assuming such orders might result in a conflict with environmental requirements, DOE could potentially reissue its emergency orders every 90 days for an indeterminate amount of time. Repeated emergency orders may raise feasibility questions, such as whether successive emergency orders would be upheld by the courts or whether power plant owners would make long-term investments to maintain power plants that are operating primarily under emergency orders.

Congress could consider evaluating and clarifying via legislation whether the Section 202(c) authority is better reserved for short-term situations or whether application to long-term situations is appropriate. Some backers of power plants at risk of retirement (e.g., coal-fired power plants) might support extended emergency orders based on long-term economic considerations. At the same time, some backers of power plants with low greenhouse gas emissions (e.g., solar generators) might support extended emergency orders based on long-term environmental considerations. Others might prefer to limit DOE's emergency authorities to short-term situations. A more limited role for DOE in electricity system operations allows for greater use of market forces and reliance on local- and state-level processes to prepare for and respond to emergencies.

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[12] PJM, "PJM Statement on the U.S. Department of Energy 202(c) Order of May 30," press release, May 31, 2025, https://www.pjm.com/-/media/DotCom/about-pjm/newsroom/2025-releases/20250531-doe-202c-statement-to-defer-retirements-of-certain-generators.pdf.

Another potential aspect for congressional consideration is the definition of "emergency" in the context of Section 202(c). Current law gives DOE broad discretion in determining what constitutes an emergency. Congress could consider whether this level of discretion is appropriate, or whether additional (or alternative) statutory direction would better serve current system needs.

As noted above, some supporters of specific kinds of power plants might view sustained economic conditions or environmental impacts as emergencies that warrant DOE action. Those situations would appear to be novel exercises of DOE authority under Section 202(c), if DOE were to interpret them in such a way. Amendments to the Federal Power Act could clarify congressional intent regarding use of DOE's emergency authority in response to those situations or any other long-term situation.

Other stakeholders might wish to limit DOE's discretion in when to issue emergency orders—for example, by modifying the currently broad statutory language or by requiring additional review by FERC or another entity.

A third potential aspect for congressional consideration is the scope of interventions allowed under the emergency authority. Current law allows DOE to order almost any change in operation of the electricity system.

Emergency orders between 2000 and 2024 directed either the operation of certain generators as needed for reliability or the temporary interconnection of the main Texas grid with neighboring regions' grids. One of DOE's May 2025 emergency orders requires Puerto Rico's local utility to conduct vegetation management activities.

One operational consideration that has not been tested under DOE's emergency authority (at least not in the orders available on DOE's website) is the curtailment of certain generators. Curtailment occurs when a grid operator directs a generator to reduce its output or cease operating altogether for a certain amount of time. Curtailment is sometimes necessary when generation levels in a given location exceed the transmission system's capacity to transmit energy out of that location.

Congress could evaluate the appropriateness of DOE's currently broad discretion to order interventions in the operation of the electricity system. Amendments to the Federal Power Act could clarify what kinds of interventions DOE may require.

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Disclaimer

U.S. Government Accountability Office

Electricity: Information on Peak Demand Power Plants

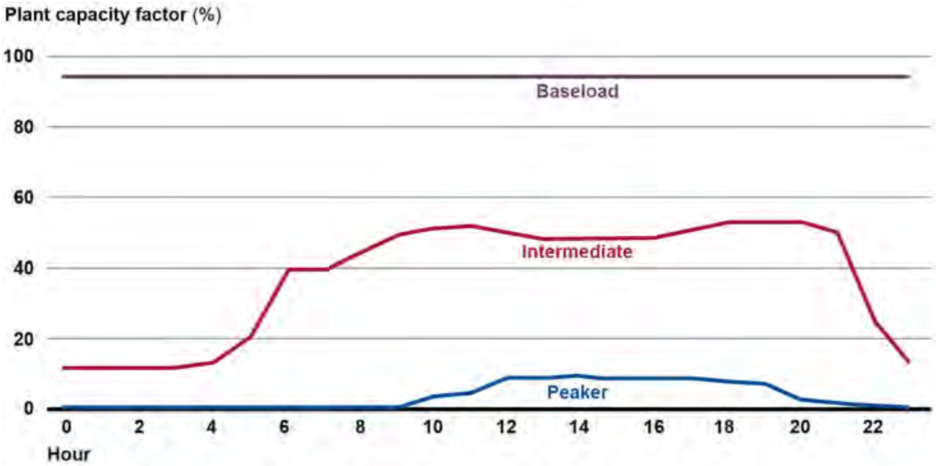
GAO-24-106145
Q&A Report to Congressional Requesters

May 21, 2024

Why This Matters

Peaker power plants are part of the U.S. energy infrastructure and help meet peak electricity demand. Peak demand generally occurs at times during the day when cooling and heating needs are generally the highest among households. Peakers are used to supplement other types of power plants, such as baseload plants, which run consistently throughout the day and night, and intermediate plants, which run mostly during the day and less at night (see fig. 1).

Figure 1: Illustrative Example of Annual Average Hourly Capacity Factors, by Plant Type



Source: GAO Analysis of Environmental Protection Agency data. | GAO-24-106145

Note: A plant’s capacity factor is the percent of energy it produced of the total energy it could have produced during a certain time frame if it operated continuously at full power.

Peakers may be less efficient than other types of plants—such as intermediate and baseload plants—because they undergo frequent startups using comparatively large amounts of fuel. Further, environmental advocates and some congressional leaders have expressed concerns that peakers may also negatively affect the air quality in communities—which may be historically disadvantaged or disproportionately low income—around the plants.

We were asked to examine pollution from peakers across the nation. We are providing information on the number and locations of peakers in the U.S.; the proximity of peakers to disproportionately low-income, and historically disadvantaged racial or ethnic populations; the extent to which they emit pollutants and how these pollutants affect the health of people exposed; alternatives for replacing them; and potential challenges of replacing them.

