UNITED STATES OF AMERICA
BEFORE THE
UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order re Eddystone Generating Station	Order No. 202-25-4

MOTION TO INTERVENE AND REQUEST FOR REHEARING OF THE JOINT CONSUMER ADVOCATES

Pursuant to section 313*l* of the Federal Power Act ("FPA"), 16 U.S.C. § 825*l*, and Rules 212, 214, and 713 of the Commission's Rules of Practice and Procedure, 18 C.F.R. §§ 385.212, 385.214, and 385.713, the Maryland Office of People's Counsel, the Delaware Division of the Public Advocate, New Jersey Division of Rate Counsel, Illinois Attorney General, and the Citizens Utility Board of Illinois (collectively, "Joint Consumer Advocates" or "JCA"): (1) move to intervene in this proceeding jointly and individually and (2) request that the Department of Energy ("Department" or "DOE") grant rehearing of Order No. 202-25-4 (May 30, 2025) ("Order"). The Order "determine[s] that an emergency exists in portions of the electricity grid operated by PJM Interconnection, LLC ("PJM") due to a shortage of facilities for the generation of electric energy, resource adequacy concerns, and other causes," and invokes the Department's emergency authority under FPA section 202(c), 16 U.S.C. § 824a(c), to direct that PJM and Constellation Energy "take all measures necessary to ensure that

Eddystone Units are available to operate" during the period May 30, 2025 until August 28, 2025.

MOTION TO INTERVENE

The Maryland Office of People's Counsel ("MPC") is a state agency created by Maryland state law. It is authorized, in relevant part, to "appear before any federal or State [agency] to protect the interests of residential and non-commercial users [of utility services in Maryland]." Md. Code, Public Utilities Article, sec. 2-205(b) (2024). Maryland is located within the area served by the facilities and markets administered by PJM. The costs of continued operation of the Eddystone plant, collected through rates administered by PJM, and the plant's continued operation's impact on reliability of the PJM grid will affect the cost and level of service of electricity to consumers in Maryland. The ratepayers that MPC represents have a direct interest in PJM's administration of its tariff to provide resource adequacy and reliable service. Accordingly, MPC moves to intervene in this proceeding with full rights as a party and files this request for rehearing in furtherance of its statutory charge "to protect the interests of" Maryland's residential and noncommercial electric consumers.

The Delaware Division of the Public Advocate ("DPA") is empowered to "[t]o appear on behalf of the interest of consumers in the courts of this state, the federal courts, and federal administrative and regulatory agencies and commissions in matters involving rate, services, and public utilities."[1] Established in 1978, DPA exists in part to "advocate primarily on behalf on behalf of residential and small commercial customers."[2] The Public Advocate is nominated by the Governor, and confirmed by the Delaware Senate,[3] and the current Public Advocate, Jameson Tweedie, was sworn in in May of 2025. Delaware is located within the area served by the facilities and markets administered by PJM. The costs of continued operation of the Eddystone plant, collected through rates administered by PJM, and the plant's continued operational impact on reliability of the PJM grid will affect the cost and level of service of electricity to consumers in Delaware. The ratepayers that DPA represents have a direct interest in PJM's administration of its tariff to provide resource adequacy and reliable service. Accordingly, DPA moves to intervene in this proceeding with full rights as a party and files this request for rehearing in furtherance of its statutory charge "to appear on behalf of the interest of [Delaware] consumers."

The New Jersey Division of Rate Counsel ("NJ Rate Counsel") is the administrative agency charged under New Jersey Law with the general protection of the interests of utility ratepayers. N.J.S.A. § 52:27EE- 46 et seq. NJ Rate Counsel is explicitly empowered to represent the public interest in federal

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[1] *Del. C.* 8716 (e)(3)(a).

[2] "About the Division of the Public Advocate" https://publicadvocate.delaware.gov/division-public-advocate/ (last visited June 25, 2025).

[3] *Del. C.* 8716(A).

proceedings. N.J.S.A. § 52:27EE-55. NJ Rate Counsel moves to intervene in this proceeding with full rights as a party and files this request for rehearing in furtherance of its statutory charge to represent the interests of New Jersey utility ratepayers.

The Illinois Attorney General represents the People of the State of Illinois and their interest in receiving reliable electric services at the least possible cost. Illinois law provides that the Illinois Attorney General "shall have the power and duty on behalf of the people of the State to intervene in, initiate, enforce, and defend all legal proceedings on matters relating to the provision, marketing, and sale of electric . . . service whenever the Attorney General determines that such action is necessary to promote or protect the rights and interests of all Illinois citizens, classes of customers, and users of electric . . . services." 15 ILCS 205/6.5(c). In addition to this investigative and enforcement authority, the Illinois Attorney General "shall be a party as a matter of right to all proceedings, investigations, and related matters involving the provision of electric . . . services before the Illinois Commerce Commission, the courts, and other public bodies." *Id.* at 6.5(d). The Illinois Attorney General's office represents Illinois ratepayers in PJM's ComEd Zone who have a significant interest in resource adequacy and maintaining reliable service at least possible cost that is materially affected by the outcome of this proceeding.[4] As such, the Illinois Attorney General moves to intervene in this proceeding and files this request for rehearing.

The Citizens Utility Board of Illinois ("CUB") is an Illinois-based statewide organization of residential ratepayers. The Citizens Utility Board Act, the Illinois statute that created and governs CUB, states that CUB shall "Represent and protect the interests of the residential utility consumers of this State." Protecting Illinois' roughly five million consumers is the driving force behind CUB's work. The Commonwealth Edison utility in northern Illinois is part of the PJM Interconnection. These ratepayers will be materially affected by the outcome of this docket. CUB has an interest in ensuring that all costs allocated to ratepayers are prudently incurred. The Eddystone Order threatens these principles and stands to unjustly increase electric bills for Illinois consumers.

The Joint Consumer Advocates note that the level of charges that will be imposed on ratepayers is unknown. DOE has referred rate issues relating to the Order to the Federal Energy Regulatory Commission. FERC, in turn, has issued a notice acknowledging the referral and expressing an intention to undertake actions concerning the "rate issues" that are "corresponding" to the Order in "appropriate proceedings."[5]

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[4] *See* PJM Open Access Transmission Tariff, Attachment J, PJM Transmission Zones, https://agreements.pjm.com/oatt/4443.

[5] Order on Referral and Providing Notice of Intent to Take Action, United States Department of Energy, Docket No. AD2515000 (June 24, 2025) at P 6.

Accordingly, the Joint Consumer Advocates each move to intervene in this proceeding, jointly and individually, with full rights as parties and file this request for rehearing in furtherance of their statutory duties to protect the interests of ratepayers in their respective states.

SUMMARY

DOE's authority to direct continued operation of power plants under FPA section 202(c) is not unbounded—it applies in and is limited to narrow "emergency" situations. It is intended to work in conjunction with the extensive, layered, and highly technical regulatory framework for assuring "resource adequacy" of the power grid, which include tariff provisions administered by the regional transmission operators ("RTOs"), including PJM, subject to regulation by FERC, as well as reliability standards overseen by the North American Electric Reliability Corporation ("NERC") and through delegations to regional electric reliability organizations—in PJM's case, Reliability First Corporation ("RFC").[6] All of these entities devote enormous resources into ensuring resource adequacy and reliable system operation to prevent the emergency situations that would require an exercise of section 202(c).

Consistent with this context, DOE's 202(c) orders have generally been issued to address matters arising on the electric grid due to very short-term weather phenomena (hurricanes or hot or cold snaps)[7] or situations in which

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[6] NERC has defined resource adequacy as: "the ability of the electricity system to supply the aggregate electrical demand and energy requirements of the end-use customers at all times, taking into account scheduled and reasonably expected unscheduled outages of system elements" NERC, *Reliability Terminology* (2013). *See also* NERC, *Planning Resource Adequacy Analysis, Assessment and Documentation, BAL-5-2-RFC-02* (Definitions).

[7] *E.g.,* Order No. 202-25-5. This order was issued on June 24, 2025 (at 3:50 AM) in response to "heat and humidity" experienced in the service territory of Duke Energy Carolinas, LLC (Duke Energy), which includes North Carolina and South Carolina. Order at 1. Duke Energy sought an order under section 202(c) based on concerns that, absent relief, it "may not have sufficient generation available to meet this unusually high demand and may have to curtail load in order to

environmental regulations constrain needed power facility operations. And past 202(c) orders generally have been issued in cooperation with state officials regulating the electric sector and grid operators and administrators.

DOE's Order should be reconsidered because it is *ultra vires*. The linchpin of the Order is the Secretary's conclusion that the existing circumstances constitute an "emergency" within unidentified "portions" of the PJM administered "electrical grid." Respectfully, this determination is not supported by the language of section 202(c), the Department's own regulations, applicable precedent, or the extant facts. DOE's definition of the type of "emergency" that may animate section 202(c) relief (found at 10 C.F.R. § 250.371) includes short term, unanticipated, unexpected, unforeseen circumstances that demand immediate action. As we demonstrate *infra*, the Order fails to demonstrate that any such circumstance is present here.

In fact, the Order is counter to and undermines the existing machinery for addressing resource adequacy in PJM, which involves coordination among PJM, NERC, and RFC. While DOE says (Order at 1) that "[u]pcoming retirements, including the planned retirement of Unit 3 and Unit 4 of the Eddystone Generating Station in Eddystone, Pennsylvania, will exacerbate [PJM's] resource adequacy

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maintain security and reliability of the grid." Order at 1-2. Order No. 202-25-5 allows Duke Energy to operate certain specified facilities, "subject to the exhaustion of all available imports, demand response, and identified behind-the-meter generation resources selected to minimize an increase in emissions available to support grid reliability[.]" *Id*. at 3. The relief is for an extremely limited time frame, expiring at 10:00 PM (EDT) on June 25, 2025. Order at 3.

issues," each of the organizations with oversight of resource adequacy in PJM have concluded that it faces no resource adequacy emergency during Summer 2025. The June 1, 2025, retirement of these resources has been anticipated since at least December 1, 2023.[8] PJM studied the proposed deactivation and did not identify any resulting reliability violations.[9] PJM has not recanted that conclusion, sought to delay the deactivation, or announced that the loss of these units would cause a resource adequacy shortfall. To the contrary, and as explained below, PJM's installed reserves are forecast to far exceed its target reserve margin. DOE's contrary and unilateral conclusion—that a resource adequacy emergency exists and justifies countermanding this long-planned retirement two days before it was set to occur—is arbitrary, capricious, and unsupported by substantial evidence and reasoned decision-making.

Our opposition should not be taken to mean that PJM has no resource adequacy concerns at all. The Order refers (at 1) to testimony by a PJM executive that the region faces a "growing resource adequacy concern." Perhaps so. But on its face a "growing … concern" is not an emergency. And, in part in response to

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[8] Letter from Bryan C. Hanson, Executive Vice President and Chief Generation Officer, Constellation, to Michael Bryson, Senior Vice President, Operations, PJM Interconnection, LLC (Dec. 1, 2023) (notifying PJM of intent to deactivate Eddystone Generating Station Units 3 and 4 effective on or about May 31, 2025), https://www.pjm.com/-/media/DotCom/planning/gen-retire/deactivation-notices/eddystone-deactivation-letter.pdf. Documents cited herein are attached as an appendix to this pleading.

[9] Letter from Paul McGlynn, VP Planning, PJM Interconnection LLC, to Bryan C. Hanson, Executive Vice President and Chief Generation Officer, Constellation (Feb. 27, 2024), https://www.pjm.com/-/media/DotCom/planning/gen-retire/deactivation-notices/pjm-response-letter-eddystone.pdf.

the complaints from consumer advocates, state commissions, and others, PJM is attempting to address the region's resource adequacy concerns through a set of rule changes and other initiatives. Those have been or are being reviewed by FERC in accord with traditional regulatory processes.[10] While we think PJM needs to do more to address both resource adequacy and related affordability concerns, that does not include keeping an aging power plant online at ratepayer subsidy that even its owner would prefer to retire.

Finally, we note that while the Order is directed at the Eddystone plant, it appears to be a response to a larger context shaped by at least two Executive Orders ("EOs") and ongoing DOE planning initiatives responding to those EOs.[11] These initiatives could result in future use of section 202(c) authority for possible extensions of the Eddystone order and potentially other retiring power plants in the PJM footprint.[12] The Joint Consumer Advocates here contest the legal sufficiency

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[10] *See e.g., PJM Interconnection, LLC*, 190 FERC ¶ 61,117, *on reh'g*, 191 FERC ¶ 61,221(2025); *PJM Interconnection, LLC*, 190 FERC ¶ 61,088, *Notice Denying Reh'g*, 190 FERC ¶ 62,035 (2025).

[11] The Order was issued in the context of several EOs, namely EO 14156, *Declaring a Nat'l Energy Emergency*, 90 Fed. Reg. 8433 (Jan. 29, 2025) (declaring a "national energy emergency"), followed by EO 14262, *Strengthening the Reliability & Security of the United States Elec. Grid*, 90 Fed. Reg. 15, 521 (April 14, 2025). The latter calls for the development by DOE of a "uniform methodology for analyzing current and anticipated reserve margins for all regions of the bulk power system regulated by the [FERC] and [DOE] shall utilize this methodology to identify current and anticipated regions with reserve margins below acceptable levels as identified by the Secretary of Energy." EO 14262 called for the methodology to be developed within thirty days of the order. This deadline for development (and presumably public disclosure of the reserve margin methodology) has been extended and now is understood to be July 7, 2025.

[12] The Order refers (at 2) to DOE's development of a "methodology to identify current and anticipated reserve margins for all regions of the bulk-power system regulated by the Federal

of the Eddystone Order and reserve their right to challenge other potential initiatives conducted under the purported authority of FPA section 202(c).

BACKGROUND

The Eddystone plant is located in Pennsylvania adjacent to the Delaware River and south of Philadelphia. It is connected to the electric transmission grid administered by PJM. The resource is comprised of two generating Units 3 and 4, each a steam turbine power generating unit, rated approximately a nominal 380 Megawatts ("MWs"), fired with natural gas or distillate fuel oil. The generating units are approximately 50 years old; they began operation in 1974 and 1976, respectively, and are effectively at the end of their useful service lives.[13] The electric output from the Eddystone plant has been minimal since 2012, achieving less than 1 percent capacity factor over the last five years as reported by the plant owner, Constellation.

In July 2024, PJM conducted an annual capacity auction for the procurement of generating capacity for a delivery year running from June 1, 2025 to May 31, 2026. Consistent with its planned deactivation, the Eddystone plant did not participate in that auction and was assumed to be retired, yet the auction procured sufficient capacity to meet applicable reliability requirements for the full PJM service area (or "footprint") for the delivery year.

Energy Regulatory Commission[,]" and to use of that "methodology to further evaluate Eddystone Units 3 and 4."

[13] https://www.gridinfo.com/plant/eddystone-generating-station/3161.

In May 2025, PJM assessed resource adequacy for the upcoming summer and determined that its resource adequacy targets for its entire service area were met.

On May 30, 2025, following the close of business and less than two days before the scheduled June 1 retirement date of the Eddystone plant, DOE issued its 202(c) Order directing the plant's continued operation through the summer of 2025.

STATEMENT OF ISSUES AND SPECIFICATIONS OF ERROR

As explained *infra*, the Joint Consumer Advocates submits the following statement of issues and specification of error:

1. The Order is arbitrary and capricious and contrary to law because it fails to establish the existence of an emergency under section 202(c) or the Department's regulations implementing section 202(c). The statutory text, legislative history, judicial construction and DOE's regulations all confirm that an "emergency" is an occurrence that is sudden, unexpected and requiring immediate action. The Order introduces no facts that would satisfy that definition. 16 U.S.C. § 824a(c); 10 C.F.R. § 205.371; *Richmond Power and Light v. FERC*, 574 F.2d 610, 615 (D.C. Cir. 1978); *Otter Tail Power Co. v. Fed. Power Comm.*, 429 F.2d 232, 233-34 (1970).
2. The Order is arbitrary and capricious and contrary to law because it fails to present substantial evidence for its emergency determination and fails to exercise reasoned decision-making by ignoring critical facts,

including the contrary determinations by PJM, NERC, and RFC concerning the status of resource adequacy in PJM for Summer 2025. *E.g. Emera Maine v. FERC*, 854 F.3d 9, 22 (D.C. Cir. 2017) (order under the Federal Power Act must reflect "a principled and reasoned decision supported by the evidentiary record" (quotation marks omitted)); *Motor Vehicle Mfrs. Ass'n of U.S., Inc. v. State Farm Mut. Auto. Ins. Co.*, 463 U.S. 29, 43 (1983) (agency must examine the relevant data and articulate a satisfactory explanation for its action including a rational connection between the facts found and the choice made); *Burlington Truck Lines, Inc. v. United States*, 371 U.S. 156, 168 (1962) (an "agency must make findings that support its decision, and those findings must be supported by substantial evidence").

3. The Order is arbitrary, capricious, and contrary to law because it exceeds the Department's statutory authority. Section 202(c) is limited to emergencies and does not afford the DOE the right to intrude on authority reserved to States and to other federal regulators to regulate resource adequacy.

ARGUMENT

I. Resource Adequacy in PJM's footprint is subject to rules and procedures administered by PJM in accord with rules and regulations established by NERC pursuant to FPA section 215, 16 USC §824o.

Resource adequacy within the PJM footprint is subject to an established, extensive, layered, framework of oversight and regulation. The resource adequacy contribution of each PJM electric generating plant operating is subject to on-going, technical reviews by PJM, pursuant to its tariff, and in conformity within rules promulgated and periodic grid reliability reviews conducted by RFC and NERC, respectively.[14] NERC and RFC have adopted an exacting technical, probabilistic metric and criterion for determining resource adequacy, described as the "one day in 10 years" (or 1-in-10) criterion, which, in turn, has been adopted by PJM in the oversight and planning of wholesale power supply within its area of service.[15] Determining compliance with this criterion requires a detailed assessment of

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[14] *See, e.g., North American Electric Reliability Corp.*, 116 FERC ¶ 61,062, *order on reh'g & compliance*, 117 FERC ¶ 61,126 (2006), *aff'd sub nom. Alcoa, Inc. v. FERC*, 564 F.3d 1342 (D.C. Cir. 2009); Order No. 748, Final Rule, 134 FERC ¶ 61,213 (2011). FERC approved regional reliability standards applicable to PJM, developed by RFC and submitted to FERC by NERC. *Notice of Proposed Rulemaking on Plan. Res. Adequacy Assessment Reliability Standard*,133 FERC ¶ 61,066 (2010) (proposed rule for RFC); *Plan. Res. Adequacy Assessment Reliability Standard*, Order No. 747, 134 FERC ¶ 61,212 (2011) (final approval of RFC's Resource Adequacy Reliability Standard).

[15] RF, Standard BAL-502-RF-03, A.R1.1.1 (requiring each Planning Coordinator (here PJM) to conduct an annual Resource Adequacy analysis that requires calculating "a planning reserve margin that will result in the sum of probabilities for load of Load for the integrated peak for all days of each planning year analyzed... being equal to 0.1 (This is comparable to the 'one day in 10 year criterion.')"; PJM, *Manual 20A, Resource Adequacy Analysis* (2025), p. 8 ("This manual focuses on the criteria, studies, and methodologies employed to ensure resource adequacy of the PJM system effective with the 2025/2026 Delivery Year…. 1.3. Resource Adequacy Criteria. RTO-wide. The RTO-wide Resource Adequacy Criteria is a LOLE [loss of load expectation] criterion of 1 day in 10 years, or 0.1 days per year").

available generation capacity, projected outage rates, load forecasts, the performance of demand response and other measures, and possible effects on load and plant performance of changes in weather, among other factors.[16]

PJM administers a process for the advance centralized procurement of capacity resources that incorporates criteria to ensure the commitment of sufficient generating resources to meet the reliability standards established by NERC.[17] The process is a market-based capacity auction intended to "procure the least-cost, competitively-priced combination of resources necessary to meet the region's reliability objectives."[18] PJM also plans, oversees and initiates measures to assure that the electric grid within its footprint adheres to rules for maintaining grid reliability established by RFC and NERC.[19] Under this authority, if PJM finds that a plant retirement could cause a grid reliability violation, it can request that the power plant seeking retirement defer its request for deactivation and direct the

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[16] *See* RF, Standard BAL-502-RF-03, *Planning Resource Adequacy Analysis, Assessment and Documentation*; PJM Manual 20A, *PJM Resource Adequacy Analysis*.

[17] *See Manual 18, PJM Capacity Market* (2025) ("The PJM Capacity Market is designed to ensure the adequate availability of necessary resources that can be called upon to ensure the reliability of the grid.") at 11; ("The Reliability Pricing Model is the PJM resource adequacy construct that ensures that adequate Capacity Resources, including planned and existing Generation Capacity Resources, Energy Efficiency Resources and planned and existing Demand Resources will be made available to provide reliable service to loads within the PJM Region.") at 14.

[18] *N.J. Bd. of Pub. Utils. v. FERC*, 744 F.3d 74, 101 (3d Cir. 2014) (*citing PJM Interconnection, L.L.C., et al. v. PJM Interconnection, L.L.C.*, 137 FERC ¶ 61,145, P 90 (2011) (subsequent history omitted)). Resource adequacy requirements in RTO/ISO tariffs constitute practices affecting rates subject to FERC regulation pursuant to FPA sections 205 and 206. *Conn. Dept. of Pub. Utils. v. FERC*, 569 F.3d 477, 483 (D.C. Cir. 2009).

[19] PJM OATT, Part V, sections 113-122; PJM, *Manual 14D, Generator Operational Requirements* (2025) at 91-95.

construction of transmission projects to address the violations of grid reliability rules resulting from the plant retirement.

II. PJM's capacity market secured sufficient capacity for the summer of 2025 to satisfy resource adequacy requirements without the Eddystone Plant.

PJM conducted an auction for the procurement of capacity from generating resources to meet the resource adequacy requirements established by NERC and RFC and adopted by PJM to cover the delivery year, beginning June 1, 2025, and running to May 31, 2026. This auction, conducted in July 2024, resulted in the procurement of sufficient resources to meet PJM's anticipated capacity requirements for the summer of 2025.[20]

In their regular, advance seasonal assessment of conditions conducted closer in time to the summer of 2025, NERC, RFC, and PJM, each indicated that there would be no emergency in the operation of the electric grid within the PJM footprint during the summer of 2025, assuming the retirement of Eddystone Units 3 and 4. NERC, RFC, and PJM made these determinations within and in conformance with the regulatory framework for assuring grid reliability established by NERC. These findings followed PJM's determination in early 2024 that continued operation of the Eddystone plant was not needed to assure maintenance of the PJM power grid in conformity with the grid reliability rules

[20] 2025/2026 Base Residual Auction Report, July 30, 2024, at 3. https://www.pjm.com/-/media/DotCom/markets-ops/rpm/rpm-auction-info/2025-2026/2025-2026-base-residual-auction-report.pdf.

established by NERC and PJM and, on that basis, consented to the plant's retirement.

Specifically, in May 2025, NERC, RFC, and PJM conducted resource adequacy assessments in PJM in summer 2025. NERC concluded, based on reporting from PJM, the following regarding resource adequacy in PJM:

> 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.[21]

NERC did not identify the PJM footprint, unlike selected other regions of the country, as an "area[] fac[ing] risks of electricity supply shortfalls during periods of elevated risk during periods of extreme summer conditions."[22] Rather, NERC reported that PJM faced "normal risk" for summer 2025.[23]

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[21] NERC, *2025 Summer Reliability Assessment* (May 14, 2025) at 13.

[22] *Id.* at. 5-6 (listing other areas of the country and Canada that did present this risk (characterizing them as facing "elevated risk" (meaning "potential for insufficient operating reserves in above-normal conditions"), but characterizing the PJM area as facing "normal risk" (meaning "sufficient operating reserves expected")). *See* Figure 1 at 6.

[23] *Id*.

RFC also reported on the assessment of resource adequacy for PJM for the summer of 2025 determining that:

> [The] PJM area[] [has] adequate resources to serve normal electric demand in the upcoming summer season, including during expected periods in which generation resources become unavailable…. . PJM's planning reserve requirement is 17.7% for the 2025 planning year, while its forecasted reserve margin comes in above that figure at 24.7%. *As a result, PJM is considered a low risk of electricity supply shortage this summer.*[24]

PJM's 2025 summer resource adequacy assessment is consistent with these conclusions.[25]

As noted above, PJM had earlier reviewed the specific issues arising from the retirement of the Eddystone plant through the power plant deactivation procedures established by PJM's FERC-approved tariff. PJM Open Access Transmission Tariff ("OATT"), Part V, Sections 113-122 and PJM Manual 14D. On December 1, 2023, Constellation notified PJM that it intended to retire Eddystone Units 3 and 4, effective on May 31, 2025, and requested that the plant be removed from its status as a PJM capacity market resource for the 2025/2026

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[24] Tim Fryfolge, *Reliability First 2025 Summer Assessment* (available from Reliability First web-site). Emphasis supplied.

[25] *See* PJM, *Summer 2025 Reliability Assessment*, presentation to the Pennsylvania Public Utility Commission (May 2025). In its summer 2025 resource adequacy assessments, PJM, as is customary in resource adequacy reviews, also examined conditions with lower probability of occurrence. Thus, PJM noted a concern about "potential reserve margin shortages during peak operating periods," but identified that risk under "stressed system scenario[s]," which included combined contingencies including a 90/10 forecast, increased discrete generator outages, low solar/no wind production, occurrence of the largest gas electric contingency, and reduction in firm interchanges. *See* PJM Operating Committee, *2025 Summer Preliminary Capacity Overview* (May 8, 2025).

delivery year.[26] Constellation explained the reasons for retiring the units, namely that "continued operation of these units is expected to be uneconomic."[27] In response, PJM performed a study of the PJM Transmission System and "did not identify any reliability violations resulting from the proposed deactivation of the Eddystone Generating Units #3&4." Accordingly, PJM informed Constellation that: "[b]ecause there are no reliability violations associated with the deactivation of this generator… the generating unit may deactivate on May 31, or sooner if desired."[28]

III. DOE's authority under FPA section 202(c) is narrowly tailored to address "emergencies"; DOE's order exceeds that authority.

DOE's authority to direct continued operation of power plants under FPA section 202(c) applies in and is limited to narrow "emergency" situations. The statute, in relevant part, states:

> **(c) TEMPORARY CONNECTION AND EXCHANGE OF FACILITIES DURING EMERGENCY**
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> **(1)** During the continuance of any war in which the United States is engaged, or whenever the Commission[[29]] determines that an *emergency exists by reason of a sudden increase in the demand for electric energy, or a shortage of electric energy or of facilities for the generation or transmission of electric energy, or of fuel or water for generating facilities, or other causes*, the Commission shall have authority, either upon its own motion or upon complaint, with or

[26] Letter, B. Hanson, EVP, Constellation to M. Bryson, SVP, Operations, PJM (Dec. 1, 2023).

[27] *Id.*

[28] Letter, P. McGlynn, VP Planning, PJM to B. Hanson, EVP, Constellation (Feb. 27, 2024).

[29] Authority for administration of the statute is vested in the Secretary of Energy, pursuant to the sec. 301(b) of the 1977 Department of Energy Organization Act, 42 U.S.C. §7151. *See* Congressional Research Service ("CRS"), *Federal Power Act: The Department of Energy's Emergency Authority* (updated to May 22, 2025).

> without notice, hearing, or report, to 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.[30]

Though the Federal Power Act does not define the terms "emergency" or "sudden," the plain meaning of these terms indicates that Congress intended section 202(c) authority to be invoked rarely, in response to acute events that demand immediate response. [31] As the D.C. Circuit Court of Appeals has recognized, the text dictates that circumstances triggering a section 202(c) order are specific, unexpected, urgent, and temporary.[32] DOE's interpreting regulations and historical use of section 202(c) authority accord with the text's plain meaning. DOE defines an "emergency" as an "unexpected" supply shortage, which "may be the result of weather conditions, acts of God, or unforeseen occurrences not reasonably within the power of the affected 'entity' to prevent."[33] DOE's

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[30] 16 U.S.C. §824a(c) (emphasis supplied).

[31] The commonly understood definition of "emergency" in 1930 when Congress enacted the FPA was "a sudden or unexpected appearance or occurrence .... An unforeseen occurrence or combination of circumstances which call for immediate action or remedy." Webster's New International Dictionary of the English Language (1930).

[32] *See Richmond Power & Light v. FERC*, 574 F.2d 610, 615 (D.C. Cir. 1978) (stating that section 202(c) "speaks of 'temporary' emergencies, epitomized by wartime disturbances, and is aimed at situations in which demand for electricity exceeds supply"). *See also Fed. Power Comm'n v. Fla. Power & Light Co.*, 404 U.S. 453 n.1 (1972) (relating section 202(c) to "the exigencies of 'war'"); *Duke Power Co. v. Fed. Power Comm'n*, 401 F.2d 930, 944 (D.C. Cir. 1968) (stating that section 202(c) "relate[s] exclusively to temporary interconnections during national emergencies").

[33] 10 C.F.R. § 205.371 (other examples may include a "sudden" demand spike, a fuel shortage, "regulatory action" prohibiting the use of certain generators, or "[e]xtended periods of insufficient . . . supply" due to planning failures).

regulations further state that section 202(c) orders "are envisioned as meeting a specific inadequate power supply situation."

These definitions accord with the FPA's legislative history, in which section 202(c) is characterized as an authority to be used in response to "crises":

> This is a temporary power designed to avoid a repetition of the conditions during the last war, when a serious power shortage arose. Drought and other natural emergencies have created similar crises in certain sections of the country; such conditions should find a federal agency ready to do all that can be done in order to prevent a break-down in electric supply.

S. Rep. No. 74-621 at 49 (1935). Accordingly, DOE has rarely exercised its section 202(c) authority. Past emergency orders typically have responded to acute crises such as blackouts or severe storms.[34]

Simply put, Section 202(c) is a backstop authority to enable steps needed to avert concrete, present emergencies—not a means to implement policy preferences about long-term power procurement or generation technology choices. The statute "is aimed at situations in which demand for electricity exceeds supply and not at those in which supply is adequate but a means of fueling its production is in disfavor."[35] Under the FPA's cooperative federalism structure, choices about long-

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[34] *See generally*, B. Rolsma, *The New Reliability Override*, 57 Conn. L. Rev. 789 (2025).

[35] *Richmond Power and Light*, 574 F.2d at 615.

term resource mix fall to the states,[36] while PJM administers and FERC regulates capacity auctions to ensure resource adequacy in light of those choices.

DOE's exercise of its narrow, emergency authority under section 202(c) is intended to backstop—not supplant, overrule, or interfere with—this careful jurisdictional balance and the extensive, existing framework for assuring resource adequacy, administered by the regional transmission operators (e.g., PJM, within the PJM footprint), regulated by FERC, and subject to reliability standards overseen by NERC and through delegations to regional reliability organizations (in PJM's case, RFC). As the DOE said in its rulemaking to adopt regulations governing its section 202(c) practice: "The DOE does not intend these regulations to replace prudent utility planning and system expansion."[37] Yet, here, DOE's

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[36] 16 U.S.C. § 824(b)(1) ("The Commission shall have jurisdiction over all facilities for such transmission or sale of electric energy, *but shall not have jurisdiction*, except as specifically provided in this subchapter and subchapter III of this chapter, over facilities used for the generation of electric energy." (emphasis added)); *Hughes v. Talen Energy Mktg., LLC,* 578 U.S. 150, 154 (2016) (noting the "States' reserved authority . . . over in-state 'facilities used for the generation of electric energy'" (quoting 16 U.S.C. 824(b)(1)); *Citizens Action*, 125 F.4th at 238–39 ("[T]he States retain authority to choose their preferred mix of energy generation resources"); *Conn. Dep't of Pub. Util. Control v. FERC*, 569 F.3d 477, 481 (D.C. Cir. 2009) (upholding FERC's approval of capacity requirements because they do not interfere with the right of "[s]tate and municipal authorities . . . to require retirement of existing generators," to prefer "environmentally friendly units," or "to take any other action in their role as regulators of generation facilities without direct interference from the Commission"). *Devon Power LLC et al.,* 109 FERC ¶ 61,154, P 47 (2004) ("Resource adequacy is a matter that has traditionally rested with the states, and it should continue to rest there. States have traditionally designated the entities that are responsible for procuring adequate capacity to serve loads within their respective jurisdictions.").

[37] *See Emergency Interconnection of Elec. Facilities and the Transfer of Elec. to Alleviate an Emergency Shortage of Elec. Power*, 46 Fed. Reg. 39984 at 39985-39986 (1981) ("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. The final

action to direct the continued operation of the Eddystone power plant through the summer of 2025, when neither PJM, RFC, NERC, or FERC has found that to be necessary, is an unlawful use of DOE's 202(c) authority to insert the agency into longer term resource adequacy issues planned for and addressed by PJM, RFC and NERC.

DOE's twelfth-hour override of decisions made using the existing resource adequacy machinery—the 2025/2026 Base Residual Auction (BRA) results, PJM's conclusion that Eddystone retirement would produce no reliability violations, and its decision not to seek to retain the units with a cost-of-service agreement—is simply an inappropriate use of the Secretary's section 202(c) emergency power. If DOE believed any of those assessments or resulting decisions were wrong, it could have brought its concerns to PJM and FERC at any point after the December 2023 deactivation announcement.[38] Alternatively, DOE could have proposed a rule or policy statement for the Commission's consideration under 42 U.S.C. § 7173.

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regulations also recognize that power pools and electric utility contractual or coordination relationships are a basic element in resolving electric energy shortages."). *See also* CRS Report (2025), p. 1. ("The Section 202(c) emergency authority is primarily focused on short-term situations…. DOE's regulations emphasize the short-term nature of "emergencies" in this context.").

[38] *See* 16 U.S.C. § 825e ("Any person" may file a complaint complaining of anything done or omitted to be done by any . . . public utility in contravention of the provisions of this chapter."); 18 C.F.R. § 385.206 ("Any person" may file a complaint.); 18 C.F.R. § 385.207 (same for petitions); 18 C.F.R. § 385.214(a)(1) ("The Secretary of Energy is a party to any proceeding upon the filing of a notice of intervention in that proceeding.").

But as explained above and in the next section, there is no emergency justifying a section 202(c) order to retain the Eddystone units. Although the $14.7 billion price tag was both enormous and unnecessarily high,[39] the 2025/2026 BRA cleared enough capacity to ensure resource adequacy on a PJM-wide basis without the Eddystone units. The 2025/2026 BRA failed to secure enough local capacity resources in two Locational Delivery Areas (LDAs)—Baltimore Gas & Electric (BGE) and Dominion. Perhaps an emergency might exist in one of those zones if other resources (not cleared through the BRA) were not available to supplement the BRA-cleared capacity. In the BGE zone, no emergency existed because PJM negotiated cost-of-service arrangements to retain the Brandon Shores and Wagner generating stations. Had the resources' owner refused to continue operating them even though they were needed for reliability, *that might* have constituted an emergency justifying the Secretary's section 202(c) intervention.[40] But none of those concerns is relevant to the Eddystone situation. PJM concluded that the Eddystone units were not needed either for resource adequacy (per the BRA) or transmission system security (per PJM's review of the units' deactivation notice). The DOE order provides no basis to override those decisions.

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[39] *See Joint Consumer Advocates v. PJM Interconnection, L.L.C.*, FPA section 206 complaint filed initiated FERC Docket No. EL25-76-000 (Apr. 14, 2025), eLibrary no. 20250414-5190.

[40] *See* Letter from David S. Lapp, Maryland People's Counsel, to Mark Takahashi, Chair, PJM Board of Managers (Feb. 28, 2025) (asking PJM to seek prophylactically a section 202(c) order of the Secretary of Energy requiring the operation of the Brandon Shores and Wagner units after May 31, 2025, because that operation is needed to avoid reliability violations until certain transmission upgrades are complete).

IV. DOE's justifications do not withstand scrutiny.

The justifications offered by DOE for its action fail to support a finding that PJM is currently facing an "emergency" necessitating the continued operation of Eddystone. The Order begins (at 1) by quoting testimony from a PJM executive that the region faces a "growing resource adequacy concern." But on its face, "growing concern" is not an immediate emergency.

The Order similarly notes (*id.*) PJM's February 2023 assessment of increasing reliability "risk in the coming years" due to a "potential timing mismatch" between load growth, resource retirement, and resource entry. But that two-and-a-half-year-old assessment says little about conditions on the ground today and certainly carries less weigh than PJM's more recent determinations that Eddystone could be allowed to deactivate, that the 2025/2026 BRA cleared sufficient region-wide capacity, and that PJM did not need to seek to retain Eddystone or ask the Secretary for a section 202(c) order.

Among other things, the February 2023 assessment does not address steps PJM has taken since then to facilitate resource entry and maximize the availability of existing resources.[41] According to PJM,[42] these include:

> **Interconnection Process Reform** – PJM has streamlined its process through which new generation connects to the grid. Additional automation in the interconnection process, along with increased staffing over the past several years, has improved quality while reducing the backlog by 60%. PJM on April 10 also announced a multiyear collaboration with Google and Tapestry to deploy AI-enhanced tools to further streamline PJM's interconnection process.
>
> **Reliability Resource Initiative** – PJM on May 2 announced the projects chosen for this one-time program to boost reliability in the PJM footprint. It includes 51 shovel-ready generation projects with 9,300 MW in capacity that can come online by 2030 or 2031.
>
> **Surplus Interconnection Service** – PJM obtained FERC approval to streamline the use of the unused portion of interconnection service for facilities that cannot or do not operate continuously, every hour of every day, year-round (such as adding battery storage to a renewable site).
>
> **Capacity Interconnection Rights Transfer** – A reform package endorsed by PJM stakeholders and

[41] The Order also relies on PJM's Report, *Energy Transition in PJM Resource Retirements, Replacements and Risks* (2023) (the "4R Report"), describing PJM's projection of the risks arising from the anticipated trend of retiring generation out-pacing new entry of capacity to replace it over a longer-term horizon for future periods extending over the next half decade or more following summer 2025. PJM's 4R Report was similarly undertaken before subsequent changes not considered in that Report that may have a corrective impact on the adverse trends cited therein, including very significant increases in the prices paid to capacity in the PJM footprint.

[42] PJM Interconnection, LLC, PJM Summer Outlook 2025: Adequate Resources Available for Summer Amid Growing Risk, PJM INSIDE LINES (May 9, 2025) (PJM's 2025 Summer Outlook), https://insidelines.pjm.com/pjm-summer-outlook-2025-adequate-resources-available-for-summer-amid-growing-risk/.

currently pending review by FERC would facilitate an expedited interconnection process for a replacement resource seeking to use the capacity interconnection rights of a retiring resource.

Demand Response Availability – FERC on May 5 approved a PJM proposal that improves dispatch and accreditation of demand response resources. The proposal broadens the window for demand response participation from a limited set of hours during summer and winter to around-the-clock throughout the year, enhancing grid reliability and resource adequacy.

To be sure, PJM still sees long-term challenges. As the Order notes (at 1), PJM forecasts that "[t]hrough 2030" it will face reliability risk from "increasing electricity demand, generator retirement outpacing new resource construction, and characteristics of resources in PJM's interconnection queue." But PJM's understanding that it may face reliability risks over the next five years does not support a finding that PJM currently faces an "unexpected," "sudden," and "unforeseen" set of circumstances. To the contrary, PJM is aware of the challenges and is attempting to address them. The Order contains no assessment by PJM, DOE, or anyone else of the impact of PJM's recent initiatives (including Supplemental Interconnection Service, the Reliability Resource Initiative, or more stringent must-offer requirements) on long-term resource adequacy. In any case, the Order's near-term requirements cannot address—and are not justified by—potential emergencies that may (or may not) exist years from now. The question is whether an emergency exists today, and the Order falls far short of establishing that premise.[43]

The only evidence the Order cites for the proposition that an emergency exists *this summer*, the period covered by the Order, is PJM's 2025 Summer Outlook which the Order quotes misleadingly. The Order quotes that document for the proposition that generation "may" fall short of required resources "in an extreme planning scenario," which hardly suggests the kind of emergency that would justify section 202(c) action. But the remainder of PJM's 2025 Summer Outlook makes the absence of need even plainer. The document's overall conclusion is that PJM will have "adequate resources available for [this] summer" without Eddystone. PJM reached this conclusion on the basis of forecasts of a hotter-than-normal summer producing a forecasted peak load of 154,000 MW, which is greater than the actual peak loads of the last two summers (152,700 MW

[43] To the contrary, the only "emergency" in this situation seems to be the one created by the Order. PJM's June 9, 2025, letter to PJM Stakeholders addressing the Order, states:

> Given the exigent circumstances presented by the Secretary's Order, which went into effect upon its issuance, and the corresponding requirement that the Eddystone Units continue to be available to operate starting on June 1, the Board intends to conduct this CIFP process on a truncated timeframe, beginning June 10, and ending with the Members Committee meeting on June 18.

Section 202(c) is intended to address situations involving "exigent circumstances." But as PJM explains, in this case it is the Order itself that has *created* exigent circumstances, rather than responded to them.

and 147,000 MW, respectively). And even in an "extreme planning scenario" reflecting an "all-time PJM peak load" of 166,000 MW, PJM indicated that it could "call on contracted demand response to meet required reserve needs."

There is no basis in the Order to conclude that PJM's pre-Summer 2025 forecasts were inaccurate. We have compiled immediately below data concerning 2025 planned and actual experience in PJM.

PJM Summer Peak Load (Planning and experience during June 23-25, 2025).		
	Source	Amount (Units)
PJM 2025 Load Forecast 50/50 Summer Peak Forecast, Table B-1	PJM 2025 Load Forecast, Table B-1.	154,144 MW (2025)
PJM 2025 Load Forecast Summer Extreme Weather 90/10 Peak Load	PJM 2025 Load Forecast, Table D-1.	166,562 MW (2025)
Max. Peak Load, June 23, 2025	PJM – Data Miner	161,120 MW (6:00 PM) Exports at peak (5 minute interval): 2,444 MWs
Max. Peak Load, June 24, 2025	PJM – Data Miner	158,755 MW (5:45 PM) Exports at peak (5 Minute interval): 3256 MWs
Max. Peak Load, June 25, 2025	PJM – Data Miner	153,410 MW (2:45 PM) Exports at peak (5 minute interval): 1,932 MWs

As shown in this table, the experience of the past few days—which included 95 degree-plus temperatures in portions of PJM over a three-day period—were nonetheless within the range of outcomes anticipated by PJM in the forecasts it developed earlier in the year. The table shows that the peak loads experienced on

June 23, 24, and 25 (based on 5-minute interval data) are all below PJM's "extreme weather" scenario.

Even more important, our preliminary review of data concerning system performance indicates that during the daily peaks (measured at 5-minute intervals) for the June 23-25, 2025, period PJM was a net *exporter* to other RTO regions. Tie-line flow data for the relevant period are arrayed in the table below:

		June 23-25	23-Jun	24-Jun	25-Jun
Net	MWhs	(273,062)	(79,607)	(101,252)	(92,203)
Average	MW	(3,801)	(3,317)	(4,234)	(3,855)
Max	MW	(743)	(743)	(2,388)	(1,291)
Min	MW	(6,372)	(6,372)	(6,054)	(5,749)

These data, which were culled from the PJM "Data Miner," available at https://dataminer2.pjm.com/list, show that over the three-day period, PJM exported 273,062 megawatt-hours over tie-lines to other RTO regions. Exporting megawatt-hours to others is inconsistent with the Order's finding that PJM is in the throes of a resource adequacy "emergency."

In short, the Order's conclusion that PJM faces an emergency this summer that justifies extraordinary section 202(c) action is not supported by substantial evidence and is arbitrary and capricious. Accordingly, the Secretary should grant rehearing and withdraw the order.

Respectfully submitted,

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June 27, 2025

Appendix of Documents Cited

Order No. 202-25-4

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 electricity grid operated by PJM Interconnection (PJM) due to a shortage of facilities for the generation of electric energy, resource adequacy concerns, and other causes, and that issuance of this Order will meet the emergency and serve the public interest.

Emergency Situation

PJM has recently stated its system faces "growing resource adequacy concern" due to load growth, the retirement of dispatchable resources, and other factors.[1] Upcoming retirements, including the planned retirement of Unit 3 and Unit 4 of the Eddystone Generating Station in Eddystone, Pennsylvania, will exacerbate these resource adequacy issues.