Key Takeaways

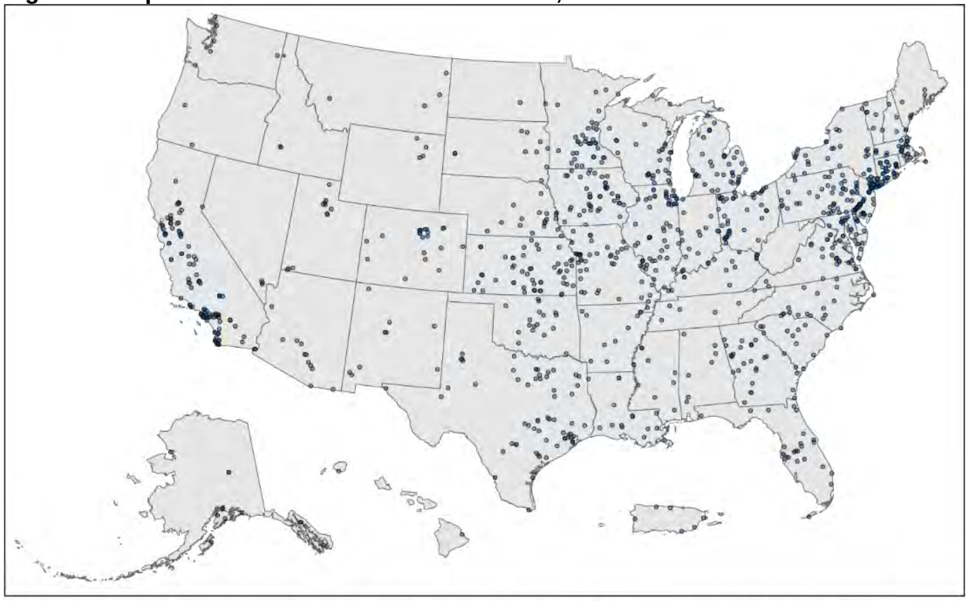
- Historically disadvantaged racial or ethnic communities tend to be closer to peakers.

- Fossil-fueled peakers are primarily fueled by natural gas and emit air pollutants associated with various negative health effects, including on respiratory, cardiovascular, and nervous systems.
- Alternatives are available that could potentially replace or provide similar services as peakers, but we identified challenges for their use related to costs, reliability, space, and location.

How many peakers are there in the U.S., and where are they located?

We identified 999 peakers in the U.S. in 2021, based on our analysis of Environmental Protection Agency (EPA) data (see fig. 2).[1] For the purpose of our report, we generally define peakers as plants that use fossil fuels, including natural gas, coal, and oil; have a capacity factor (the percent of energy produced over a certain time frame, out of what could have been produced at continuous full power operation) of 15 percent or less; and have a nameplate capacity (the designed full-load sustained output of a facility) of greater than 10 megawatts (MW) of electricity.[2] Most of these peakers are fueled by natural gas (see table 1). In 2021, these peakers accounted for 3.1 percent of annual net generation and 19 percent of total nameplate capacity for all power plants.

Figure 2: Map of Peaker Power Plants in the U.S., as of 2021



Source: GAO analysis of Environmental Protection Agency Emissions & Generation Resource Integrated Database (eGRID).
| GAO-24-106145

Note: Alaska, Hawaii, and Puerto Rico are shifted for display purposes. We define peakers as fossil-fueled power plants that have a capacity factor of 15 percent or less and a nameplate capacity of greater than 10 megawatts of electricity. Areas with multiple peakers appear darker than those with only one. This map does not identify whether there is any statistically significant spatial association or differentiate whether peakers are more concentrated in certain geographies relative to underlying population size.

Table 1: Total Net Electricity Generation and Total Nameplate Capacity of Peaker Power Plants, by Primary Fuel Type, 2021

Plant primary fossil fuel type	Number (%)	Total net generation (MWh)[a] (%)	Total nameplate capacity[b] (MW)
Natural gas	698 (69.87)	106,791,342 (82.75)	190,373
Oil	267 (26.73)	2,646,700 (2.05)	23,991
Coal	33 (3.30)	19,617,924 (15.20)	22,904
Other[c]	1 (0.10)	-9,824 (0.00)[d]	99
Total	**999 (100)**	**129,046,142 (100)**	**237,367**

Source: GAO analysis of Environmental Protection Agency data. I GAO-24-106145

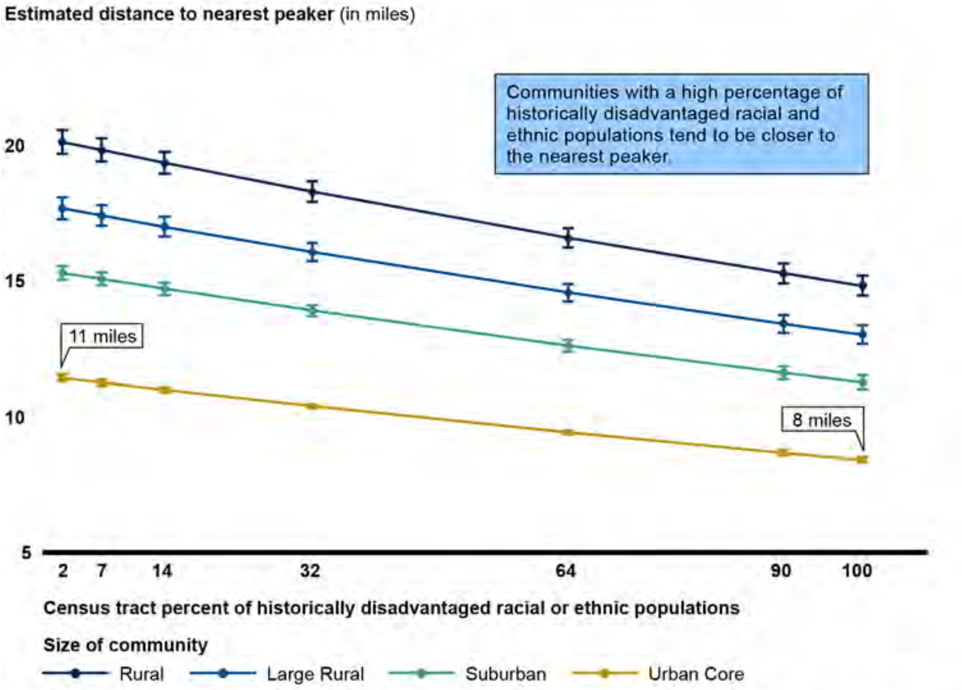
Note: We define peakers as fossil-fueled power plants that have a capacity factor of 15 percent or less and a nameplate capacity of greater than 10 megawatts of electricity.

[a] MWh = megawatt hour
[b] Nameplate capacity is the maximum output of electricity a power plant can produce without exceeding design thermal limits.
[c] This category includes other fossil fuels including blast furnace gas, other gasses, or tire-derived fuel.
[d] This plant has a negative net generation because electricity consumed by the plant exceeds the gross generation of the plant.

How closely are peakers located to historically disadvantaged and low-income communities?

We found that historically disadvantaged racial or ethnic communities (i.e., census tracts with higher percentages of historically disadvantaged racial or ethnic populations) are associated with being closer to peakers (see fig. 3).[3] To perform this analysis, we developed a statistical model to assess how community demographics are associated with proximity to peakers.[4] We tested this model with four alternative definitions of peakers and found that historically disadvantaged racial or ethnic communities are associated with being closer to peakers for all four definitions.[5] For example, based on our model and main definition of a peaker, a community that is 71 percent historically disadvantaged is expected to be 9 percent closer to the nearest peaker than the average community, which is 40 percent historically disadvantaged.[6] In addition, we found that the estimated distance to the nearest peaker varies according to population density, where urban communities have smaller estimated distances to the nearest peaker when compared to otherwise similar rural or suburban communities.

Figure 3: Estimated Distance to Nearest Peaker Power Plant Based on Percent of Community That Is Historically Disadvantaged, by Population Density

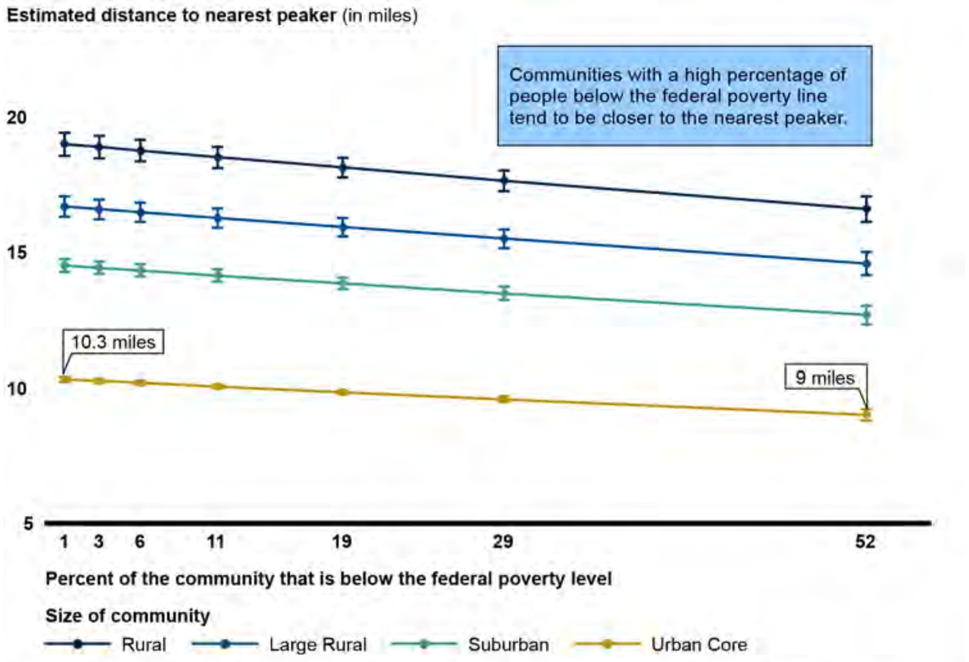


Source: GAO analysis of Census Bureau American Community Survey, Department of Agriculture Economic Research Services, National Oceanic and Atmospheric Administration National Weather Service, and Energy Information Administration data. | GAO-24-106145

Note: We define peakers as fossil-fueled power plants that have a capacity factor of 15 percent or less and that generate greater than 10 megawatts of electricity. We tested our model with alternative definitions of peakers and found similar results. This figure summarizes the results of our model assessing the relationship between the distance from a census tract to the nearest peaker and the demographic characteristics of that census tract. Our model includes controls for population density (e.g., rural or urban), climate, and other factors. Values on the x-axis represent various sample percentiles. Whiskers represent 95 percent confidence intervals, and non-overlapping whiskers are significantly different.

We found mixed results for income. Specifically, for three of our four definitions of a peaker, we found that communities with higher percentages of people below the federal poverty level were statistically significantly closer to the nearest peaker (see fig. 4).[7] Income was not statistically significant for our fourth definition.[8]

Figure 4: Estimated Distance to Nearest Peaker Power Plant Based on Percent of Community That Is Below the Federal Poverty Level, by Population Density



Source: GAO analysis of Census Bureau American Community Survey, Department of Agriculture Economic Research Services, National Oceanic and Atmospheric Administration National Weather Service, and Energy Information Administration data. | GAO-24-106145

Note: We define peakers as fossil-fueled power plants that have a capacity factor of 15 percent or less and that generate greater than 10 megawatts of electricity. We tested our model with alternative definitions of peakers and found similar results for three definitions, but insignificant results for one definition. This figure summarizes the results of our model assessing the relationship between the distance from a census tract to the nearest peaker and the demographic characteristics of that census tract. Our model includes controls for population density (e.g., rural or urban), climate, and other factors. Values on the x-axis represent various sample percentiles. Whiskers represent 95 percent confidence intervals, and non-overlapping whiskers are significantly different.