PJM indicates that resource constraints could exist within the service territory under peak load conditions, stating that "available generation capacity may fall short of required reserves in an extreme planning scenario."[2] In its February 2023 assessment "*Energy Transition in PJM: Resource Retirements, Replacements & Risks,*" PJM highlights the increasing risk of reliability risk in the coming years due to the "potential timing mismatch between resource retirements, load growth and the pace of new generation entry" under "low new entry" scenarios for renewable generation.[3]

In December 2024, PJM filed revisions with the Federal Energy Regulatory Commission (FERC) to Part VII of its Open Access Transmission Tariff, known as the Reliability Resource Initiative (RRI), to address near-term resource adequacy concerns. In a February 2025 order, FERC accepted the revisions and found "the possibility of a resource adequacy shortfall driven by significant load growth, premature retirements, and delayed new entry."[4] In March 2025 congressional testimony, PJM found "a growing resource adequacy concern" due to a combination of load growth, the retirement of dispatchable resources, and other factors.[5] Through 2030, PJM anticipates reliability risk from increasing electricity demand, generator retirement outpacing new resource construction, and characteristics of resources in PJM's interconnection queue.[6]

[1] https://www.pjm.com/-/media/DotCom/library/reports-notices/testimony/2025/20250325-asthana-testimony-us-house-subcommittee-on-energy.pdf
[2] https://insidelines.pjm.com/pjm-summer-outlook-2025-adequate-resources-available-for-summer-amid-growing-risk/
[3] https://www.pjm.com/-/media/DotCom/library/reports-notices/special-reports/2023/energy-transition-in-pjm-resource-retirements-replacements-and-risks.ashx
[4] https://elibrary.ferc.gov/eLibrary/filelist?accession_number=20250211-3120
[5] https://www.pjm.com/-/media/DotCom/library/reports-notices/testimony/2025/20250325-asthana-testimony-us-house-subcommittee-on-energy.pdf
[6] Ibid.

Constellation Energy owns the Eddystone Generating Station, which includes Unit 3 and Unit 4, each of which has a nameplate capacity of 380 MW. Units 3 and 4 have a planned retirement date of May 31, 2025. The retirement of these units would further decrease available dispatchable generation within PJM's service territory.

Pursuant to Executive Order 14262, *Strengthening the Reliability and Security of the United States Electric Grid* (EO 14262), DOE is developing a methodology to identify current and anticipated reserve margins for all regions of the bulk-power system regulated by the Federal Energy Regulatory Commission. EO 14262 requires this methodology to be published by July 7, 2025, and be used to establish a protocol to identify which generation resources within a region are critical to system reliability and prevent identified generation resources from leaving the bulk-power system. DOE plans to use this methodology to further evaluate Eddystone Units 3 and 4.

ORDER

Given the emergency nature of resource adequacy concerns, the declared state of national energy emergency, the responsibility of PJM to ensure maximum reliability on its system, and the ability of PJM to identify and dispatch generation necessary to meet load requirements, I have determined that, under the conditions specified below, operational availability and economic dispatch of the aforementioned Eddystone Units 3 and 4 (Eddystone Units) is necessary to best meet the emergency and serve the public interest for purposes of FPA section 202(c). This determination is based on, among other things:

- The emergency nature of the potential load stress due to aforementioned resource adequacy concerns, and the potential loss of power to homes and local businesses in the areas that may be affected by curtailments, presenting a risk to public health and safety.
- The potential shortage of electric energy, shortage of facilities for the generation of electric energy, and other causes in the region support the need for the Eddystone Units to contribute to system reliability.
- PJM's responsibility to ensure maximum reliability on its system, and, with the authority granted in this Order, its ability to identify and dispatch generation, including the Eddystone Units, necessary to meet the load demands.

This Order is limited in duration to align with the anticipated 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)(2) 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. To minimize adverse environmental impacts, this Order limits operation of dispatched units to the times and within the parameters determined by PJM for reliability purposes.

Based on my determination of an emergency set forth above, I hereby order:

A. From the time this Order is issued on May 30, 2025, PJM and Constellation Energy shall take all measures necessary to ensure that Eddystone Units are available to operate. For the duration of this order, PJM is directed to take every step to employ economic dispatch of the units to minimize cost to ratepayers. Following conclusion of this Order, sufficient time for orderly ramp down is permitted, consistent with industry practices. Constellation Energy is directed to comply with all orders from PJM related to the availability and dispatch of the Eddystone Units.

B. To minimize adverse environmental impacts, this Order limits operation of dispatched units through the expiration of the Order. PJM shall provide a daily notification to the Department (via AskCR@hq.doe.gov) reporting whether the Eddystone Units have operated in compliance with the allowances contained in this Order.

C. All operation of the Eddystone Units 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, PJM 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 of the Eddystone Units consistent with the public interest. PJM 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. In addition, PJM and Constellation Energy are directed to file with the Federal Energy Regulatory Commission any tariff revisions or waivers necessary to effectuate this order. Rate recovery is available pursuant to 16 U.S.C. § 824a(c).

F. This Order shall not preclude the need for the Eddystone Units to comply with applicable state, local, or Federal law or regulations following the expiration of this Order.

G. This Order shall be effective upon its issuance, and shall expire at 5:03 PM EDT on August 28, 2025, with the exception of the reporting requirements in paragraph D.

H. Issued in Simi Valley, California, at 5:03 PM Eastern Daylight Time on this 30th day of May 2025.

Chris Wright
Secretary of Energy

Department of Energy
Washington, DC 20585

Order No. 202-25-5

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 within the Duke Energy Carolinas, LLC ("Duke Energy") service territory due to a shortage of electric energy, a shortage of facilities for the generation of electric energy, and other causes, and that issuance of this Order will meet the emergency and serve the public interest.

Emergency Situation

On June 23, 2025, Duke Energy, an investor-owned utility whose combined service territory includes electric customers in North Carolina and South Carolina, filed a *Request for Emergency Order Under Section 202(c) of the Federal Power Act* (Application) with the United States Department of Energy (Department) "to preserve the reliability of the bulk electric power system." Duke Energy's service territory will be impacted by a ridge of high pressure that will stall over the eastern United States resulting in elevated ambient temperatures combined with high humidity for many eastern power pools. This combination of heat and humidity is expected to result in a significant increase in demand for electricity on the Duke Energy system. These conditions are expected to begin on June 23, 2025, and extend through June 25, 2025. Peak temperatures across the service territory – outside of the high elevation – are expected to range from 96ºF to 102ºF during this time with heat indices in the range of 100ºF to 110ºF. Duke Energy anticipates unusually high load forecasts during this time of approximately 21,968 MW for Duke Energy Carolinas and 35,623 MW for the Carolinas. Application at 1. The ridge weakens after June 25, 2025, then higher rain chances will provide relief from extreme temperatures and load from June 26-27, 2025. Application at 2.

Duke Energy has indicated that, while the vast majority of generating units in the Duke Energy service territory continue to function as expected under these stressed conditions, some units may experience operating difficulties due to hot weather in the coming days. Specifically, approximately 1,500 MW of generating units are currently in outage or derated. Additionally, other units may be limited in their availability by conditions and limitations in their environmental permits. As a result, Duke Energy states that it may not have sufficient generation available to meet this unusually high demand and may have to curtail load in order to maintain security and reliability of the grid. In anticipation of this emergency, Duke Energy has entered Grid Status Red and anticipates declaring an EEA Level 2. Application at 2.

Additionally, Duke Energy, in its role as Reliability Coordinator for VACAR South ("RC"), filed a formal endorsement on June 23, 2025, of the Application. RC Letter at 1.

Description of Mitigation Measures

Duke Energy has indicated that it has taken extensive conservation measures in an effort to reduce load so that the supply of power will continue to be sufficient to meet system demand and reserve requirements. On June 23, 2025, Duke Energy issued public conservation appeals encouraging customers to reduce usage. Additionally, Duke Energy has curtailed all recallable energy sales and implemented its load management program, including implementing residential demand response programs and large load curtailments. Duke Energy also notified wholesale customers to implement in-kind load management programs. These efforts are expected to reduce demand by approximately 700 - 1000 MW across the peak demand period. Application at 2.

In addition to the conservation measures, Duke Energy has also exhausted its ability to obtain more power through other means, including utilizing its Carolinas reserve sharing group and purchasing external capacity. As a result of these efforts, Duke Energy has secured approximately 1332 MW. Application at 2.

Subject to the exceptions included in this Order, Duke Energy has indicated that it will continue to take such actions, including utilizing other supply resources, before operating any units or calling on any generator to operate any units in a manner that will result in a conflict with a requirement of any federal, state, or local environmental statute or regulation, including requirements in permits issued pursuant to such laws or regulations. Duke Energy anticipates needing to continue these emergency actions through June 25, 2025. Application at 2.

Request for Order

Duke Energy requests that the Secretary issue an order immediately, effective June 23, 2025, through 10:00pm EDT on June 25, 2025, authorizing "the provision of additional energy from the Specified Resources, as well as any other generating units, regardless of emissions or other permit limitations" in the Duke Energy service territory. Application at 3. The generating units (Specified Resources) that this Order pertains to are listed on the Order 202-25-5 Resources List, as described below.

ORDER

Given the emergency nature of the expected load stress, the responsibility of Duke Energy to ensure maximum reliability on its system, and the ability of Duke Energy to identify and dispatch generation necessary to meet load requirements, I have determined that, under the conditions specified below, additional dispatch of the Specified Resources 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 expected load stress, shortage of electric energy, shortage of facilities for the generation of electric energy, and other causes by the current extreme weather event and its aftermath, 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.

In line with the anticipated circumstances, this Order is limited to the period of the likely hottest weather conditions and highest forecast load. 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)(2) 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. Duke Energy anticipates that this Order may result in exceedance of emissions of nitrogen oxide and particulate matter. To minimize adverse environmental impacts, this Order limits operation of dispatched units to the times and within the parameters determined by Duke Energy for reliability purposes.

Based on my determination of an emergency set forth above, I hereby order:

A. In the event that Duke Energy determines that generation from the Specified Resources is necessary to meet the electricity demand that Duke Energy anticipates in its service territory, I direct Duke Energy to dispatch such unit or units and to order their operation only as needed to maintain the necessary generation. Specified Resources are those generating units set forth on the Order 202-25-5 Resource List, subject to updates directed here and as described in paragraph D, which the Department shall post on www.energy.gov.

B. To minimize adverse environmental impacts, this Order limits operation of dispatched units to the times and within the parameters determined by Duke Energy for maintaining grid reliability and to the maximum extent practicable is consistent with any applicable environmental law. Duke Energy shall provide a daily notification to the Department (via AskCR@hq.doe.gov) reporting each generating unit that has been designated to use the allowance and operated in reliance on the allowances contained in this Order.

   In furtherance of the foregoing and, in each case, subject to the exhaustion of all available imports, demand response, and identified behind-the-meter generation resources selected to minimize an increase in emissions available to support grid reliability:

   (i) For any generation resource that is unable, or expected to be unable, to produce at its maximum output due to an emissions or other limit in any federal environmental permit, at any point before 10:00pm EDT on June 25, 2025, the unit will be allowed to exceed any such limit only during any period for which Duke Energy declared an Energy Emergency Alert (EEA) Level 2 or Level 3, except as described in item (iii) below in certain limited circumstances in anticipation of an EEA Level 2. Once Duke Energy declares that the EEA Level 2 event has ended, the unit would be required to immediately return to operation within its permitted limits. And at all other times, the unit would be required to operate within its permitted limits, except for the limited exceptions provided herein for operations in anticipation of an EEA Level 2 to prevent the cycling of units or facilitate the charging or pumping of other resources necessary for the EEA Level 2.

(ii) For any generation resource that is offline or would need to go offline at any point before 10:00pm EDT on June 25, 2025, due to an emissions or other limit in any federal environmental permit, Duke Energy may (or direct the unit operator to) bring the unit online, or to keep the unit online, and to operate at the level consistent with its permits but subject to the exceptions set forth in this Order. In this circumstance, the operator is allowed to make all of the unit's capacity available to Duke Energy for dispatch during any period for which Duke Energy has declared an EEA Level 2 or 3, except as described in item (iii) below in certain limited circumstances in anticipation of an EEA Level 2. Once Duke Energy declares that such an EEA Level 2 event has ended, the unit would be required to immediately return to operating at a level below the higher of its minimum operating level or the maximum output allowable under the permitted limit.

(iii) Duke Energy is hereby granted authority to operate the Specified Resources in certain limited circumstances in advance of declaring an EEA Level 2 where such operation or continued operation of the Specified Resource is reasonably necessary to avoid shutting down and restarting the Specified Resources. Duke Energy has represented that such cycling of units can cause reliability issues regarding restarting, delays, and increased emissions during start up. Duke Energy is further authorized to operate the Specified Resources in certain limited circumstances in advance of the declaring an EEA Level 2 where such operation or continued operation of the Specified Resource is reasonably necessary to facilitate charging storage resources or pumping for pumped storage facilities that will needed during an anticipated EEA Level 2. Duke Energy is required to take measures to dispatch units for which cycling would otherwise be required in a manner reasonably intended to limit the duration and operating level of those units in such a way as to minimize exceedance of permit limitations consistent with the security and reliability of the Duke Energy service territory.

C. All operation of the Specified Resource must comply with applicable environmental requirements, including but not limited to monitoring, reporting, and recordkeeping requirements, to the maximum extent feasible while operating consistent with the emergency conditions. This Order does not provide relief from any obligation to pay fees or purchase offsets or allowances for emissions that occur during the emergency condition or to use other geographic or temporal flexibilities available to generators.

D. In the event that Duke Energy identifies additional generation units that it deems necessary to maintain the reliability of the power grid, Duke Energy shall provide prompt written notice to the Department of Energy at AskCR@hq.doe.gov with the name and location of those units that Duke Energy has identified. Such additional generation unit shall be deemed a Specified Resource for the purpose of this Order for the hours prior to the required written notice to the Department updating Exhibit A, and Duke Energy may dispatch such additional generation units, provided that if the Department of Energy notifies Duke Energy that it does not approve of such generation unit being designated as a Specified Resource, such generation unit shall not constitute a Specified Resource upon notification from the Department.

E. Duke Energy 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.

F. This Order shall not preclude the need for the Specified Resources to comply with applicable state, local, or Federal law or regulations following the expiration of this Order.

G. This Order shall be effective upon its issuance, and shall expire at 10:00pm EDT on June 25, 2025, with the exception of the reporting requirements in paragraph D and applicable compliance obligations in paragraph E. Renewal of this Order, should it be needed, must be requested before this Order expires.

Issued in Washington, D.C. at 3:50 AM EDT on this 24th day of June 2025.

Chris Wright
Secretary of Energy

2025/2026 Base Residual Auction Report

July 30, 2024

For Public Use

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Contents

Introduction

This document provides information for PJM stakeholders regarding the results of the 2025/2026 Reliability Pricing Model (RPM) Base Residual Auction (BRA).

In each BRA, PJM seeks to procure a target capacity reserve level for the RTO in a least-cost manner while recognizing the following reliability-based constraints on the location and type of capacity that can be committed:

- Internal PJM locational constraints are established by setting up Locational Deliverability Areas (LDAs) with each LDA having a separate target capacity reserve level and a maximum limit on the amount of capacity that it can import from resources located outside of the LDA.
- Across the RTO, seasonal sell offers must account for annual CP commitments by matching summer-period and winter-period sell offers.

The clearing solution may be required to commit capacity resources out-of-merit order but again in a least-cost manner to ensure that all of these constraints are respected. In those cases where one or more of the constraints results in out-of-merit commitment in the auction solution, resource clearing prices will be reflective of the price of resources selected out of merit order to meet the necessary requirements.

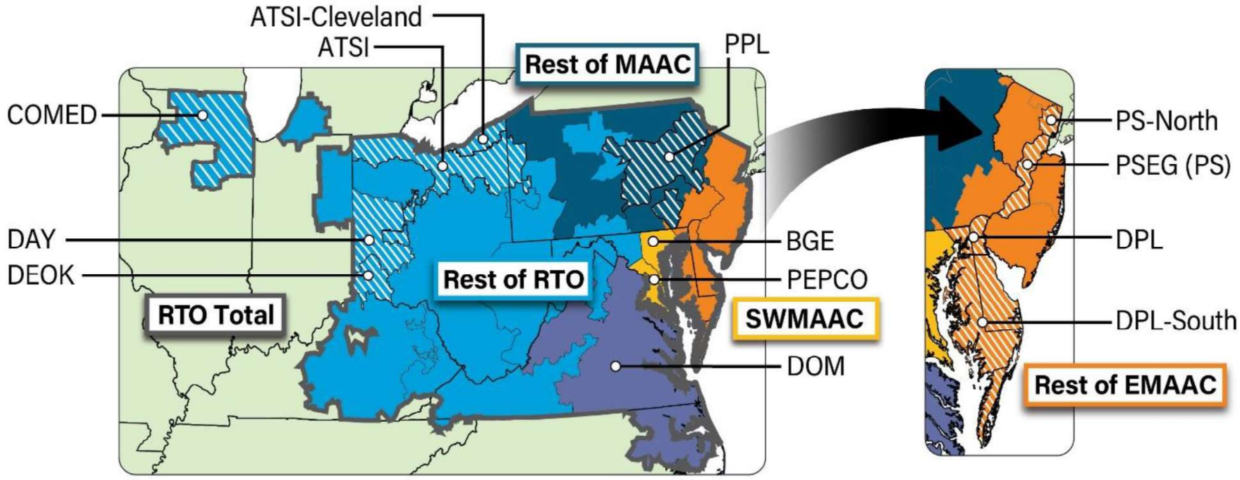
An LDA was modeled in the BRA and had a separate VRR Curve if (1) the LDA has a CETO/CETL margin that is less than 115%; or (2) the LDA had a locational price adder in any of the three immediately preceding BRAs; or (3) the LDA is EMAAC, SWMAAC and MAAC. An LDA not otherwise qualifying under the above three tests may also be modeled if PJM finds that the LDA is determined to be likely to have a Locational Price Adder based on historic offer price levels or if such LDA is required to achieve an acceptable level of reliability consistent with the Reliability Principles and Standards.

As a result of the above criteria, MAAC, EMAAC, SWMAAC, PSEG, PS-NORTH, DPL-SOUTH, PEPCO, ATSI, ATSI-Cleveland, COMED, BGE, PL, DAY, DOM and DEOK were modeled as LDAs in the 2025/2026 RPM Base Residual Auction. A Locational Price Adder represents the difference in Resource Clearing Prices for the Capacity Performance product between a resource in a constrained LDA and the immediate higher level LDA.

Locational Deliverability Area Definition

Locational Deliverability Areas (LDAs) defined as "(rest of)" do not include figures from modeled child LDAs contained within the parent LDA. For example, the PS (rest of) LDA does not include PS-NORTH within its totals.	• **EMAAC** total includes DPL-SOUTH, PS-NORTH, PS (rest of), EMAAC (rest of). • **SWMAAC** total includes PEPCO, BGE, SWMAAC (rest of). • **MAAC** total includes EMAAC total, SWMAAC total, PPL, MAAC (rest of).	**RTO total** includes MAAC total, ATSI (rest of), ATSI-Cleveland, COMED, DAY, DEOK, DOM, RTO (rest of). See **Map 1.**

Map 1. PJM LDAs



Executive Summary

The 2025/2026 Reliability Pricing Model (RPM) Base Residual Auction (BRA) cleared 135,684 MW of unforced capacity in the RTO from non-energy efficiency annual, summer-period, and winter-period resources representing a 18.6% reserve margin. Energy Efficiency (EE) resources are excluded from this calculation because their impact is reflected in a lower load forecast and therefore not used to meet the Reliability Requirement. The total cost to load for the 2025/2026 BRA was $14.7 billion, which includes the cost of EE. The reserve margin for the entire RTO, which includes Fixed Resource Requirement (FRR) is 18.5% or 0.7 percentage points higher than the target reserve margin of 17.8%. This is a significant reduction in the overall reserve margin, which includes FRR, from the 2024/2025 BRA. The 2024/2025 overall reserve margin for the entire RTO was 20.4%, or 5.7 percentage points higher than the target reserve margin of 14.7% The 2025/26 to 2024/25 Delivery Year supply and demand changes are not straightforward comparisons because of the implementation of marginal Effective Load Carrying Capability accreditation for all resources and the associated reduction of the reliability requirement through the Forecast Pool Requirement (FPR) as well as the transition of load from FRR into RPM. The Delivery Year over Delivery Year unforced capacity or reliability requirement comparisons in the report have not been adjusted for these changes.

Supply offered into the RPM capacity market, excluding EE resources, declined 13,252.1 MW from 148,945.7 MW in the 2024/2025 BRA to 135,692.3 MW in the 2025/2026 BRA. This is the fourth BRA in a row where the total capacity offered from non-EE resources has declined. The number of constrained LDAs dropped from five to two in the 2025/2026 BRA. The total amount of capacity, excluding EE Resources, in RPM that cleared decreased by 5,743.6 MW from 140,415.8 MW in the 2024/2025 BRA to 134,672.2 MW in the 2025/2026 BRA.

The RTO as a whole failed the Market Structure Test (i.e., the Three-Pivotal Supplier Test), resulting in the application of market power mitigation to all Existing Generation Capacity Resources. Mitigation was applied to a supplier's existing generation resources resulting in utilizing the lesser of the supplier's approved Market Seller Offer Cap for such resource or the supplier's submitted offer price for such resource in the RPM Auction clearing.

Table 1. Comparison of BRA Clearing Prices by Delivery Year by LDA

		BRA Resource Clearing Prices ($/MW-day)		
Capacity Type	**BRA**	**Rest of RTO**	**BGE**	**DOM**
Capacity Performance	2025/26	***$269.92***	***$466.35***	***$444.26***
	2024/25	***$28.92***	***$73.00***	-

Note: Clearing prices in bold indicate constrained LDA

The following is a list of new market rules or planning parameter changes that may have impacted the auction results:

- Planning Parameters (please see the Planning Parameters Report) changes which include:
  - 3,243 MW increase in forecasted load
  - IRM increase from 14.7% to 17.8%
- Significant decrease in overall supply from retirements (actual retirements plus must offer exceptions for future retirements), change in status from capacity resource to energy only and must offer exceptions for exports (see change of status and must offer exception report)

- Critical Issue Fast Path (CIFP) changes were approved by FERC (ER24-99-000). These changes included marginal resource accreditation (ELCC), Forecast Pool Requirement (FPR) and a binding notice of intent for planned resources among other changes.
- Dominion FRR has changed to RPM and therefore the entire Dominion zone is now in RPM.
- Net CONE values used to determine the VRR Curve changed significantly in some LDAs. In most cases, LDAs received lower Net CONE values, and the range was between +4.1% in the PE zone to -80.6% in the BGE zone.

***Note:** This BRA was conducted under a compressed auction schedule where the auction occurred ~10 months prior to the start of the delivery year. A typical BRA is held more than three years before the start of the delivery year. The prior BRA was conducted under the same compressed auction schedule.*

Detailed Report

Table 2 contains a summary of the RTO clearing prices, cleared unforced capacity and implied cleared reserve margins for the 2015/2016 through 2025/2026 RPM BRAs. The Reserve Margin presented in **Table 2** represents the percentage of installed capacity cleared in RPM and committed by FRR entities in excess of the RTO load (including load served under the FRR alternative). The reserve margin for the entire RTO, which includes FRR and RPM load, is 18.5%, or 0.7 percentage points higher than the target reserve margin of 17.8%.

Table 2. RPM Base Residual Auction Resource Clearing Price Results in the RTO

	Auction Results				
Delivery Year	Resource Clearing Price	Cleared UCAP (MW)	RPM Reserve Margin	Total Reserve Margin[1]	Total Cost to Load ($ billion)
2015/16[2]	$136.00	164,561.2	19.7%	19.3%	$9.7
2016/17[3]	$59.37	169,159.7	20.7%	20.3%	$5.5
2017/18	$120.00	167,003.7	20.1%	19.7%	$7.5
2018/19	$164.77	166,836.9	20.2%	19.8%	$10.9
2019/20	$100.00	167,305.9	22.9%	22.4%	$7.0
2020/21[4]	$76.53	165,109.2	23.9%	23.3%	$7.0
2021/22	$140.00	163,627.3	22.0%	21.5%	$9.3
2022/23	$50.00	144,477.3	21.1%	19.9%	$3.9
2023/24	$34.13	144,870.6	21.6%	20.3%	$2.2
2024/25	$28.92	147,478.9	21.7%	20.4%	$2.2
2025/26[5]	$269.92	135,684.0	18.6%	18.5%	$14.7

[1] Reserve Margin includes FRR+RPM (Total ICAP/Total Peak-1; [2] 2015/2016 BRA includes a significant portion of AEP and DEOK zone load previously under the FRR Alternative; [3] 2016/2017 BRA includes EKPC zone;
[4] Beginning 2020/2021 Cleared UCAP (MW) includes Annual and matched Seasonal Capacity Performance sell offers; [5] DOM zone included in RPM

Figure 1 represents the trend in BRA capacity price by delivery year for RTO, EMAAC, SWMAAC and MAAC. For 2025/2026, all four LDAs cleared at $269.97. This clearing price was an increase from $28.92 in RTO, $49.49 in MAAC and SWMAAC and $54.95 in EMAAC in the 2024/2025 BRA. The number of constrained LDAs decreased from five LDAs (MAAC, BGE, DPL-S, EMAAC and DEOK) to two LDAs (BGE and DOM).

Figure 1. BRA Clearing Prices by Delivery Year for Major LDAs

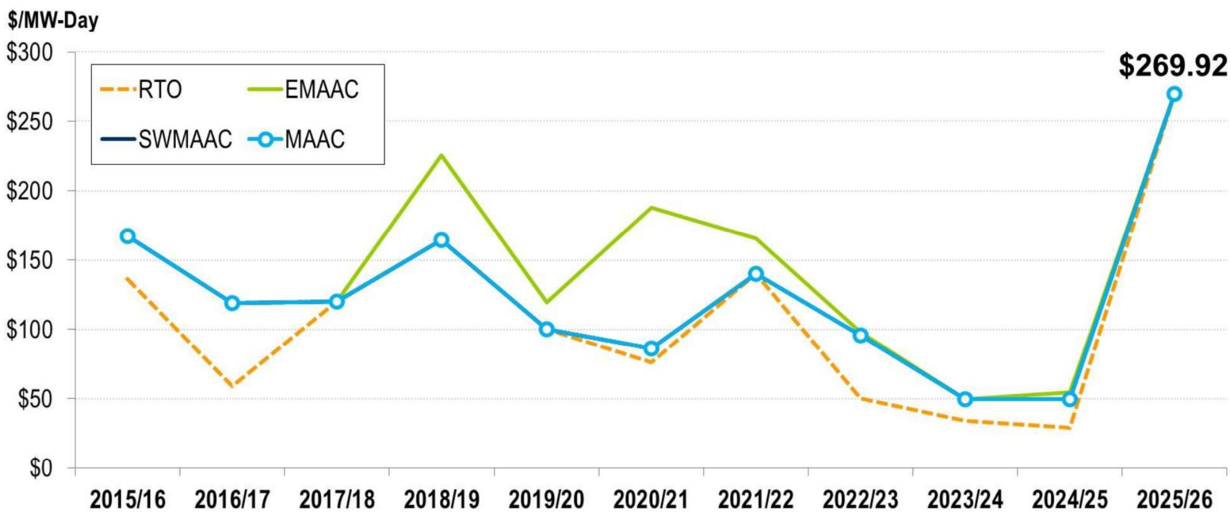


Table 3 provides the total offered and cleared MWs and associated prices by LDA. This table provides an indication of how much supply did not clear for each LDA. Since BGE and DOM were constrained LDAs, they cleared at a higher price than the rest of RTO or $466.35 and $444.26, respectively.

Since BGE and DOM were constrained LDAs, Capacity Transfer Rights (CTRs) will be allocated to loads in these constrained LDAs for the 2025/2026 Delivery Year. CTRs are allocated by load ratio share to all Load Serving Entities (LSEs) in a constrained LDA that has a higher clearing price than the unconstrained region. CTRs serve as a credit back to the LSEs in the constrained LDA for use of the transmission system to import less expensive capacity into that constrained LDA and are valued at the difference in the clearing prices of the constrained and unconstrained regions.

For 2025/2026, only 20.7 MW UCAP of annual generation and DR resources did not clear in the auction. Any remaining amount that did not clear was winter only where there were no summer-only resources that did not clear.

Table 3. Offered and Cleared MWs and Associated Prices by LDA

	MW (UCAP)		System Marginal Price	Locational Price Adder***	RCP for Capacity Performance Resources
LDA	Offered MW*	Cleared MW**			
ATSI	7,791.9	7,764.9	$269.92	$0.00	$269.92
ATSI-CLEVELAND	1,615.5	1,614.0	$269.92	$0.00	$269.92
COMED	22,524.4	21,813.9	$269.92	$0.00	$269.92
DAY	493.1	488.6	$269.92	$0.00	$269.92
DEOK	1,639.5	1,633.8	$269.92	$0.00	$269.92
DOM	20,100.2	20,049.6	$269.92	$174.34	$444.26
MAAC	51,529.4	51,303.2	$269.92	$0.00	$269.92
PPL	8,785.1	8,757.6	$269.92	$0.00	$269.92
EMAAC	24,478.2	24,373.3	$269.92	$0.00	$269.92
DPL-SOUTH	960.4	956.9	$269.92	$0.00	$269.92
PSEG	4,446.5	4,390.3	$269.92	$0.00	$269.92
PS-NORTH	2,536.4	2,507.4	$269.92	$0.00	$269.92
SWMAAC	5,089.1	5,060.8	$269.92	$0.00	$269.92
BGE	612.9	606.9	$269.92	$196.43	$466.35
PEPCO	2,285.5	2,263.2	$269.92	$0.00	$269.92
RTO	**137,152.1**	**135,684.0**	**$269.92**	**$0.00**	**$269.92**

** Offered MW values include Annual, Summer-Period, and Winter-Period Capacity Performance sell offers.*
*** Cleared MW values include Annual and matched Seasonal Capacity Performance sell offers within the LDA.*
**** Locational Price Adder is with respect to the immediate parent LDA*

As seen in **Figure 2**, the 2025/2026 BRA procured 110.3 MW of capacity from new generation and 753.8 MW from uprates to existing or planned generation. The quantity of new generation is down from the previous BRA where there was 328.5 MW of new generation. The quantity of capacity procured from external Generation Capacity Resources in the 2025/2026 BRA is 1,268.5 MW. All external generation capacity that cleared in the 2025/2026 BRA are Prior Capacity Import Limit (CIL) Exception External Resources[1] that qualify for an exception for the 2025/2026 Delivery Year to satisfy the enhanced pseudo-tie requirements established by FERC Order ER17-1138. The total quantity of DR procured in the 2025/2026 BRA is 6,064.7 MW, and the total quantity of EE procured in the 2025/2026 BRA is 1,459.8 MW.

Figure 2. Cleared MWs (UCAP) by New Generation/Uprates/Imports by Delivery Year

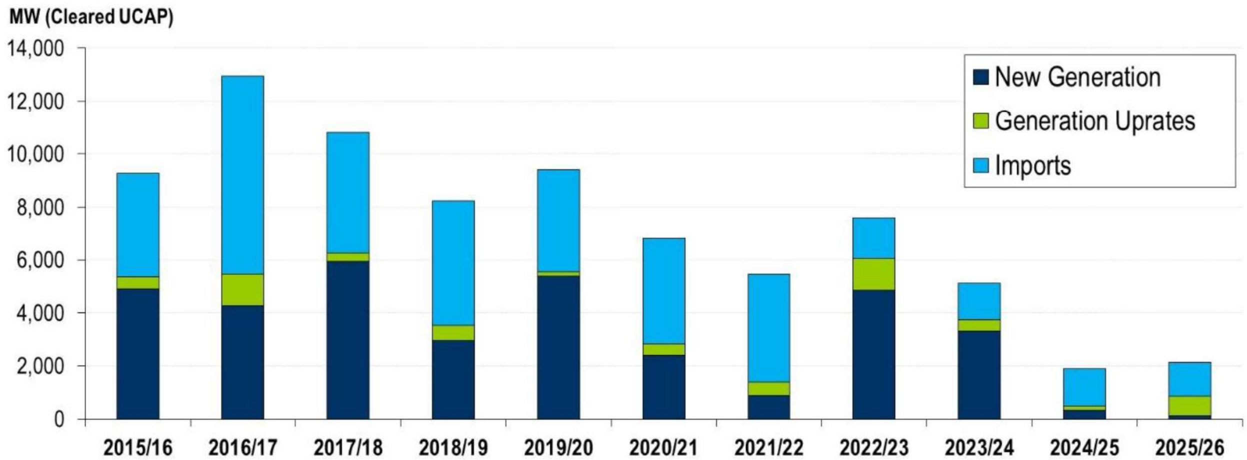


Table 4 contains a summary of the RTO resources for each cleared BRA from 2015/2016 through the 2025/2026 Delivery Years in terms of ICAP. The summary includes all resources located in the RTO (including FRR Capacity Plans).

A total of 195,853.1 MW of ICAP was eligible to be offered into the 2025/2026 Base Residual Auction or used in an FRR Capacity Plan. The total amount of supply in PJM decreased from 202,376.6 MW ICAP to only 195,853.1 MW ICAP, or a decline in the total amount of supply by 6,523.5 MW ICAP. Since this comparison is in ICAP and includes total eligible capacity for both FRR and RPM, it is not impacted by the CIFP capacity accreditation changes or the addition of Dominion load into RPM.

[1] A Prior CIL Exception Resource is an external Generation Capacity Resource for which (1) a capacity market seller had, prior to May 9, 2017, cleared a Sell Offer in an RPM Auction under the exception provided to the definition of CIL as set forth in Article 1 of the Reliability Assurance Agreement or (2) an FRR Entity committed, prior to May 9, 2017, in an FRR Capacity Plan under the exception provided to the definition of CIL.

A total of 171,324.3 MW (ICAP) of generation and Demand Response capacity was offered into the Base Residual Auction. This is an increase of 17,262 MW from that which was offered into the 2024/2025 BRA and was driven by the return of Dominion to RPM from FRR. The total DR offered into the auction significantly declined from 9321.1 MW ICAP to 8009.7 MW ICAP. EE resources are considered to be included in the forecast and therefore do not contribute to meeting the reliability requirement. A total of 24,528.8 MW (ICAP) was eligible, but not offered due to (1) inclusion in an FRR Capacity Plan; (2) export of the resource; (3) excused from offering into the auction; (4) Deactivated; or (5) not required to offer into the auction and elected to not offer into the auction. Resources were excused from the must offer requirement for the following reasons: approved retirement requests or external sale of capacity. Resources with approved removal of capacity status requests also did not have a capacity must offer requirement.

Table 4. Total RTO Resources (RPM + FRR) Offered vs Unoffered by Resource Type Used To Meet the Reliability Requirement

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	Delivery Year *(All values in ICAP)*										
Auction Supply	**2015/16***	**2016/17****	**2017/18**	**2018/19**	**2019/20**	**2020/21**	**2021/22**	**2022/23**	**2023/24**	**2024/25**	**2025/26*****
Internal PJM Gen Capacity	187,407.7	193,052.5	190,333.2	191,322.3	195,203.0	197,804.7	198,726.6	193,412.2	189,704.7	191,133.4	186,134.2
Internal PJM DR+PRD Capacity	19,243.6	13,932.9	10,855.2	10,772.8	10,859.2	8,245.5	10,694.8	9,501.2	9,517.2	9,626.1	8,233.7
Imports Offered	4,649.7	8,412.2	6,300.9	5,724.6	4,821.4	5,440.5	4,725.0	1,649.1	1,601.2	1,617.1	1,485.2
Eligible RPM Capacity	211,301.0	215,397.6	207,489.3	207,819.7	210,883.6	211,490.7	214,146.4	204,562.5	200,823.1	202,376.6	195,853.1
Exports/ Delistings	1,218.8	1,218.8	1,223.2	1,313.4	1,318.2	1,319.8	1,319.8	1,525.3	1,518.9	1,522.7	1,525.3
FRR Commitments	15,997.9	15,576.6	15,776.1	15,793.0	15,385.3	13,931.6	13,657.4	33,297.1	33,500.7	34,584.2	13,184.5
Excused	8,712.9	8,524.0	4,305.3	2,348.4	1,454.5	8,384.4	9,433.8	2,190.0	9,949.6	12,207.4	9,819.0
Total Eligible RPM Capacity: Excused	25,929.6	25,319.4	21,304.6	19,454.8	18,158.0	23,635.8	24,411.0	37,012.4	44,969.2	48,314.3	24,528.8
Remaining Eligible RPM Capacity	185,371.4	190,078.2	186,184.7	188,364.9	192,725.6	187,854.9	189,735.4	167,550.1	155,853.9	154,062.3	171,324.3
Generation Offered	166,127.8	176,145.3	175,329.5	177,592.1	181,866.4	178,807.1	178,823.5	157,872.2	146,571.7	144,741.2	163,314.6
DR Offered	19,243.6	13,932.9	10,855.2	10,772.8	10,859.2	9,047.8	10,911.9	9,677.9	9,282.2	9,321.1	8,009.7
Total Eligible RPM Capacity: Offered	**185,371.4**	**190,078.2**	**186,184.7**	**188,364.9**	**192,725.6**	**187,854.9**	**189,735.4**	**167,550.1**	**155,853.9**	**154,062.3**	**171,324.3**

*Note: *includes a significant portion of AEP and DEOK zone load previously under the FRR Alternative; **includes EKPC zone; ***includes DOM zone load previously under the FRR Alternative.*

Table 5 shows the Generation, DR, and EE Resources Offered and Cleared in the RTO translated into Unforced Capacity (UCAP) MW amounts. Until the 2025/2026 Delivery Year, participants' sell offers for thermal resource EFORd values were used to convert a resource's installed capacity (ICAP) values into unforced capacity (UCAP) values. Effective for 2025/2026, the appropriate Accredited UCAP Factor will be used to convert installed capacity (ICAP) values into unforced capacity (UCAP) values. Prior to the 2025/2026 Delivery Year, DR sell offers and EE sell offers were converted into UCAP using the appropriate Forecast Pool Requirement (FPR). Beginning in 2025/2026, DR sell offers are converted into UCAP using the appropriate DR Accredited UCAP Factor while EE sell offers remain as in prior years, by multiplying the EE nominated value by the Forecast Pool Requirement.

Total offered Gen and DR (UCAP) used to meet the reliability requirement declined from 148,945.7 MW to 135,692.3 MW. Please note that UCAP for Delivery Years prior to 2025/2026 were not calculated using the marginal ELCC methodology, and these changes are in part responsible for the year-over-year decrease in offered and cleared UCAP.

Table 5. Capacity Resource Offered and Cleared by Type by Delivery Year (UCAP)

		Delivery Year										
	Auction Results	**2015/16**	**2016/17**	**2017/18**	**2018/19**	**2019/20**	**2020/21***	**2021/22**	**2022/23**	**2023/24**	**2024/25**	**2025/26**
Offered	Generation	157,691.1	168,716.0	166,204.8	166,909.6	172,071.2	171,262.3	171,663.2	152,128.6	141,026.7	138,799.3	129,607.5
	DR	19,956.3	14,507.2	11,293.7	11,675.5	11,818.0	9,846.7	11,886.8	10,513.0	10,116.7	10,146.4	6,084.8
	Total GEN/DR Offered	**177,647.4**	**183,223.2**	**177,498.5**	**178,585.1**	**183,889.2**	**181,109.0**	**183,550.0**	**162,641.6**	**151,143.4**	**148,945.7**	**135,692.3**
	EE	940.3	1,156.8	1,340.0	1,306.1	1,650.3	2,242.5	2,954.8	5,056.8	5,471.1	8,417.0	1,459.8
Cleared	Generation	148,805.9	155,634.3	154,690.0	154,506.0	155,442.8	155,976.5	150,385.0	131,541.6	131,777.4	132,423.1	128,607.5
	DR	14,832.8	12,408.1	10,974.8	11,084.4	10,348.0	7,820.4	11,125.8	8,811.9	8,096.2	7,992.7	6,064.7
	Total GEN/DR Cleared	**163,638.7**	**168,042.4**	**165,664.8**	**165,590.4**	**165,790.8**	**163,796.9**	**161,510.8**	**140,353.5**	**139,873.6**	**140,415.8**	**134,672.2**
	EE	922.5	1,117.3	1,338.9	1,246.5	1,515.1	1,710.2	2,832.0	4,810.6	5,471.1	7,668.7	1,459.8
	Uncleared GEN/DR	14,008.7	15,180.8	11,833.7	12,994.7	18,098.4	17,312.1	22,039.2	22,288.1	11,269.8	8,529.9	1,020.1

Note: RTO numbers include all LDAs. UCAP calculated using ELCC values for Generation Resources. DR and EE UCAP values include appropriate DR AUCAP Factor and FPR.
**Starting 2020/2021: Generation, DR, and EE offered and cleared values include Annual, Summer-Period, and Winter-Period Capacity Performance sell offers.*

The 2025/2026 numbers in **Tables 6** and **7** have been significantly impacted by the marginal ELCC accreditation changes so it is difficult to simply compare delivery year over delivery year results. **Table 6** shows the offered and cleared megawatts by Resource type for RPM plus FRR commitments over the last four delivery years. Since Energy Efficiency is already included in the load forecast, it is not used to meet the Reliability Requirement and therefore separated from the Grand Totals in the tables to provide a more accurate picture of the Resources that will be used to meet the Reliability Requirement.

Table 6. Offered and Cleared MWs by Type for RPM and Committed FRR for Previous BRAs

	Offered and Cleared UCAP							
	2022/23		2023/24		2024/25		2025/26 (Reflects ELCC Accreditation)	
Type	Offered	Cleared	Offered	Cleared	Offered	Cleared	Offered	Cleared
Coal	45,754	39,230	37,164	31,811	35,114	31,532	30,081	30,081
Distillate Oil (No.2)	3,178	2,897	2,894	2,855	2,776	2,674	2,408	2,408
Gas	85,562	79,329	85,217	81,643	85,469	83,258	66,354	66,354
Nuclear	31,944	26,140	31,960	31,960	31,835	31,629	30,549	30,549
Oil	2,674	2,527	2,350	2,269	2,493	2,220	578	578
Solar	2,633	2,096	2,945	2,935	4,234	4,232	1,337	1,337
Water	6,917	6,749	6,375	6,375	6,137	6,137	5,365	5,361
Wind	2,595	1,839	1,608	1,416	1,396	1,396	2,618	1,676
Battery/Hybrid	-	-	16	16	36	36	14	14
Other	1,205	1,168	1,185	1,185	1,153	1,153	911	911
Demand Response	10,604	8,903	10,652	8,631	10,334	8,180	6,363	6,342
Aggregate Resource	484	386	511	511	503	503	327	273
Total (without EE)	**193,551**	**171,263**	**182,875**	**171,605**	**181,481**	**172,951**	**146,905**	**145,883**
Energy Efficiency	5,057	4,811	5,471	5,471	8,417	7,669	1,460	1,460
Total (with EE)	198,608	176,073	188,346	177,076	189,898	180,620	148,364	147,343

*The table shows the UCAP MW quantities that offered and cleared in the BRA of each DY plus the UCAP MW committed to FRR Capacity Plans. Notes: Offered and Cleared MW quantities include Annual, Summer-Period, and Winter-Period Capacity Performance sell offers. Other consist of: Kerosene, Other Gas, Other Liquid, Other Solid, Wood. *Starting in 2020/2021, Generation, DR, and EE offered and cleared values include Annual, Summer-Period, and Winter-Period Capacity Performance*

Capacity Import Participation

Table 7 shows the quantity of capacity imports cleared in the 2025/2026 BRA at 1,268.5 MW (UCAP). The majority of the imports are from resources located in regions west of the PJM RTO. All external generation capacity that has cleared are Prior CIL Exception External Resources that qualify for an exception for the 2025/2026 Delivery Year to satisfy the enhanced pseudo-tie requirements established by FERC Order ER17-1138.

Table 7. Capacity Imports (UCAP) Offered and Cleared by Region

	External Source Zones					
	NORTH	WEST 1	WEST 2	SOUTH 1	SOUTH 2	Total
Offered MW (UCAP)*	233.7	0.0	570.3	227.2	237.3	**1,268.5**
Cleared MW (UCAP)*	233.7	0.0	570.3	227.2	237.3	**1,268.5**
Resource Clearing Price ($/MW-day)	$269.97	$269.97	$269.97	$269.97	$269.97	

**Offered and Cleared MW quantities include resources that received CIL Exception and those associated with pre-OATT grandfathered transmission. Attachment G of Manual 14B provides a mapping of outside Balancing Authorities to the External Source Zones.*

Resource Type Participation

Table 8 provides a breakdown of the offered and cleared megawatts by season by Resource Type. There were 448 MW of Summer capability and 1,447.4 MW of Winter capability offered in the auction. All 448 MW of Summer resources were matched with Winter resources to meet the annual Capacity Performance capability requirement.

Table 8. Offered and Cleared (UCAP) by Resource Type by Season

	Capacity Performance					
	Offered MW (UCAP)			Cleared MW (UCAP)		
Resource Type	Annual	Summer	Winter	Annual	Summer	Winter
GEN	128,115.1	45.0	1,447.4	128,114.5	45.0	448.0
DR	5,962.5	122.3	-	5,942.4	122.3	-
EE	1,179.1	280.7	-	1,179.1	280.7	-
PRD	210.2	-	-	210.2	-	-
Grand Total	**135,466.9**	**448.0**	**1,447.4**	**135,446.2**	**448.0**	**448.0**

Figure 3 displays the trend in offered and cleared DR and PRD and cleared EE by Delivery Year. Both DR and EE offered and cleared amounts declined significantly for 2025/2026, particularly for EE, which declined by 6,209 MW from the previous year. The amount of PRD remains small and declined slightly in the 2025/2026 Delivery Year.

Figure 3. DR and PRD Offered and Cleared and EE Cleared MW(UCAP) by Delivery Year

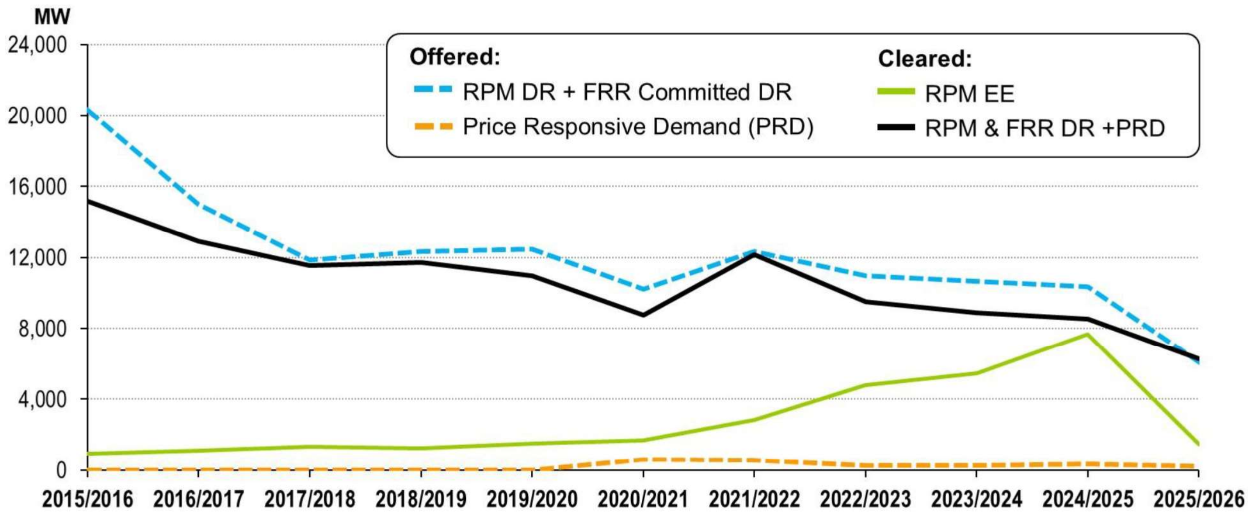

Table 9 provides a breakdown of offered and cleared DR and EE by LDA. COMED cleared the most DR and EE (1,424.5 MW), followed by AEP (1,055.7 MW) and then DOM (827.7 MW).

Table 9. DR and EE Offered and Cleared by LDA

		Offered MW (UCAP)*			Cleared MW (UCAP)*		
LDA	**Zone**	**DR**	**EE**	**Total**	**DR**	**EE**	**Total**
EMAAC	*AECO*	44.7	17.5	**62.2**	40.9	17.5	**58.4**
EMAAC/DPL-S	*DPL*	117.3	32.7	**150.0**	117.3	32.7	**150.0**
EMAAC	*JCPL*	104.8	52.7	**157.5**	100.7	52.7	**153.4**
EMAAC	*PECO*	296.4	137.8	**434.2**	292.6	137.8	**430.4**
PSEG/PS-N	*PSEG*	237.3	167.2	**404.5**	228.9	167.2	**396.1**
EMAAC	*RECO*	2.3	2.2	**4.5**	2.3	2.2	**4.5**
EMAAC Sub Total		**802.8**	**410.1**	**1,212.9**	**782.7**	**410.1**	**1,192.8**
PEPCO	*PEPCO*	132.5	80.0	**212.5**	132.5	80.0	**212.5**
BGE	*BGE*	163.0	71.8	**234.8**	163.0	71.8	**234.8**
MAAC	*METED*	136.0	21.8	**157.8**	136.0	21.8	**157.8**
MAAC	*PENELEC*	208.2	17.7	**225.9**	208.2	17.7	**225.9**
PPL	*PPL*	422.5	45.7	**468.2**	422.5	45.7	**468.2**
MAAC Sub Total**		**1,865.0**	**647.1**	**2,512.1**	**1,844.9**	**647.1**	**2,492.0**
RTO	*AEP*	926.2	129.5	**1,055.7**	926.2	129.5	**1,055.7**
RTO	*APS*	478.9	60.8	**539.7**	478.9	60.8	**539.7**
ATSI/ATSI-C	*ATSI*	546.1	68.5	**614.6**	546.1	68.5	**614.6**
COMED	*COMED*	1,086.9	337.6	**1,424.5**	1,086.9	337.6	**1,424.5**
DAY	*DAY*	140.1	18.5	**158.6**	140.1	18.5	**158.6**
DEOK	*DEOK*	159.6	24.9	**184.5**	159.6	24.9	**184.5**
RTO	*DOM*	673.5	154.2	**827.7**	673.5	154.2	**827.7**
RTO	*DUQ*	86.9	18.7	**105.6**	86.9	18.7	**105.6**
RTO	*EKPC*	121.6	-	**121.6**	121.6	-	**121.6**
Grand Total		**6,084.8**	**1,459.8**	**7,544.6**	**6,064.7**	**1,459.8**	**7,524.5**

** MW values include both Annual and Summer-Period Capacity Performance DR and EE*

*** MAAC sub-total includes all MAAC Zones*

Price Responsive Demand Participation

210.2 MW (UCAP) of PRD was elected and committed in the 2025/2026 BRA. PRD is provided by a PJM Member that represents retail customers having the ability to predictably reduce consumption in response to energy wholesale prices. In the PJM capacity market, a PRD Provider may voluntarily make a firm commitment of the quantity of PRD that will reduce its consumption in response to real time energy price during a Delivery Year. A PRD Provider that is committing PRD in a BRA must also submit a PRD election in the Capacity Exchange system that indicates the Nominal PRD Value in megawatts that the PRD Provider is willing to commit at different reservation prices ($/MW-day). The VRR Curve of the RTO and each affected LDA is shifted leftward along the horizontal axis by the UCAP MW quantity of elected PRD where the leftward shift occurs only for the portion of the VRR Curve at or above the PRD Reservation price. The Planning Parameters includes a breakdown of elected PRD in ICAP, which can be converted to UCAP by taking ICAP * FPR. The breakdown of PRD UCAP that elected and committed is: 126.7 MW in the BGE LDA, 70.4 MW in the PEPCO LDA, and 13.1 MW in the rest of EMAAC LDA. The VRR Curve of the RTO and each affected LDA is shifted leftward along the horizontal axis by the UCAP MW value of these quantities at the PRD Reservation Price. Once committed in a BRA, a PRD commitment cannot be replaced; the commitment can only be satisfied through the registration of price response load in the DR Hub system prior to or during the delivery year.

Table 10. PRD UCAP Committed

PRD UCAP Committed (MW)

Zone/LDA Location			
BGE	PEPCO	EMAAC	Total
126.7	**70.4**	**13.1**	**210.2**

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	

Bryan C. Hanson
Executive Vice President and Chief Generation Officer
1310 Point Street
Baltimore, MD 21231
bryan.hanson@constellation.com

December 1, 2023

Mr. Michael Bryson
Senior Vice President, Operations

PJM Interconnection, LLC
PO Box 1525
Southeastern, PA 19399-1525
Via Email: generatordeactivation@pjm.com

Dear Mr. Bryson:

Pursuant to PJM Interconnection, LLC (PJM) FERC Electric Tariff, Part V, Section 113 and PJM Manual 14D: Generator Operational Requirements, Revision 62, Section 9, Constellation Energy Generation, LLC, ("Constellation") hereby officially provides this Deactivation Notice to PJM of Constellation's intent to deactivate through retirement Eddystone Generating Station Units 3 and 4, effective on or about May 31, 2025. This Deactivation Notice satisfies the 18-month notification commitment required by Section 1.a.ii of the Revised Exelon-Constellation Merger Settlement ("Revised Merger Agreement") with the Independent Market Monitor for PJM (IMM), which the Maryland Public Service Commission approved in February 2022.

Constellation is contemporaneously submitting a written request to PJM and the IMM for removal of capacity resource status beginning with the 2025/26 delivery year.

Constellation is retiring Eddystone Units 3 and 4 because continued operation of these units is expected to be uneconomic. Pursuant to Section 1.a.iii of the Revised Merger Agreement, Constellation will provide the IMM with the required economic analysis supporting this decision with the written request for removal of capacity resource status.

All communications regarding this Notice and the proposed retirement of these units should be directed to Adrien Ford at (215) 251-2427 or adrien.ford@constellation.com.

Sincerely,

Bryan C. Hanson
Executive Vice President and Chief Generation Officer
Constellation Energy Generation, LLC

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Brandi Nieland
Director, Consumer
Assistance Unit

Carissa Ralbovsky
Chief Operating Officer

February 28, 2025

Mr. Mark Takahashi, Chair, PJM Board of Managers
Mr. Manu Asthana, President and CEO
PJM Interconnection, LLC
2750 Monroe Boulevard
Audubon, Pennsylvania 19403

Re: Request for application under the Federal Power Act, section 202(c) (16 USC § 824a(c)) for an order for continued operation of the Brandon Shores and Wagner Power Plants.

Dear Mr. Takahashi and Mr. Asthana:

The Maryland Office of the People's Counsel of Maryland ("OPC") writes to ask PJM Interconnection, LLC ("PJM") to establish a backstop to ensure reliability is maintained for Maryland electric customers in the wake of certain threats to that reliability made in filings with the Federal Energy Regulatory Commission ("FERC"). Specifically, we request that PJM prophylactically request the Secretary of the Department of Energy to issue an order under the Federal Power Act ("FPA"), section 202(c), directing Talen Energy Corporation and its two subsidiaries, Brandon Shores LLC and Wagner LLC (collectively referred to here as "Talen"), to maintain service after May 31, 2025, should Talen take steps to act upon its threat to cease to operate the Brandon Shores and Wagner power plants (the "Power Plants").[1]

As you are aware, PJM has determined that the continued operation of the Power Plants following June 1, 2025, is required until certain transmission upgrades can be completed in order to avoid certain grid reliability criteria violations. Following this determination by PJM, Talen filed with FERC on April 18, 2024, to provide Part V Reliability Service, under the terms of PJM's Open Access Transmission Tariff ("OATT")

[1] FPA, § 202(c) (16 USC §824a(c)) and its implementing regulations provide that PJM may request an order to require operation of electric facilities on a temporary basis to address emergencies due to, among other causes, a "shortage... of facilities for the generation or transmission of electric energy...." *See also* 10 CFR §205.371 (the "emergency" supporting resort to a §202(c) order may include "an unexpected inadequate supply of electric energy..."). The Secretary of the Department of Energy exercises the authority conferred by FPA, §202(c), pursuant to 42 USC §7151(b).

(also referred to as “reliability must-run" or “RMR” service) commencing on June 1, 2025, through operation of the Power Plants. FERC opened two dockets to consider Talen’s filings, ER24-1787 (for Wagner) and ER24-1790 (for Brandon Shores). In these filings (the “Talen Initial Filings”), Talen expressly opted for the “cost of service” method of compensation as provided under OATT, sec. 119, as determined by FERC.

A number of parties objected to the level of compensation sought by Talen, including OPC, and FERC, in its initial order in the proceedings, set the matters for hearing and settlement procedures.[2] Following that FERC order, Talen and certain other consenting parties, including PJM, agreed to settle the matter and Talen filed with FERC proposed joint settlement offers (“JSOs”) on January 27, 2025, seeking FERC approval.

In its cover letters to the JSOs filings at FERC, Talen states:

> Failure by the Commission to approve the Offer[s] of Settlement would result in not only collapse of the settlement process but also the permanent deactivation of the [Power Plants] .... before the completion of the transmission upgrades that PJM has stated are critically needed. [Talen] cannot, and will not, be in a position where it continues to operate its facility, contrary to its wishes, yet does not know the rates, terms, or conditions of such service. The Commission has been clear that it cannot force [the Power Plants] ... to run. Absent approval of the Offer of Settlement, however, [Talen] will do just that.[3]

As documented in the comments on the JSOs of Monitoring Analytics, LLC, PJM’s independent market monitor (the “IMM”), and OPC in pleadings filed at FERC dated February 18, 2025, the level of compensation sought by Talen in the JSOs for the provision of Part V Reliability Service from the Power Plants far exceeds any reasonable determination of the cost of service of the Power Plants as is permissible under the FPA and under the standard that Talen elected to follow in its filings with FERC for approval of RMR arrangements for the Power Plants. The IMM and OPC have identified in their filed comments with specificity the excessive level of compensation sought by Talen as identified in the JSOs.[4] Moreover, FERC Trial Staff, in its initial comments on the JSOs, while not objecting to the overall framework of the JSOs, states:

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[2] *H.A. Wagner LLC and Brandon Shores LLC,* 187 FERC ¶ 61,176 (2024).
[3] Talen, Joint Offer of Settlement re: Continuing Operations Rate Schedule Request for Expedited Consideration, Dockets ER24-1787-001, ER24-1790-001 (January 27, 2025), p. 7.
[4] See, OPC, Protest of Contested Settlement, Dockets ER-1787 et al. (Feb. 18, 2025), p. 21; IMM, Comments of the IMM for PJM in Opposition to Offer of Settlement, Dockets ER-1787-001 et al. (Feb. 18, 2025) (Attachment, Affidavit of Joseph E. Bowring on behalf of the IMM, p. 8).

> Trial Staff does not agree with each and every individual component that would be needed to reach the black box Monthly Fixed Cost Charges reflected in the Stipulation. Most importantly, [Talen's] proposed starting net book value for the Facilities, and their interpretation of the Original Cost Test, would be contested and potentially adjusted in a hearing. The same is true of the [Talen's] proposed depreciation methodology for the Facilities and, more generally, the Generators' return on equity and capital structure.[5]

The JSO filings and Talen's recently filed reply comments in support of the JSOs do not provide substantial evidence to counter the comments of OPC and IMM and the supporting affidavit of the IMM, showing that the JSOs' level of compensation is far in excess of just and reasonable rates as required by the FPA. Moreover, FERC Trial Staff in its reply comments, while not objecting to the overall settlement, provide substantial evidence that the level of compensation embodied in the JSOs exceeds the cost of service of the Power Plants by $83 million per year.[6] In filing their comments on the JSOs and objecting to the excessive levels of compensation sought in the JSOs, OPC and IMM are doing no more than pursuing their rights as intervenors in the FERC proceedings addressing Talen's RMR arrangements seeking compliance with the FPA's mandate that rates be "just and reasonable."

The excessive RMR costs are particularly a concern given the extreme impacts on the affordability to ratepayers in the Baltimore metropolitan area due to the concurrent impacts on their wholesale electric power rates beginning on June 1, 2025, including:

> (a) the huge increase in capacity costs resulting from PJM's annual capacity auction conducted in July 2024 for service during the 2025/2026 PJM capacity market delivery year;
>
> (b) the additional increase in capacity costs within the BGE locational deliverability area ("LDA"), in excess of the PJM-footprint wide capacity costs during the 2025/2026 delivery year; and
>
> (c) the beginning of charging for the Talen RMR arrangement costs (particularly as inflated by the level of compensation sought in the JSOs) which start June 1, 2025, a majority of which will be allocated

[5] Trial Staff, Initial Comments of the Commission Trial Staff on Offer of Settlement (Feb. 18, 2025), p. 13.

[6] Trial Staff's reply comments indicate that the JSOs proposed level of compensation is some $83 million/yr. (or 85%) in excess of the "cost of service independently calculated by Trial Staff." Trial Staff, Reply Comments of the Commission Trial Staff on Offer of Settlement (February 26, 2025), p. 10.

> to ratepayers in the BGE LDA and will not be offset, during the 2025/26 delivery year, by capacity market revenues attributable to the Power Plants.

The unjust and unreasonable JSOs are even more a concern because the high capacity costs for the 2025/2026 delivery year are directly traceable to the removal of the Power Plants from the supply offers considered in the July, 2024 PJM capacity market auction for the 2025/2026 delivery year commencing on June 1, 2025, and their treatment, instead, as RMR resources, as determined by IMM[7] and OPC,[8] in separate analyses. Moreover, by requiring inclusion of RMR units in capacity auction supply offers in future auctions, in a PJM filing approved by FERC, PJM concurs in that conclusion.[9]

In their protests of the JSOs, both OPC and IMM emphasize their support for continued operation of the Power Plants under RMR arrangements. But that should only occur at levels of compensation that conform to the just and reasonable requirement of the FPA and not the excessive levels as set forth in the JSOs.

Talen's assertion in the JSOs filings—linking the payment of the excessive charges set forth in the JSOs to continued operation of the Power Plants—evidences a raw exercise of improper leverage over the settling parties and the public, exploiting the market power Talen has by virtue of the reliability contributions of the Power Plants. Talen's threat makes clear its implication that anything less will lead Talen to shut down the Power Plants and withdraw from the obligation to provide Part V Reliability Service. As such, it is contrary to the public interest, and contrary to the FPA. Put simply, owners of electric generating units are not permitted to intentionally exercise market power through their decisions relating to their generating units.

Moreover, Talen's asserted premise to its threat to shut down the Power Plants in the event that the JSOs are not summarily approved—namely, that it cannot operate the Power Plants without "know[ing] the rates, terms and conditions of such service"—is infirm. OPC and IMM are not objecting to the non-rate terms and conditions of the JSOs, and Talen is assured of compensation at just and reasonable levels for operation of the

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[7] IMM, *Analysis of the 2025/2026 RPM Base Residual Auction, Part A* (Sep. 20, 2024) ("[H]olding everything constant, the fact that the RMR resources in the BGE LDA [i.e., the Power Plants] were not included in the supply curve at $0-MW day resulted in a 41.2 percent increase in RPM revenues, $4,287,256,309 for the 2025/2026 RPM Base Residual Auction compared to what RPM revenues would have been had the capacity of those RMR resources been included in the supply curve at $0 per MW-day") at 2, 9, 12-13.
[8] *See* Maryland Office of People's Counsel, *Bill and Rate Impacts of PJM's 2025/2026 Capacity Market Results and Reliability Must-Run Units in Maryland* (August 2024, corrected 8/29/24) at 27.
[9] *PJM Interconnection, LLC*, 190 FERC ¶ 61,088 (Feb. 14, 2025) (accepting proposed PJM capacity market rule changes to require inclusion of qualifying RMR units in the capacity market supply stack for future BRAs).

Power Plants. It will receive just and reasonable compensation as determined by FERC. Talen will both (i) receive compensation as filed in Talen's Initial Filings, subject to refund of amounts in excess of FERC's final ruling, immediately from the commencement date of the provision of Part V Reliability Service on June 1, 2025, and (ii) collect compensation that conforms to the FPA's requirements for just and reasonable levels, as determined by FERC in any litigation of the compensation due the Power Plants, should FERC act favorably on the OPC's and IMM's objections.

For the foregoing reasons, OPC requests that PJM, faced with Talen's assertions cited above, prepare an application under FPA, section 202(c), for an order from the Secretary of the Department of Energy to direct continued operation of the Power Plants following May 31, 2025, to allow the Commission to establish procedures to permit a determination of the appropriate level of compensation conforming to the FPA, while assuring and maintaining the continued operation of the Power Plants and the provision of OATT, Part V Reliability Service.

Respectfully,

David S. Lapp
People's Counsel

Cc: Frederick Hoover, Chair, Maryland Public Service Commission (PSC)
Miles Mitchell, General Counsel, PSC
Joseph Bowring, PJM Independent Market Monitor (IMM)
Jeffrey Mayes, General Counsel IMM

2750 Monroe Blvd.
Audubon, PA 19403-2497

Paul McGlynn
VP Planning

February 27, 2024

Bryan C. Hanson
Executive Vice President and Chief Generation Officer
Constellation Energy Generation, LLC
1310 Point Street
Baltimore, MD 21231
bryan.hanson@constellation.com

Re: Deactivation Notice for Eddystone Generating Units #3&4

Dear Mr. Hanson,

This letter is submitted by PJM Interconnection, L.L.C. ("PJM"), in response to the notice submitted by Constellation Energy Generation, LLC dated December 1, 2023 notifying PJM of the intent to deactivate the following generating unit located in the PJM region effective on May 31, 2025:

- Eddystone Generating Units #3&4

In accordance with Section 113.2 of the PJM Open Access Transmission Tariff (PJM Tariff), PJM System Planning and the affected Transmission Owner performed a study of the PJM Transmission System and did not identify any reliability violations resulting from the proposed deactivation of the Eddystone Generating Units #3&4.

Because there are no reliability violations associated with the deactivation of this generator, consistent with Section 113.2 of the PJM Tariff, the generating unit may deactivate on May 31, 2025, or sooner if desired. Please confirm the date on which you will deactivate this generator.

Please be advised that PJM's deactivation analysis does not supersede any outstanding contractual obligations between Eddystone Generating Units #3&4 and any other parties that must be resolved before deactivating this generator.

Also please note that in accordance with the PJM Tariff Part VI, Subpart C, a Generation Owner will lose the Capacity Interconnection Rights associated with a deactivated generating unit one year from the actual Deactivation Date unless the holder of such rights submits a new Generation Interconnection Request within one year after the Deactivation Date.

In addition, if a generating unit is receiving Schedule 2 payments for Reactive Supply and Voltage Control, the generating unit owner must notify PJM in writing when the unit is deactivated. Moreover, in accordance with the requirements of Schedule 2 of the PJM Tariff, the generation unit owner must: (1) submit a filing to the Federal Energy Regulatory Commission ("FERC") to terminate or adjust its cost-based rate schedule to account for the deactivated or transferred unit; or (2) submit an informational filing to the FERC explaining the basis for the decision not to terminate or revise its cost-based rate schedule.

Please contact Augustine Caven (610-666-8200) (Augustine.Caven@pjm.com) in PJM's Transmission Coordination & Analysis Department if you have any questions about the PJM analysis.

Very truly yours,

Paul McGlynn

Paul McGlynn,
VP Planning

cc:
Joseph Bowring, MMU, Joseph.Bowring@monitoringanalytics.com
Adrien Ford; Adrien.Ford@constellation.com
Todd Brecher; Todd.Brecher@constellation.com
Cheryl Petschke; Cheryl.Petschke@constellation.com
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NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

2025 Summer Reliability Assessment

May 2025

Table of Contents

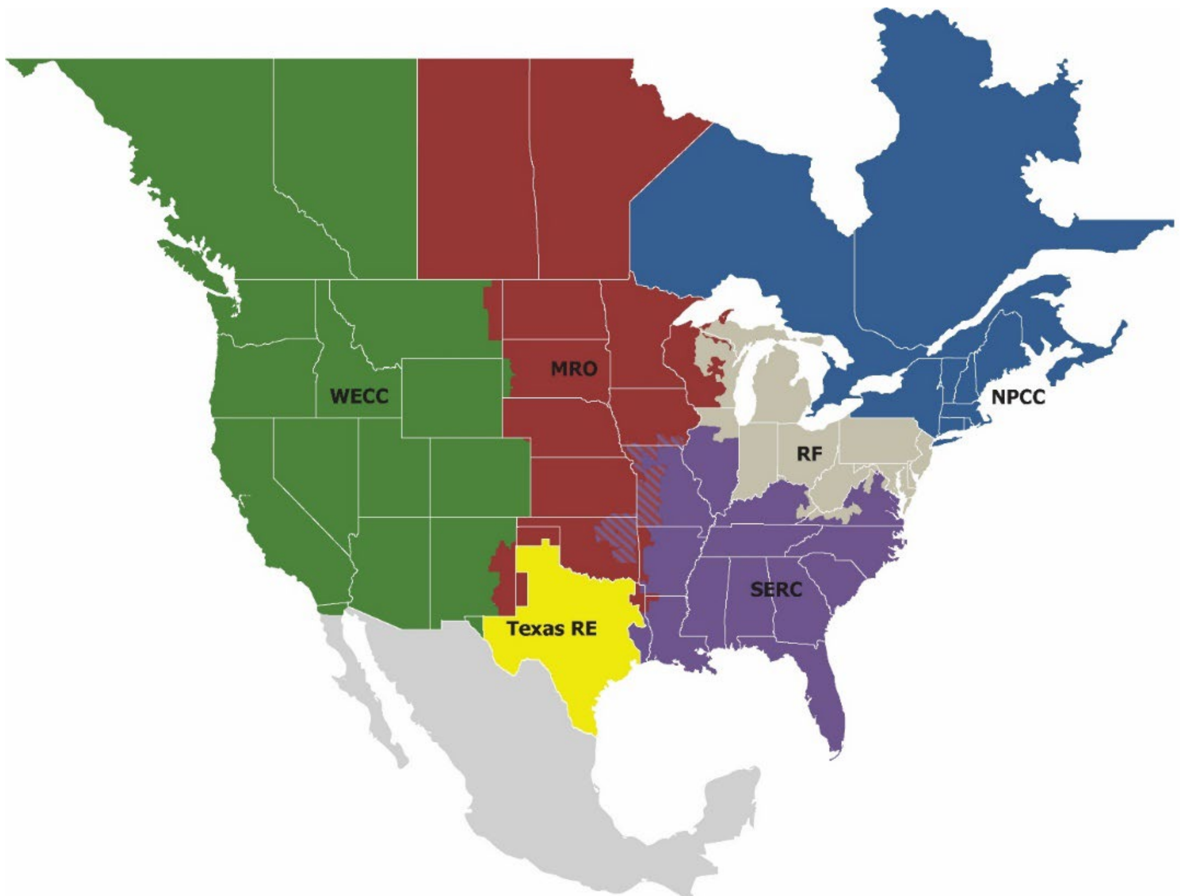
Preface

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

Reliability | Resilience | Security

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

The North American BPS is spans six Regional Entities as shown on the map and in the corresponding table below. The multicolored area denotes overlap as some load-serving entities participate in one Regional Entity while associated Transmission Owners/Operators participate in another.



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

About this Assessment

NERC's *2025 Summer Reliability Assessment* (*SRA*) identifies, assesses, and reports on areas of concern regarding the reliability of the North American BPS for the upcoming summer season. In addition, the *SRA* presents peak electricity demand and supply changes and highlights any unique regional challenges or expected conditions that might affect the reliability of the BPS. The reliability assessment process is a coordinated evaluation between the NERC Reliability Assessment Subcommittee, the Regional Entities, and NERC staff with demand and resource projections obtained from the assessment areas. This report reflects an independent assessment by NERC and the ERO Enterprise and is intended to inform industry leaders, planners, operators, and regulatory bodies so that they are better prepared to take necessary actions to ensure BPS reliability. This report also provides an opportunity for industry to discuss plans and preparations to ensure reliability for the upcoming summer period.

Key Findings

NERC's annual *SRA* covers the upcoming four-month (June–September) summer period. This assessment evaluates generation resource and transmission system adequacy as well as energy sufficiency to meet projected summer peak demands and operating reserves. This includes a deterministic evaluation of data submitted for peak demand hour and peak risk hour as well as results from recently updated probabilistic analyses. Additionally, this assessment identifies potential reliability issues of interest and regional topics of concern. While the scope of this seasonal assessment is focused on the upcoming summer, the key findings are consistent with risks and issues that NERC highlighted in the *2024 Long-Term Reliability Assessment (LTRA)*, which covers a 10-year horizon, and other earlier reliability assessments and reports.[1]

Rising electricity demand forecasts, generation growth, and the increasing pace of change in the resource mix feature prominently in the summer risk profile. Since last summer, the aggregate of peak electricity demand for NERC's 23 assessment areas has risen by over 10 GW—more than double the year-to-year increase that occurred between the summers of 2023 and 2024. Over 7.4 GW of generator capacity (nameplate) has retired or become inactive for the upcoming summer, including 2.5 GW of natural-gas-fired and 2.1 GW of coal-fired generators.[2] Meanwhile, growth in solar photovoltaic (PV) and battery storage resources has accelerated with the addition of 30 GW of nameplate solar PV resources and 13 GW of new battery storage. The new solar and battery resource additions are expected to provide over 35 GW in summer on-peak capacity. New wind resources are expected to provide 5 GW on peak. Operators in many parts of the BPS face challenges in meeting higher demand this summer with a resource mix that, in general, has less flexibility and more variability.

The following findings are derived from NERC and the ERO Enterprise's independent evaluation of electricity generation and transmission capacity as well as potential operational concerns that may need to be addressed for Summer 2025.

Resource Adequacy Assessment and Energy Risk Analysis

All areas are assessed as having adequate anticipated resources for normal summer peak load conditions (see **Figure 1**). However, the following areas face risks of electricity supply shortfalls during periods of more extreme summer conditions. This determination of elevated risk is based on analysis of plausible scenarios, including 90/10 demand forecasts and historical high outage rates as well as low wind or solar PV energy conditions:

- **Midcontinent Independent System Operator (MISO):** MISO is expecting to have an existing certain capacity of 142,793 MW in the *2025 SRA*, which is a slight reduction from the 143,866 MW submitted for the *2024 SRA*. The retirement of 1,575 MW of natural gas and coal-fired generation since last summer, combined with a reduction in net firm capacity transfers due to some capacity outside the MISO market opting out of the MISO planning resource auction, is contributing to less dispatchable generation in MISO. With higher demand and less firm resources, MISO is at elevated risk of operating reserve shortfalls during periods of high demand or low resource output. MISO's most recent energy assessment reveals that the period of highest energy shortfall risk has shifted from July to August. This shift is driven by the decline in dispatchable generation and the increasing share that solar and wind resources have in meeting demand. The risk of supply shortfalls increases in late summer as solar output diminishes earlier in the day, leaving variable wind and a more limited amount of dispatchable resources to meet demand.
- **NPCC-New England:** The New England area expects to have sufficient resources to meet the 2025 summer peak demand forecast. As of April 1, the 50/50 peak summer demand is forecast to be 24,803 MW for the weeks beginning June 1, 2025, through September 14, 2025, with a lowest projected net margin of -1,473 MW (6.0%). The lowest projected net margin assumes a net interchange of 1,245 MW, which is capacity-backed; however, ISO New England (ISO-NE) has typically imported around 3,000 MW during summer peak load conditions. ISO-NE anticipates an increase of approximately 500 MW in forced outages from its generating fleet compared to Summer 2024. Based on NPCC's most recent energy assessment, some use of New England's operating procedures for mitigating resource shortages is anticipated during Summer 2025. Cumulative loss of load expectation (LOLE) of <0.031 days/period, loss of load hours (LOLH) of <0.120 hours/period, and expected unserved energy (EUE) of <94 MWh/period were estimated for the expected load with expected summer resources while the reduced resources and highest peak load scenario resulted in an estimated cumulative LOLE risk of 4.369 days/period, with associated LOLH of 19.554 hours/period and EUE of 19,847 MWh/period.
- **MRO-SaskPower:** For the upcoming summer months, no capacity constraints or reliability issues are expected under normal conditions. However, in the event of generator forced outages of more than 350 MW, combined with above-normal peak demand, SaskPower may need to rely on short-term imports from neighboring utilities. Other remedial actions could include quickly activating demand-response programs, adjusting maintenance schedules, and, if necessary, implementing temporary load interruptions. SaskPower's modeling projects

[1] NERC's long-term, seasonal, and special reliability assessments are published on the Reliability Assessments webpage.

[2] Other retirements include 1.2 GW nuclear capacity following the retirement of some units at the Pickering Nuclear Generator Station in Ontario, and 1.6 GW of petroleum, hydro, and other generation. Source: NERC and EIA data.

the probability of experiencing a generation forced outage exceeding 350 MW to be 21.5%. Assuming maximum available imports, the same modeling projects the number of hours with an operating reserve shortfall this summer to be about 0.65 hours with the highest likelihood occurring in June, estimated at 0.43 hours.

- **MRO-SPP:** SPP's Anticipated Reserve Margin (28.5%) is similar to last summer, and resource shortfalls are not expected for the upcoming Summer 2025 season under normal conditions. However, SPP remains at risk for energy shortfalls if above-normal peak demand periods coincide with low wind output and high generator forced outages. Other known operational challenges for the upcoming season include managing wind energy fluctuations; SPP often experiences sharp ramps of its wind generation that can cause transmission system congestion as well as scarcity conditions.
- **Texas RE-ERCOT:** An additional 7 GW of installed solar PV resource capacity and nearly 7.5 GW in new battery storage is helping ERCOT meet rising summer peak demand. ERCOT is projected to have sufficient operating reserves for the August peak load hour given normal summer system conditions. Nevertheless, continued growth in both loads and intermittent renewable resources drives a risk of emergency conditions in the evening hours when solar generation ramps down and loads remain elevated. ERCOT's probabilistic risk assessment of energy emergency alert (EEA) likelihood for the highest risk periods associated with evening hours in the peak month of August is projected to fall to 3%, down from over 15% in 2024. Lower risk is attributed to a nearly doubling of battery energy storage capacity and improved energy availability from new battery storage and operational rules. The South Texas Interconnection reliability operating limit (IROL) continues to present a system constraint, which, under specific unlikely conditions, could ultimately require ERCOT system operators to direct firm load shedding to remain within IROL limits and prevent cascading load loss. For Summer 2025, this risk is being mitigated by updating transmission line dynamic ratings and switching actions to divert power away from the most limiting transmission circuits.
- **WECC-Mexico:** The WECC-Mexico assessment area in Baja California has a peak summer demand of 3,770 MW and is served by a resource mix that is mainly natural-gas-fired generation, with some geothermal, solar, wind, and oil-fired resources (5,636 MW total installed capacity, of which 4,125 MW are gas-fired generators). WECC-Mexico's 14% Anticipated Reserve Margin exceeds the Reference Margin Level for reliability (10%) calculated by WECC. For the upcoming summer, NERC assesses that historically average generator outage rates for peak demand periods can cause a supply shortfall within the WECC-Mexico assessment area and trigger the need for non-firm resources from neighboring areas. Note, in prior SRA reports, the Baja California portion of the BPS was included as part of the WECC-CA/MX assessment area. The *2025 SRA* includes a new assessment area map for the Western Interconnection. The new assessment area boundaries provide reliability risk information in more geographic detail for the United States and Mexico.

Resource additions since last summer have helped lower the risk of energy shortfalls in several areas. Across the U.S. portion of the Western Interconnection, over 6.5 GW of installed solar capacity has been added, along with nearly 7 GW in battery storage. The resources are expected to provide close to 14 GW in on-peak capacity. In British Columbia, new hydroelectric generators were commissioned, contributing to an additional 500 MW in capacity for the summer. The resource additions have alleviated capacity and energy shortfall risks identified in these assessment areas prior to Summer 2024 and provide supplies across the Western Interconnection.

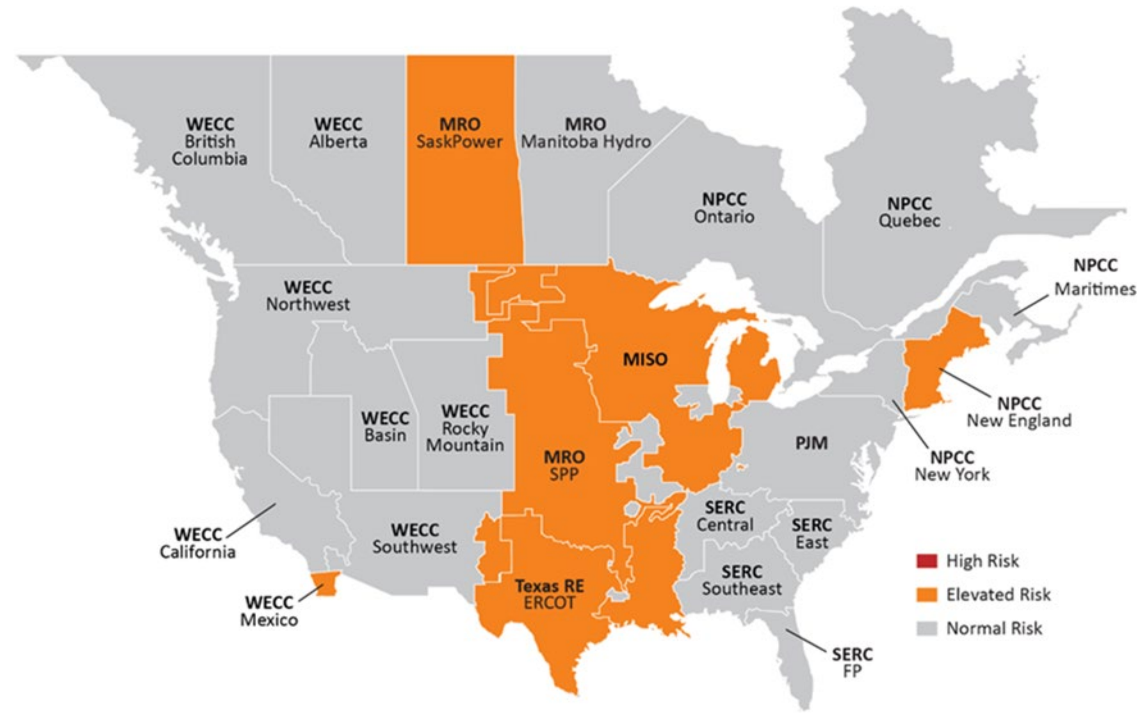


Figure 1: Summer Reliability Risk Area Summary

Seasonal Risk Assessment Summary	
High	Potential for insufficient operating reserves in normal peak conditions
Elevated	Potential for insufficient operating reserves in above-normal conditions
Normal	Sufficient operating reserves expected

Other Reliability Issues

- **Weather services are expecting above-average summer temperatures across much of North America and continued below-average precipitation in the Northwest and Midwest.** In summer-peaking areas, temperature is one of the main drivers of demand and can also contribute to forced outages for generation and other BPS equipment. Average temperatures last summer across the United States and Canada were not as hot as Summer 2023, but Summer 2024 still managed to rank in the top four hottest recorded summers with certain areas breaking records yet again. Few high-level EEAs were issued between June and September 2024, and there were no supply disruptions that resulted from inadequate resources as Balancing Authorities (BA), Transmission Operators (TOP), and Reliability Coordinators (RC) employed a variety of operational mitigations and demand-side management measures. Natural-gas-fired electricity generation broke records last year—highlighting the criticality of natural gas in meeting electric demand. This continuing trend will be key in operator preparations that help to ensure fuel availability for the coming summer. The **Review of 2024 Capacity and Energy Performance** section describes actual demand and resource levels in comparison with NERC's *2024 SRA* and summarizes 2024 resource adequacy events.

- **Load growth is driving higher peak demand forecasts and contributing to resource and transmission adequacy challenges in many areas.** Fifteen of the 23 assessment areas are expecting an increase in peak summer demand from Summer 2024. Aggregated peak demand across all assessment areas has increased by over 10 GW since 2024. This is more than double the increase in peak demand from 2023 to 2024. One of the largest increases is seen in the U.S. West (+5%), where a new peak demand record was set last summer. Extreme heat is reported as a main reliability concern this year among BAs in WECC. With precipitation expected to be lower than average in the Northwest, natural-gas-fired generation and demand-side management could be important in offsetting any lower-than-normal levels of hydroelectric generation availability. SERC Southeast is also projecting a sizable increase in peak demand of more than 2% from NERC's *2024 SRA.* Entities in the assessment area cite economic growth and increased industrial and data mining loads as the main drivers.

- **Aging generation facilities present increased challenges to maintaining generator readiness and resource adequacy.** Forced outage rates for conventional generators and wind resources have trended toward historically high levels in recent years.[3] System operators face increasing risk of resource shortfalls and operating challenges caused by forced generator outages, especially during periods of high demand or when relatively few conventional resources are dispatched to serve load. The threat to BPS reliability can be compounded in areas where aging resources are further depended upon to provide essential reliability services. In the Southwest, for example, a portion of capacity has been in operation for roughly 60 years. Electric utilities in SERC-Central have also described aging generation as a reliability challenge. Historical performance has demonstrated the need for planning assumptions that account for elevated forced outage rates for these generators. Older generators can also require extensive overhauls, such as generator rewinds, that take resources out of service for extended periods of time as discovery work can lead to additional unplanned maintenance.

- **Battery resource additions are helping reduce energy shortfall risks that can arise from resource variability and peaks in demand.** In Texas, California, and across the U.S. West, the influx of battery energy storage systems (BESS) in recent years has markedly improved the ability to manage energy risks during challenging summer periods. These areas can be exposed to energy shortfalls during hours of peak demand and into evening as solar PV output diminishes, but BESS resources that maintain their charge during the day can help meet peak demand and also overcome energy shortfalls on the system that might otherwise occur with solar down-ramps or variability. Natural-gas-fired generation also continues to play an important role in meeting peak demand and flexibly responding to fluctuations output from variable energy resources (VER).

- **Grid operators need to remain vigilant for the potential of inverter-based resources (IBR) to unexpectedly trip during grid disturbances.** While this near-term challenge persists, NERC continues to work diligently with industry to develop long-term solutions to this issue. In April, NERC published the *Aggregated Report on NERC Level 2 Recommendation to Industry: Findings from Inverter-Based Resource Model Quality Deficiencies Alert*.[4] In the report, NERC summarized the deficiencies identified in the Level 2 alert issued in June 2024. The report's findings were as follows:
  - Many grid operators indicated that they did not have the requested data readily available, supporting the previous finding that data acquisition and management was insufficient.
  - Interconnection process requirements are insufficient.
  - Two-thirds of the protection settings used by grid operators are not set to provide the maximum capability. This creates a significant artificial limitation of overall ride-through capability of BPS-connected solar photovoltaic (PV) facilities.
  - 20% of the surveyed facilities use a facility capability with a 0.95 power factor limit, which means that a significant amount of underused reactive capability exists on the BPS.
  - Dynamic model data is inconsistent.

[3] See Key Findings in NERC's [2024 *State of Reliability* report]

[4] *Findings from Inverter-Based Resource Model Quality Deficiencies Alert*

As solar, wind, and battery resources remain the predominant types of resources being added to the BPS, it is imperative for industry, vendors, and manufacturers to take the recommended steps for system modeling and study practices and IBR performance.

- **Operators of natural-gas-fired generators should maintain lines of communication with natural gas system operators to support electric grid reliability.** The 2024 summer season was the fourth hottest on record,[5] and natural-gas-fired generation broke records with a peak monthly average in July of 208 TWh, up 4% from July 2023, per the latest data from the Energy Information Administration (EIA). The EIA projects that rising demand for natural gas exports this year in the wake of ramped up liquefied natural gas (LNG) production combined with lower field production levels could tighten natural gas supplies relative to last summer. Amid year-over-year increases in load projections in most assessment areas, this summer could see another record year for natural-gas-fired generation, thereby stretching supplies even further. Given that late spring and early summer are seasons when natural gas system owners and operators typically perform maintenance requiring system outages, vigilance is needed to ensure the reliability of fuel delivery to natural-gas-fired-generators.[6]
- **Supply chain issues continue to affect lead times for Bulk Electric System (BES) equipment maintenance, replacement, and construction.** While no specific reliability issues for the upcoming summer have been identified, Transmission Owners (TO) and Generator Owners (GO) face delays in parts, materials, and skilled technicians. When summer maintenance preparations or installations are delayed, effects on equipment availability can challenge system operators. Over the long term, supply chain issues and uncertainty continue to affect development. Lead times for transformers remain virtually unchanged, averaging 120 weeks in 2024. Large transformer lead times averaged 80–210 weeks.[7]
- **Wildfire risks in the areas that comprise the Western Interconnection remain ever present.** Wildfire conditions can affect transmission operations by prompting preemptive circuit outages to reduce the risk of fire ignition as well as through fire impacts to transmission infrastructure. Transmission system congestion and reduced import capacity can accompany wildfire conditions. Moreover, fires near wind generation result in curtailment for safety reasons, and solar facilities can be susceptible to range fires. Fire damage to transmission lines interconnected to remote hydro sites in the Pacific Northwest can be particularly problematic with restoration typically taking weeks to months to accomplish.

[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.

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.

[9] See NERC Level 2 Alert: Inverter-Based Resource Performance Issues, March, 2023. Owners and operators of BPS-connected IBRs that are currently not registered with NERC should consult NERC's IBR Registration Initiative for information on the registration process.