To what extent do peakers emit pollutants, and how can these pollutants affect the health of people exposed?

When operating, peakers emit similar types of pollutants to other power plants that also use fossil fuels, and these pollutants are associated with various negative health effects, according to existing literature.

Pollutants

Compared to non-peakers, peakers emitted more pollutants—such as nitrogen oxides and sulfur dioxide—per unit of electricity generated, but fewer total annual pollutants in 2021, according to our analysis of EPA data (see table 2).[9] In other words, peakers emit less in total because there are fewer peakers and they operate less frequently overall than non-peakers. However, when they do operate, they emit more pollution per unit of electricity produced. For example, the median sulfur dioxide emission rate for natural gas fueled peakers was 1.6 times more per unit of electricity generated than the median emission rate for non-peakers. Conversely, total annual sulfur dioxide emissions from peakers were 96.8 percent lower than total non-peaker annual sulfur dioxide emissions. Overall, peakers contributed 3 percent of the total annual sulfur dioxide emissions and 9 percent of total annual nitrogen oxide emissions.

Table 2: Sulfur Dioxide and Nitrogen Oxide Emissions from Fossil-fueled Peaker and Non-peaker Power Plants with Nameplate Capacity Greater than 25 MW, 2021

	Fuel Type	**Peaker**	**Non-peaker**
Median sulfur dioxide emission rate (pounds per megawatt hour)	Natural Gas	0.008[b]	0.005
	Coal	2.487	1.308
	Oil	4.218	2.174
	Other[a]	—	0.027
	All fuel types	**0.009**	**0.008**
Median nitrogen oxides emission rate (pounds per megawatt hour)	Natural Gas	0.949[b]	0.156
	Coal	1.554	1.330
	Oil	15.014[b]	3.152
	Other	—	0.670
	All fuel types	**1.272[b]**	**0.468**
Total annual sulfur dioxide emissions (tons)	—	32,111	1,014,787
Total annual nitrogen oxides emissions (tons)	—	83,874	885,345

Source: GAO analysis of Environmental Protection Agency data. | GAO-24-106145

Note: This analysis is limited to fossil-fueled plants with a nameplate capacity greater than 25 megawatts of electricity (1,605 plants) because plants of this size are required to report certain emissions, including sulfur dioxide and nitrogen oxides. Peakers in this analysis include plants with a capacity factor of 15 percent or less, and non-peakers include baseload and intermediate plants that supply more consistent power throughout the day. This analysis excludes plants that had incomplete emissions or generation data (57 plants).

[a] This category includes other fossil fuels including blast furnace gas, other gasses, or tire-derived fuel.
[b] Statistically, the median for peakers is significantly different from the median for non-peakers at the 0.05 level.

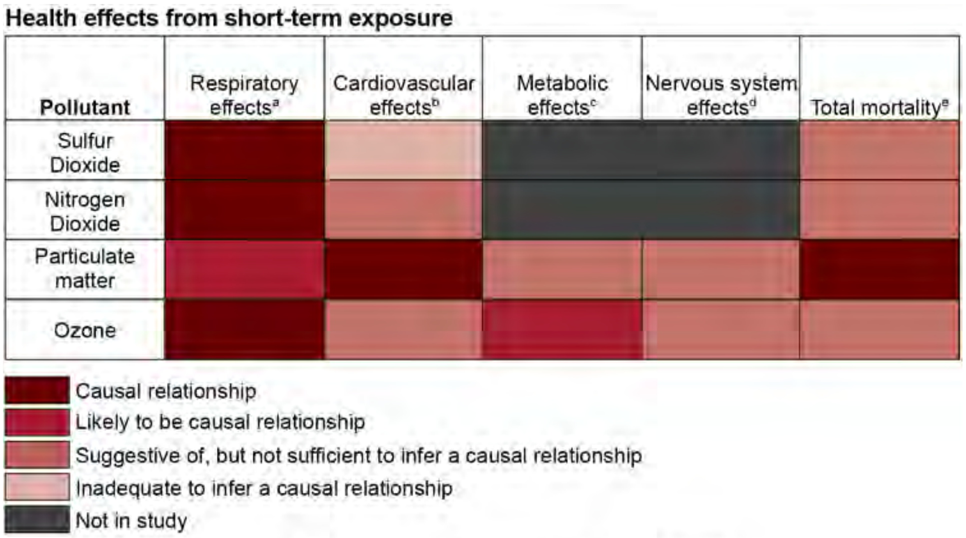
In addition to sulfur dioxide and nitrogen oxides, ground-level ozone and particulate matter are pollutants related to the operation of peaker plants. Ground-level ozone is formed through chemical reactions between nitrogen oxides—emitted by peakers—and volatile organic compounds. Particulate matter is a mixture of solid particles and liquid droplets found in the ambient air and can be directly emitted from power plants or formed by chemical reactions involving pollutants such as sulfur dioxide that are emitted by peakers.

Peakers may have higher median emission rates per unit of electricity generated because of the nature of their operations. According to EPA, emissions generally increase under partial load conditions, which is how peakers operate.[10] Further, peakers typically do not have emissions control technologies, according to EPA officials.

Health effects

Multiple pollutants that are emitted from peakers and other plants are associated with various negative health effects for the people exposed, according to federal agency reports we reviewed.[11] In particular, EPA's Integrated Science Assessments identified causal relationships between short-term exposures to four key pollutants (nitrogen dioxide, sulfur dioxide, particulate matter, and ozone) and health effects that vary in degree of severity and duration (see fig. 5).[12] For instance, short-term exposure to sulfur dioxide—the indicator for sulfur oxides used in EPA's assessments—can lead to negative respiratory effects, such as decreased lung function, cough, chest tightness, and throat irritation.