Summer Temperature and Drought Forecasts

During the summer season, heat drives peak electricity demand as consumers use more electricity to cool their homes and businesses. Summer 2024 was the fourth hottest summer on record for the United States and Canada, and Summer 2025 is expected to bring similar intensity. Assessment area load forecasts account for many years of historical demand data, often up to 30 years, to predict summer peak demand and prepare for more extreme conditions. According to their probabilistic assessments of the coming summer season, late July and early August are the periods most frequently identified among the assessment areas as the expected period of peak demand. Peak demand hours may not coincide with the highest risk hours in the summer as the resource mix shifts during a 24-hour cycle, particularly when there are prolonged periods of above-normal temperatures. Coordinating pre-season preparations and maintenance remains critical to avoiding forced outages where possible and mitigating risks to BPS reliability.

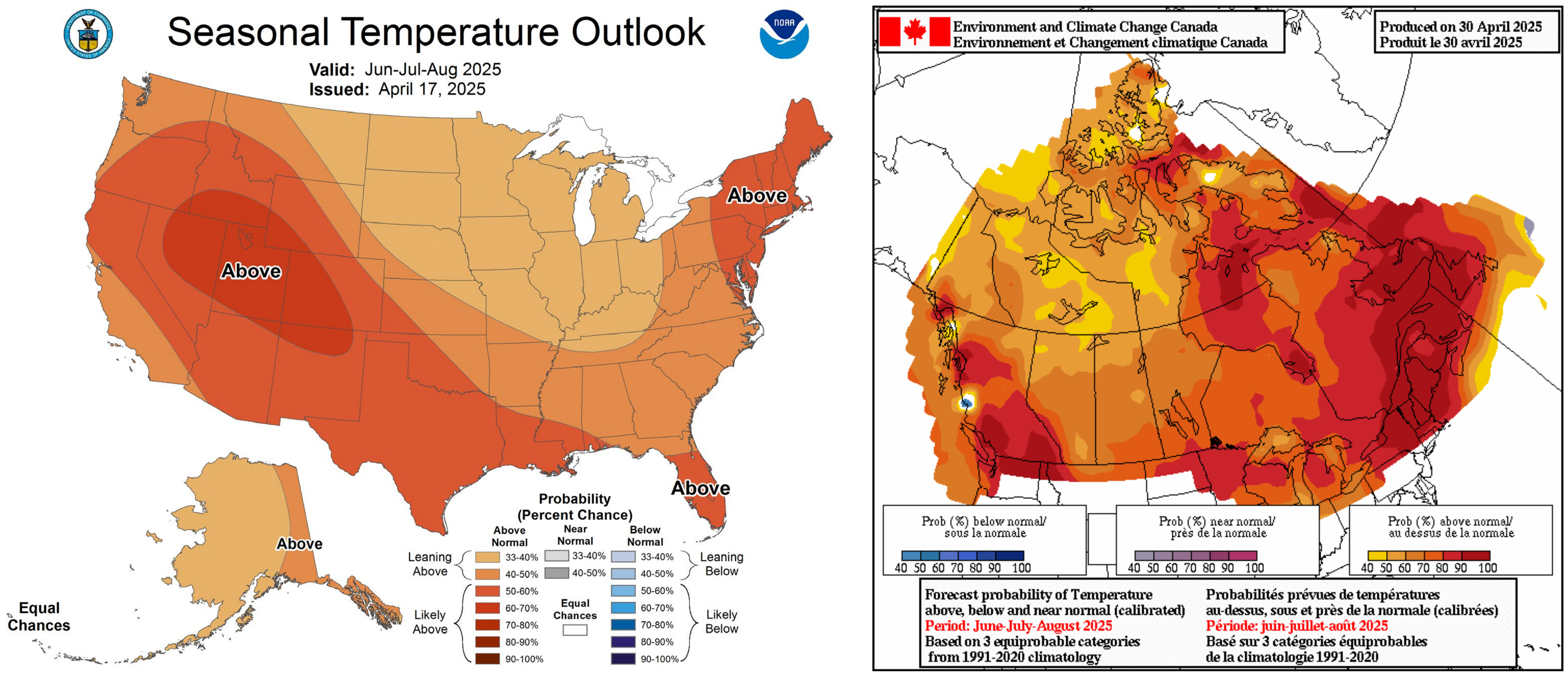


Figure 2: United States and Canada Summer Temperature Outlook[10]

[10] Seasonal forecasts obtained from U.S. National Weather Service and Natural Resources Canada: https://www.cpc.ncep.noaa.gov/products/predictions/long_range/ and https://weather.gc.ca/saisons/prob_e.html

Risk Assessment Discussion

NERC assesses the risk of electricity supply shortfall in each assessment area for the upcoming season by considering Planning Reserve Margins, seasonal risk scenarios, probability-based risk assessments, and other available risk information. NERC provides an independent assessment of the potential for each assessment area to have sufficient operating reserves under normal conditions as well as above-normal demand and low-resource output conditions selected for the assessment. A summary of the assessment approach is provided in **Table 1**.

Table 1: Seasonal Risk Assessment Summary	
Category	**Criteria[1]**
High Potential for insufficient operating reserves in normal peak conditions	• Planning Reserve Margins do not meet Reference Margin Levels • Probabilistic indices exceed benchmarks (e.g., LOLH of 2.4 hours over the season) • Analysis of the risk hour(s) indicates resources will not be sufficient to meet operating reserves under **normal peak-day demand and outage scenarios[2]**
Elevated Potential for insufficient operating reserves in above-normal conditions	• Probabilistic indices are low but not negligible (e.g., LOLH above 0.1 hours over the season) • Analysis of the risk hour(s) indicates resources will not be sufficient to meet operating reserves under **extreme peak-day demand with normal resource scenarios** (i.e., typical or expected outage and derate scenarios for conditions)[2] • Analysis of the risk hour(s) indicates resources will not be sufficient to meet operating reserves under **normal peak-day demand with reduced resources** (i.e., extreme outage and derate scenarios)[3]
Normal Sufficient operating reserves expected	• Probabilistic indices are negligible • Analysis of the risk hour(s) indicates resources will be sufficient to meet operating reserves under normal and extreme peak-day demand and outage scenarios[4]

Table Notes:
[1]The table provides general criteria. Other factors may influence a higher or lower risk assessment.
[2]**Normal resource scenarios** include planned and typical forced outages as well as outages and derates that are closely correlated to the extreme peak demand.
[3]**Reduced resource scenarios** include planned and typical forced outages and low-likelihood resource scenarios, such as extreme low-wind scenarios, low-hydro scenarios during drought years, or high thermal outages when such a scenario is warranted.
[4]Even in normal risk assessment areas, extreme demand and extreme outage scenarios that are not closely linked may indicate risk of operating reserve shortfall.

Assessment of Planning Reserve Margins and Operational Risk Analysis

Anticipated Reserve Margins, which provide the Planning Reserve Margins for normal peak conditions, as well as reserve margins for seasonal risk scenarios of more extreme conditions are provided in **Table 2**.

Table 2: Seasonal Risk Scenario On-Peak Reserve Margins

Assessment Area	Anticipated Reserve Margin	Anticipated Reserve Margin with Typical Outages	Anticipated Reserve Margin with Higher Demand, Outages, Derates in Extreme Conditions
MISO	24.7%	9.3%	-1.9%
MRO-Manitoba	14.6%	11.2%	3.8%
MRO-SaskPower	33.5%	28.3%	22.4%
MRO-SPP	28.5%	18.2%	3.4%
NPCC-Maritimes	42.2%	31.7%	18.6%
NPCC-New England	14.1%	3.9%	4.0%
NPCC-New York	31.6%	12.5%	5.2%
NPCC-Ontario	23.4%	23.4%	3.7%
NPCC-Québec	32.7%	28.2%	19.1%
PJM	24.7%	15.0%	5.3%
SERC-C	19.6%	12.7%	3.2%
SERC-E	29.1%	21.8%	13.0%
SERC-FP	20.2%	14.0%	11.8%
SERC-SE	41.3%	37.7%	12.5%
TRE-ERCOT	43.2%	33.0%	-5.1%
WECC-AB	42.6%	40.3%	20.5%
WECC-Basin	24.3%	15.9%	-27.2%
WECC-BC	24.3%	24.2%	-6.6%
WECC-CA	56.9%	51.0%	4.7%
WECC-Mex	14.1%	1.6%	-16.8%
WECC-NW	32.1%	29.4%	-13.0%
WECC-RM	25.7%	18.2%	-18.9%
WECC-SW	22.3%	14.0%	-13.0%

Seasonal risk scenarios for each assessment area are presented in the **Regional Assessments Dashboards** section. The on-peak reserve margin and seasonal risk scenario charts in each dashboard provide potential summer peak demand and resource condition information. The reserve margins on the right side of the dashboard pages provide a comparison to the previous year's assessment. The seasonal risk scenario charts present deterministic scenarios for further analysis of different demand and resource levels with adjustments for normal and extreme conditions. The assessment areas determined the adjustments to capacity and peak demand based on methods or assumptions that are summarized in the seasonal risk scenario charts; more information about these dashboard charts is provided in the **Data Concepts and Assumptions** section.

The seasonal risk scenario charts can be expressed in terms of reserve margins: In **Table 2**, each assessment area's Anticipated Reserve Margins are shown alongside the reserve margins for a typical generation outage scenario (where applicable) and the extreme demand and resource conditions in their seasonal risk scenario.

Highlighted in **orange** are the areas identified as having resource adequacy or energy risks for the summer in the **Key Findings** section. The typical outage reserve margin includes anticipated resources minus the capacity that is likely to be in maintenance or forced outage at peak demand. If the typical maintenance or forced outage margin is the same as the Anticipated Reserve Margin, it is because an assessment area has already factored typical outages into the anticipated resources. The extreme conditions margin includes all components of the scenario and represents the most severe operating conditions of an area's scenario. Note that any reserve margin below zero indicates that the resources fall below demand in the scenario.

In addition to the peak demand and seasonal risk hour scenario charts, the assessment areas provided a resource adequacy risk assessment that was probability-based for the summer season. Results are summarized in **Table 3**. The risk assessments account for the hour(s) of greatest risk of resource shortfall. For most areas, the hour(s) of risk coincides with the time of forecasted peak demand; however, some areas incur the greatest risk at other times based on the varying demand and resource profiles. Various risk metrics are provided and include LOLE, LOLH, EUE, and the probabilities of an EEA occurrence.

Energy Emergency Alerts

Extreme generation outages, low resource output, and peak loads similar to those experienced in wide-area heat events and the heat domes experienced in western parts of North America during the last three summers are ongoing reliability risks in certain areas for Summer 2025. When forecasted resources in an area fall below expected demand and operating reserve requirements, BAs may need to employ operating mitigations or EEAs to obtain the capacity and energy necessary for reliability. A description of each EEA level is provided below.

Energy Emergency Alert Levels

EEA Level	Description	Circumstances
EEA1	All available generation resources in use	• The BA is experiencing conditions in which all available generation resources are committed to meet firm load, firm transactions, and reserve commitments and is concerned about sustaining its required contingency reserves. • Non-firm wholesale energy sales (other than those that are recallable to meet reserve requirements) have been curtailed.
EEA2	Load management procedures in effect	• The BA is no longer able to provide its expected energy requirements and is an energy-deficient BA. • An energy-deficient BA has implemented its operating plan(s) to mitigate emergencies. • An energy-deficient BA is still able to maintain minimum contingency reserve requirements.
EEA3	Firm load interruption is imminent or in progress	• The energy-deficient BA is unable to meet minimum contingency reserve requirements.

Table 3: Probability-Based Risk Assessment		
Assessment Area	**Type of Assessment**	**Results and Insight from Assessment**
MISO	The Planning Year 2025–2026 LOLE Study Report, an annual LOLE probabilistic study[11]	The values for LOLH and EUE are taken from the assessment report noted, where the annual LOLE is set at 1 day in 10 years, or 0.1 LOLE for the summer season. For Summer 2025, LOLH is 0.252 hrs/year and EUE is 626.2 MWH/year for the Reference Margin Level. Expectations for load-loss and unserved energy are less than these amounts because MISO's resources are above the Reference Margin Level.
MRO-Manitoba	The 2024 LOLE Study	Manitoba Hydro's probability-based resource adequacy risk assessment for the summer (June–September) season is that there is a low risk of resource adequacy issues. The study indicated Annual Probabilistic Indices for the Manitoba Hydro system for 2026 of 5 MWh per year of EUE, considering a range of flow conditions, and that all of this risk would be in the higher load winter season. The increases in Manitoba load since the 2022 LOLE Study were more than offset by a reduction in long-term exports contract with the expiration of a major export sale in April 2025.
MRO-SaskPower	Probability-based capacity adequacy assessment Summer 2025	According to the study, SaskPower's expected number of hours with an operating reserve shortfall between June and September is about 0.65 hours, assuming maximum available imports. June has the highest likelihood of an EEA, estimated at 0.43 hours. For Summer 2025, the projected probability of experiencing a generation forced outage exceeding 350 MW stands at 21.5%. This number represents an approximation of the likelihood, during any given hour of the summer period, of encountering a generation forced outage surpassing the 350 MW threshold.
MRO-SPP	2024 NERC *LTRA* with Probabilistic Assessment (ProbA)	With the current SPP fleet, the ProbA base case Year 2 produced no LOLE.
NPCC	NPCC conducted an all-hour probabilistic assessment that consisted of a base case and several more severe scenarios examining low resources, reduced imports, and higher loads. The highest peak load scenario has a 7% probability of occurring.	NPCC Regional Entity assesses that there will be an adequate supply of electricity across the Regional Entity this summer. Necessary strategies and procedures are in place to deal with operational challenges and emergencies as they may develop. Preliminary results of the probabilistic analysis by assessment area are below. NPCC anticipates releasing the assessment in May.
NPCC-Maritimes		NPCC's assessment results indicate that Maritimes expects minimal LOLE, LOLH, and EUE over the May–September period, with the highest risk occurring in July and August. The assessment projected LOLE at less than 0.089 days per period, LOLH at less than 0.4 hours per period, and EUE at less than 16.5 MWh per period under the reduced resources and highest peak demand scenario.
NPCC-New England		Based on NPCC's assessment, cumulative LOLE (<0.031 days/period), LOLH (<0.120 hours/period), and EUE (<94 MWh/period) risks were estimated over the summer May to September period for the expected load with expected resources scenario. The highest peak load level conditions with reduced resources scenario resulted in an estimated cumulative LOLE risk (4.369 days/period), with associated LOLH (19.554 hours/period) and EUE (19,847 MWh/period) with the highest risk occurring in June, with some in July and August.
NPCC-New York		Negligible cumulative LOLE (<0.018 days/period), LOLH (<0.054 hours/period), and EUE (33 MWh/period) risks were estimated over the summer May–September period for the expected load with expected resources for the summer. For highest peak load level with low likelihood, reduced resource conditions resulted in an estimated cumulative LOLE risk (1.7 days/period), with associated LOLH (6.5 hours/period) and EUE (4,860 MWh/period) with the highest risk occurring in July and August.

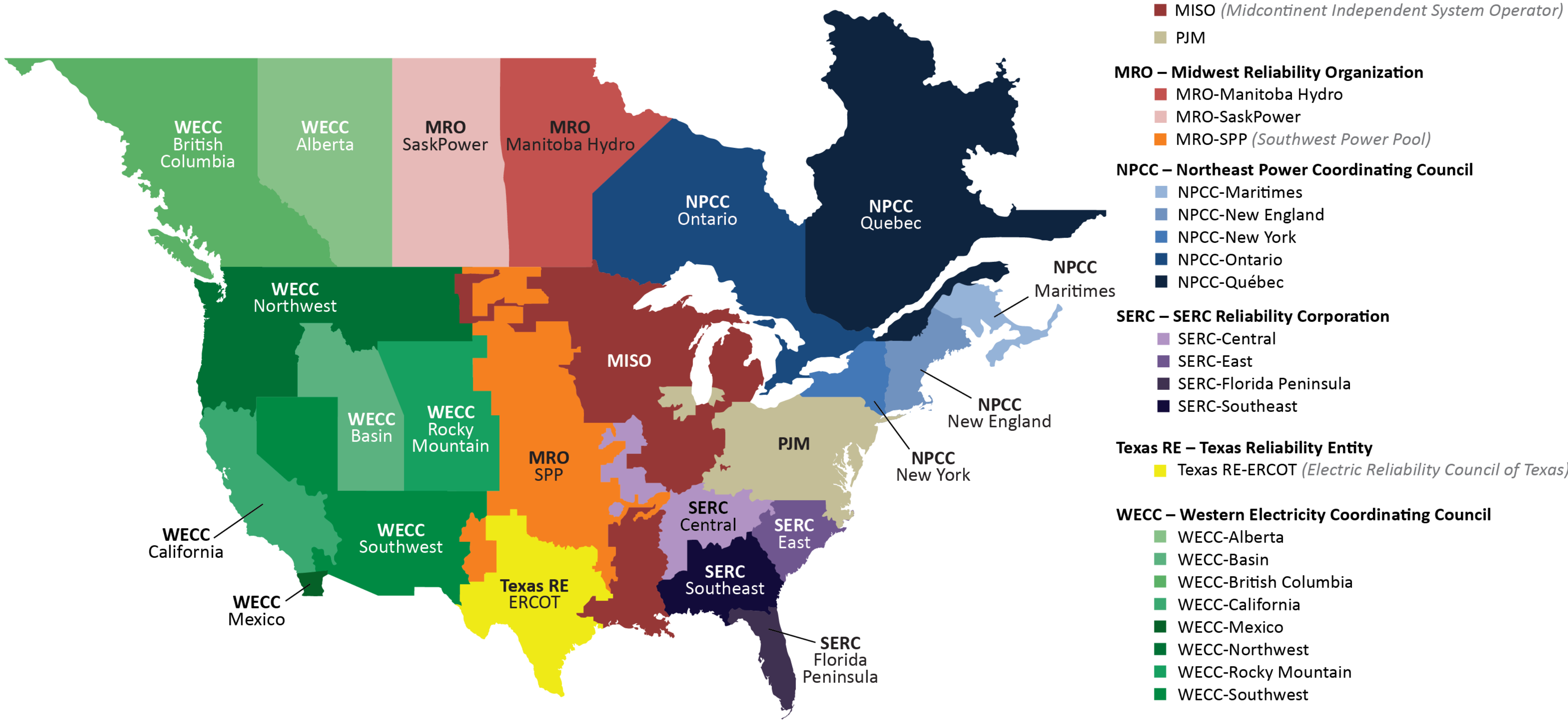
[11] PY 2025–2026 LOLE Study Report

Table 3: Probability-Based Risk Assessment		
Assessment Area	**Type of Assessment**	**Results and Insight from Assessment**
NPCC-Ontario		NPCC's preliminary result of this assessment indicates that the low-likelihood resource case, highest peak load level conditions resulted in a negligible cumulative LOLE (0.081 days/period), with associated cumulative LOLH (0.212 hours/period) and EUE (145.4 MWh/period) with the highest risks occurring predominantly in July, with some in August. Negligible cumulative LOLE, LOLH, and EUE risks were estimated over the May–September summer period for the other scenarios modeled.
NPCC-Québec		The Québec assessment area is not expected to require use of their operating procedures designed to mitigate resource shortages during Summer 2025. Québec did not demonstrate any measurable amounts of cumulative LOLE, LOLH, or EUE risks over the May–September summer period for all the scenarios modeled since the system is winter peaking.
PJM	2023 PJM Reserve Requirement Study (RRS)	PJM is expecting a low risk of resources falling below required operating reserves during Summer 2025. PJM is forecasting around 27% installed reserves (including expected committed demand resources), which is above the target installed reserve margin of 17.7% necessary to meet the 1-day-in-10-years LOLE criterion. The Reserve Requirement Study analyzed a wide range of load scenarios (low, regular, and extreme) as well as multiple scenarios for system-wide unavailable capacity due to forced outages, maintenance outages, and ambient derations. Due to the rather low penetration of limited and variable resources in PJM relative to PJM's peak load, the hour with the most loss-of-load risk remains the hour with the highest forecasted demand.
SERC-Central **SERC-East** **SERC-Florida Peninsula** **SERC-Southeast**	2024 NERC *LTRA* with ProbA. For the ProbA, SERC evaluates 8,760 hourly load and 1,900 sequential Monte Carlo simulations. The results are a probability weighted average of cases, including 38 historic weather-years that are applied to load forecasts for years 2026 and 2028. The model applies a range of economic load forecast errors from -4% to 4% and other noted assumptions.	The 2024 ProbA indicates some resource adequacy risk to SERC with the results for the year 2028 showing slightly higher risk than the year 2026. For the entire SERC footprint, Summer 2026 shows a low risk in summer afternoons into evenings, and for Summer 2028, that risk is still low but extends from summer evenings later into summer nights.
Texas RE-ERCOT	ERCOT probabilistic assessment using the Probabilistic Reserve Risk Model	The simulation indicates some risk of having to declare an EEA for hours ending 20 and 21 for the peak load day in August. These two hours have the highest EEA risk (reflecting corresponding high net load conditions) with probabilities of declaring an EEA 3.05% and 1.54%, respectively. This is categorized by ERCOT as "Low risk" per its criteria of hourly EEA probability that is equal to or less than 10%. For the *2024 SRA*, ERCOT reported EEA declaration probabilities for hours ending 20 and 21 of 18.4% and 9.2%, respectively. The large decrease in EEA probabilities is due to the addition of 7,414 MW of BESS capacity.
WECC	2024 Western Assessment on Resource Adequacy employs a probabilistic energy, area-wide assessment, using Multi Area Variable Resource Integration Convolution (MAVRIC) model	

Table 3: Probability-Based Risk Assessment		
Assessment Area	**Type of Assessment**	**Results and Insight from Assessment**
WECC-AB		Probabilistic analysis performed by WECC found no LOLH or EUE for this summer. All resource margins have increased since last summer with the addition of new capacity, including almost 2,700 MW of new natural gas capacity, 1,200 MW of new wind (+27%), 200 MW of new solar (+13%), and 54 MW of new energy storage systems (+27.5%) on-line. The peak hour has moved earlier, to 3:00 p.m. from 4:00 p.m., still in late July.
WECC-Basin		Probabilistic analysis performed by WECC found no LOLH or EUE for this summer. The reserve margins are not anticipated to fall below the reference margin (14%) for the upcoming summer—existing-certain is forecast at 19% with anticipated and prospective at 24%. The area is expected to peak in early July around 3:00 p.m.
WECC-BC		Probabilistic analysis performed by WECC found no LOLH or EUE for this summer. The reserve margins are not anticipated to fall below the reference margin for the upcoming summer. All reserve margins have increased since 2024 due to increased capacity and energy availability. The peak hour for summer is forecast for early August around 4 p.m.
WECC-CA		Probabilistic analysis performed by WECC found no LOLH or EUE for this summer. The reserve margins are not anticipated to fall below the reference margin for the upcoming summer. Reserve margins have increased since last summer with the increased existing-certain and Tier 1 planned capacity more than offsetting the decrease in available demand response.
WECC-Mex		Probabilistic analysis performed by WECC found no LOLH or EUE for this summer. The peak hour is expected to occur in early August around 4:00 p.m. The reserve margins (14%) are not anticipated to fall below the reference margin (10%) for the upcoming summer. An extreme summer peak load is anticipated to be 4,067 MW. Under extreme conditions, typical forced outages are expected to be 472 MW and derates for thermal generation resources are expected to be 330 MW, requiring imports from neighboring areas. The expected operating reserve requirement on peak is 226 MW.
WECC-RM		Probabilistic analysis performed by WECC found no LOLH or EUE for this summer. The peak hour is expected to occur in late July around 4:00 p.m. Summer 2025 reserve margins (existing-certain 25%, and anticipated and prospective 26%) are not anticipated to fall below the reference margin (17%). An extreme summer peak load may be around 15 GW, and the area has 17.3 GW of existing-certain capacity plus 104 MW of planned new resources. Typical forced outages could be 1,044 MW and derates under extreme conditions of 1,561 MW for thermal and 990 MW for wind. The expected operating reserve requirement on peak is 846 MW.
WECC-NW		Probabilistic analysis performed by WECC found no LOLH or EUE for this summer. Summer 2025 peak hour is expected to occur in early July around 5:00 p.m. Reserve margins (existing-certain 29% and anticipated and prospective 32%) are not anticipated to fall below the reference margin (23%). An extreme summer peak load may be around 32,740 MW. Typical forced outages are forecast to be 777 MW with derates for thermal under extreme conditions to be 1,584 MW and 2,649 MW for wind. The expected operating reserve requirement on peak is 1,750 MW.
WECC-SW		Probabilistic analysis performed by WECC found no LOLH or EUE for this summer. The peak hour is expected to occur in early July around 5:00 p.m. The existing-certain 17% reserve margin does not fall below the reference margin (13%) for the upcoming summer. The anticipated and prospective reserve margin rises to 22%. An extreme summer peak load could approach 40 GW during the riskiest hour, while the region is anticipated to have 40.3 GW of existing-certain energy available and an additional 2 GW of Tier 1 planned resources. Typical forced outages are estimated near 3 GW, and derates for thermal under extreme conditions can shave another 3 GW from available energy. The expected operating reserve requirement is 2,119 MW.

Regional Assessments Dashboards

The following assessment area dashboards and summaries were developed based on data and narrative information collected by NERC from the six Regional Entities on an assessment area basis. Guidelines and definitions are in the **Data Concepts and Assumptions** table. On-peak reserve margin bar charts show the Anticipated Reserve Margin compared to a Reference Margin Level that is established for the areas to meet resource adequacy criteria. Prospective Reserve Margins can give an indication of additional on-peak capacity but are not used for assessing adequacy. The operational risk analysis shown in the following regional assessments dashboard pages provides a deterministic scenario for understanding how various factors that affect resources and demand can combine to impact overall resource adequacy. For each assessment area, there is a risk-period scenario graphic; the left **blue** column shows anticipated resources (from the **Demand and Resource Tables**), and the **orange** column at the right shows the two demand scenarios of the normal peak net internal demand (from the **Demand and Resource Tables**) and the extreme summer peak demand determined by the assessment area. The middle **red** or **green** bars show adjustments that are applied cumulatively to the anticipated resources. Adjustments may include reductions for typical generation outages (maintenance and forced not already accounted for in anticipated resources) and additions that represent the quantified capacity from operational tools (if any) that are available during scarcity conditions but have not been accounted for in the *SRA* reserve margins. Resources throughout the scenario are compared against expected operating reserve requirements that are based on peak load and normal weather. The cumulative effects from extreme events are also factored in through additional resource derates or low-output scenarios. In addition, results from a probability-based resource adequacy assessment are shown in the Highlights section of each dashboard. Methods varied by assessment area and provided further insights into the risk conditions forecasted for the summer period.



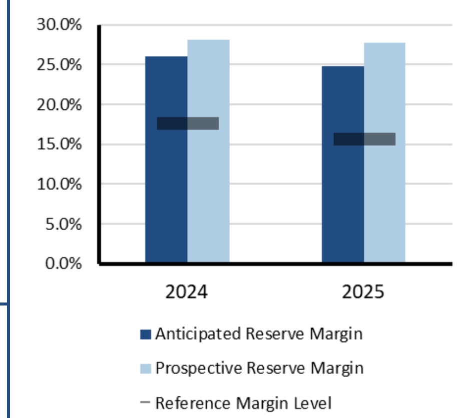
MISO

MISO is a not-for profit, member-based organization that administers wholesale electricity markets that provide customers with valued service; reliable, cost-effective systems and operations; dependable and transparent prices; open access to markets; and planning for long-term efficiency. MISO manages energy, reliability, and operating reserve markets that consist of 36 local BA and 394 market participants, serving approximately 42 million customers. Although parts of MISO fall in three Regional Entities, MRO is responsible for coordinating data and information submitted for NERC's reliability assessments.

Highlights

- Demand forecasts and resource data indicate that MISO is at elevated risk of operating reserve shortfalls during periods of high demand or low resource output.
- The performance of wind and solar generators during periods of high electricity demand is a key factor in determining whether system operators need to employ operating mitigations, such as maximum generation declarations and energy emergencies; MISO has over 31,000 MW of installed wind capacity and 18,245 MW of installed solar capacity; however, the historically based on-peak capacity contribution is 5,616 MW and 9,123 MW, respectively.
- Since last summer, over 1,400 MW of thermal generating capacity has been retired in MISO, and the new generation that has been added is predominantly solar (8,080 MW nameplate/4,140 MW on-peak).
- MISO's most recent energy assessment reveals that the period of highest energy shortfall risk has shifted from July to August.

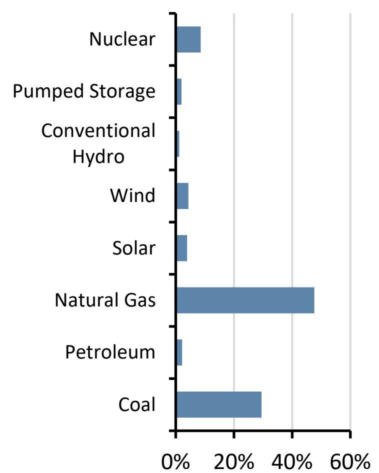
On-Peak Reserve Margin



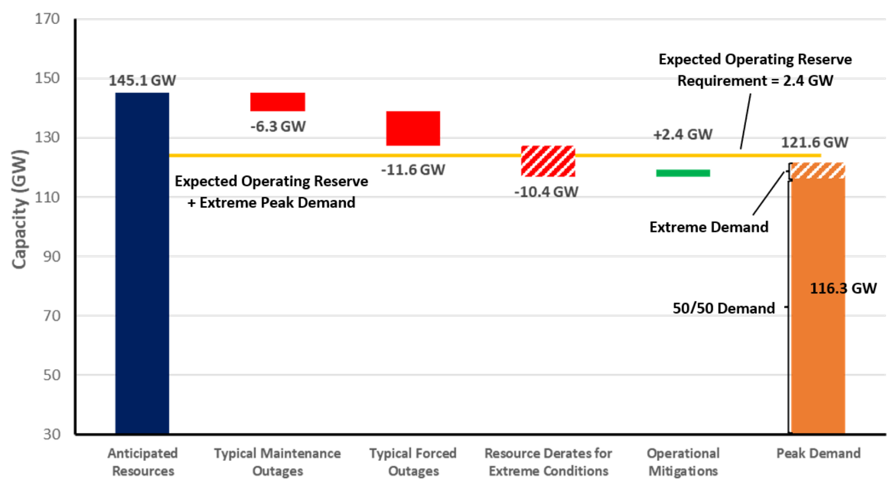
Risk Scenario Summary

Expected resources meet operating reserve requirements under normal peak-demand scenarios. Above-normal summer peak load and extreme generator outage conditions could result in the need to employ operating mitigations (e.g., load-modifying resources and energy transfers from neighboring systems) and EEAs. Emergency declarations that can only be called upon when available generation is at maximum capability are necessary to access load-modifying resources (demand response) when operating reserve shortfalls are projected.

On-Peak Fuel Mix



2025 Summer Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

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

Demand Scenarios: Net internal demand (50/50) and (90/10) demand forecast using 30 years of historical data

Maintenance Outages: Rolling five-year summer average of maintenance and planned outages

Forced Outages: Five-year average of all outages that were not planned

Extreme Derates: Maximum historical generation outages

Operational Mitigations: A total of 2.4 GW capacity resources available during extreme operating conditions

MRO-Manitoba Hydro

Manitoba Hydro is a provincial Crown corporation and one of the largest integrated electricity and natural gas distribution utilities in Canada. Manitoba Hydro is a leader in providing renewable energy and clean-burning natural gas. Manitoba Hydro provides electricity to approximately 608,500 electric customers in Manitoba and natural gas to approximately 293,000 customers in southern Manitoba. Its service area is the province of Manitoba, which is 251,000 square miles. Manitoba Hydro is winter peaking. Manitoba Hydro is its own Planning Coordinator (PC) and BA. Manitoba Hydro is a coordinating member of MISO, which is the RC for Manitoba Hydro.

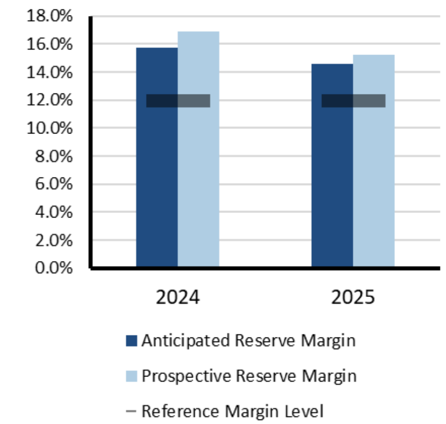
Highlights

- Manitoba Hydro is not anticipating any operational challenges and/or emerging reliability issues in its assessment area for Summer 2025; the Anticipated Reserve Margin for Summer 2025 exceeds the 12% Reference Margin Level.
- While Manitoba Hydro experienced demand growth in the past year, the growth is less than the recent reduction in firm export contracts.
- Manitoba Hydro water supply conditions are below average but improved from this time last year, and above-average winter snowfall will favorably impact spring runoff.
- Manitoba Hydro expects to reliably supply its internal demand and export obligations even if extreme drought develops throughout the year.

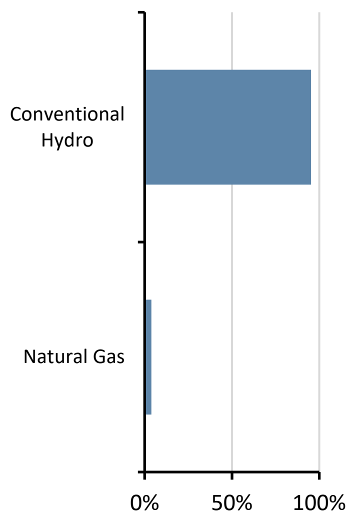
Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed scenarios.

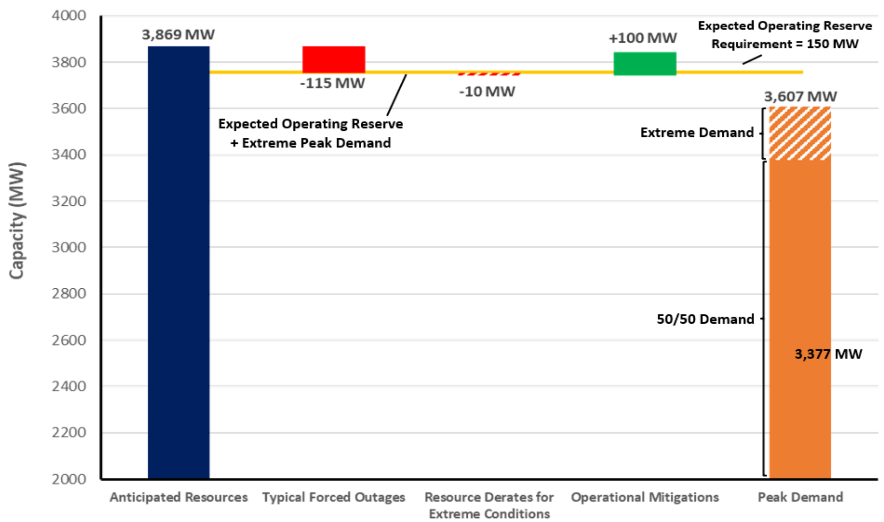
On-Peak Reserve Margin



On-Peak Fuel Mix



2025 Summer Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

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

Demand Scenarios: (50/50) Demand with allowance for extreme demand based on extreme summer weather scenario of 35.4 C (96 F)

Forced Outages: Typical forced outages

Extreme Derates: Summer wind capacity accreditation of 18.1% of nameplate rating based on MISO seasonal analysis

Normal hydro generation expected for this summer.

Operational Mitigations: Utilize Curtailable Rate Program to manage peak demand; utilize operating reserve if additional measures required

MRO-SaskPower

MRO-SaskPower is an assessment area in the Saskatchewan province of Canada. The province has a geographic area of 651,900 square kilometers (251,700 square miles) and a population of approximately 1.1 million. Peak demand is experienced in the winter. The Saskatchewan Power Corporation (SaskPower) is the PC and RC for the province of Saskatchewan and is the principal supplier of electricity in the province. SaskPower is a provincial Crown corporation and, under provincial legislation, is responsible for the reliability oversight of the Saskatchewan BES and its Interconnections.

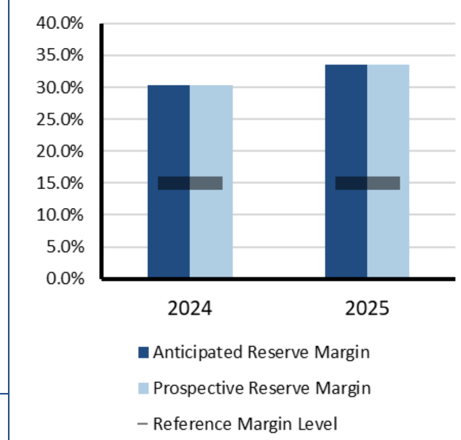
Highlights

- Although Saskatchewan is mainly a winter-peaking region, summer can also bring high electricity demand due to extreme heat.
- Each year, SaskPower works with Manitoba Hydro on a joint summer operating study with input from the Western Area Power Administration and Basin Electric to develop operational guidelines to address any potential challenges.
- The expected number of hours with an operating reserve shortfall between June and September is about 0.65 hours, assuming maximum available imports. The risk of shortfall increases if major unplanned generator outages coincide with scheduled maintenance during peak demand months (June to September). For Summer 2025, the projected probability of experiencing a generation forced outage exceeding 350 MW stands at 21.5%. This number represents an approximation of the likelihood of encountering a generation forced outage surpassing the 350 MW threshold during any given hour of the summer period.
- If extreme heat coincides with significant generation outages, SaskPower will act by activating demand-response programs, arranging short-term power imports from neighboring utilities, and, if necessary, implementing temporary load interruptions to maintain grid stability.

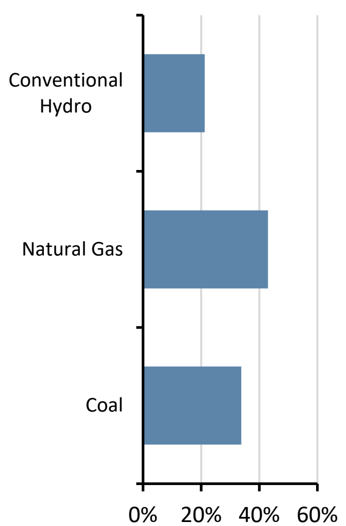
Risk Scenario Summary

Expected resources meet operating reserve requirements under normal peak demand and outage conditions. Above-normal summer peak load and outage conditions are likely to result in the need to employ operating mitigations (e.g., demand response and transfers) and EEAs.

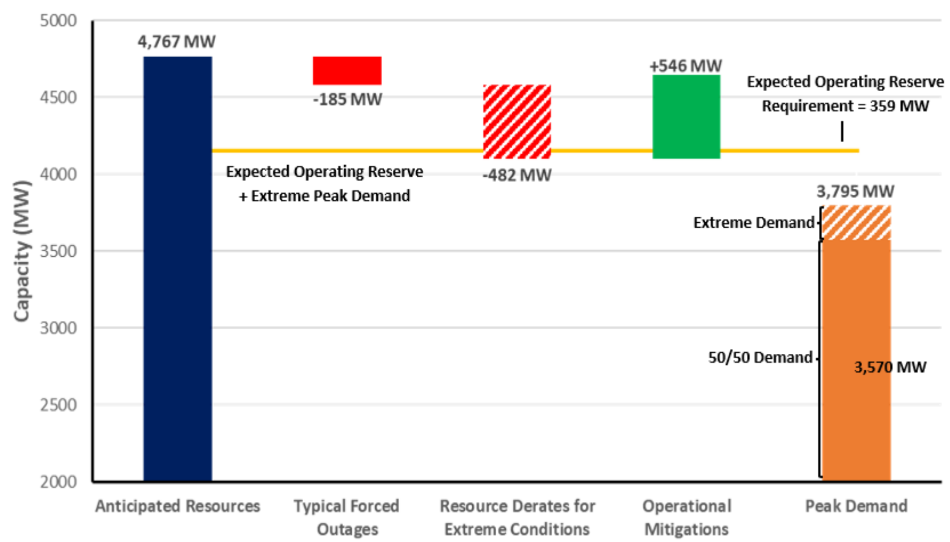
On-Peak Reserve Margin



On-Peak Fuel Mix



2025 Summer Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

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

Demand Scenarios: Net internal demand (50/50) and above-normal scenario based on peak demand with lighting and all consumer loads

Forced Outages: Estimated by using SaskPower forced outage model

Extreme Derates: Estimated resources unavailable in extreme conditions

Operational Mitigations: Estimated non-firm imports and standby generators on 2–7-day notice

MRO-SPP

SPP PC's footprint covers 546,000 square miles and encompasses all or parts of Arkansas, Iowa, Kansas, Louisiana, Minnesota, Missouri, Montana, Nebraska, New Mexico, North Dakota, Oklahoma, South Dakota, Texas, and Wyoming. The SPP long-term assessment is reported based on the PC footprint, which touches parts of the MRO Regional Entity and the WECC Regional Entity. The SPP assessment area footprint has approximately 61,000 miles of transmission lines, 756 generating plants, and 4,811 transmission-class substations, and it serves a population of more than 18 million.

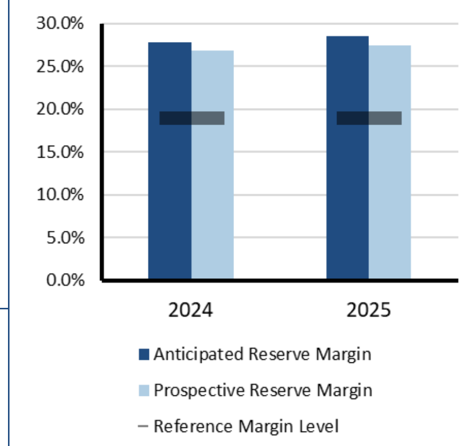
Highlights

- SPP projects a low likelihood of any emerging reliability issues impacting the area for the 2025 Summer season.
- Generation availability is not expected to be impacted by fuel shortages or river conditions this summer.
- BA generation capacity deficiency risks remain depending on wind generation output levels and unanticipated generation outages in combination with high load periods.
- Using the current operational processes and procedures, SPP will continue to assess the resource needs for the 2025 Summer season and will adjust generation and energy supply portfolios as needed to ensure that real-time energy sufficiency is maintained throughout the summer.

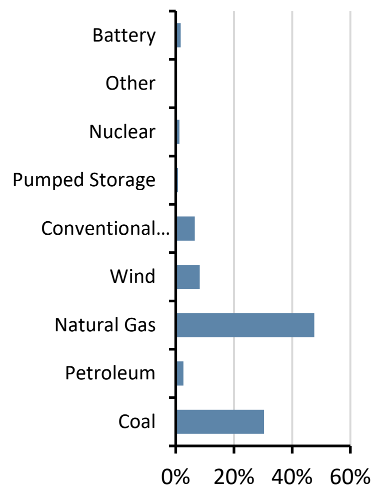
Risk Scenario Summary

Expected resources are sufficient to meet operating reserve requirements under normal peak-demand and outage scenarios. Above-normal summer peak load, low wind conditions, and higher-than-normal forced outages could result in the need for operating mitigations (e.g., demand response and transfers from neighboring systems) and EEAs.

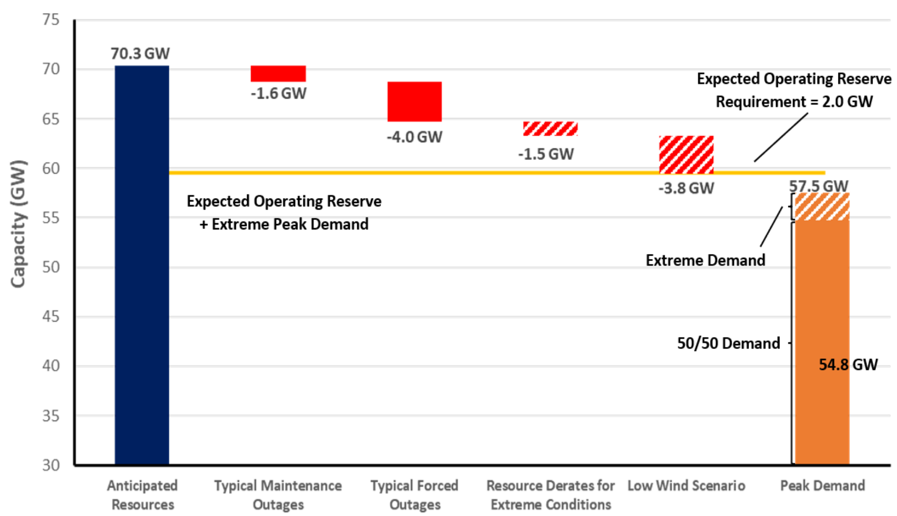
On-Peak Reserve Margin



On-Peak Fuel Mix



2025 Summer Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

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

Demand Scenarios: Net internal demand (50/50) and extreme demand is a 5% increase from net internal demand

Maintenance and Forced Outages: Represent five-year historical averages; calculated from SPP's generation assessment process

Extreme Derates: Additional unavailable capacity from operational data at high-demand periods

Low Wind Scenario: Derates reflecting a low-wind day in the summer

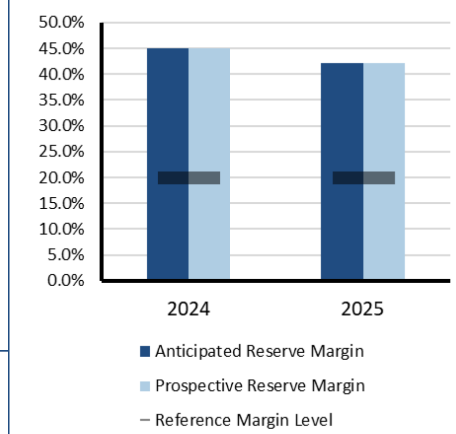
NPCC-Maritimes

The Maritimes assessment area is a winter-peaking NPCC area that contains two BAs. It is comprised of the Canadian provinces of New Brunswick, Nova Scotia, and Prince Edward Island and the northern portion of Maine, which is radially connected to the New Brunswick power system. The area covers 58,000 square miles with a total population of 1.9 million.