Figure 5: EPA's Assessment of Causal Determinations for Relationships between Short-Term Exposure to Certain Air Pollutants and Health Effects



Health effects from short-term exposure

Pollutant	Respiratory effects[a]	Cardiovascular effects[b]	Metabolic effects[c]	Nervous system effects[d]	Total mortality[e]
Sulfur Dioxide	■	□	▩	▩	▨
Nitrogen Dioxide	■	▨	▩	▩	▨
Particulate matter	▣	■	▨	▨	■
Ozone	■	▨	▣	▨	▨

■ Causal relationship
▣ Likely to be causal relationship
▨ Suggestive of, but not sufficient to infer a causal relationship
□ Inadequate to infer a causal relationship
▩ Not in study

Source: Environmental Protection Agency (EPA) Integrated Science Assessments. | GAO-24-106145

Notes: Short-term exposure refers to time periods from minutes to 1 month.

We used sulfur dioxide and nitrogen dioxide in the figure because they are the indicators for sulfur oxides and nitrogen oxides, respectively, and sources of health effects studies for causal determinations in EPA's integrated science assessments.

The causal determinations related to particulate matter in the figure are associated with exposure to particles that are 2.5 microns or less in diameter. Causal determinations are also made for exposure to particles of other sizes (e.g., 10 microns or less).

We selected four of the six criteria air pollutants because we deemed them the most relevant pollutants to our analysis. This figure focuses on health effects of short-term exposures to these four pollutants. EPA's Integrated Science Assessments also include causal determinations for long-term exposures and for health effects that are not specific to short-term or long-term exposures (e.g., cancer and pregnancy and birth outcomes for particulate matter exposure).

[a] Respiratory effects include decreased lung function, cough, chest tightness, and throat irritation.
[b] Cardiovascular effects include heart attack, stroke, and changes in blood pressure.
[c] Metabolic effects include changes in blood glucose level and inflammation.
[d] Nervous system effects include brain inflammation and oxidative stress.
[e] Total mortality includes all nonaccidental causes of mortality and is informed by findings for the spectrum of morbidity effects (e.g., respiratory, cardiovascular) that can lead to mortality.

Additionally, mercury emitted from peakers, and other sources, is associated with neurological health effects, including tremors and disturbances of vision and cognitive performance, according to federal agency reports we reviewed.[13]

According to EPA, elevated temperatures can directly increase the rate of ground-level ozone formation, worsening air quality effects on human health. Elevated temperatures can also drive increased electricity demand, which is associated with the operation of peakers. As previously noted, the operation of peakers further increases ozone—and other pollutant—levels, exacerbating air quality issues and poor public health days.

What are some available alternatives that can potentially replace fossil-fueled peakers?

Available alternatives such as battery storage systems could potentially replace fossil-fueled peakers, according to studies we reviewed and stakeholders we interviewed (see table 3).[14] These alternatives could decrease emissions associated with peakers.

Table 3: Examples of Alternatives That Could Potentially Replace Fossil-fueled Peakers

Alternative type	Potential examples
Electricity generation and storage: Alternatives able to store or generate electricity to directly replace the output of peakers.	• Battery storage, which consists of rechargeable batteries charged during off-peak times, and discharged during times of peak demand. • Pumped hydroelectric storage is an energy storage system that pumps water to higher

	levels during off-peak times and releases said water to turn turbines and generate electricity during peak times. • Thermal energy storage is an energy storage system that stores thermal energy, which is released to power turbines during times of peak demand. • Renewable energy systems (e.g., wind and solar) may be paired with energy storage. For example, adding roof-top solar and battery storage to houses could reduce the demand for peakers in adjacent areas.
Transmission and distribution infrastructure improvements: Upgrades or expansions to increase the capacity of current infrastructure that transmits and distributes electricity. These upgrades or expansions may help enable existing underutilized plants to meet peak demand.	• Upgrading transmission lines by expanding the capacity of current lines or adding additional lines to solve bottlenecks in the grid and allow electricity to be moved to other locations. • Upgrading distribution systems by expanding or adding infrastructure to deliver electricity more efficiently.
Efforts to decrease consumers' use of power during peak times: Efforts to incentivize consumers to reduce or shift electricity use during times of peak use to off-peak times.	• Consumer based demand initiatives that provide lower prices for energy consumption during off peak hours, such as overnight electric vehicle charging. • Various energy efficiency programs.

Source: GAO analysis of literature and stakeholder interviews. | GAO-24-106145

Note: These alternatives are not comprehensive. For example, there are other alternatives that are not ready for grid-scale deployment and are in early development stages, such as other types of energy storage technologies.

What are the potential challenges of replacing peakers?

Potential challenges to replacing peakers with non-emitting or non-combustion alternatives include challenges related to cost, reliability, and location, according to studies we reviewed and stakeholders we interviewed (see table 4).

Table 4: Potential Challenges Associated with Alternatives for Replacing Fossil-fueled Peakers

	Alternatives		
	Electricity generation and storage	**Transmission and distribution improvements**	**Efforts to decrease consumers' use of power during peak times**
Cost: some alternatives may have higher capital and operating costs compared to current fossil-fueled peakers	✓	✓	✓
Reliability: current alternatives may not be able to provide the same reliability of current fossil-fueled peakers	✓	—	✓
Location: alternatives may not be able to be installed because of space and location concerns	✓	✓	—

Source: GAO analysis of literature and stakeholder interviews. | GAO-24-106145

Replacing peakers, some of which have already paid off their capital costs, will likely lead to additional up-front or operating costs compared to keeping the existing peakers. Further, the U.S. Energy Information Administration (EIA) reported that solar and wind plants had higher average construction costs compared to natural gas-fired plants in 2023.[15]

Similarly, some alternatives may create reliability challenges. For the grid to be reliable, the energy resources in an area need to be able to supply power to meet peak demand for as long as it lasts, according to U.S. Department of Energy (DOE) officials. Some battery storage systems provide up to 4 hours of output, but peak demand may be longer in some areas. In contrast, a fossil-fueled peaker is only limited by fuel availability—a natural gas-fueled peaker could keep operating so long as natural gas is available.

Some alternatives may also run into space constraints or location concerns. For example, a densely populated urban community likely would not have sufficient space for a large renewable energy system paired with battery storage to help meet peak electricity demand.

In general, recognizing these challenges, some officials with whom we spoke identified trends that may lead to the continued use of fossil-fueled peakers. According to DOE officials, some U.S. peakers may not be able to be replaced with existing alternatives within cost, reliability, and location constraints. Combinations of electricity generation and storage technologies, transmission and distribution improvements, and efforts to decrease consumer’s use of power during peak times may be too costly for consumers in some areas to provide an adequate level of grid reliability. Further, officials at two utilities noted that due to increased use of intermittent renewable resources on the grid (e.g., wind and solar power), the continued use of peakers to meet electricity demand may be necessary to maintain grid reliability. For example, the availability of sunlight for a solar installation may not match with peak demand in the evening when the sun goes down. Therefore, additional supplemental energy resources would be needed to fill the gaps and meet demand.

Agency Comments

We provided a draft of this report to DOE, EPA, and the Federal Energy Regulatory Commission (FERC) for review and comment. DOE and EPA provided technical comments, which we incorporated, as appropriate. FERC did not have any comments on the report.

How GAO Did This Study

To identify the number and location of peakers, we analyzed data from EPA’s Emissions and Generation Resource Integrated Database and EIA power plant data. We generally define peakers as plants that use fossil fuels, have a capacity factor of 15 percent or less, and have a nameplate capacity of greater than 10 megawatts of electricity. In addition to the primary definition of peakers used in this report, we also considered several other definitions including plants with a capacity factor of 10 percent or less and a nameplate capacity over 0 megawatts (total of 1495 peakers).

To describe the relationship between community demographic characteristics (e.g., race, ethnicity, and income)[16] and distance to a peaker, we developed a statistical model that includes controls for population density (e.g., rural or urban), climate, and other factors. (See app. I for more detail.)

To identify air quality effects associated with peakers, we analyzed data from EPA’s Emissions and Generation Resource Integrated Database to describe emissions and emission rates from peakers versus non-peakers. Our emission rate analysis focused on plants with a nameplate capacity greater than 25 MW because EPA regulations define that as the threshold for continuous emission monitoring and reporting requirements, including for emissions of sulfur dioxide and nitrogen oxides, under the state and federal Acid Rain Program.[17] We reported median emission rates because the median is robust to outliers. For example, the top three emitting plants for sulfur dioxide had emission rates in the hundreds of pounds per megawatt, and two of the three had nitrogen oxide emission rates in the thousands of pounds per megawatt. Officials from EPA and EIA told us these plants were likely used infrequently as peakers, or they generated electricity for on-site consumption.

To identify health effects, we reviewed reports from EPA, the Agency for Toxic Substances and Disease Registry, and the Centers for Disease Control and Prevention that assess the health effects of exposure to selected pollutants that are emitted from, or related to, emissions from power plants. We also conducted a systematic literature search of peer reviewed journals and grey literature published from 2013–2023 in databases such as ProQuest Research Library and Natural Science Collection, and Dialog Energy & Environment collection. We conducted an additional search to identify studies on the health effects of peakers in the same databases, and additionally PubMed, published from 2018–2023. Based on these searches, conducted from November 2022 to March 2023, we did not identify studies that looked specifically at health effects of peaker plants.

To identify available alternatives for and challenges to replacing peakers, and to inform our other reporting questions, we conducted a systematic literature search. We conducted searches of databases such as ProQuest Research Library, Harvard Kennedy School Think Tank Search, SCOPUS, and Dialog Energy and Environment collection to identify studies and grey literature published between 2013 and 2023 that were relevant to our research objectives. We performed these searches from November 2022 to March 2023. Additionally, we reviewed studies recommended to us by stakeholders.

To inform all our questions, we also interviewed federal officials from DOE, EPA, and FERC, and state officials from California, Georgia, Indiana, New York, and Texas. We selected these states based on their geographic diversity and electricity market structure (e.g., traditionally regulated or deregulated). We also interviewed stakeholders representing 13 industry and nongovernmental organizations with a diversity of perspectives about peakers. The sample of officials and stakeholders we interviewed is non-generalizable.

We used data from EPA, EIA, and the U.S. Census Bureau. We reviewed information about the data and the systems that produced them, and interviewed agency officials knowledgeable about the data. We requested and received written responses about data reliability from EPA and EIA. We determined that the data were sufficiently reliable for the purposes of our reporting objectives.

We conducted this performance audit from July 2022 through May 2024 in accordance with generally accepted government auditing standards. Those standards require that we plan and perform the audit to obtain sufficient, appropriate evidence to provide a reasonable basis for our findings and conclusions based on our audit objectives. We believe that the evidence obtained provides a reasonable basis for our findings and conclusions based on our audit objectives.

List of Addressees

The Honorable Jamie Raskin
Ranking Member
Committee on Oversight and Accountability
House of Representatives

The Honorable Alexandria Ocasio-Cortez
House of Representatives

The Honorable Yvette D. Clarke
House of Representatives

We are sending copies of this report to the appropriate congressional committees, the Secretary of Energy, the Administrator of EPA, and the Chairman of FERC. In addition, the report is available at no charge on the GAO website at https://www.gao.gov.

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Appendix I: Technical Appendix

To assess the relationship between the distance to the nearest peaker and the demographic characteristics of a community (i.e., census tract), we developed an ordinary least squares regression model where the outcome is distance and the covariates are the demographic characteristics of a community. These characteristics are the percent of a community that are from historically disadvantaged racial or ethnic populations and percent of a community at or below the federal poverty level. We also controlled for the community's climate, population density, and distance to the nearest power plant.