Highlights

- As Maritimes is a winter-peaking system, no issues are expected for the upcoming summer assessment period with sufficient firm capacity to meet forecast peak demand. If an event were to occur, emergency operations and planning procedures are in place.
- Probabilistic analysis performed by NPCC for the NPCC *Summer Reliability Assessment* found negligible LOLH and EUE for the expected load and resource levels this summer. A scenario with an extreme high load shape produced minimal amounts of cumulative LOLE (<0.089 days/period), LOLH (<0.4 hours/period), or EUE (< 16.5 MWh/period) over the May–September summer period with the highest risk occurring in July and August.
- Dual-fueled units will have sufficient supplies of heavy fuel oil (HFO) on site to sustain operations in the event of natural gas supply interruptions.

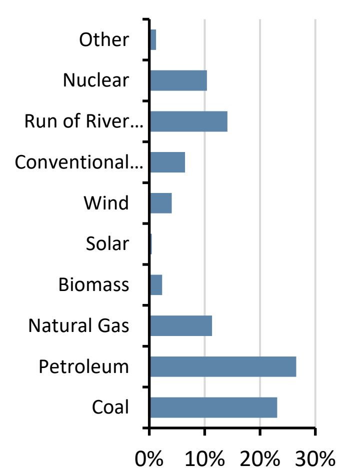
On-Peak Reserve Margin



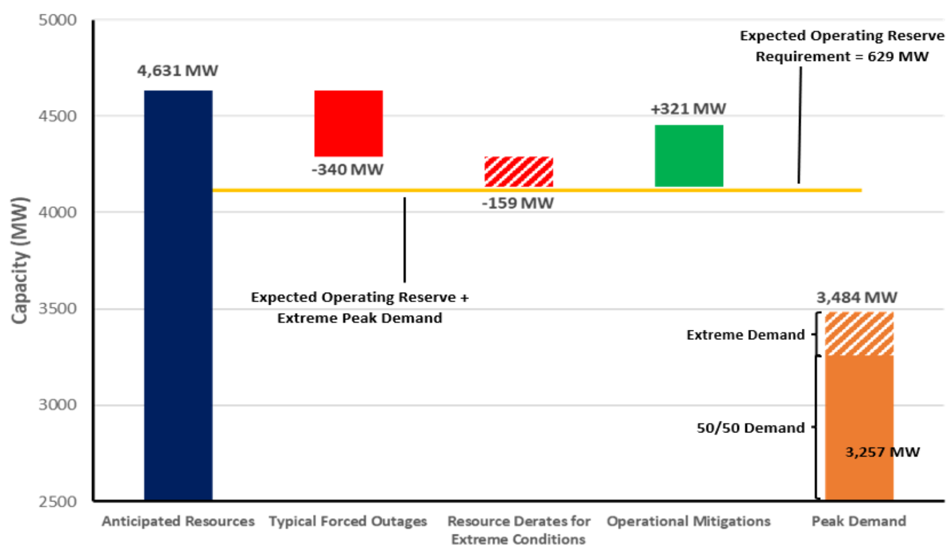
Risk Scenario Summary

Expected resources meet operating reserve requirements under normal peak-demand scenarios. Above-normal summer peak load or extreme outage conditions could necessitate operating mitigations (e.g., demand response and non-firm transfers) and EEAs.

On-Peak Fuel Mix



2025 Summer Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

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

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

Forced Outages: Based on historical operating experience

Extreme Derates: A low-likelihood scenario resulting in an additional 50% derate in the remaining capacity of both natural gas and wind resources under extreme conditions

Operational Mitigations: Imports anticipated from neighbors during emergencies, (e.g. New Brunswick Power System Operator can increase import capability from 200 MW to 550 MW under emergency operations for up to 30 minutes)

NPCC-New England

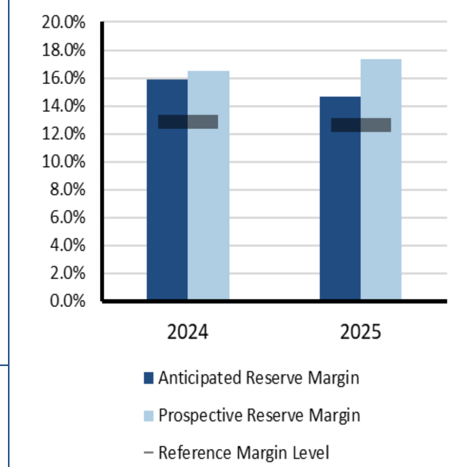
NPCC-New England is an assessment area consisting of the states of Connecticut, Maine, Massachusetts, New Hampshire, Rhode Island, and Vermont that is served by ISO New England (ISO-NE) Inc. ISO-NE is a regional transmission organization that is responsible for the reliable day-to-day operation of New England's bulk power generation and transmission system, administration of the area's wholesale electricity markets, and management of the comprehensive planning of the regional BPS.

The New England BPS serves approximately 14.5 million customers over 68,000 square miles.

Highlights

- ISO-NE forecasts adequate transmission capability and manageable capacity margins to meet the expected peak demand.
- Probabilistic analysis performed by NPCC for the NPCC *Summer Reliability Assessment* identified small amounts of cumulative LOLE, LOLH, and EUE for the expected load with anticipated resources for the summer. A reduced resources and highest peak load level scenario resulted in an estimated cumulative LOLE risk of 4.369 days/period, with associated LOLH (19.554 hours/period) and EUE (19,847 MWh/period). The highest risk occurs in June, with some risk in July and August.
- The NPCC 2025 *Summer Reliability Assessment* will be approved on or about May 12, 2025, and posted on NPCC's website.

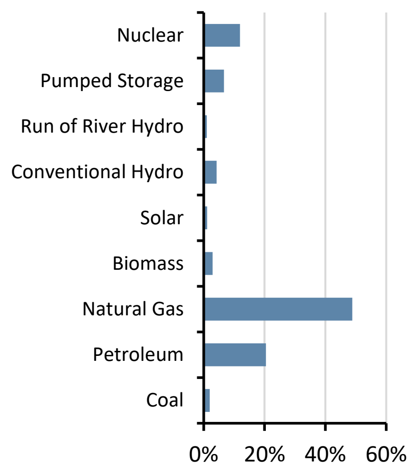
On-Peak Reserve Margin



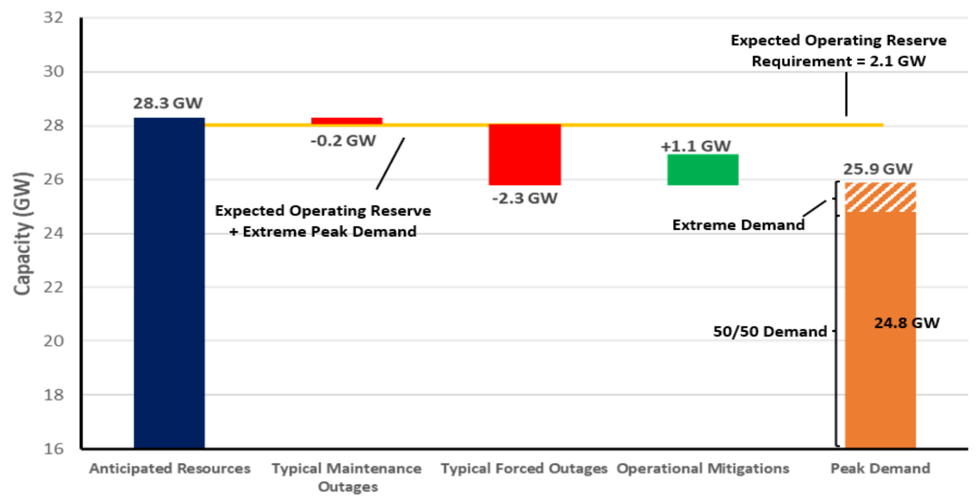
Risk Scenario Summary

Expected resources do not meet operating reserve requirements under normal peak-demand and outage scenarios. Additional non-firm transfers are likely to be needed and available from neighbors. More severe conditions (e.g., above-normal summer peak load and outage conditions) could result in an EEA.

On-Peak Fuel Mix



2025 Summer Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

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

Demand Scenarios: Peak net internal demand (50/50) and (90/10) extreme demand forecast

Maintenance Outages: Based on historical weekly averages

Typical Forced Outages: Based on seasonal capacity of each resource as determined by ISO-NE

Operational Mitigations: Based on load and capacity relief assumed available from invocation of ISO-NE operating procedures

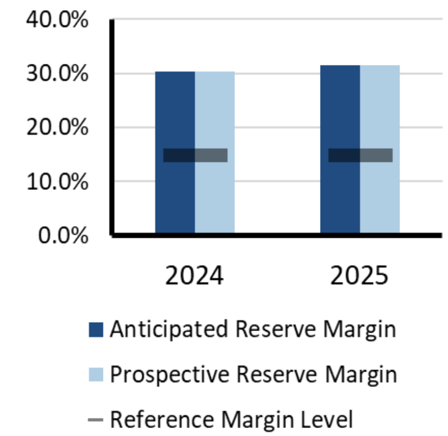
NPCC-New York

NPCC-New York is an assessment area consisting of the New York ISO (NYISO) service territory. NYISO is responsible for operating New York's BPS, administering wholesale electricity markets, and conducting system planning. NYISO is the only BA within the state of New York. The BPS in New York encompasses over 11,000 miles of transmission lines and 760 power generation units and serves 20.2 million customers. For this *SRA*, the established Reference Margin Level is 15%. Wind, grid-connected solar PV, and run-of-river totals were derated for this calculation. However, New York requires load-serving entities to procure capacity for their loads equal to their peak demand plus an Installed Reserve Margin (IRM). The IRM requirement represents a percentage of capacity above peak load forecast and is approved annually by the New York State Reliability Council. The council approved the 2025–2026 IRM at 24.4%.

Highlights

- NYISO is not anticipating any operational issues for the upcoming summer operating period. Adequate reserve margins are anticipated.
- Probabilistic analysis performed by NPCC for the NPCC *Summer Reliability Assessment* found that use of New York's established operating procedures are sufficient to maintain a balance between electricity supply and expected 50/50 demand if needed to mitigate resource shortages during Summer 2025. Negligible cumulative LOLE (<0.018 days/period), LOLH (<0.054 hours/period), and EUE (33 MWh/period) risks were estimated over the summer May to September period for the expected load with expected resources for the summer. The highest peak load level with low likelihood reduced resource conditions resulted in an estimated cumulative LOLE risk (1.7 days/period), with associated LOLH (6.5 hours/period) and EUE (4860 MWh/period) with the highest risk occurring in July and August.
- The NPCC 2025 *Summer Reliability Assessment* will be approved on or about May 12, 2025, and posted on NPCC's website.

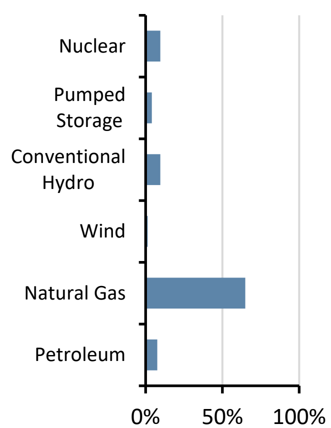
On-Peak Reserve Margin



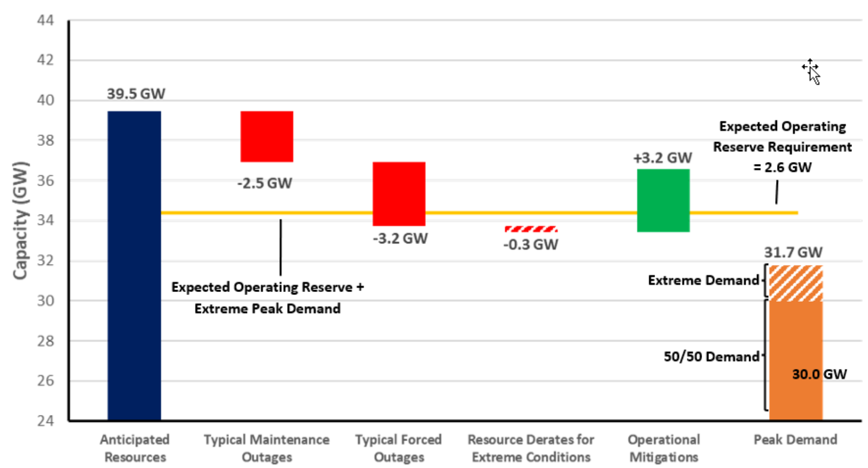
Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed scenarios. Operating mitigations (e.g., demand response and transfers) may be needed to meet above-normal summer peak load and outage conditions.

On-Peak Fuel Mix



2025 Summer Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

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

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

Maintenance Outages: Based on historical performance and the new NYISO capacity accreditation process

Forced Outages: Based on historical five-year averages

Extreme Derates: Estimated resources unavailable in extreme conditions

Operational Mitigations: A total of 3.2 GW based on operational/emergency procedures in area emergency operations manual

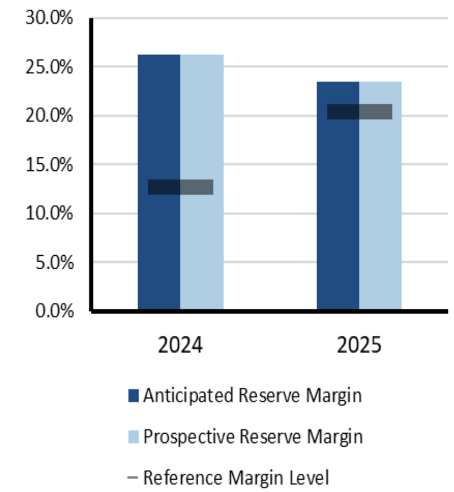
NPCC-Ontario

NPCC-Ontario is an assessment area in the Ontario province of Canada. The Independent Electricity System Operator (IESO) is the BA for the province of Ontario. The province of Ontario covers more than 1 million square kilometers (415,000 square miles) and has a population of m16 million. Ontario is interconnected electrically with Québec, MRO-Manitoba, states in MISO (Minnesota and Michigan), and NPCC-New York.

Highlights

- Overall, Ontario is operating within a period where generation and transmission outages are more challenging to accommodate. The IESO is prepared and expects to have adequate supply for Summer 2025.
- The IESO has been actively coordinating and planning with market participants to maintain reliability.
- This season, the grid will benefit from increased capacity secured through the capacity auction and more planned projects, including new storage, coming into service.
- The IESO is working throughout 2025 to better integrate storage solutions into the electricity markets.
- Starting with this seasonal assessment, demand is forecasted by using probabilistic weather modeling, comparable to the methodology used in the IESO 18-month *Reliability Outlook* as opposed to the previous approach of using weather scenarios."

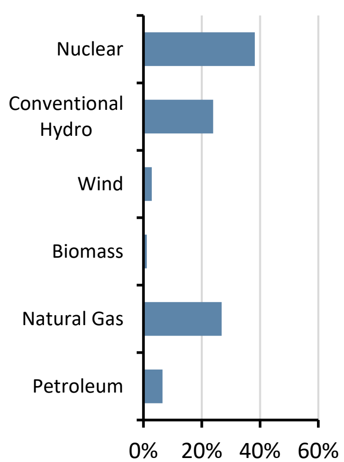
On-Peak Reserve Margin



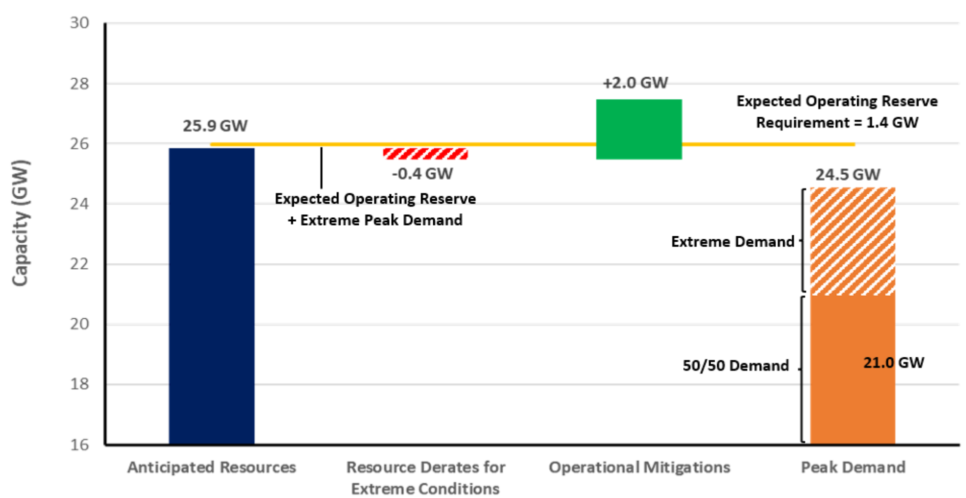
Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed scenarios.

On-Peak Fuel Mix



2025 Summer Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

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

Demand Scenarios: Net internal demand (50/50 forecast) and highest weather-adjusted daily demand based on 31 years of demand history, and extreme weather represents a 97/3 distribution of probabilistically modelled data

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

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

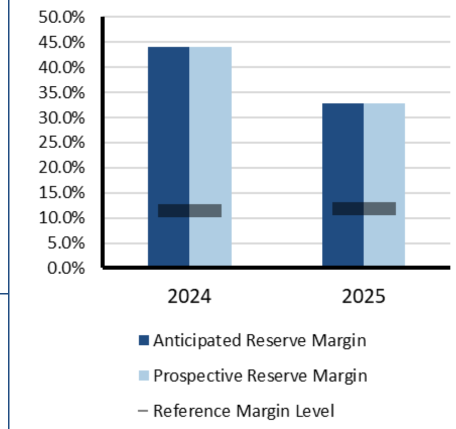
NPCC-Québec

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

Highlights

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

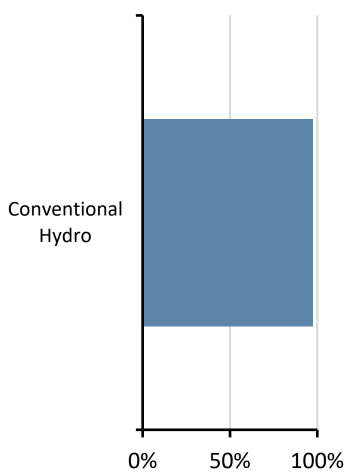
On-Peak Reserve Margin



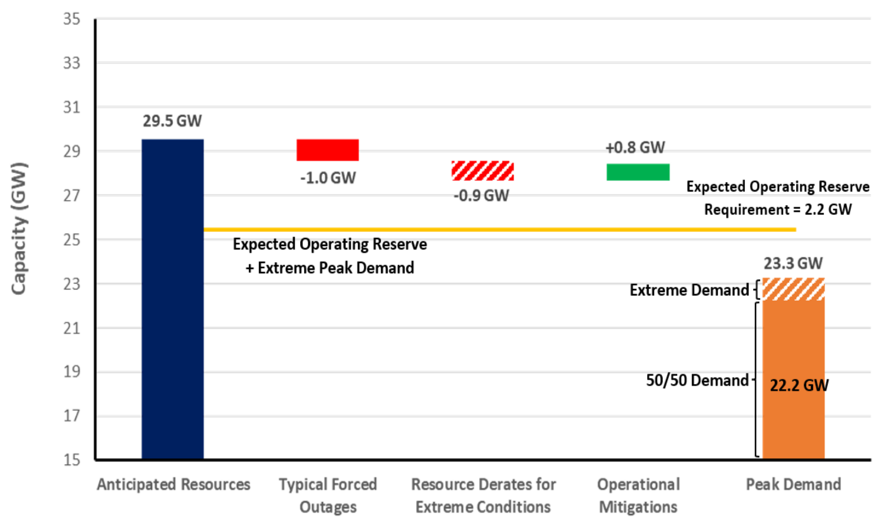
Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed scenarios.

On-Peak Fuel Mix



2025 Summer Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

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

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

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

PJM

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

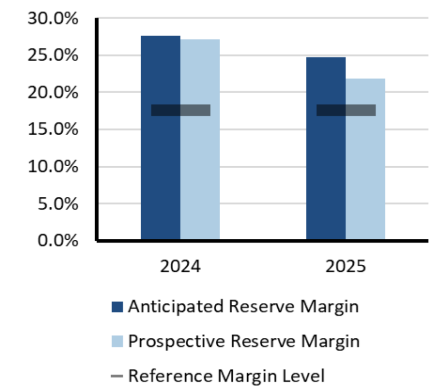
Highlights

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

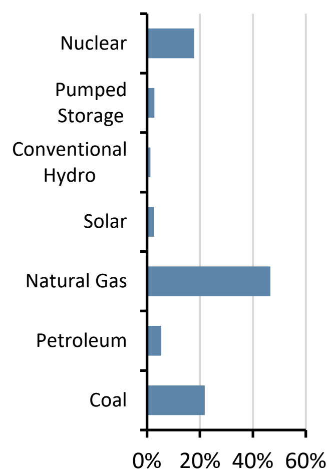
Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed scenarios.

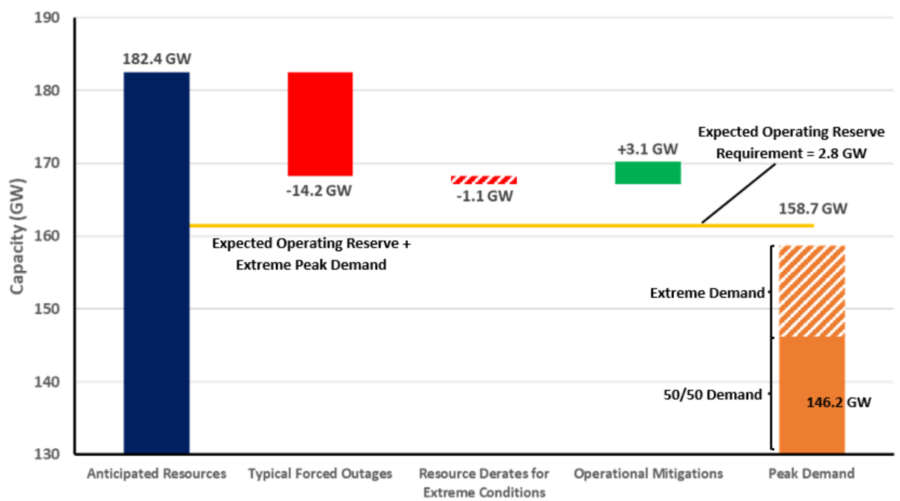
On-Peak Reserve Margin



On-Peak Fuel Mix



2025 Summer Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

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

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

Forced Outages: Based on historical data and trending

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

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

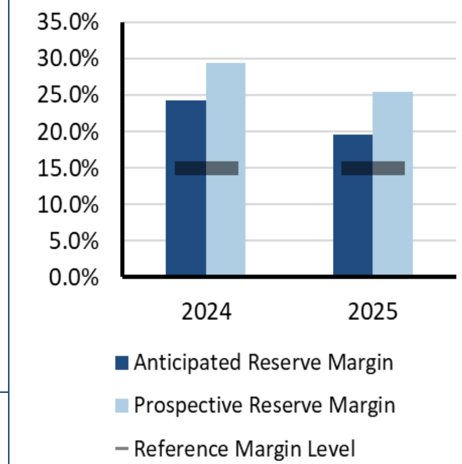
SERC-Central

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

Highlights

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

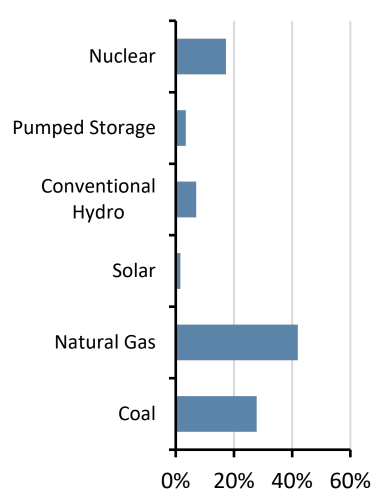
On-Peak Reserve Margin



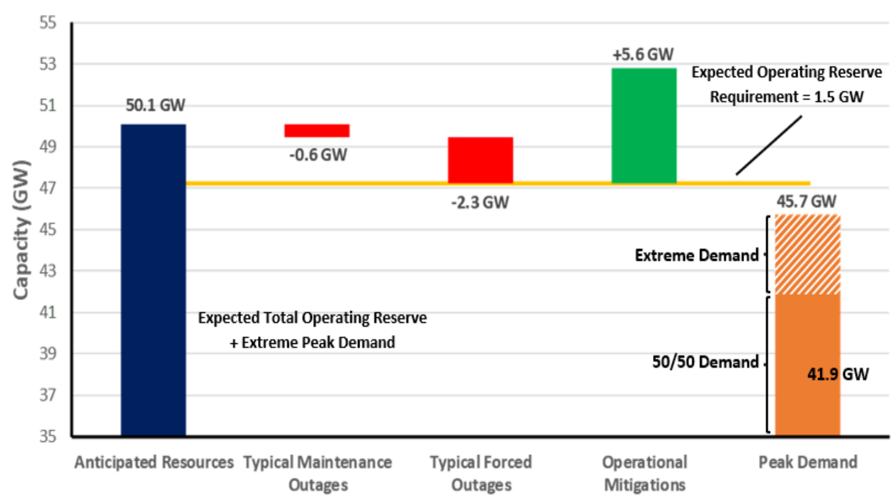
Risk Scenario Summary

Expected resources meet operating reserve requirements under assessed scenarios. More severe conditions (e.g., above-normal summer peak load and outage conditions) result in the need for additional non-firm transfers available from neighbors.

On-Peak Fuel Mix



2025 Summer Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

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

Demand Scenarios: Net internal demand (50/50) and extreme demand forecast based on extreme summer weather (equals or exceeds the (90/10) demand forecast)

Maintenance Outages: Adjusted for higher outages resulting from extreme summer temperatures and aggregated on a SERC subregional level

Forced Outages: Accounts for reduced thermal capacity contributions due to performance in extreme conditions

Operational Mitigations: 5.6 GW based on operational/emergency procedures

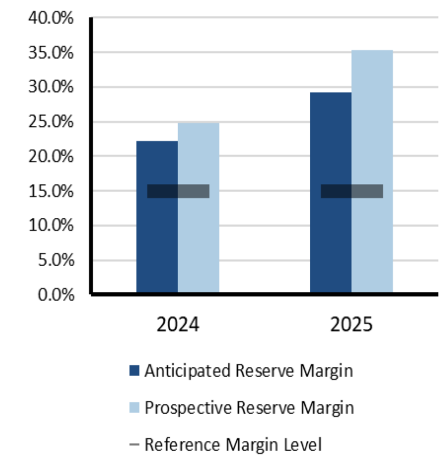
SERC-East

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

Highlights

- SERC-East's reserves are largely unchanged compared to the reference margin as compared to last summer's assessment.
- SERC-East's anticipated resources meet operating reserve requirements under the expected conditions and under the summer risk period scenario.
- While the last probabilistic analysis indicated that SERC-East could face potential unserved energy in summer, the 2026 and 2028 probabilistic analysis found the SERC-East unserved energy risk has shifted to winter mornings.
- Members of SERC-East actively participate in the SERC working groups to perform coordinated studies and develop mitigating actions for any potential or emerging reliability impacts on transmission and resource adequacy.

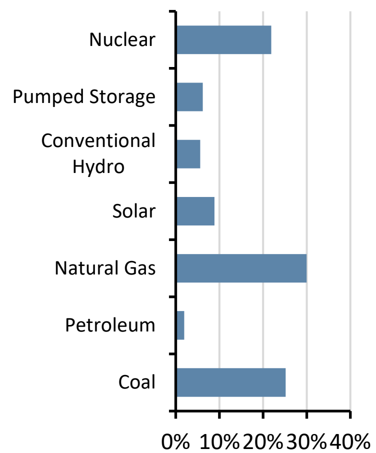
On-Peak Reserve Margin



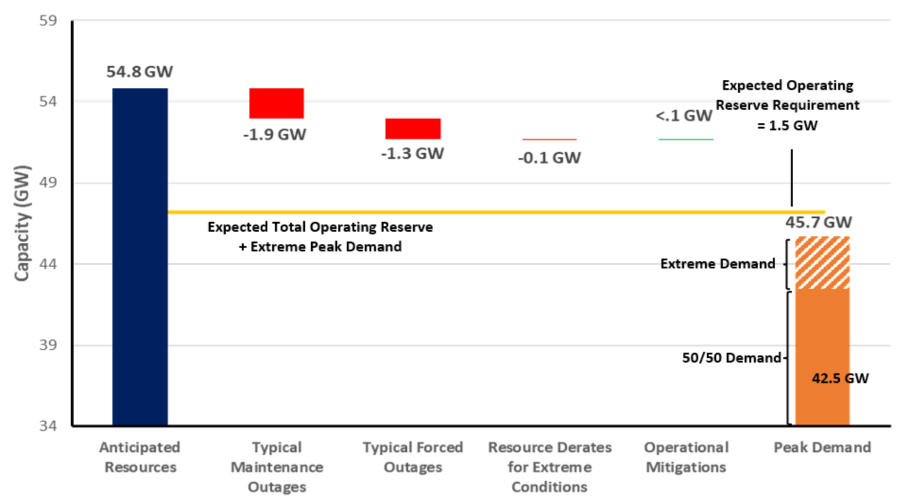
Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed scenarios.

On-Peak Fuel Mix



2025 Summer Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

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

Demand Scenarios: Net internal demand (50/50) and extreme demand forecast based on extreme summer weather (equals or exceeds the (90/10) demand forecast)

Maintenance Outages: Adjusted for higher outages resulting from extreme summer temperatures and aggregated on a SERC subregional level

Forced Outages: Accounts for reduced thermal capacity contributions due to performance in extreme conditions

Operational Mitigations: A total of 45 MW based on operational/emergency procedures

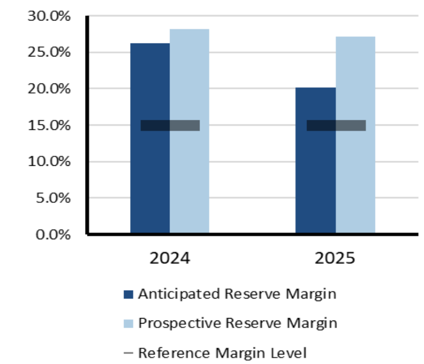
SERC-Florida Peninsula

SERC-Florida Peninsula is a summer-peaking assessment area within SERC. SERC is one of the six companies across North America that are responsible for the work under FERC-approved delegation agreements with NERC. SERC is specifically responsible for the reliability and security of the electric grid across the Southeastern and Central areas of the United States. This area covers approximately 630,000 square miles and serves a population of more than 91 million. The SERC Regional Entity includes 36 BAs, 28 planning entities, and 6 RCs.

Highlights

- SERC Florida-Peninsula's anticipated resources meet operating reserve requirements under the expected conditions and under the summer risk period scenario.
- The probabilistic analysis metrics indicate adequate energy resources for the subregion during the summer.
- Members of SERC-Florida Peninsula actively participate in the SERC working groups to perform coordinated studies and develop mitigating actions for any potential or emerging reliability impacts on transmission and resource adequacy.
- Entities have not identified any emerging reliability issues or operational concerns for the upcoming summer season.

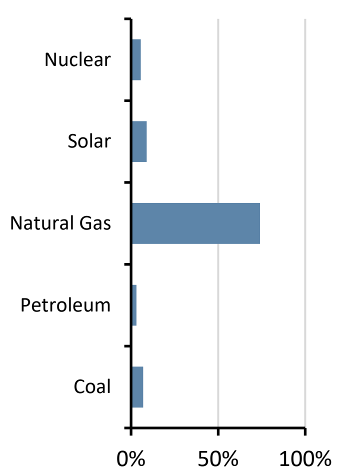
On-Peak Reserve Margin



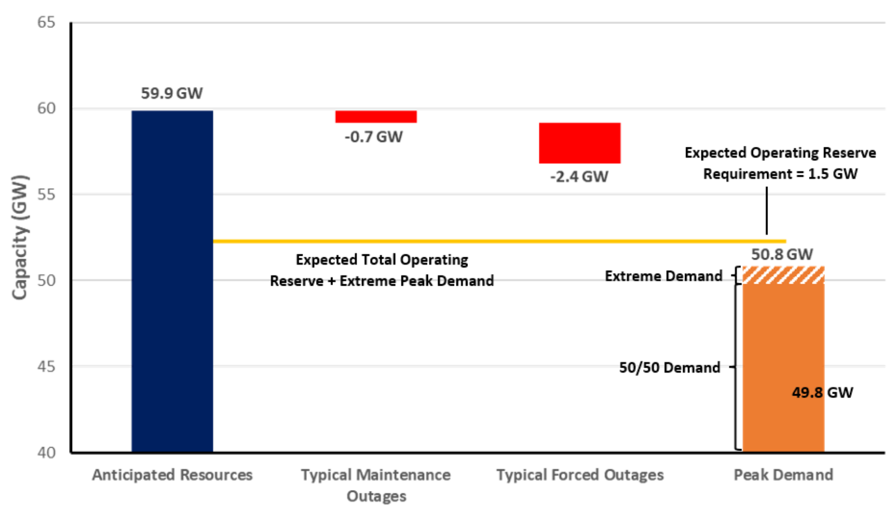
Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed scenarios.

On-Peak Fuel Mix



2025 Summer Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

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

Demand Scenarios: Net internal demand (50/50) and extreme demand forecast based on extreme summer weather (equals or exceeds the (90/10) demand forecast)

Maintenance Outages: Adjusted for higher outages resulting from extreme summer temperatures and aggregated on a SERC subregional level

Forced Outages: Accounts for reduced thermal capacity contributions due to performance in extreme conditions

SERC-Southeast

SERC-Southeast is a summer-peaking assessment area within the SERC Regional Entity. SERC-Southeast includes all or portions of Georgia, Alabama, and Mississippi. SERC is one of the six companies across North America that are responsible for the work under FERC-approved delegation agreements with NERC. SERC is specifically responsible for the reliability and security of the electric grid across the Southeastern and Central areas of the United States. This area covers approximately 630,000 square miles and serves a population of more than 91 million. The SERC Regional Entity includes 36 BAs, 28 planning entities, and 6 RCs.

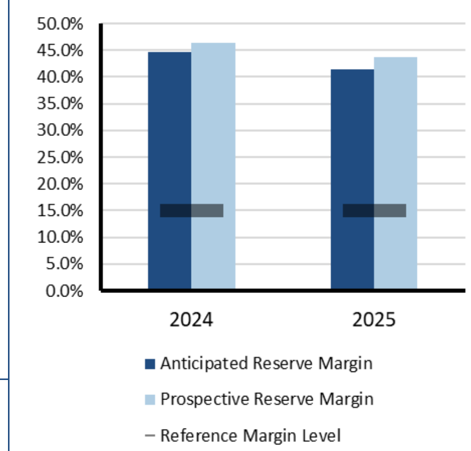
Highlights

- An area within SERC-Southeast notes that natural gas pipeline constraints could impact reliability in summer, but this is not expected to pose a significant summer operational challenge.
- SERC-Southeast's anticipated resources meet operating reserve requirements under the expected conditions and under the summer risk period scenario.
- The probabilistic analysis metrics indicate adequate energy resources for the subregion.
- Members of SERC-Southeast actively participate in the SERC working groups to perform coordinated studies and develop mitigating actions for any potential or emerging reliability impacts on transmission and resource adequacy.

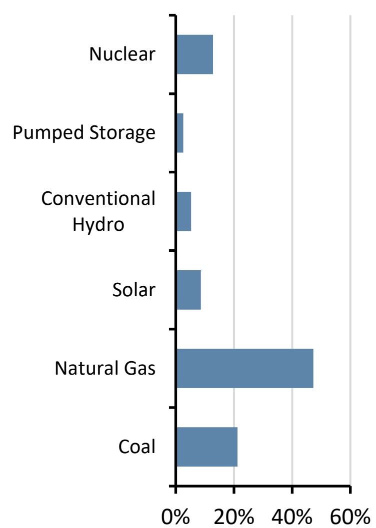
Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed scenarios.

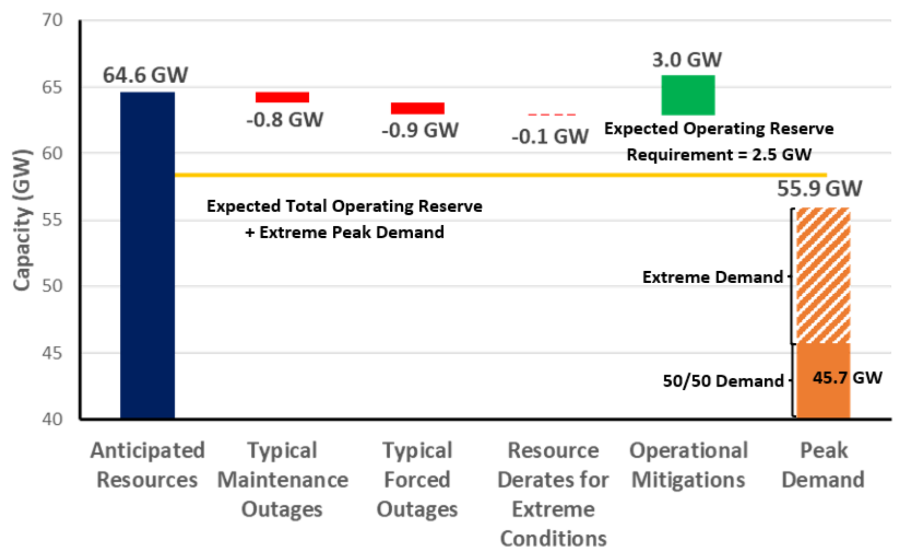
On-Peak Reserve Margin



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

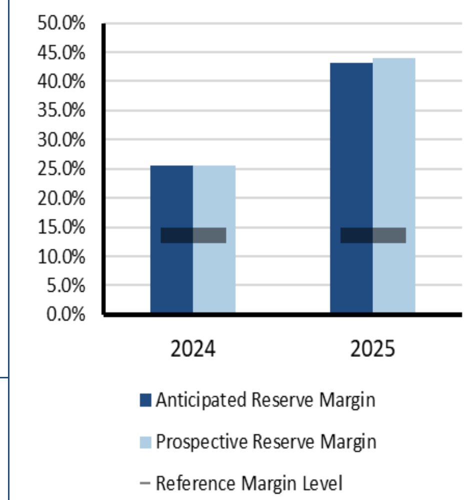
Texas RE-ERCOT

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.

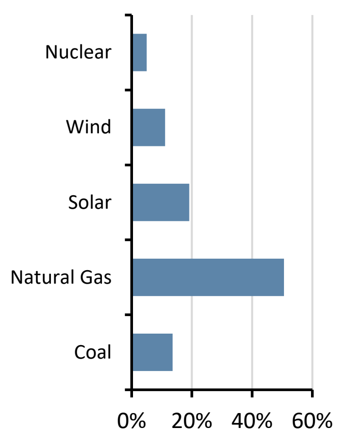
On-Peak Reserve Margin



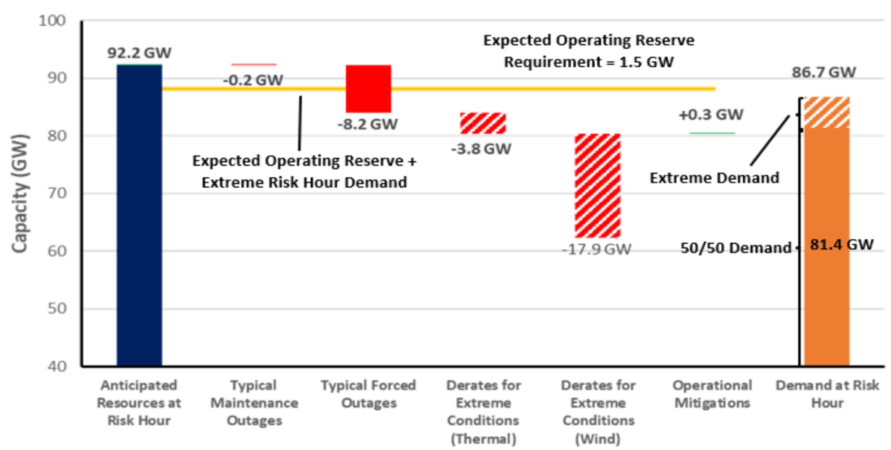
Risk Scenario Summary

Expected resources meet operating reserve requirements for the peak demand hour scenario. However, there is a risk of supply shortages during evening hours (when solar generation ramps down and demand remains high) if there are conventional generation forced outages or extreme low-wind conditions.

On-Peak Fuel Mix



2025 Summer Risk Period Scenario (9:00 p.m. local time)



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at hour ending 9 p.m. local time as solar PV output is diminished and demand remains high

Demand Scenarios: Net internal demand (50/50) and extreme demand (95/5) based on August peak load

Forced Outages: Based on the 95th percentile of historical averages of forced outages for June through September weekdays, hours ending 3:00–8:00 p.m. local time for the last three summer seasons

Extreme Derates: Based on the 90th percentile of thermal forced outages for peak August load day

Low Wind Scenario: Based on the 10th percentile of historical averages of hourly wind for June through September, hours ending 1:00–9:00 p.m. local time

Operational Mitigations: Additional capacity from switchable generation and additional imports

WECC-Alberta

WECC-Alberta is a winter-peaking assessment area in the WECC Regional Entity that consists of the province of Alberta. It has 16,369 miles of transmission. WECC is responsible for coordinating and promoting BES reliability in the Western Interconnection. WECC's 329 members include 40 BAs, representing a wide spectrum of organizations with an interest in the BES. Serving an area of nearly 1.8 million square miles and more than 84.5 million customers, it is geographically the largest and most diverse Regional Entity.

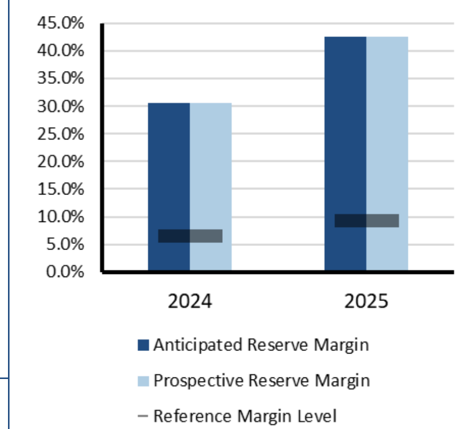
Highlights

- Anticipated and prospective reserve margins are projected to remain above the Reference Margin Level.
- All resource margins have increased by about 50% since last summer with the addition of 23.2% new capacity, including almost 2,700 MW of new natural gas capacity, 1,200 MW of new wind (+27%), 200 MW of new solar (+13%), and 54 MW of new energy storage systems (+27.5%).
- The peak hour has moved earlier, to 3:00 p.m. from 4:00 p.m., still in late July.
- High temperatures, import limitations, and low or declining renewable output during summer evenings can result in grid alerts.
- Wildfires can threaten generating assets and transmission infrastructure requiring invocation of Alberta Electric System Operator (AESO) protocols that include instructing available assets and long lead-time assets to deliver energy up to their maximum capability, calling upon demand response, and maximizing import capability.

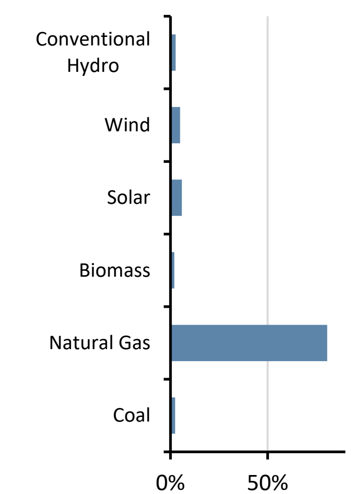
Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed scenarios.

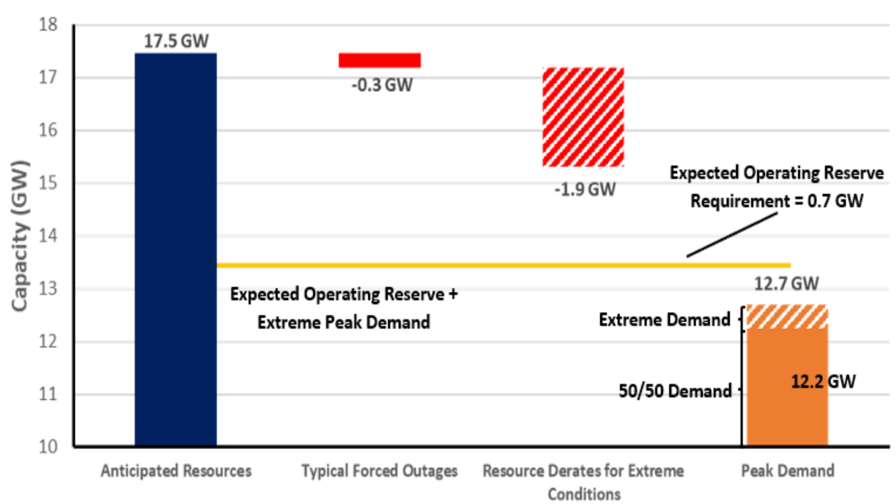
On-Peak Reserve Margin



On-Peak Fuel Mix



2025 Summer Risk Period Scenario



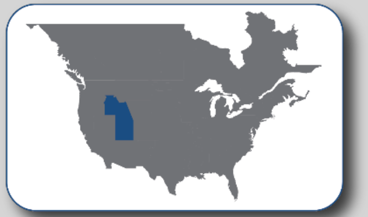
Scenario Description (See Data Concepts and Assumptions)

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

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

Typical Forced Outages: Average seasonal outages

Extreme Derates: Using (90/10) point of resource performance distribution



WECC-Basin

WECC-Basin is a summer-peaking assessment area in the WECC Regional Entity that includes Utah, southern Idaho, and a portion of western Wyoming, covering Idaho Power and PacifiCorp's eastern Balancing Authority Area. The population of this area is approximately 5.4 million. It has 15,910 miles of transmission. WECC is responsible for coordinating and promoting BES reliability in the Western Interconnection. WECC's 329 members include 40 BAs, representing a wide spectrum of organizations with an interest in the BES. Serving an area of nearly 1.8 million square miles and more than 84.5 million customers, it is geographically the largest and most diverse Regional Entity. *Note: The 2025 SRA includes a new assessment area map for the U.S. Western Interconnection. The new assessment area boundaries provide more geographic detail of reliability risk information. WECC-Basin is a new assessment area in 2025 that was part of WECC-NW in the 2024 SRA*.

Highlights

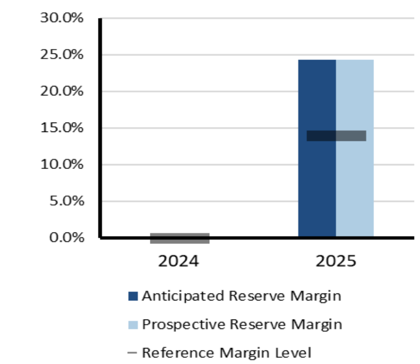
- Total internal expected demand has increased 8% and demand response has increased almost 28% for a net internal demand increase of 7.2%.
- Reserve margins are not anticipated to fall below the reference margin (14%) for the upcoming summer; an early July peak is expected at around 3:00 p.m.
- During periods of contingency reserve shortage, EEAs may be declared in the region to obtain reserves from the Northwest Power Pool.
- Seasonal fluctuations in hydro supply require monitoring and forecasting to have high certainty that these resources will meet anticipated capacity; the Summer 2025 drought outlook for the United States indicates minimal drought conditions in Idaho and some drought areas in Utah this summer.
- Wildfires near wind generation can result in safety curtailments, and fire damage to transmission lines interconnected to hydro sites can present restoration challenges.

Risk Scenario Summary

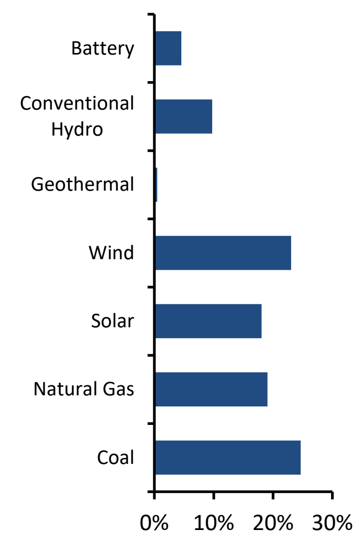
Expected resources meet operating reserve requirements under the assessed scenarios with imports.

On-Peak Reserve Margin

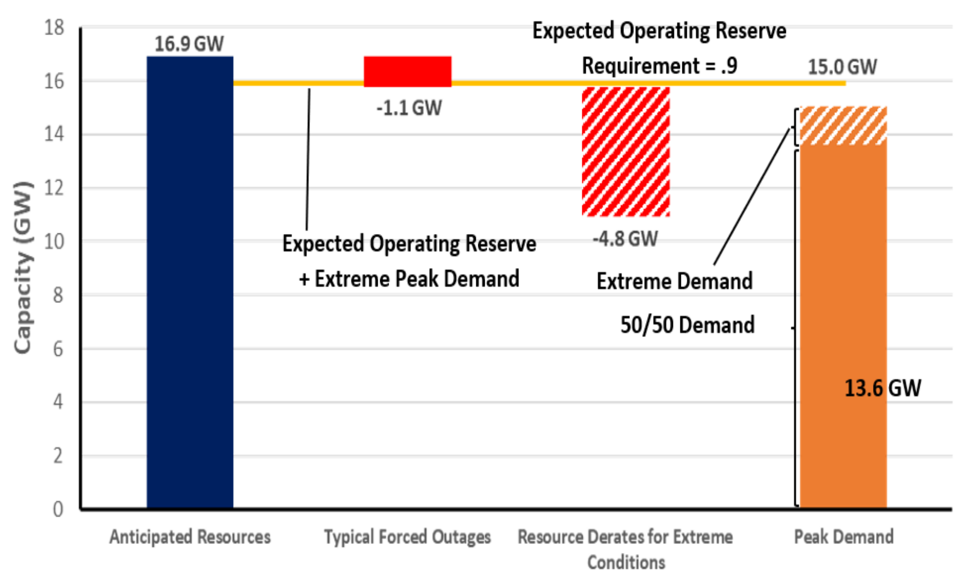
(Note: year comparison not available)



On-Peak Fuel Mix



2025 Summer Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

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

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

Forced Outages: Average seasonal outages

Extreme Derates: Using (90/10) resource performance distribution at peak hour

WECC-British Columbia

WECC-British Columbia (BC) is a winter-peaking assessment area in the WECC Regional Entity that consists of the province of British Columbia. It has 11,184 miles of transmission. WECC is responsible for coordinating and promoting BES reliability in the Western Interconnection. WECC's 329 members include 40 BAs, representing a wide spectrum of organizations with an interest in the BES. Serving an area of nearly 1.8 million square miles and more than 84.5 million customers, it is geographically the largest and most diverse Regional Entity.

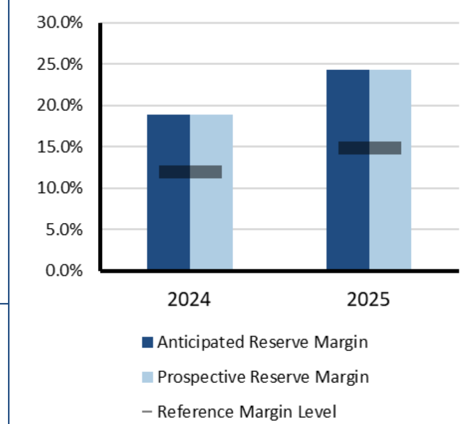
Highlights

- Existing capacity reserve margin has increased from 19% to 22%, and anticipated and prospective reserve margin from 19% to 24%.
- Reserve margins are not anticipated to fall below the reference margin for the upcoming summer.
- The peak hour is forecast for early August at 4:00 p.m., two hours earlier than last summer's outlook of 6:00 p.m.
- About 60% of hydro owned or contracted energy comes from the Columbia and Peace basins. Heavy precipitation in Fall 2024 mitigated the impact of below-average snowpack the previous winter, resulting in hydro storage tracking close to historical averages as of Spring 2025.
- Wildfires can affect the transmission network and generator availability and have caused energy emergencies on the electric system in the past.

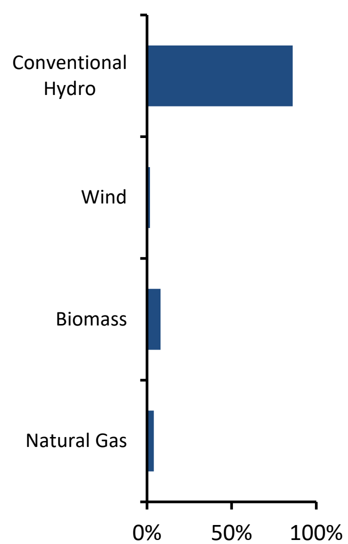
Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed scenarios.

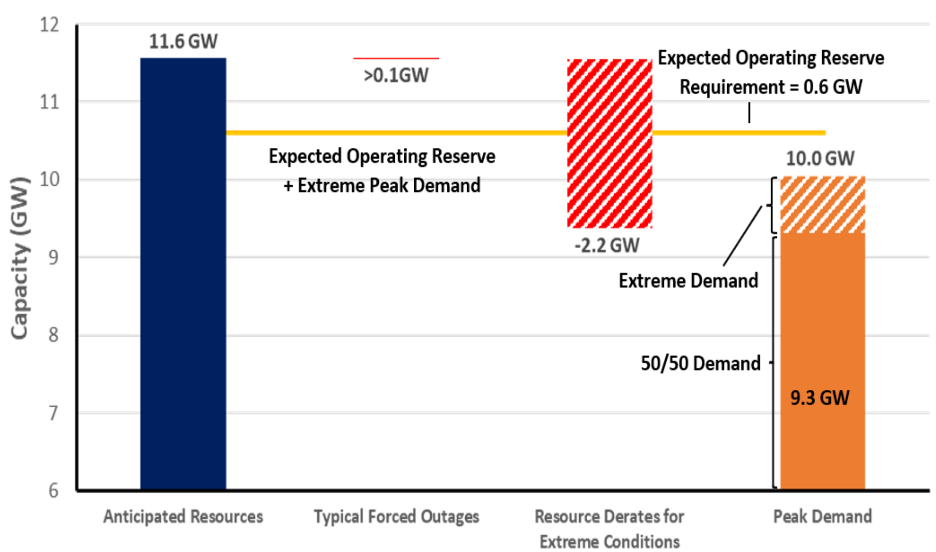
On-Peak Reserve Margin



On-Peak Fuel Mix



2025 Summer Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

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

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

Forced Outages: Average seasonal outages

Extreme Derates: Using (90/10) resource performance distribution at peak hour

WECC-California

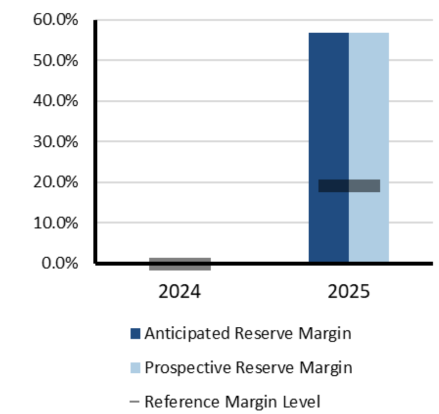
WECC-California is a summer-peaking assessment area in the Western Interconnection that includes most of California and a small section of Nevada. The assessment area has a population of over 42.5 million people. The area includes the California ISO, Los Angeles Department of Water and Power, Turlock Irrigation District, and the Balancing Area of Northern California. It has 32,712 miles of transmission. WECC is responsible for coordinating and promoting BES reliability in the Western Interconnection. WECC's 329 members include 40 BAs, representing a wide spectrum of organizations with an interest in the BES. Serving an area of nearly 1.8 million square miles and more than 84.5 million customers, it is geographically the largest and most diverse Regional Entity. *Note: The 2025 SRA includes a new assessment area map for the U.S. Western Interconnection. The new assessment area boundaries provide more geographic detail of reliability risk information. WECC-California is a new assessment area in 2025 that was part of WECC-CA/MX in the 2024 SRA.*

Highlights

- Demand response is down 8.6% since last summer, existing-certain capacity is up 5.8%, and Tier 1 planned capacity is up 41.2% for a net increase in anticipated resources of 9%; anticipated and prospective reserve margins are up by 11.4%. The peak hour is still forecasted for early September around 4:00 p.m.
- Reserve margins are not anticipated to fall below the reference margin for the upcoming summer, and probabilistic assessment of normal and extreme resource/demand scenarios reveal no EUE or LOLH.
- Wildfires can and have threatened both the California Oregon Intertie line, resulting in import capability limitations.
- Prolonged elevated demand during heat waves in combination with thermal resource derates and forced outage rates present significant risk.
- An influx of IBRs and corresponding reduction in system inertia can potentially trigger system reliability issues and require additional regulation, flexible ramp, and future imbalance reserve requirements.
- Increased solar penetrations in this region along with changing load patterns from elevated temperatures and residential demand are shifting the hours with the most challenging resource adequacy needs later into the evening rather than traditional afternoon gross peak load periods.

On-Peak Reserve Margin

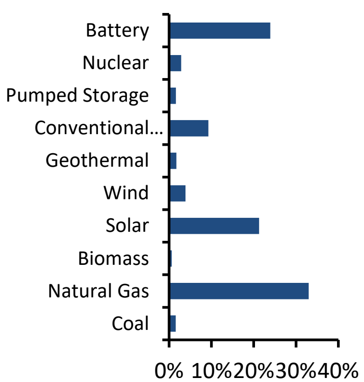
(Note: year comparison not available)



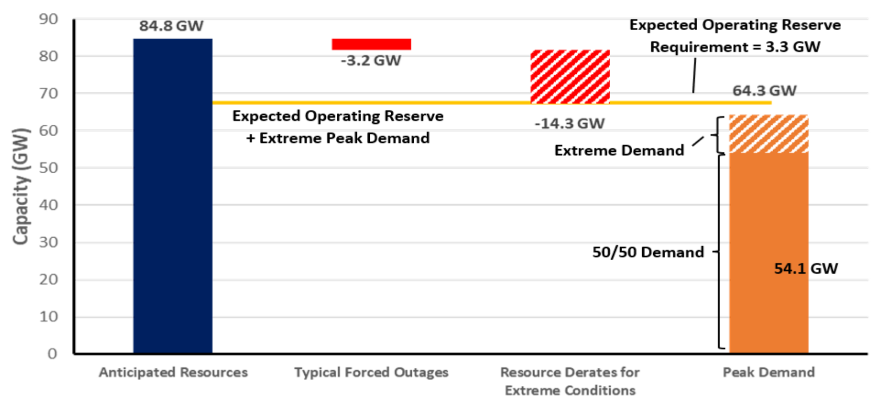
Risk Scenario Summary

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

On-Peak Fuel Mix



2025 Summer Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

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

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

Forced Outages: Estimated using market forced outage model

Extreme Derates: On natural gas units based on historical data and manufacturer data for temperature performance and outages

WECC-Mexico

WECC-Mexico is a summer-peaking assessment area in the Western Interconnection that includes the northern portion of the Mexican state of Baja California, which has a population of 3.8 million people and includes CENACE. It has 1,568 miles of transmission. WECC is responsible for coordinating and promoting BES reliability in the Western Interconnection. WECC's 329 members include 40 BAs, representing a wide spectrum of organizations with an interest in the BES. Serving an area of nearly 1.8 million square miles and more than 84.5 million customers, it is geographically the largest and most diverse Regional Entity. *Note: The 2025 SRA includes a new assessment area map for the U.S. Western Interconnection. The new assessment area boundaries provide more geographic detail of reliability risk information. WECC-Mexico is a new assessment area in 2025 that was part of WECC-CA/MX in the 2024 SRA.*

Highlights

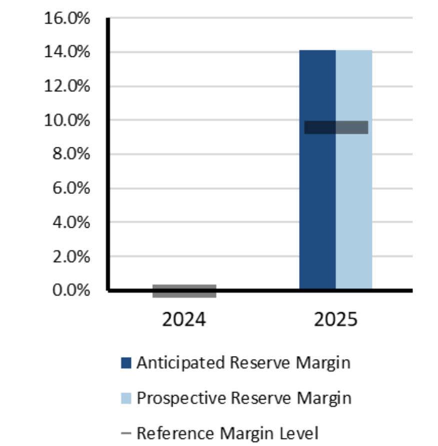
- Total and net internal expected (50/50) demand are up 6.8%, existing-certain capacity is up 29.8% or 989 MW, and Tier 1 planned capacity has fallen 100% to zero, leading to a decrease in the anticipated reserve margin from 22.9% down to 14.1%
- The peak hour is expected to occur in early August around 4:00 p.m.
- Operating reserves are a concern in this region during periods of extreme heat and elevated demand. High loading on Path 45 (See: WECC Path Rating Catalog) coupled with outages or derates to large thermal assets in this region can result in the declaration of an EAA and a request for assistance from RC West.

Risk Scenario Summary

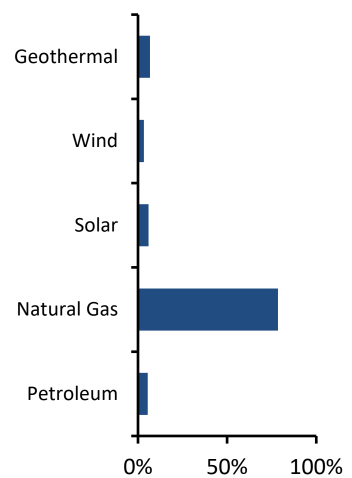
Expected resources at normal peak demand and outage conditions require some imports to maintain operating reserves. Thus, above-normal demand, high forced outage conditions, or transmission derates in the neighboring area could place WECC-Mexico in an energy emergency.

On-Peak Reserve Margin

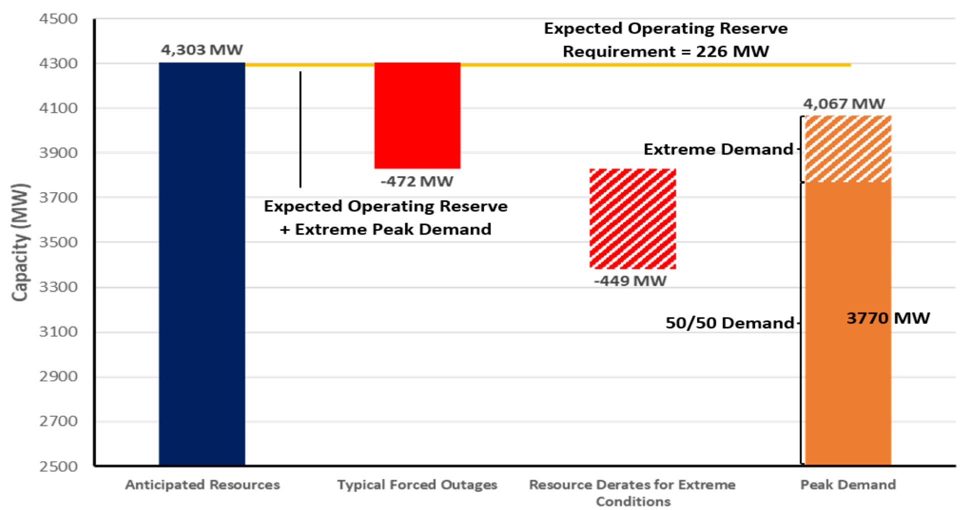
(Note: year comparison not available)



On-Peak Fuel Mix



2025 Summer Risk Period Scenario



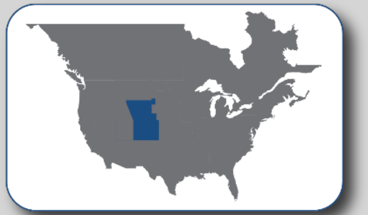
Scenario Description (See Data Concepts and Assumptions)

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

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

Forced Outages: Average seasonal outages

Extreme Derates: Using (90/10) resource performance distribution at peak hour



WECC-Rocky Mountain

WECC-Rocky Mountain is a summer-peaking assessment area in the Western Interconnection that includes Colorado, most of Wyoming, and parts of Nebraska and South Dakota. The population of the area is approximately 6.7 million. It covers the balancing areas of the Public Service Company of Colorado and the Western Area Power Administration's Rocky Mountain Region. It has 18,797 miles of transmission. WECC is responsible for coordinating and promoting BES reliability in the Western Interconnection. WECC's 329 members include 40 BAs, representing a wide spectrum of organizations with an interest in the BES. Serving an area of nearly 1.8 million square miles and more than 84.5 million customers, it is geographically the largest and most diverse Regional Entity. *Note: The 2025 SRA includes a new assessment area map for the U.S. Western Interconnection. The new assessment area boundaries provide more geographic detail of reliability risk information. WECC-Rocky Mountain is a new assessment area in 2025 that was part of WECC-NW in the 2024 SRA.*

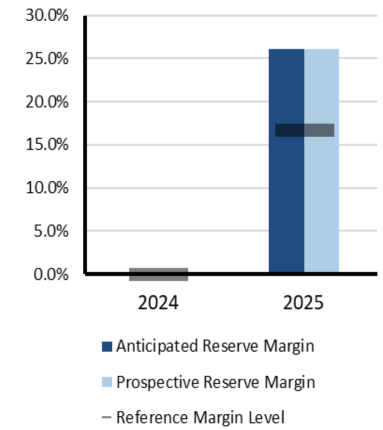
Highlights

- The reserve margins (existing-certain 25% and anticipated and prospective 26%) are not anticipated to fall below the reference margin (17%) for Summer 2025.
- Total and net internal demand (50/50) is up 25% or almost 2,800 MW, leading to a decline in the Anticipated Reserve Margin by almost a third.
- During the summer, there is increased load and decreased market purchase availability. Low wind availability and ramping scarcity events are a concern.
- Environmental and ecological factors have contributed to a rise in wildfire frequency and shortening of the fire return interval in the Rocky Mountain region, which, in addition to having caused generation outages, threatens rural co-ops disproportionately due to the extensive line buildout over remote regions.

Risk Scenario Summary

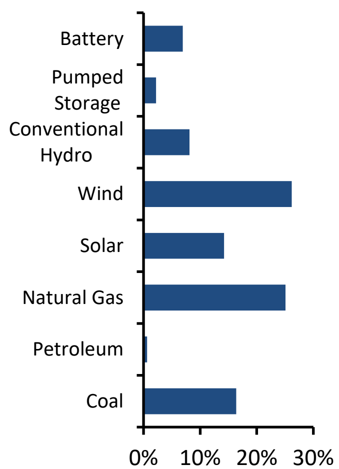
Expected resources meet operating reserve requirements under assessed scenarios with imports.

On-Peak Reserve Margin

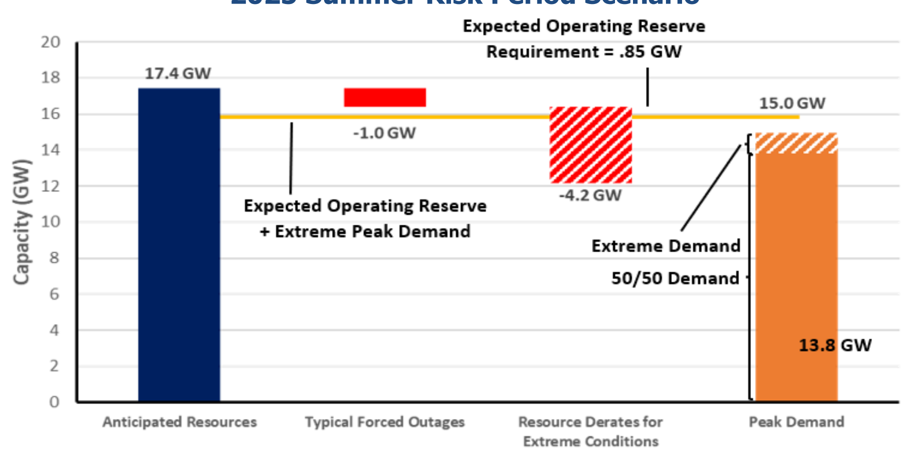


(Note: year comparison not available)

On-Peak Fuel Mix



2025 Summer Risk Period Scenario



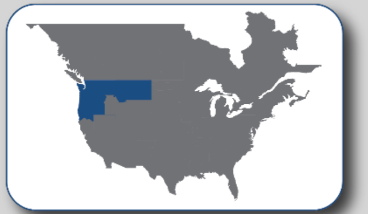
Scenario Description (See Data Concepts and Assumptions)

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

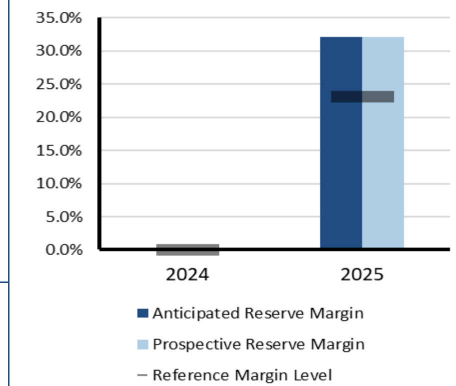
- The reserve margins (existing-certain 29% and anticipated and prospective 32%) are not anticipated to fall below the reference margin (23%) for the upcoming summer. An extreme summer peak load may be around 32,740 MW.
- Typical forced outages are forecast to be 771 MW, with derates for thermal under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

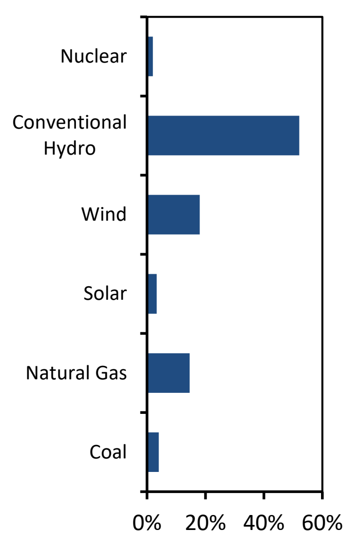
Expected resources meet operating reserve requirements under assessed scenarios with imports.

On-Peak Reserve Margin

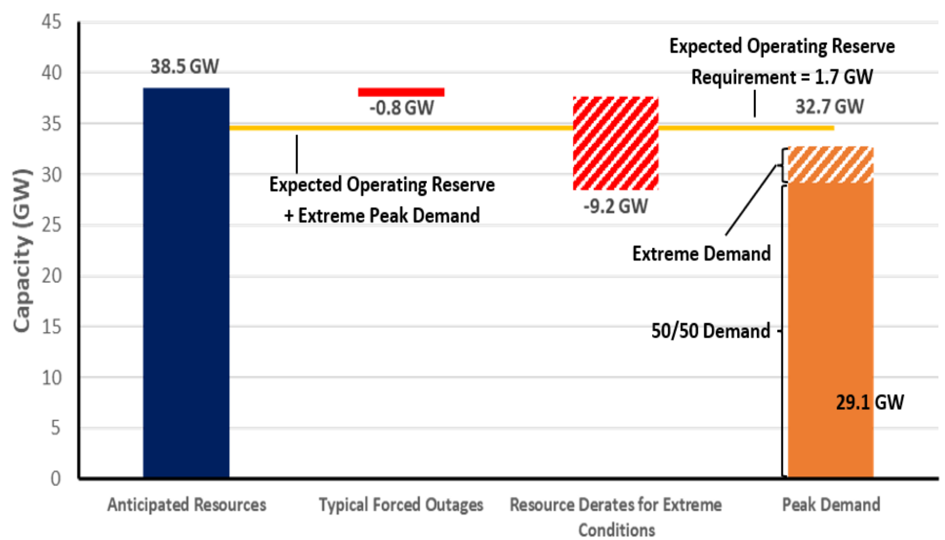
(Note: year comparison not available)



On-Peak Fuel Mix



2025 Summer Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

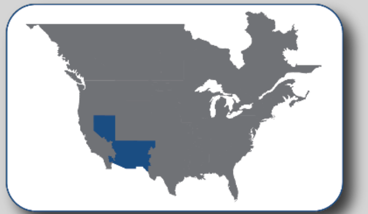
Risk Period: Highest risk for unserved energy occurs at the hour of peak demand

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

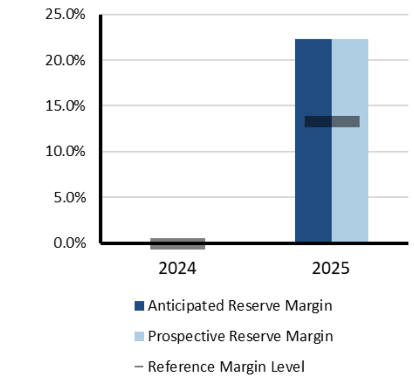
- Anticipated Reserve Margins for the summer are 22%, exceeding the Reference Margin Level for reliability calculated by WECC.
- WECC's probabilistic analysis indicates that the area is not expected to encounter LOLH or EUE under a range of demand and resource conditions.
- The peak hour is expected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

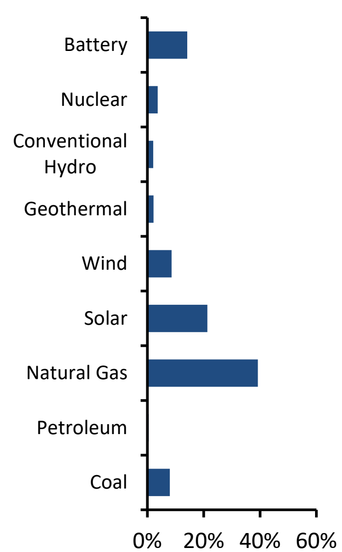
Expected resources meet operating reserve requirements under assessed scenarios with imports.

On-Peak Reserve Margin

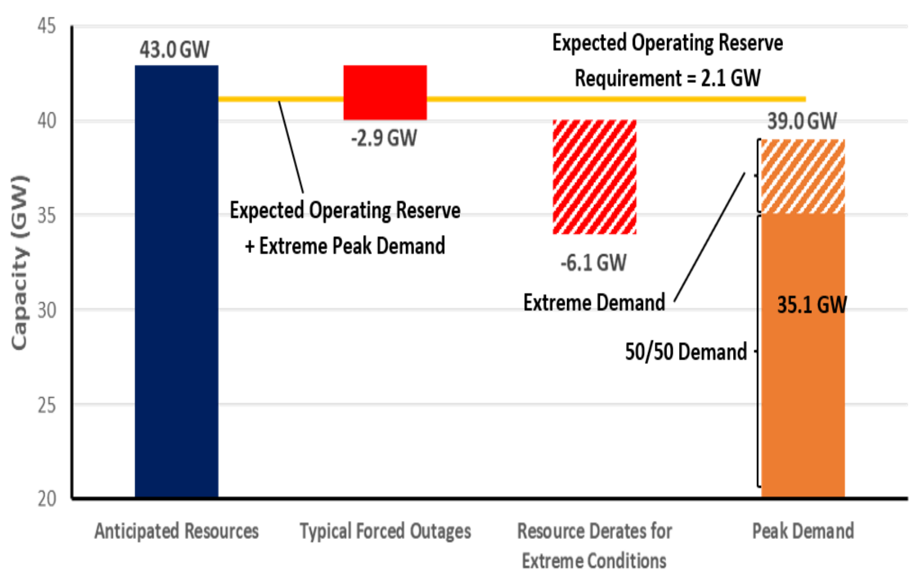
(Note: year comparison not available)



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.

[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**.

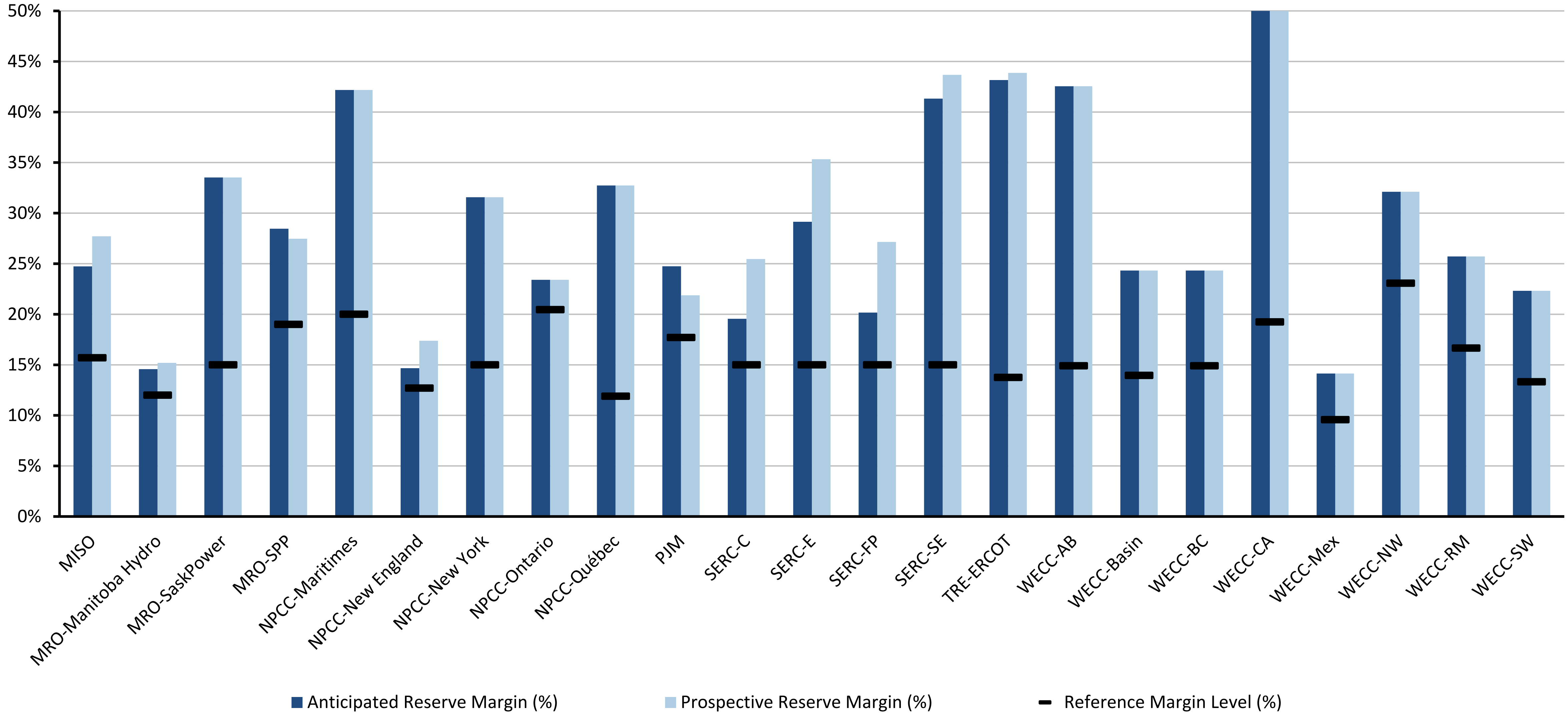


Figure 4: Summer 2025 Anticipated/Prospective Reserve Margins Compared to Reference Margin Level

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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.

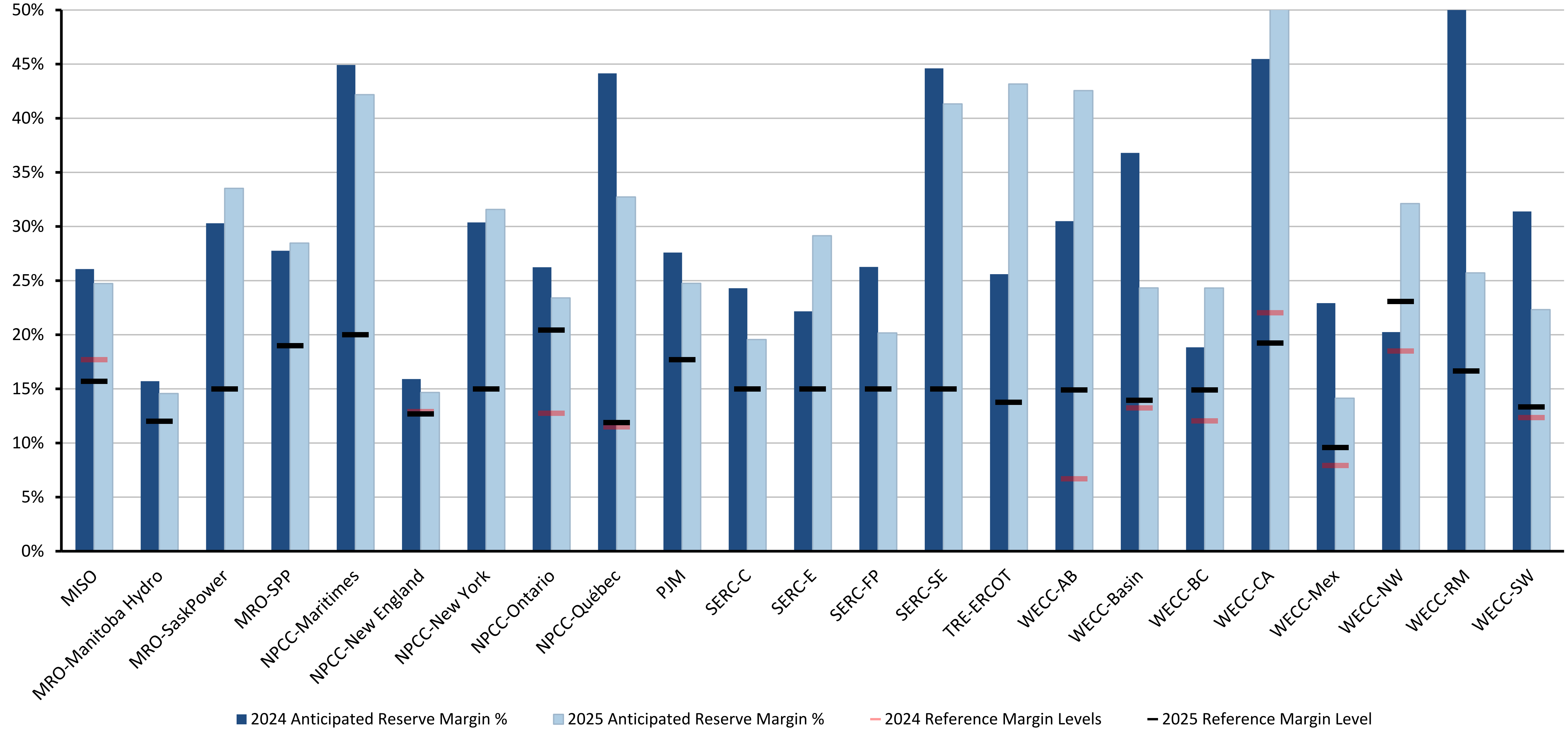

Figure 5: Summer 2024 and Summer 2025 Anticipated Reserve Margins Year-to-Year Change

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.

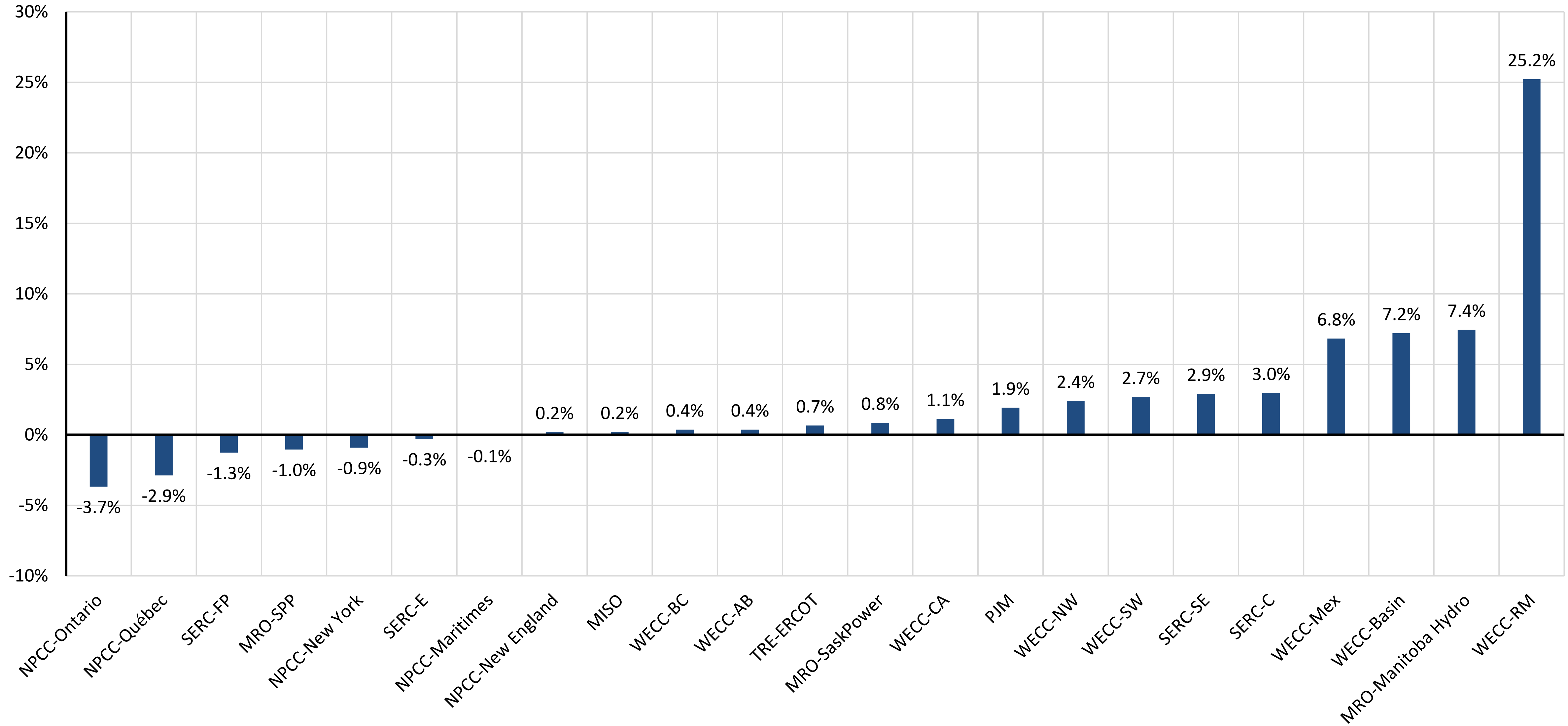

Figure 6: Changes in Net Internal Demand—Summer 2024 Forecast Compared to Summer 2025 Forecast

[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.

David Mills
Chair, PJM Board of Members

PJM Interconnection
2750 Monroe Blvd.
Audubon, PA 19403

VIA ELECTRONIC DELIVERY

June 9, 2025

Dear PJM Stakeholders,

On the evening of May 30, 2025, the Secretary of Energy issued an Order[1] pursuant to his authority under Federal Power Act Section ("FPA") 202(c),[2] regarding Constellation Energy's Eddystone Units 3 and 4, which were scheduled to retire at the end of the following day. The Secretary's Order found that an emergency existed in portions of the PJM footprint "due to a shortage of facilities for the generation of electric energy, resource adequacy concerns, and other causes," and directed, among other things, that PJM and Constellation Energy take "all measures necessary" to ensure that the Eddystone Units are available for continued operation until August 28, 2025. While the Secretary's Order was issued in the absence of a PJM request or application, PJM nonetheless intends to comply in accordance with the requirements of federal law.

As relevant here, the Secretary's Order directed PJM and Constellation to "file with the Federal Energy Regulatory Commission any tariff revisions or waivers necessary to effectuate this order," and further specified that "[r]ate recovery is available pursuant to [FPA section 202(c)]."

In accordance with FPA section 202(c),[3] Constellation has communicated its agreement to utilize the Deactivation Avoidable Cost Credit ("DACC"), as described in Part V of the PJM Tariff. PJM supports this determination and is willing to agree to the use of the DACC for the Eddystone Units during this 90-day period.

However, Part V of the PJM Tariff as it currently stands addresses the retention of generation facilities based upon specific transmission constraints, and accordingly its corresponding cost allocation methodology is not oriented towards resource adequacy concerns, which is the basis for the Secretary's Order.

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[1] A copy of the Secretary's Order No. 202-25-4 is available here: https://www.energy.gov/ceser/federal-power-act-section-202c-pjm-interconnection

[2] 16 U.S.C. § 824a(c).