The resulting coefficients from our model allowed us to

- describe whether there was a statistically significant relationship, and if so, the direction of the relationship. For an otherwise similar community and for significant coefficients, a negative coefficient means communities with higher values of the covariate are associated with being closer to a peaker, whereas a positive coefficient means they are further.
- quantify the estimated distance in miles to the nearest peaker for communities with higher rates of disadvantaged populations and for those with lower rates of this demographic, but that are otherwise similar.
- estimate the percentage decrease in distance to the nearest peaker for a community that is "above average" on a demographic, compared to an otherwise similar, but average community. Note we define "above average" as one standard deviation above the sample value of that demographic.

Model Variables/Data Sources

- Distance. We assigned to each community the distance between its central point and the central point of the nearest peaker's property, and this formed the outcome of our model. Similarly, we assigned to each community the distance between its central point and the nearest power plant, which was included as a control in our model. We used great circle distances.
- Demographics. We used American Community Survey (ACS) 2021 5-year estimates for the percent of people in a community who are below the federal poverty level and the percent of people in the community who are from historically disadvantaged racial or ethnic populations. Specifically, individuals who identify as African American or Black; American Indian or Alaska Native; Asian; Hispanic or Latino; Native Hawaiian or Other Pacific Islander; and two or more races.
- Climate. We included the county level heating and cooling degree days from 2017–2019 as indicators of electricity demand for heating and cooling. These indicators are intended to control for climate variations within states in our model. These data are not available for Alaska or Hawaii; therefore, any models with climate data excluded these states. We assessed models that were otherwise similar, but that excluded climate data (hence included Alaska and Hawaii), and the results were consistent. We calculated county level averages using data accessed from Columbia University on daily minimum and maximum temperatures on a 2.5x2.5-mile grid for the contiguous United States.
- Population density. We used U.S. Department of Agriculture (USDA) Economic Research Service (ERS) 2010 rural/urban commuting area codes (RUCAs), the most recently available data, with a four-category classification scheme based on Secondary RUCA Codes to classify each tract's population density.

- We associated the 2019 USDA ERS tract codes with 2020 U.S. Census tracts using the U.S Census tract relationship files between the 2020 census tract entities and the 2010 tract entities.
  - In cases where there is more than one record for a 2020 tract, we select the tract that has the largest area of intersection.
- Definition of peakers. We identified plants as peakers using each of the four definitions described and ran separate models for each definition. To capture potential variation within a plant in recent years, the peaker status in our regression is based on 2018–2021 Environmental Protection Agency (EPA) data.

Model Specifications. We took several steps to assess the validity and sensitivity of our models.

- Statistical significance was determined at the 0.05 level of significance.
- Our distance and climate measures were on the logarithm scale to satisfy model assumptions, such as normality of errors, and to scale the effect of these factors and account for non-linearity.
- We used robust standard error estimation.
- We included fixed-effects for states to account for state-to-state variation.
- We assessed models that were otherwise similar to our primary model, but that excluded climate, and results were consistent. This allowed us to assess the sensitivity of our results when including Alaska and Hawaii, states that did not have weather data.
- We examined the four different definitions of peaker described in this report, and conclusions regarding race or ethnicity and population density were consistent across peaker definitions, but conclusions regarding poverty were inconsistent. In particular, models that did not factor in the plant startup time when defining a plant as a peaker resulted in a significant association with poverty, whereas only one definition of peaker that incorporated plant startup time was significant for the primary definition of poverty.
- We examined an alternative specification of race and ethnicity that separately accounted for race and ethnicity within the model. The results were consistent with our primary model and models that used alternative definitions of peaker.
- We examined an alternative specification of poverty that examined the percent of a community that was at twice the federal poverty level, and results were again inconsistent for different definitions of peakers.
- While we chose to examine race, ethnicity, and poverty, other measures of vulnerability exist, and are often correlated. Therefore, similar results might be discovered when examining other measures of vulnerability. Some of these measures—such as the ACS 5-year estimates for percent of a tract that speaks English less than “very well,” or the Council on Environmental Quality (CEQ) Climate and Economic Justice (CEJ) Screening Tool—have large margins of error, do not assess margins of error, or have higher rates of missingness when compared to our selected demographics. Additionally, the CEQ Screening Tool uses the census tract boundaries from 2010 because many of the data sources in that tool use the 2010 census boundaries, but those boundaries are not consistent with most recently available 2020 U.S. Census and ACS demographics. Further, the CEQ Screening Tool uses a binary classification of

communities as “disadvantaged” or “not” based on indicators of burdens, but other classifications exist. We chose to use continuous measures of the proportion of population in different race, ethnicity, and poverty groups to assess the association between communities with a range of percentages, from low or high, of their populations with these demographics, rather than using a definitive, yet subjective, classification of a community as “disadvantaged” or “not.”

Limitations. We took several steps to assess the validity and sensitivity of our models, but certain limitations remain. Importantly, our measure of distance does not include other aspects—such as stack height, wind speed, or wind direction—that play important roles in the dispersion of pollutants and potential populations exposure. In addition, although we include some variables to control for factors that could influence the findings, it is possible that other controls might be important and were not accounted for in our model. Inclusion of a state fixed-effect partially addresses this by controlling for factors that vary by state. Still, our findings of associations between distance to peakers and historically disadvantaged racial and ethnic communities does not imply any causal relationships.

Endnotes

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[1] 2021 data was the most recent year of data available from EPA.

[2] There is no standard definition of a peaker plant. We considered several other definitions for peakers in our analysis. These included plants with: (a) a capacity factor of 10 percent or less and a nameplate capacity over 0 megawatts (total of 1495 peakers), (b) a capacity factor of 15 or less, a nameplate capacity of 10 megawatts or more, and a startup time below 60 minutes (665 peakers), and (c) a capacity factor of 15 percent or less, a nameplate capacity of at least 0 megawatts, and a startup time below 60 minutes (1175 peakers).