[3] FPA section 202(c) and the Department of Energy's ("DOE") implementing regulations contemplate agreement between the relevant entities (in this case, PJM and Constellation Energy) regarding the compensation and terms and conditions of service for the duration of a 202(c) order. In the event that the relevant entities cannot agree, the DOE is required to refer the case to the Federal Energy Regulatory Commission for resolution. *See* 16 U.S.C. 824a(c) ("If the parties affected by such order fail to agree upon the terms of any arrangement between them in carrying out such order, the Commission, after hearing held either before or after such order takes effect, may prescribe by supplemental order such terms as it finds to be just and reasonable, including the compensation or reimbursement which should be paid to or by any such party."). *See also* 10 C.F.R. § 205.376 ("The applicant and the generating or transmitting systems from which emergency service is requested are encouraged to utilize the rates and charges contained in approved existing rate schedules or to negotiate mutually satisfactory rates for the proposed transactions. In the event that the DOE determines that an emergency exists under section 202(c), and the "entities" are unable to agree on the rates to be charged, the DOE shall prescribe the conditions of service and refer the rate issues to the Federal Energy Regulatory Commission for determination by that agency in accordance with its standards and procedures.").

In light of these circumstances, and to ensure that the cost impacts of the Eddystone Units' continued operation are reflective of the region-wide resource adequacy concerns contemplated by the Secretary's Order, the Board is initiating the Critical Issue Fast Path ("CIFP") accelerated stakeholder process mechanism as detailed in PJM Manual 34, section 8.6.4. The purpose of this CIFP is to engage with stakeholders and to receive feedback on the specific issue of the appropriate cost allocation methodology associated with the recovery of the DACC payments to Constellation for the Eddystone Units.[4]

Given the exigent circumstances presented by the Secretary's Order, which went into effect upon its issuance, and the corresponding requirement that the Eddystone Units continue to be available to operate starting on June 1, the Board intends to conduct this CIFP process on a truncated timeframe, beginning June 10, and ending with the Members Committee meeting on June 18. To effectuate this, PJM will hold the four stages of the CIFP on the following dates:

Stage 1	PJM provides an informational Problem Statement and Issue Charge, education, an initial proposed solution, and a Matrix with solution options it considered – June 10, 2025
Stage 2	Stakeholders provide feedback and alternatives to PJM – June 12, 2025
Stage 3	With consideration of the stakeholder feedback, PJM will refine and finalize its proposal. Stakeholders may create alternative packages – June 16, 2025
Stage 4	PJM reviews its final proposed solution and Members and invited non-members provide feedback to the Board – June 18, 2025

The Board greatly appreciates the engagement and feedback of the PJM stakeholder community as PJM works to comply with the Secretary's Order.

Sincerely,

David Mills
Chair, PJM Board of Managers

[4] This discussion may also include the potential establishment of a generic cost allocation structure that could be utilized in the event that additional 202(c) orders are issued in the future for resource adequacy purposes, and the generator owners subject to those orders elect to utilize the DACC as their form of compensation.

PJM Summer Outlook 2025: Adequate Resources Available for Summer Amid Growing Risk

PJM Forecasts High Summer Peak Demand, Potential Need To Reduce Load With Contracted Demand Response

May 9, 2025

(Valley Forge, PA – May 9, 2025) – PJM forecasts sufficient generation for typical peak demand this summer but is preparing to call on contracted demand response resources to reduce electricity use under more extreme scenarios featuring record demand.

For the season ahead, PJM forecasts summer energy use, or load, to peak at just over 154,000 MW, for which PJM should have adequate reserves to maintain reliability. This season also marks the first time in PJM's annual assessment, however, that available generation capacity may fall short of required reserves in an extreme planning scenario that would result in an all-time PJM peak load of more than 166,000 MW.

Under such circumstances, PJM would call on contracted demand response programs to meet its required reserve needs. Demand response programs pay customers who have opted in to reduce their electricity use in times of system emergencies.

The National Weather Service predicts hotter-than-normal summer conditions, especially in the Atlantic seaboard states. PJM's record summer peak load was set at 165,563 MW in 2006. Last year, PJM's summer peak was about 152,700 MW, and 147,000 MW in 2023. PJM has approximately 179,200 MW of generation capacity this summer, as well as approximately 7,900 MW of contracted demand response.

One megawatt can power about 800 homes.

PJM continues to voice concerns about the supply and demand imbalance driven by generator retirements and the slow build of new resources in the face of accelerating demand growth. PJM documented this confluence of trends in the 2023 PJM paper Resource Retirements, Replacements and Risks (PDF).

PJM and its stakeholders have taken a number of proactive measures to bring new generation resources online and maximize the availability of existing resources in the short and long term, including:

- **Interconnection Process Reform** – PJM has streamlined its process through which new generation connects to the grid. Additional automation in the interconnection process, along with increased staffing over the past several years, has improved quality while reducing the backlog by 60%. PJM on April 10 also announced a multiyear collaboration with Google and Tapestry to deploy AI-enhanced tools to further streamline PJM's interconnection process.
- **Reliability Resource Initiative** – PJM on May 2 announced the projects chosen for this one-time program to boost reliability in the PJM footprint. It includes 51 shovel-ready generation projects with 9,300 MW in capacity that can come online by 2030 or 2031.
- **Surplus Interconnection Service** – PJM obtained FERC approval to streamline the use of the unused portion of interconnection service for facilities that cannot or do not operate continuously, every hour of every day, year-round (such as adding battery storage to a renewable site).
- **Capacity Interconnection Rights Transfer** – A reform package endorsed by PJM stakeholders and currently pending review by FERC would facilitate an expedited interconnection process for a replacement resource seeking to use the capacity interconnection rights of a retiring resource.
- **Demand Response Availability** – FERC on May 5 approved a PJM proposal that improves dispatch and accreditation of demand response resources. The proposal broadens the window for demand response participation from a limited set of hours during summer and winter to around-the-clock throughout the year, enhancing grid reliability and resource adequacy.

Renewable resources will be more important than ever this summer to maintain reliability. PJM plans to issue guidance for inverter-based resource owners, typically solar and wind, to take necessary steps so that units adhere to necessary standards and operational guidelines to support reliable grid operations.

"This outlook at a record peak heat scenario reflects our years-long and mounting concerns as we plan for enough resources to maintain grid reliability," said Aftab Khan, Executive Vice President – Operations, Planning & Security. "All resources within PJM's footprint should be prepared to respond when called upon." A dedicated team of operators uses sophisticated technology to balance supply and demand and direct the power grid 24/7 from PJM's control rooms. They prepare multiple potential scenarios that could be impacted by weather, emergency conditions or equipment failure. They adjust resource output with changes in demand and ensure that no transmission lines or facilities are overloaded. The team also watches for unusual conditions and reacts to them in order to protect the electricity supply.

Summer 2025
PJM Reliability Assessment

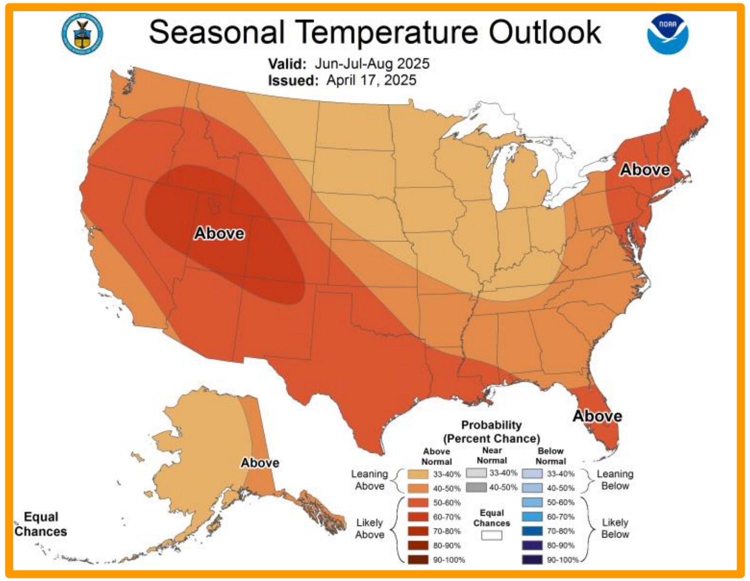
Pennsylvania Public Utility Commission

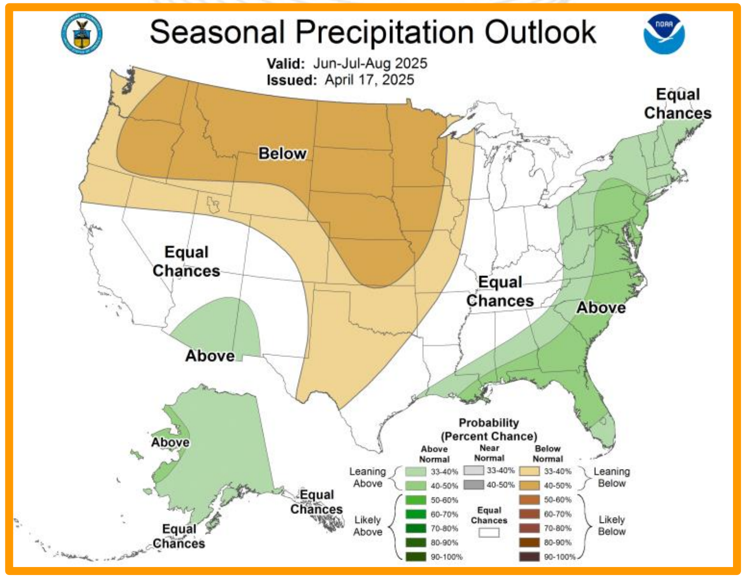
May 2025

PJM
Forward Planning for Summer

Weather Outlook

Summer 2025 Weather Projections





Temperatures forecasted to be above the 30-year norm over much of PJM

East may start with warmer temps that mitigate slightly during typical mid-summer peaks

Wetter-than-normal conditions are forecast from the Appalachians eastward

PJM is planning for an active hurricane season with early tropical activity

2025 Atlantic Hurricane Forecast

Named Storms	Hurricanes	Major Hurricanes
17	9	4

Seasonal outlook maps source: National Oceanic and Atmospheric Administration
Hurricane outlook provided by Colorado State University

PJM Summer Demand

Summer 2025	DEMAND			PJM Installed Capacity
	Forecast Summer	Summer Study Average	Summer Study High	
	154,000 MW	160,961 MW	166,562 MW	179,227 MW

Relative Peaks

2024 Summer Peak
152,700 MW

All-Time Summer Peak (2006)
165,563 MW

PJM Preparation for Summer 2025

Perform a summer reliability assessment to include any additional sensitivity analysis required

Coordinate summer assessments with neighboring systems (NYISO, MISO, TVA and VACAR)

Conduct emergency procedures drill to prepare PJM staff and PJM stakeholder staff for any emergency operations

Request periodic generator fuel inventory and supply data to maintain situational awareness throughout the summer of 2025

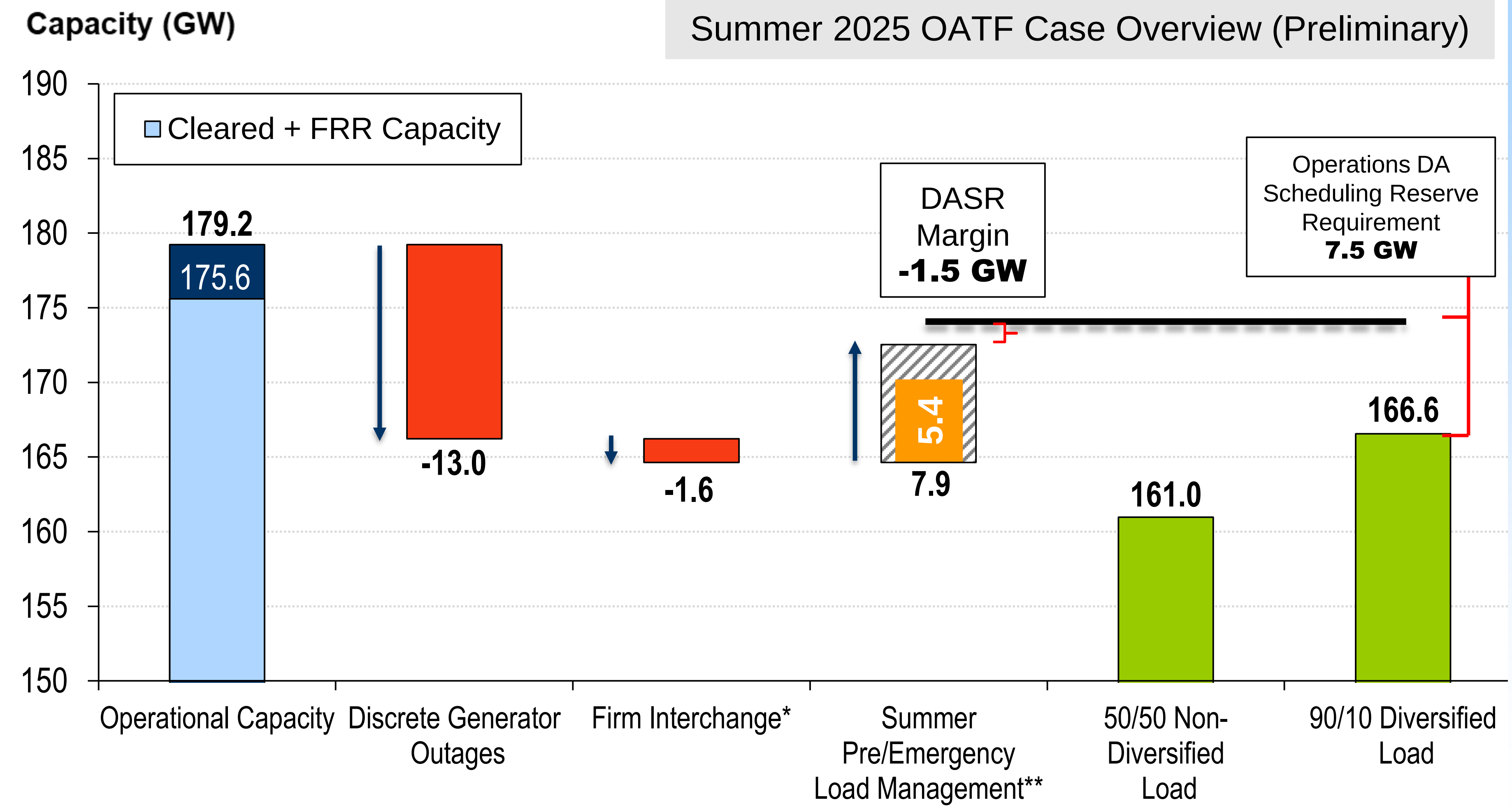
2025 Summer Transmission Study – Sensitivities

Sensitivity Studies	Impact
▪ External Contingencies	No reliability concerns
▪ N-1-1 Relay Trip Conditions	No reliability concerns
▪ Max-Cred Contingency Analysis	No reliability concerns
▪ Transfer Interface Analysis	No reliability concerns
▪ 90/10 Load Forecast Study (166,562 MW)	No reliability concerns
▪ Solar and Wind Generation Sensitivity Study	No reliability concerns

PJM

2025 Resource Adequacy Assessment

Waterfall Chart
(Summer 2025 – Preliminary)

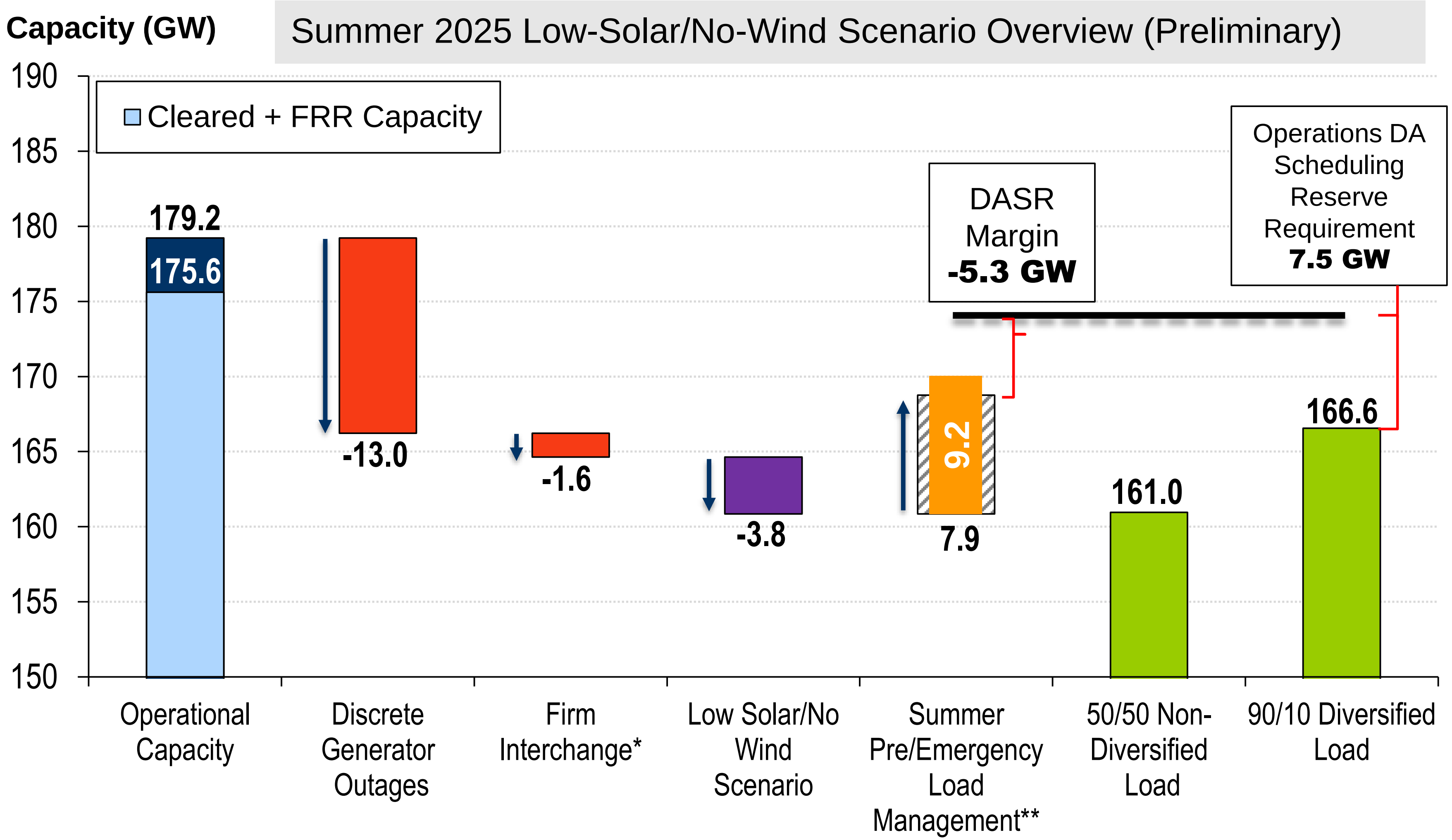


Anticipated PJM actions to reliably serve the 90/10 Forecast:

1. Issue Max Gen/Load Management Alert (DA)
2. Schedule all Available Generation (DA)
3. Curtail all Recallable Exports (RT)
4. Implement Demand Response (~5.4 GW) to Maintain Primary Reserve Requirement of 3.5 GW (RT)

1,600 MW out of the total* ***net interchange* *(4,200 MW) are capacity backed exports.*
*** 97% of Load Management is Pre-Emergency.*

Low-Solar and No-Wind Scenario
(Summer 2025 – Preliminary)

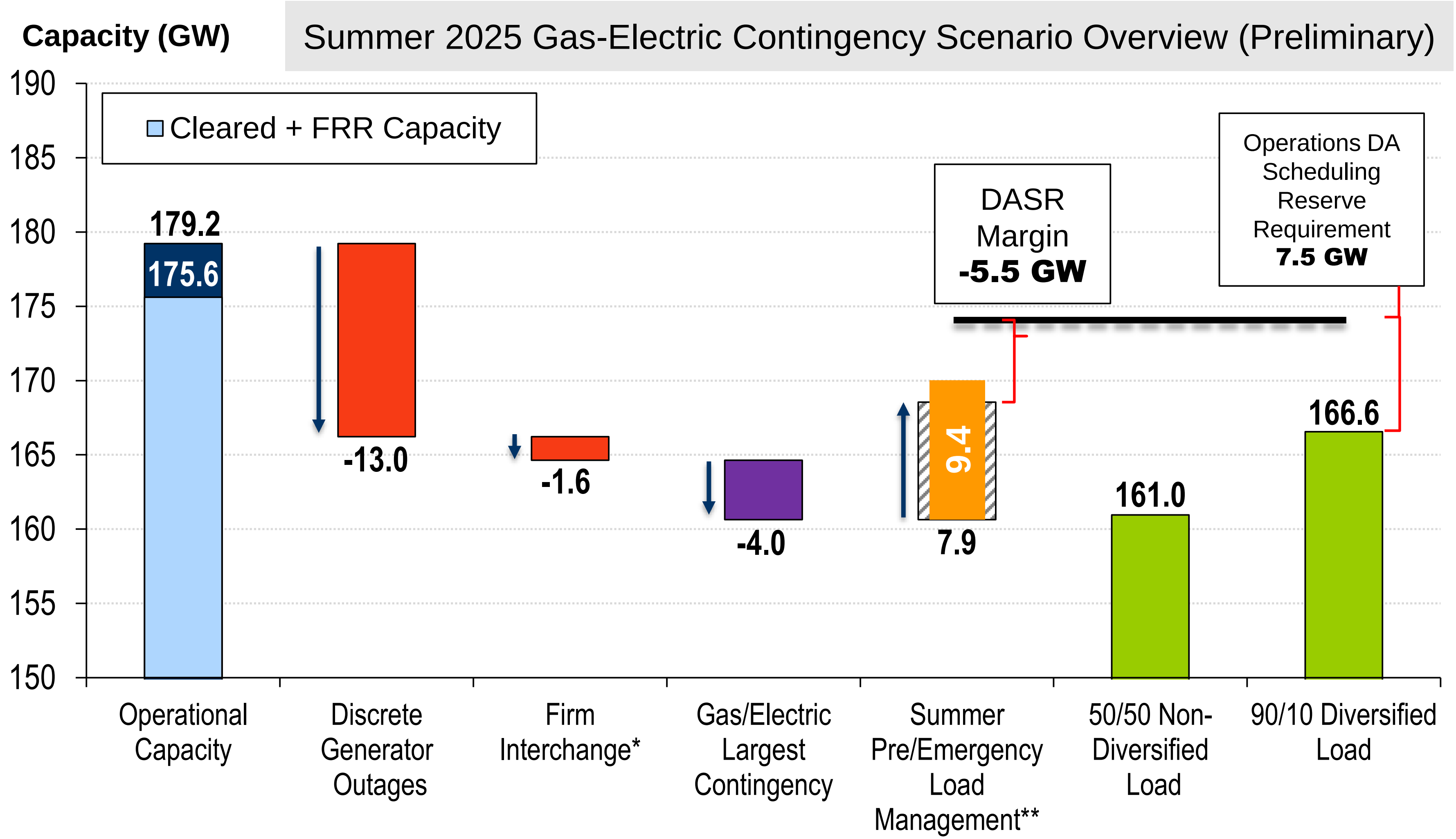


Anticipated PJM actions to reliably serve the 90/10 Forecast:

1. Issue Max Gen/Load Management Alert (DA)
2. Schedule all Available Generation (DA)
3. Curtail all Recallable Exports (RT)
4. Implement **all** Demand Response (**7.9 GW**) to meet the load + Primary Reserve Requirement of 3.5 GW (RT)
5. Call Maximum Emergency Energy into capacity and purchase Emergency Energy (If available) to address the **1.3 GW shortfall**
6. Initiate escalating Emergency Procedures if needed (RT)

1,600 MW out of the total **Net Interchange (4,200,MW) are capacity backed exports.*
*** 97% of Load Management is Pre-Emergency.*

Gas-Electric Contingency Scenario
(Summer 2025 – Preliminary)



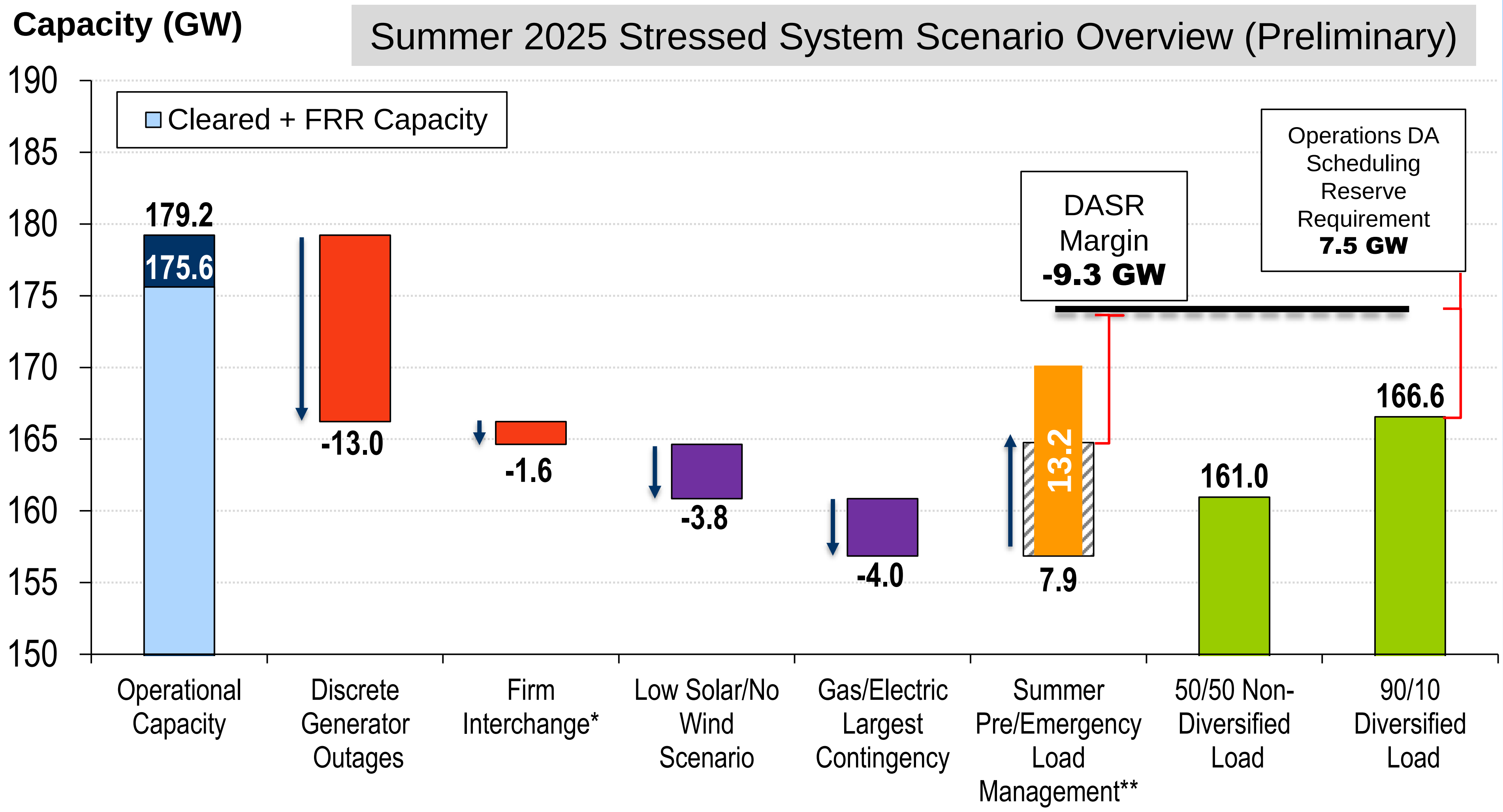
Anticipated PJM actions to reliably serve the 90/10 Forecast:

1. Issue Max Gen/Load Management Alert (DA)
2. Schedule all Available Generation (DA)
3. Curtail all Recallable Exports (RT)
4. Implement **all** Demand Response (**7.9 GW**) to meet the load + Primary Reserve Requirement of 3.5GW (RT)
5. Call Maximum Emergency Energy into capacity and purchase Emergency Energy (If available) to address the **1.5 GW shortfall**
6. Initiate escalating Emergency Procedures if needed (RT)

1,600 MW out of the total **Net Interchange (4,200 MW) are capacity backed exports.*
*** 97% of Load Management is Pre-Emergency.*

Stressed System Scenario

(Summer 2025 – Preliminary)



Anticipated PJM actions to reliably serve the 90/10 Forecast:

1. Issue Max Gen/Load Management Alert (DA)
2. Schedule all Available Generation (DA)
3. Curtail all Recallable Exports (RT)
4. Implement **all** Demand Response (**7.9 GW**) to meet the load + Primary Reserve Requirement of 3.5 GW (RT)
5. Call Maximum Emergency Energy into capacity and purchase Emergency Energy (If available) to address the **5.3 GW shortfall**
6. Initiate escalating Emergency Procedures if needed (RT)

1,600 MW out of the total **Net Interchange (4,200MW) are capacity backed exports.*

*** 97% of Load Management is Pre-Emergency.*

50/50 Non-Diversified Peak Load Base Case

LAS Load Forecast	Preliminary RTO Net Interchange	PJM RTO Installed Capacity	Discrete Generator Outages
160,961 MW	**-4,200**** MW *(Exporting)*	**179,227** MW *(preliminary)*	**13,012** MW

***OATF Case Interchange (-3,000 MW) = Forecast Net Interchange(-4,200 MW) + Pseudo-Tie Adjustment (1,200 MW)*

PEAK LOAD ANALYSIS

No transmission reliability issues identified.

50/50 Peak Load Study Results

- Identified 12 post-contingency overloads between 100-113% of emergency ratings. None of which are above their respective load dump limits
- Re-dispatch and switching required to control local thermal or voltage exceedances in some areas
- Most networked thermal overloads and voltage exceedances observed were relieved through shunt and tap adjustments, switching, PAR adjustments, applicable operating procedures, and generation re-dispatch

PJM
Resource Adequacy

Data Center Proliferation

DIVE BRIEF

PJM expects summer peak load to grow 2% a year on average, driven by data centers

DIVE BRIEF

Exelon data center pipeline jumps to 17 GW as load forecast turns positive

Gov. Pritzker, Lawmakers Celebrate Bipartisan Work to Attract Data Center Construction to Illinois

ILLINOIS.GOV

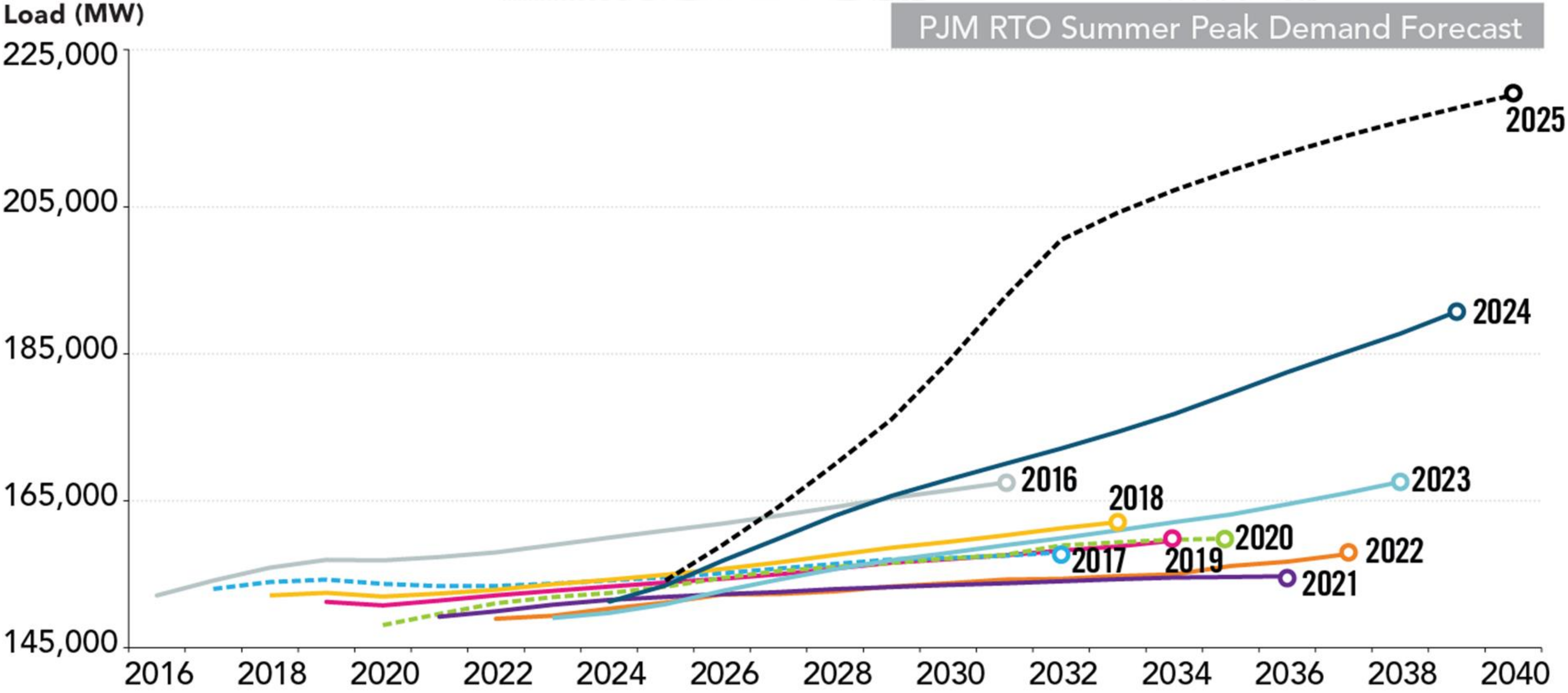
US electricity demand to surge to 128GW by 2029 due to data center growth - report

The report identifies the PJM and ERCOT as areas that will experience the largest growth in demand

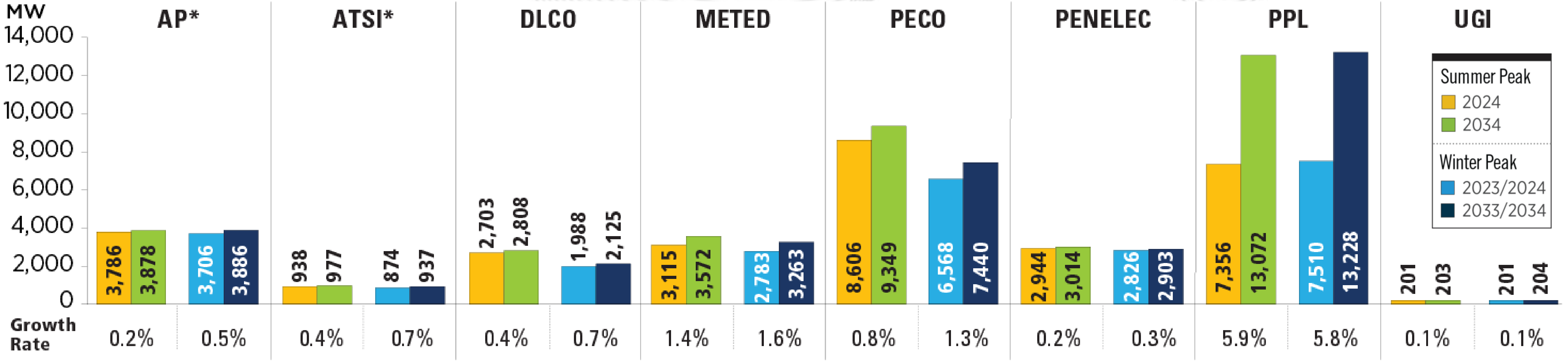
ComEd, Compass Datacenters Kick Off New, State-of-the-Art Data Center to Transform Former Sears Headquarters Site

businesswire
A BERKSHIRE HATHAWAY COMPANY

Electricity Demand Growth



PA – 2025 Load Forecast Report



*Serves load outside PA

The summer and winter peak megawatt values reflect the estimated amount of forecast load to be served by each transmission owner in the noted state/district. Estimated amounts were calculated based on the average share of each transmission owner's real-time summer and winter peak load in those areas over the past five years.

PJM RTO Summer Peak

2025	2035
154,144 MW	209,923 MW

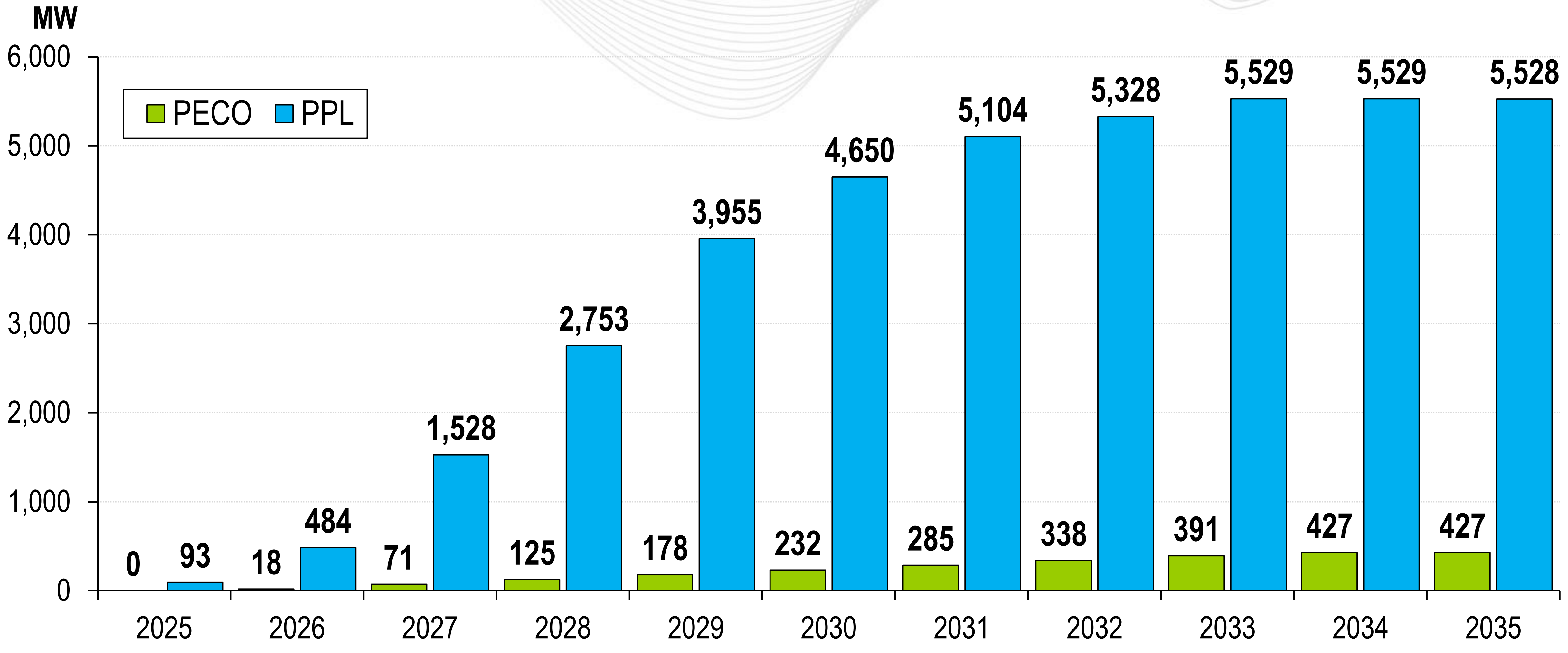
Growth Rate 3.1%

PJM RTO Winter Peak

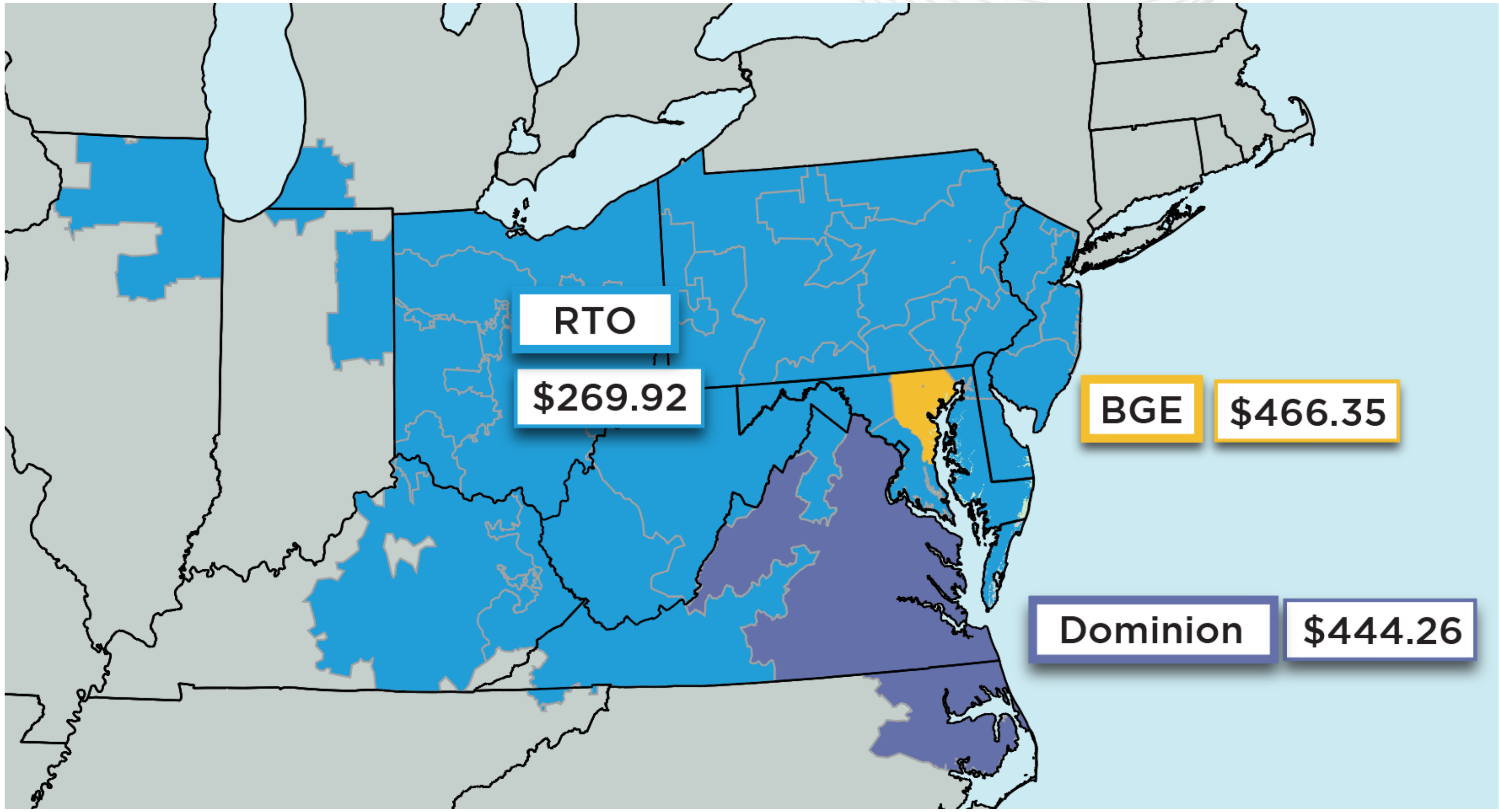
2024/2025	2034/2035
136,127 MW	198,175 MW

Growth Rate 3.8%

Large Load Adjustments (MWs)



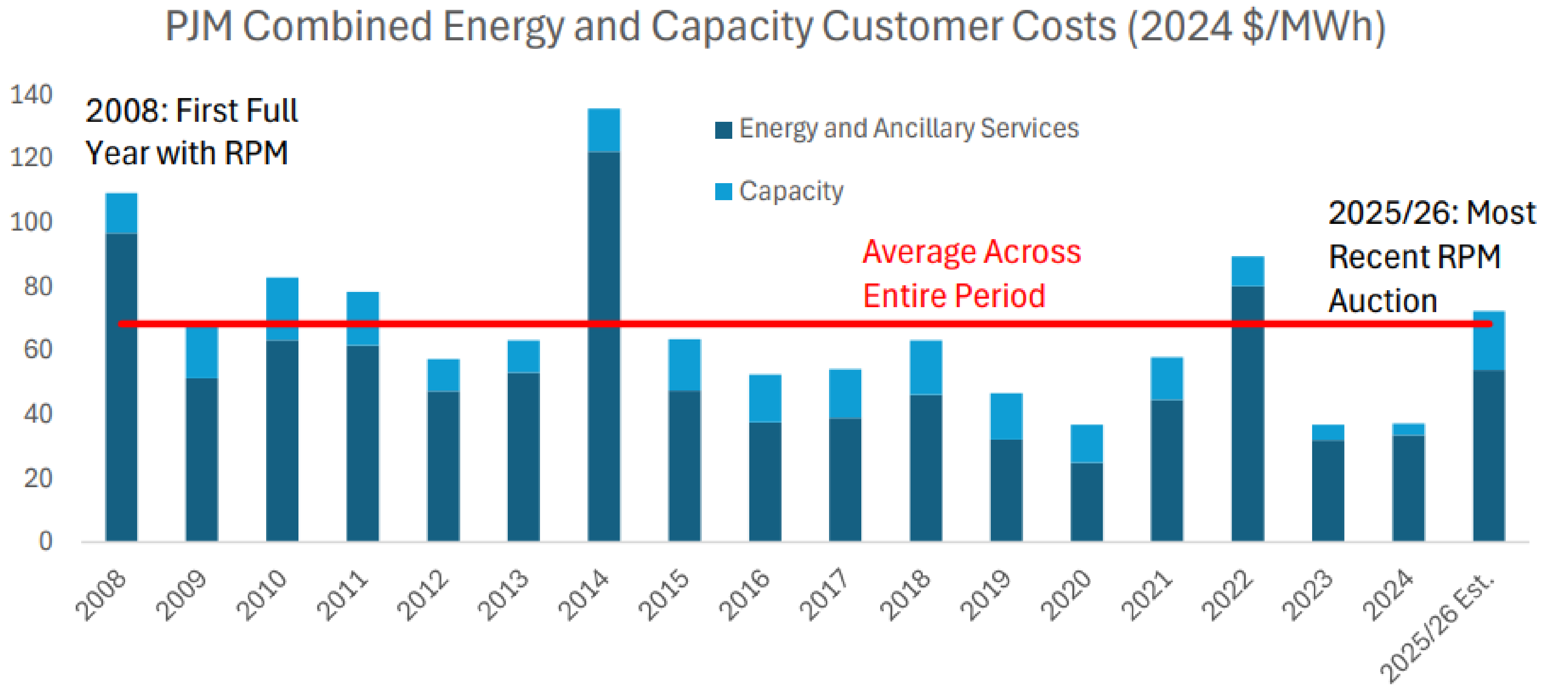
RTO & LDA Prices



RTO Price Comparison

	2025/2026	2024/2025
RTO Price:	**$269.92/** MW-day	**$29/** MW-day
Reserve Margin	**18.5%**	**20.5%**
with IRM of:	*17.8%*	*14.7%*

Historic Electricity Costs



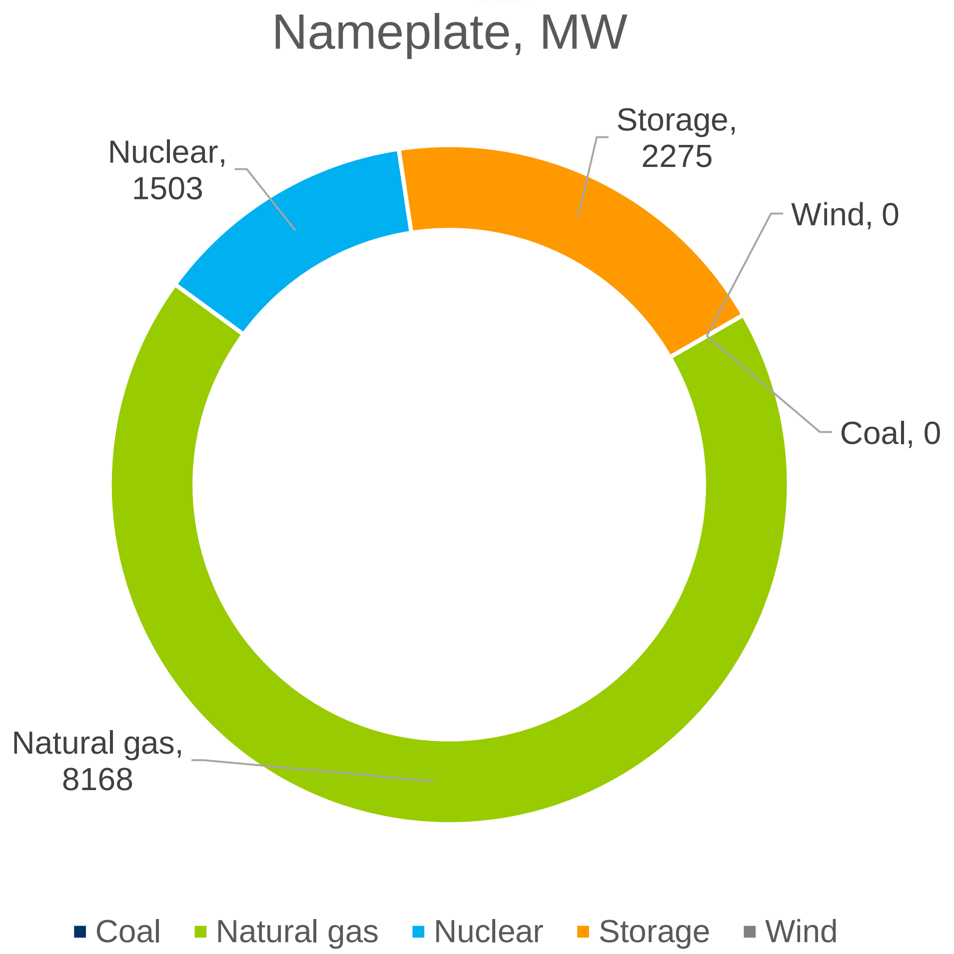
Source: Monitoring Analytics, LLC, 2024 State of the Market Report for PJM, Table 11. Estimated costs for 2025/26 based on RPM auction results and energy forward prices from S&P Global. Adjusted for inflation using GDP deflator as reported by the U.S. Federal Reserve.