[3] We use the terms “historically disadvantaged racial or ethnic populations” and “historically disadvantaged communities” to include individuals who identify as African American or Black; American Indian or Alaska Native; Asian; Hispanic or Latino; Native Hawaiian or Other Pacific Islander; and two or more races. Census tracts are small, relatively permanent statistical subdivisions of a county.

[4] Executive Order 13985 of Jan. 20, 2021, “Advancing Racial Equity and Support for Underserved Communities Through the Federal Government,” 86 Fed. Reg. 7009 (Jan. 25, 2021), charged the federal government with advancing equity for all, including communities that have long been underserved, and identifying and overcoming systemic barriers to opportunity for such communities in federal policies and programs. We chose race and ethnicity, and poverty as two dimensions of disadvantage. Both measures are components of the EPA’s Environmental Justice Screening and Mapping Tool. See appendix I for additional details.

[5] In our model, we primarily focus on peakers with a capacity factor of 15 percent or less and a nameplate capacity of greater than 10 megawatts, as previously noted. We also ran results with other definitions including plants with: (a) a capacity factor of 10 percent or less and a nameplate capacity over 0 megawatts (total of 1495 peakers), (b) a capacity factor of 15 percent or less, a nameplate capacity of 10 megawatts or more, and a startup time below 60 minutes (665 peakers), and (c) a capacity factor of 15 percent or less, a nameplate capacity of at least 0 megawatts, and a startup time below 60 minutes (1175 peakers). We found consistent results in the relationship between race/ethnicity and distance to the nearest peaker regardless of definition.

[6] The value of 40 percent corresponds to our sample average for this demographic, whereas 71 percent corresponds to one standard deviation above the sample average.

[7] References to the “federal poverty level” in this document are based on the Census Bureau’s poverty threshold, which follows the Office of Management and Budget’s Directive 14. According to the Census Bureau, it uses a set of money income thresholds that vary by family size and composition to detect who is in poverty. If a family’s total income is less than that family’s threshold, then that family, and every individual in it, is considered to be in poverty. In our model, we look at the percent of families in a Census tract whose income in the past 12 months is below the federal poverty level.

[8] In the case of poverty, for peakers defined as plants with a capacity factor of 15 percent or less, a nameplate capacity of 10 megawatts or more, and a startup time below 60 minutes, the association (regression coefficient) between a tract’s poverty rate and distance to peakers is insignificant at the 0.05 level.

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[9] Our emission rate analysis focuses on fossil-fueled peakers and non-peakers with a nameplate capacity greater than 25 megawatts because that is a threshold defined in EPA regulations for continuous emission monitoring and reporting requirements, including for emissions of sulfur dioxide and nitrogen oxides, under the state and federal Acid Rain Program. *See* 40 C.F.R. Part 75.

[10] Environmental Protection Agency, Combined Heat and Power Partnership, *Catalog of CHP Technologies*, September 2017.

[11] We conducted a literature search to identify health effects related to peakers specifically, but our literature search did not identify any such studies (e.g., studies that compare health effects based on proximity to peakers or attribution of ambient air pollution attributed to peakers). Our search strategy included conducting a systematic literature search of peer-reviewed journals as described in the section "How GAO Did This Study." We also inquired about published studies on the health effects of peakers during our interviews with agency officials and stakeholders. Our search identified some studies of the health effects related to retirements of coal fired power plants (for example, see Joan A. Casey, Deborah Karasek, Elizabeth L. Ogburn, Dana E. Goin, Kristina Dang, Paula A. Braveman, and Rachel Morello-Frosch, "Retirements of Coal and Oil Power Plants in California: Association with Reduced Preterm Birth Among Populations Nearby," *American Journal of Epidemiology*, vol. 187, no. 8 (2018), 1586-1594, DOI 10.1093/aje/kwy110). We did not conduct a systematic review of such articles because they are not peaker-specific, and because a low percentage of peakers are coal-fired.

[12] EPA's Integrated Science Assessments integrate information on criteria pollutant exposures and health effects from controlled human exposure, epidemiologic, and toxicological studies to form conclusions about the causal nature of relationships between exposure and health effects. For more information, see the EPA Preamble for Integrated Science Assessments at Preamble To The Integrated Science Assessments (ISA) | ISA: Integrated Science Assessments | Environmental Assessment | US EPA (accessed 8/30/2023).

[13] Department of Health and Human Services, Agency for Toxic Substances and Disease Registry, *Toxicological Profile for Mercury: Draft for Public Comment,* CS274127-A (April 2022). Environmental Protection Agency, National Center for Environmental Assessment, *Mercury, Elemental*, Integrated Risk Information System (IRIS) CASRN 7439-97-6.

[14] The discussion in this section applies to fossil-fueled peakers as defined above–those with a capacity factor less than 15 percent and a nameplate capacity greater than 10 megawatts—as well as to fossil-fueled peakers more broadly.

[15] U.S. Energy Information Administration, US Construction Costs Dropped for Solar, Wind, and Natural Gas-fired Generators in 2021 (October 3, 2023), https://www.eia.gov/todayinenergy/detail.php?id=60562.

[16] See appendix I for additional details.

[17] *See* 40 C.F.R. Part 75.

EIA-923							EIA-860					
Plant Id	Plant Name	Operator Name	Operator Id	Plant State	Net Generation (Megawatthours)	YEAR	Nameplate Capacity (MW)	Nameplate Power Factor	Summer Capacity (MW)	Winter Capacity (MW)	Minimum Load (MW)	Time from Cold Shutdown to Full Load
1710	J H Campbell	Consumers Energy Co - (MI)	4254	MI	136,387	2024	265.2	0.850	260.0	260.0	100.0	OVER
1710	J H Campbell	Consumers Energy Co - (MI)	4254	MI	14,384	2024	378.8	0.770	279.8	280.0	100.0	OVER
1710	J H Campbell	Consumers Energy Co - (MI)	4254	MI	8,077,299	2024	916.8	0.860	790.7	789.3	350.0	OVER