PJM Efforts to Expedite Supply

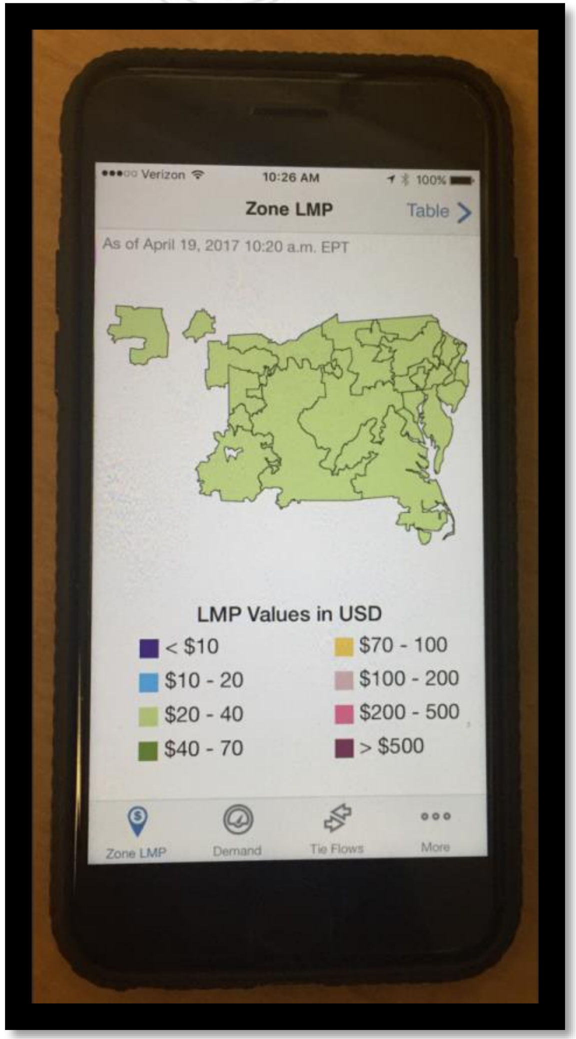
CIR Transfer	**Target:** New generation resources swapping-in for a deactivating generator that then don't need to go through queue
	Potential Outcome: Permanent modifications to the process
Reliability Resource Initiative	**Target:** Queue opened for new shovel-ready resources that can come online quickly and contribute to reliability
	Potential Outcome: One-time expansion of the eligibility criteria for Transition Cycle #2 beyond active requests received prior to September 2021
Surplus Interconnection Service	**Target:** Making it easier to add more generation to an existing site for generators that are not able to operate continually 24/7/365 (e.g. adding storage to renewable site)
	Potential Outcome: Permanent modification to Surplus Interconnection Service criteria

RRI - All Projects by State

	Number	Nameplate	CIR
Delaware			
Illinois	4	398	313
Indiana			
Kentucky	1	786	759
Maryland	2	554	548
Michigan			
North Carolina			
New Jersey	5	550	607
Ohio	9	3,363	3,242
Pennsylvania	7	1,201	1,293
Tennessee			
Virginia	22	5,095	5,309
West Virginia	1	0	14
Total	**51**	**11,945**	**12,085**



PJM Now App Available



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Energy Transition in PJM:

Resource Retirements, Replacements & Risks

Feb. 24, 2023

For Public Use

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Contents

Executive Summary

Driven by industry trends and their associated challenges, PJM developed the following strategic pillars to ensure an efficient and reliable energy transition: facilitating decarbonization policies reliably and cost-effectively; planning/operating the grid of the future; and fostering innovation.

PJM is committed to these strategic pillars, and has undertaken multiple initiatives in coordination with our stakeholders and state and federal governments to further this strategy, including interconnection queue reform, deployment of the State Agreement Approach to facilitate 7,500 MW offshore wind in New Jersey, and coordination with state and federal governments on maintaining system reliability while developing and implementing their specific energy policies.

In light of these trends and in support of these strategic objectives, PJM is continuing a multiphase effort to study the potential impacts of the energy transition. The first two phases of the study focused on energy and ancillary services and resource adequacy in 2035 and beyond. This third phase focuses on resource adequacy in the near term through 2030.[1]

Maintaining an adequate level of generation resources, with the right operational and physical characteristics[2], is essential for PJM's ability to serve electrical demand through the energy transition.

Our research highlights four trends below that we believe, in combination, present increasing reliability risks during the transition, due to a potential timing mismatch between resource retirements, load growth and the pace of new generation entry under a possible "low new entry" scenario:

- The growth rate of electricity demand is likely to continue to increase from electrification coupled with the proliferation of high-demand data centers in the region.
- Thermal generators are retiring at a rapid pace due to government and private sector policies as well as economics.
- Retirements are at risk of outpacing the construction of new resources, due to a combination of industry forces, including siting and supply chain, whose long-term impacts are not fully known.
- PJM's interconnection queue is composed primarily of intermittent and limited-duration resources. Given the operating characteristics of these resources, we need multiple megawatts of these resources to replace 1 MW of thermal generation.

[1] See Energy Transition in PJM: Frameworks for Analysis | Addendum (2021), and Energy Transition in PJM: Emerging Characteristics of a Decarbonizing Grid | Addendum (2022).

[2] See previous work on Reliability Products and Services, including PJM's Evolving Resource Mix and System Reliability (2017), Reliability in PJM: Today and Tomorrow (2021), Energy Transition in PJM: Frameworks for Analysis | Addendum (2021), and work completed through the RASTF and PJM Operating Committee (2022).

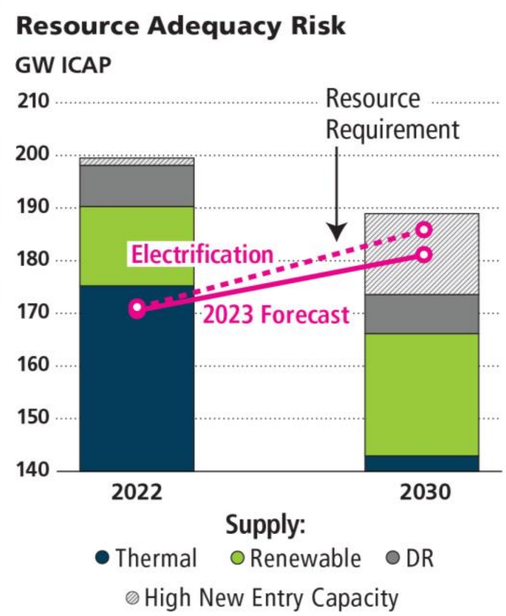
The analysis also considers a "high new entry" scenario, where this timing mismatch is avoided. While this is certainly a potential outcome, given the significant policy support for new renewable resources, our analysis of these long-term trends reinforces the importance of PJM's ongoing stakeholder initiatives, including capacity market modifications, interconnection process reform and clean capacity procurement, and the urgency for continued, combined actions to de-risk the future of resource adequacy while striving to facilitate the energy policies in the PJM footprint.

The first two phases of the energy transition study assumed that PJM had adequate resources to meet load.

In this this third phase of this living study, we explore a range of plausible scenarios up to the year 2030, focusing on the resource mix "balance sheet" as defined by generation retirements, demand growth and entry of new generation.

The analysis shows that 40 GW of existing generation are at risk of retirement by 2030. This figure is composed of: 6 GW of 2022 deactivations, 6 GW of announced retirements, 25 GW of potential policy-driven retirements and 3 GW of potential economic retirements. Combined, this represents 21% of PJM's current installed capacity[3].

In addition to the retirements, PJM's long-term load forecast shows demand growth of 1.4% per year for the PJM footprint over the next 10 years. Due to the expansion of highly concentrated clusters of data centers, combined with overall electrification, certain individual zones exhibit more significant demand growth – as high as 7% annually.[4]



The projections in this study indicate that it is possible that the current pace of new entry would be insufficient to keep up with expected retirements and demand growth by 2030.

On the other side of the balance sheet, PJM's New Services Queue consists primarily of renewables (94%) and gas (6%). Despite the sizable nameplate capacity of renewables in the interconnection queue (290 GW), the historical rate of completion for renewable projects has been approximately 5%. The projections in this study indicate that the current pace of new entry would be insufficient to keep up with expected retirements and demand growth by 2030. The completion rate (from queue to steel in the ground) would have to increase significantly to maintain required reserve margins.

In the study, we also consider generation entry beyond the queue using projections from S&P Global. Those projections indicate that, despite eroding reserve margins, resource adequacy would be maintained if the influx of renewables materializes at a rapid rate and gas remains the transition fuel, adding 9 GW of capacity. The analysis performed at the Clean Attribute Procurement Senior Task Force (CAPSTF) also suggests that further gas expansion is economic and competitive.[5]

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[3] Unless otherwise noted, thermal capacity values are expressed in ICAP, without adjustment for EFORd.

[4] PJM Load Forecast Report, January 2023.

[5] CAPSTF Analysis, Initial Results; Emmanuele Bobbio, Sr. Lead Economist – Advanced Analytics, PJM, Dec. 16, 2022.

Balance Sheet Summary (2022–2030)				
Retirements	**New Entry Wind/Solar**[6]	**New Entry Standalone Storage**	**New Entry Thermal**	**Load Growth**
40 GW **60% Coal** **30% Natural Gas** **10% Other**	**Low =** 48 GW-nameplate / 8 GW-capacity **High =** 94 GW-nameplate / 17 GW-capacity	**Low =** 3 GW **High =** 4 GW	**Low =** 4 GW **High =** 9 GW	**2023 Forecast =** 11 GW **Electrification Forecast =** 13 GW
Unless otherwise noted, thermal capacity values are expressed in ICAP, without adjustment for EFORd.				

For the first time in recent history, PJM could face decreasing reserve margins should these trends continue. The amount of generation retirements appears to be more certain than the timely arrival of replacement generation resources and demand response, given that the quantity of retirements is codified in various policy objectives, while the impacts to the pace of new entry of the Inflation Reduction Act, post-pandemic supply chain issues, and other externalities are still not fully understood.

The findings of this study highlight the importance of PJM's ongoing stakeholder initiatives (Resource Adequacy Senior Task Force, Clean Attribute Procurement Senior Task Force, Interconnection Process Subcommittee), continued efforts between PJM and state and federal agencies to manage reliability impacts of policies and regulations, and the urgency for coordinated actions to shape the future of resource adequacy. The potential for an asymmetrical pace in the energy transition, in which resource retirements and load growth exceed the pace of new entry, underscores the need to enhance the accreditation, qualification and performance requirements of capacity resources.

The composition and performance characteristics of the resource mix will ultimately determine PJM's ability to maintain reliability. It is critical that all PJM markets effectively correct imbalances brought on by retirements or load growth by incentivizing investment in new or expanded resources.

[6] Includes hybrid projects with battery storage

Background

Resource adequacy is the ability of the electric system to supply the aggregate energy requirements of electricity to consumers at all times, taking into account scheduled and reasonably expected unscheduled outages of generation and transmission facilities. To achieve the goal of resource adequacy, PJM maintains an Installed Reserve Margin in excess of the forecast peak load that achieves a loss-of-load expectation (LOLE) of one day in 10 years. This LOLE standard is consistent with that prescribed in the ReliabilityFirst Corporation standard for planning resource adequacy.[7]

Long-term reliability and resource adequacy are addressed through the combined operation of PJM's electricity markets, and in particular the capacity market, called the Reliability Pricing Model (RPM). Each PJM member that provides electricity to consumers must acquire enough power supply to meet demand, not only for today and tomorrow, but for the future. Members secure these capacity resources for future energy needs through a series of base and incremental capacity auctions, as well as Fixed Resource Requirement plans.

The capacity market ensures long-term grid reliability by procuring the appropriate amount of power supply resources needed to meet predicted energy demand up to three years in the future. These capacity resources have an obligation to perform during system emergencies, and are subject to penalties if they underperform. By matching generation with future demand, the capacity market creates long-term price signals to attract needed investments to ensure adequate power supplies. This exchange provides consumers with an assurance of reliable power in the future, while capacity resources receive a dependable flow of income to help maintain their existing capability, attract investment in new resources, and encourage companies to develop new technologies and sources of electric power.

Methodology

The size, composition and performance characteristics of the resource mix will determine PJM's ability to maintain reliability. This study explores a range of scenarios in the context of resource adequacy, focusing on the resource mix "balance sheet" as defined by demand growth, generation retirements and new entry of generation. Using the methodology described in this section, PJM evaluates the future of resource adequacy by estimating the amount of capacity required to cover load expectations versus expected capacity for the years 2023 through 2030.

The study's initial supply levels are 192.3 GW of installed capacity from generation resources and 7.8 GW of installed capacity from demand response capacity resources. The generation mix is approximately 178.9 GW of thermal resources and 13.3 GW of renewables and storage.[8]

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[7] RFC Standard BAL-502-RF-03: Planning Resource Adequacy Analysis, Assessment and Documentation

[8] This value includes the capacity value of run-of-river hydro, pumped storage hydro, solar, onshore wind, offshore wind and battery energy storage.

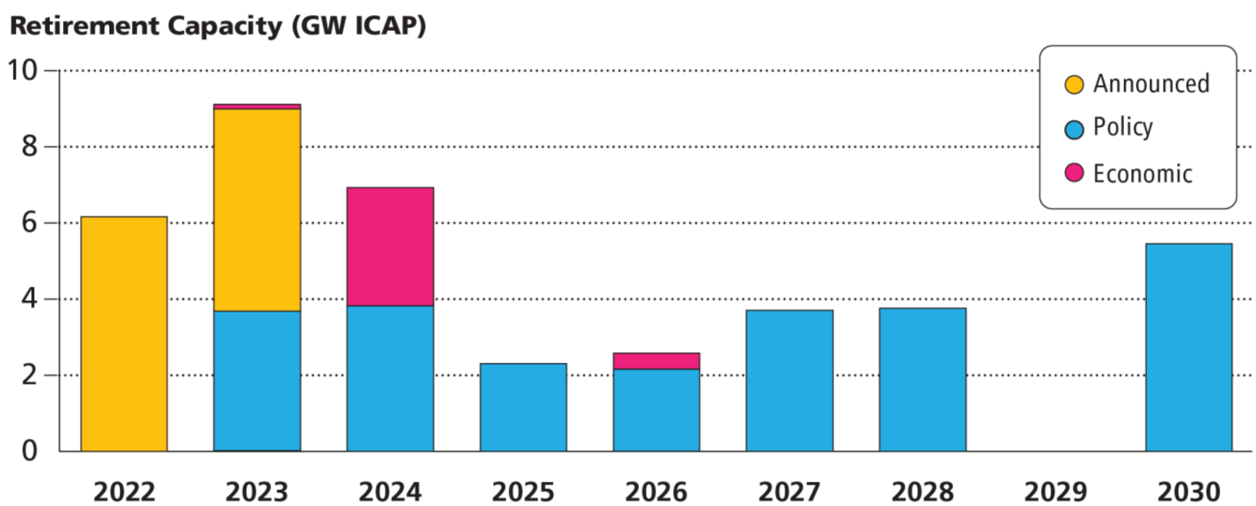
Supply Exits

PJM is undergoing a major transition in the resources needed to maintain bulk power grid reliability.

Historically, thermal resources have provided the majority of the reliability services in PJM. Today, a confluence of conditions, including state and federal policy requirements, industry and corporate goals requiring clean energy, reduced costs and/or subsidies for clean resources, stringent environmental standards, age-related maintenance costs, and diminished energy revenues are hastening the decline in thermal resources.

This study estimates anticipated retirements through 2030 by adding announced retirements with retirements likely as a result of various state and federal policies, and then with those at risk for retirement due to deteriorating unit economics. Potential policy-driven retirements, in this context, reflect resources that are subject to current and proposed federal and state environmental policies, in which it is conservatively assumed that the costs of mitigation and compliance could economically disadvantage these resources to the point of retirement. **Figure 1** highlights the 40 GW of projected generation retirements by 2030, which is composed of: 12 GW of announced retirements[9], 25 GW of potential policy-driven retirements[10] and 3 GW of potential economic retirements. Combined, this represents 21% of PJM's current installed capacity.[11] This section describes each category of potential retirements in more detail.

Figure 1. Total Forecast Retirement by Year (2022–2030)



[9] Includes 6 GW of 2022 retirements.

[10] Note that 7 GW of the 25 GW of supply with policy risk was also identified to have more immediate economic risk. The year that these 7 GW of potential policy retirements shown in **Figure 2** is based on timing identified in the economic analysis. In **Figure 4**, these 7 GW are shown in terms of the regulatory compliance timeline alone. The timeline of these potential quantities of resource retirements does not factor in any reliability "off-ramps" that may be included in established policies.

[11] In this study, PJM assumes that a resource that exits would not return to service in a future delivery year, even if operational conditions improve. Historically, a small percentage of retiring units would instead enter a "mothball" or standby state, in which the unit is put into a state where it may not operate for one or more years; however, in order to obtain an operating permit renewal, the mothballed unit would have to comply with the most recent environmental standards, likely requiring costly upgrades, making investing in newer, cleaner technologies more inviting.

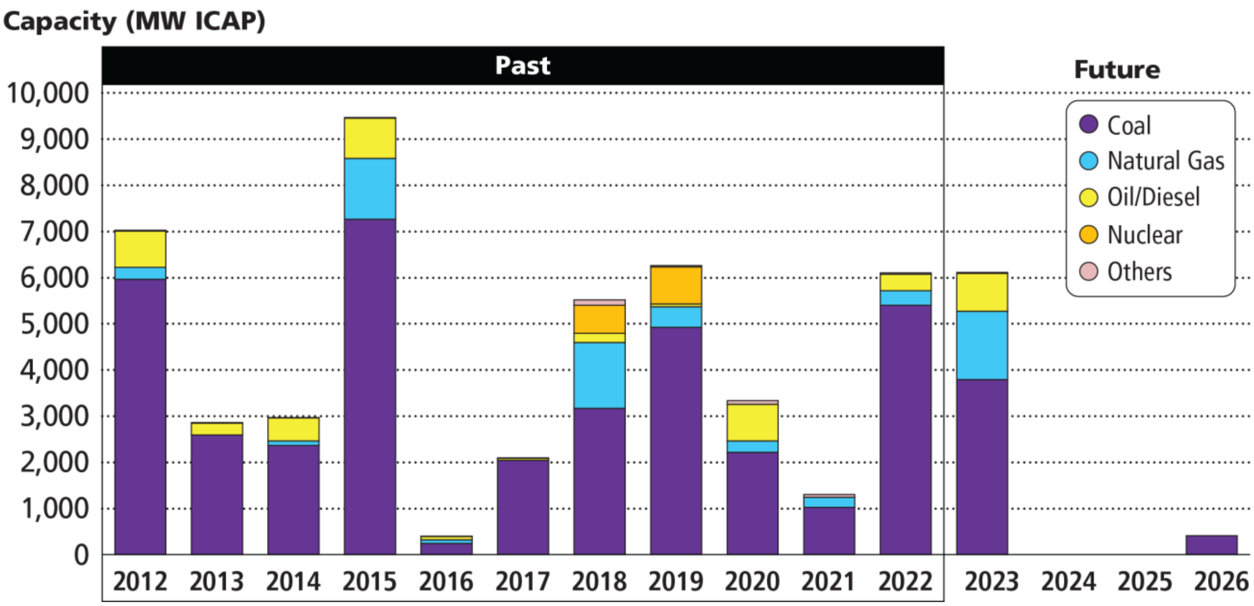
Announced Retirements

One of PJM's responsibilities is to ensure the continued reliability of the high-voltage electric transmission system when a generation owner requests deactivation. Through its Generation Deactivation process,[12] PJM identifies transmission solutions that allow owners to retire generating plants as requested without threatening reliable power supplies to customers. PJM may order transmission upgrades or additions built by transmission owners to accommodate the generation loss. PJM has no authority to order plants to continue operating. However, in some instances, to maintain reliability, PJM may formally request that a plant owner continue operating, subject to rates authorized by the Federal Energy Regulatory Commission (FERC), while transmission upgrades are completed.

Plant owners considering retirement must notify PJM at least two quarters before the proposed deactivation date. PJM and the transmission owners complete a reliability analysis in the subsequent quarter after notification to PJM. Generator retirements and any required system upgrades to keep the grid running smoothly are included in the PJM Regional Transmission Expansion Planning process and are reviewed with PJM members and stakeholders at the PJM Transmission Expansion Advisory Committee.

Between 2012 and 2022, 47.2 GW of generation retired in PJM, as detailed by fuel type in **Figure 2**. In 2022, approximately 6 GW of generation deactivated and an additional 5.8 GW announced ("future") deactivations over the 2023–2026 time frame. The deactivations are slightly above the 10-year average of 4.3 GW, but well under the historical annual peak of 9.5 GW in 2015. Coal-fired resources account for approximately 89% of retired capacity in 2022.

Figure 2. Past and Announced Future Retirements



[12] See process details in PJM Manual 14-D, Section 9, and tracking of deactivation requests at https://www.pjm.com/planning/services-requests/gen-deactivations.

Potential Policy Retirements

An analysis of federal and state policies and regulations with direct impacts on generation in the PJM region yielded the largest group of potential future retirements in this study.[13] As highlighted in **Figure 3**, the combined requirements of these regulations and their coincident compliance periods have the potential to result in a significant amount of generation retirements within a condensed time frame. These impacts will be reevaluated as these policies and regulations evolve. PJM will continue to work with both federal and state agencies on the development and implementation of environmental regulations and policies in order to address any reliability concerns.

Below are the policies and regulations included in the study:

EPA Coal Combustion Residuals (CCR): The U.S. Environmental Protection Agency (EPA) promulgated national minimum criteria for existing and new coal combustion residuals (CCR) landfills and existing and new CCR surface impoundments. This led to a number of facilities, approximately 2,700 MW in capacity, indicating their intent to comply with the rule by ceasing coal-firing operations, which is reflected in this study.

EPA Effluent Limitation Guidelines (ELG): The EPA updated these guidelines in 2020, which triggered the announcement by Keystone and Conemaugh facilities (about 3,400 MW) to retire their coal units by the end of 2028.[14] Importantly, but not included in this study, the EPA is planning to propose a rule to strengthen and possibly broaden the guidelines applicable to waste (in particular water) discharges from steam electric generating units. The EPA is expecting this to impact coal units by potentially requiring investments when plants renew their discharge permits, and extending the time that plants can operate if they agree to a retirement date.

EPA Good Neighbor Rule (GNR): This proposal requires units in certain states to meet stringent limits on emissions of nitrogen oxides (NOx), which, for certain units, will require investment in selective catalytic reduction to reduce NOx. For purposes of this study, it is assumed that unit owners will not make that investment and will retire approximately 4,400 MW of units instead. Please note that the EPA plans on finalizing the GNR in March, which may necessitate reevaluation of this assumption.

Illinois Climate & Equitable Jobs Act (CEJA): CEJA mandates the scheduled phase-out of coal and natural gas generation by specified target dates: January 2030, 2035, 2040 and 2045. To understand CEJA criteria impacts and establish the timing of affected generation units' expected deactivation, PJM analyzed each generating unit's publically available emissions data, published heat rate, and proximity to Illinois environmental justice communities and Restore, Reinvest, Renew (R3) zones. For this study, PJM focuses on the approximately 5,800 MW expected to retire in 2030.

[13] Policies impacting forward energy prices, such as the Regional Greenhouse Gas Initiative and Renewable Energy Credits, are implicitly included in economic analysis but are not explicitly included in analysis of policy-related retirements.

[14] See State Impact PA, Nov. 22, 2021. These facilities have not filed formal Deactivation Notices with PJM.

New Jersey Department of Environmental Protection CO_2 Rule: New Jersey's CO_2 rule seeks to reduce carbon dioxide (CO_2) emissions of fossil fuel-fired electric generating units (EGUs) through the application of emissions limits for existing and new facilities greater than 25 MW. Units must meet a CO_2 output-based limit by tiered start dates. The dates and CO_2 limits are:

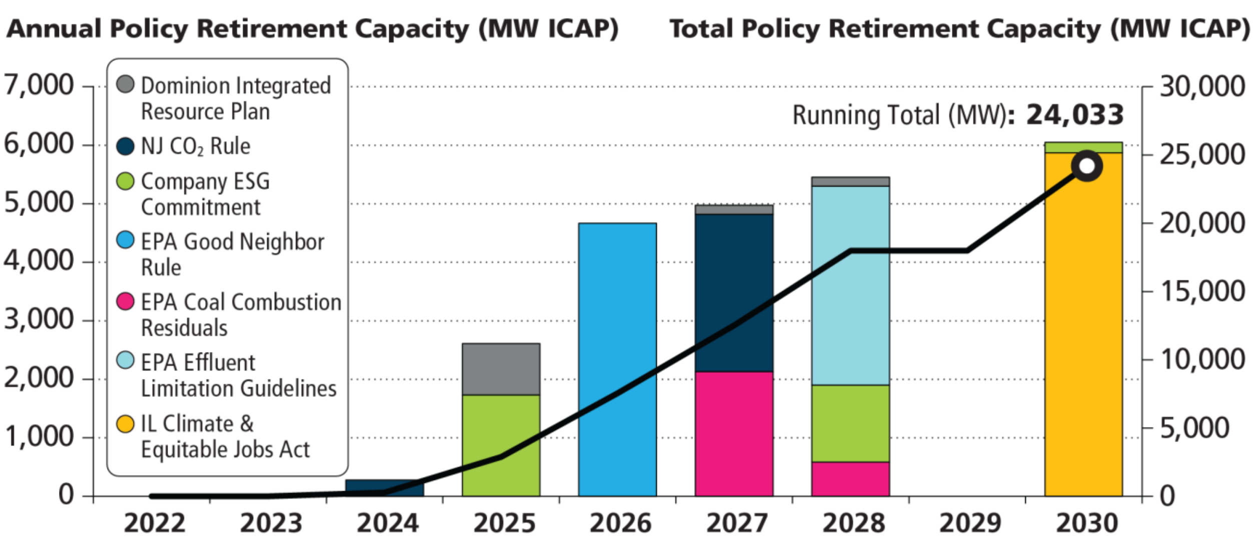
- June 1, 2024 – 1,700 lb/MWh
- June 1, 2027 – 1,300 lb/MWh
- June 1, 2035 – 1,000 lb/MWh

PJM used emissions data found in EPA Clean Air Markets Program Data to evaluate unit compliance. Where a unit's average annual emissions rate was greater than the CO_2 limit on the compliance date, the unit was assumed to be retiring. In this study PJM, estimated retirements at approximately 400 MW in 2024 and approximately 2,700 MW in 2027.

Dominion Integrated Resource Plan (IRP) commits to net zero carbon in its Virginia and North Carolina territory by 2050. PJM studied Dominion's Alternative Plan B retirement schedule, approximately 1,533 MW, for this analysis. Alternative Plan B proposes "significant development of solar, wind and energy storage resource envisioned by the VCEA," (Virginia Clean Economy Act of 2020), while maintaining natural gas generation for reliability, which is reflected in our analysis.

Company ESG (Environmental, Social, Governance) commitments are included where there is a commitment to retire resources per legal consent decree or other public statement. This includes the elimination of coal use and the retirement of the Brandon Shores, 1,273 MW, and Wagner, 305 MW, facilities in Maryland and the retirement of Rockport, 1,318 MW, in Indiana.

Figure 3. Potential Policy Retirements



Potential Economic Retirements

The third category of retirements in this study, beyond those formally announced and made likely by policy implementation, were identified through an analysis of revenue adequacy, the ability to economically cover going-forward costs from the wholesale markets. A net profit value was calculated for each existing generation resource using an estimate of future revenues and historical costs.

$$Net\ Profit = (\ Gross\ Energy\ \&\ Ancillary\ Service\ Revenue - Production\ Costs\ ) + (\ Capacity\ Revenue\ ) - (\ Fixed\ Avoidable\ Costs\ )$$

The results reveal that a portion of the thermal fleet is at risk of becoming unprofitable in the coming years.

The capacity market's Variable Resource Requirement (VRR) represents the set of prices for which load is willing to procure additional supply beyond the minimum reliability requirement. There are three points in the sloped demand curve, the first of which is anchored at a price 1.5 times the Net Cost of New Entry (Net CONE). Should the auction clear at this price level, the auction result signals that demand is willing to pay for the construction of new supply, minus the expected energy revenues the resource should expect to earn in the energy markets. As such, it is important to align the revenue expectations for the marginal resources with forward revenues, especially under PJM's continually changing landscape of business rules.

Energy & Ancillary Services Revenue and Production Cost

This study used a scaling approach to estimate forward unit-specific energy and ancillary services (E&AS) revenues from historical energy and ancillary service revenues by applying the following:

$$Fwd\ Unit\ E\&AS\ Revenue = Hist\ Unit\ E\&AS\ Revenue * \frac{Fwd\ Reference\ E\&AS\ Revenue^{15}}{Hist\ Reference\ E\&AS\ Revenue} * \frac{Reference\ Avg\ Heat\ Rate}{Unit\ Avg\ Heat\ Rate}$$

For a given reference resource type, unit dispatch was simulated using both historical and forward energy hub-adjusted energy prices. For the equivalent production cost model, the relative ratio of revenues and heat rates indicate the net effects of both rising fuel costs and energy price revenue. A unit on the margin in the energy markets, typically a natural gas unit, would set a locational price near its short-run marginal costs. Infra-marginal units, potentially coal units, would receive higher revenues as price-taking resources, and thus may see increased profitability. This is reflected in the analysis, in which a reference coal unit's forward revenues increased an average of 139% over previous revenue estimates.

[15] The forward energy and ancillary services revenue calculation used in this study is the method that was developed for use in the Forward Net Energy & Ancillary Services Offset calculation originally developed in 2020, and filed as part of the most recent Quadrennial Review.

Capacity Revenues and Fixed Avoidable Costs

Unit-specific capacity revenues were calculated from prices and cleared quantities in the 2023/2024 Base Residual Auction (BRA). The study used the published 2023/2024 BRA Default Gross Avoidable Cost Rate (ACR) values as representative total fixed costs ($/MW-day) required to keep the generating plant available to produce energy. In other words, these are projected costs that could be avoided by the retirement of the plant. Avoidable costs represent operational factors like operations and maintenance labor, fuel storage costs, taxes and fees, carrying charges, and other costs not directly related to the production of energy. When available, unit-specific ACR values from the 2023/2024 BRA supply offer mitigation process were used, otherwise the class average Gross ACR was used.

Results and Estimated Impact

This study assumes that a simulated economic loss would result in a retirement of the resource at the next available delivery year in which the unit is not committed for capacity. As such, a unit with a revenue loss that did not clear in the 2023/2024 BRA would exit in 2023, while a unit with a revenue loss that cleared in the 2023/2024 BRA would exit in 2024. While units that do not clear a single BRA may remain energy-only resources, this conservative assumption was used to provide awareness.

The economic analysis identified approximately 10 GW of supply in immediate economic risk, of which 7 GW of supply is also affected by policy risk, and 3 GW of supply is economic risk only. In aggregate, 6 GW are steam resources, and 4 GW represent combustion turbines and internal combustion resources. Several of the units identified were older steam boilers that had once converted from coal-fired to natural gas fuel; these resources are less efficient than a modern heat-recovery steam generator in a combined cycle unit. Fifty-three percent of the resources identified for economic risk did not have a PJM capacity obligation in Delivery Year 2023/2024, either through the FRR process or market clearing.

Supply Entry

The composition of the PJM Interconnection Queue has evolved significantly in recent years, primarily increasing in the amount of renewables, storage, and hybrid resources and decreasing in the amount of natural gas-fired resources entering the queue. The PJM New Services Queue stands at approximately 290 ICAP GW of generation interconnection requests, of which almost 94% (271 ICAP GW) is composed of renewable and storage-hybrid resources.

Natural Gas Headwinds

In the last decade, resources in the PJM region have benefitted from the proximity to the Marcellus Shale, an area that extends along the Appalachian Mountains from southern West Virginia to central New York. Beginning around 2010, gas extraction from hydraulic fracturing transformed this region into the largest source of recoverable natural gas in the United States. This local fuel supply decreased the prices for spot market natural gas in much of the PJM region, and prices in the PJM region often trade at negative basis to the Henry Hub spot price.

The entry of natural gas resources in the PJM region peaked in 2018, with 11.1 GW of generation commercializing that single year. From 2019 to 2022, a total of 8.1 GW of natural gas generation began service, or about a third of the 23 GW observed from 2015–2018. Queue proposals have also declined; over the last three years, only 4.1 GW of new natural gas projects entered the queue, while 15.1 GW of existing queue projects withdrew.[16]

Recent movement in the natural gas spot markets across the U.S. and Europe add another degree of uncertainty to future operations. In 2022, European natural gas supply faced many challenges resulting from the war in Ukraine and subsequent sanctions against Russia. Liquefied natural gas (LNG) imports into the EU and the U.K. in the first half of 2022 increased 66% over the 2021 annual average,[17] primarily from U.S. exporters with operational flexibility. This international natural gas demand is a new competitor for domestic spot-market consumers, resulting in significantly higher fuel costs for PJM's natural gas fleet.

This study assumes that, of the approximately 17.6 GW of natural gas generation in the queue, only those that are proposed uprates of existing generation, or currently under construction, will complete.[18] This results in 3.8 GW of entry from under-construction natural gas resources to be completed for the 2023/2024 Delivery Year. While 12 GW of natural gas have reached a signed Interconnection Service Agreement (ISA) stage, it is unclear what percentage of this capacity may move forward. If significantly more natural gas capacity achieved commercial operation, it could help avoid reliability issues.

Renewable Transition

PJM's projected resource mix continues to evolve toward lower-carbon intermittent resources. Entry into the queue from renewable and storage resources has been growing at an annualized rate of 72% per year since 2018, or 199 GW of capacity entry versus 2.8 GW commercializing and 42.1 GW withdrawn. This influx of renewable projects has led to a joint effort between PJM and its stakeholders to enact queue reforms intended to clear the backlog of projects, improve procedures around permitting and site control, simplify analysis by clustering projects, and accelerate projects that don't require network upgrades. FERC approved the proposed package in November 2022, with expected implementation in 2023.

Commercial Probability and Expanding Beyond the Queue

PJM staff developed several forecasts of the rate by which projects successfully exit the queue (the "commercial probability" of reaching an *In-Service* state). Since 1997, the PJM New Services Queue has tracked proposed generation interconnection projects from their submittal and study stages to completion of an ISA and Wholesale Market Participation Agreement (WMPA) and construction. At any point in the process, a resource may withdraw from the queue, effectively ending its commercial viability.

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[16] This capacity represents natural gas projects that were submitted prior to 2020 and withdrawn in the 2020–2022 time frame.

[17] Europe imported record amounts of liquefied natural gas in 2022, U.S. Energy Information Administration, June 14, 2022.

[18] Under construction includes the New Service Queue *Partially in Service – Under Construction* and *Under Construction* statuses.

The study utilized a logistical regression classification algorithm to predict the probability of a project reaching an *In-Service* entry (or *Withdrawn* exit) based on several properties of the project. A logistical regression searches for patterns within training datasets, resulting in a model that can forecast a probability of a result. After applying the logistical regression model for 10 years of historical project completion (Y-queue to present) without project stage, approximately 15.3 GW-nameplate/8.7 GW-capacity were deemed commercially probable out of 178 GW of projects examined.

The model results for thermal resources were reasonably in line with expectations. However, the model produced extremely low entry from onshore wind, offshore wind, solar, solar-hybrid and storage resources. The uncertainty of completion rates of newer resource types, like offshore wind, likely plays a role in these model outcomes. After adjusting the new renewable capacity by Effective Load Carrying Capability (ELCC) derations, this commercial probability analysis estimates net 13.2 GW-nameplate / 6.7 GW-capacity to the system by 2030, as shown in **Figure 4**.

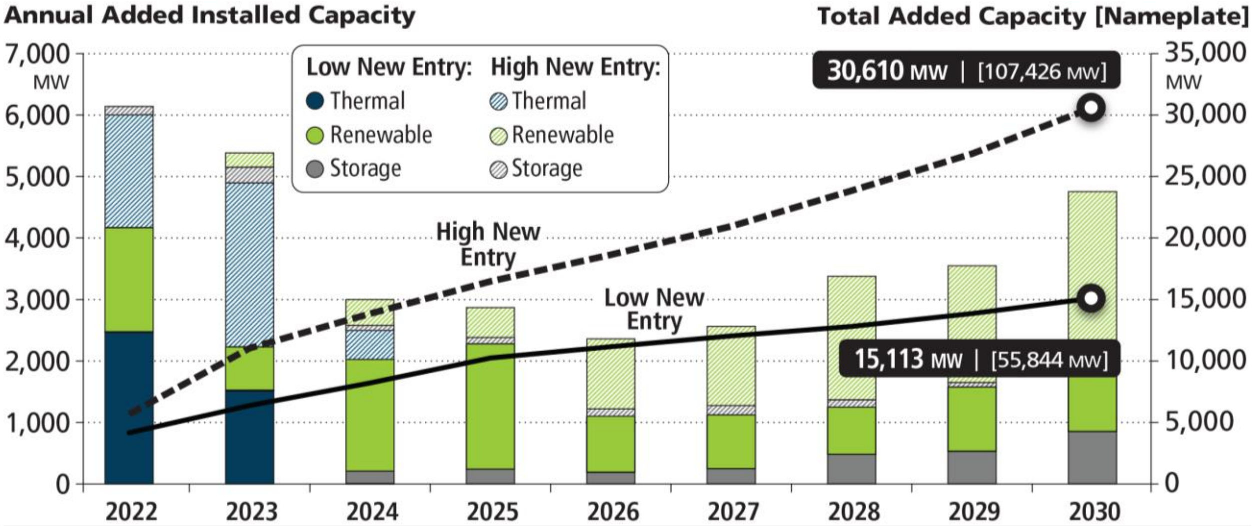
Given that this process may not capture recent policy changes and fiscal incentives toward renewable and storage development, and that the existing queue has fewer resources entered after 2026, PJM staff utilized two S&P Global Power Market Outlook analyses' generation expansion models. As estimates of future entry beyond the queue, these models are used to provide additional insight for the two scenarios: "Low New Entry" utilizes the "Planning Model,"[19] and "High New Entry" utilizes the "Fast Transition" model.[20] Based on these models, PJM added additional capacity to its commercial probability data in each scenario.

These forecasts of generation expansion are economic resource planning solutions, which take state RPS requirements and capacity margins into account to ensure new renewable builds. Over the study period, the Low New Entry scenario adds 42.6 GW-nameplate/8.4 GW-capacity to supply expectations, resulting in total entry of 55.8 GW-nameplate/15.1 GW-capacity. The High New Entry scenario adds 107 GW-nameplate/30.6 GW-capacity after ELCC derations. Net natural gas entry was approximately 5 GW, and renewables was 48.5 GW-nameplate/10.4 GW-capacity, as shown in **Figure 4**.

[19] S&P Global, North American Power Market Outlook, June 2022, planning model. This planning case incorporated effects from the 2021 Infrastructure Investment and Jobs Act, but not the 2022 Inflation Reduction Act.

[20] S&P Global, North American Power Market Outlook, Sept. 2022, Fast Transition model. This planning case assumes carbon net neutrality by 2050 through the IRA and additional policies, such as state clean energy policies, and as such assumes adjustments for increased electrification of heating, tax credits for renewable generation and higher levels of fossil retirements.

Figure 4. Forecast Added Capacity



Impact of Capacity Accreditation on Existing Renewables and Storage

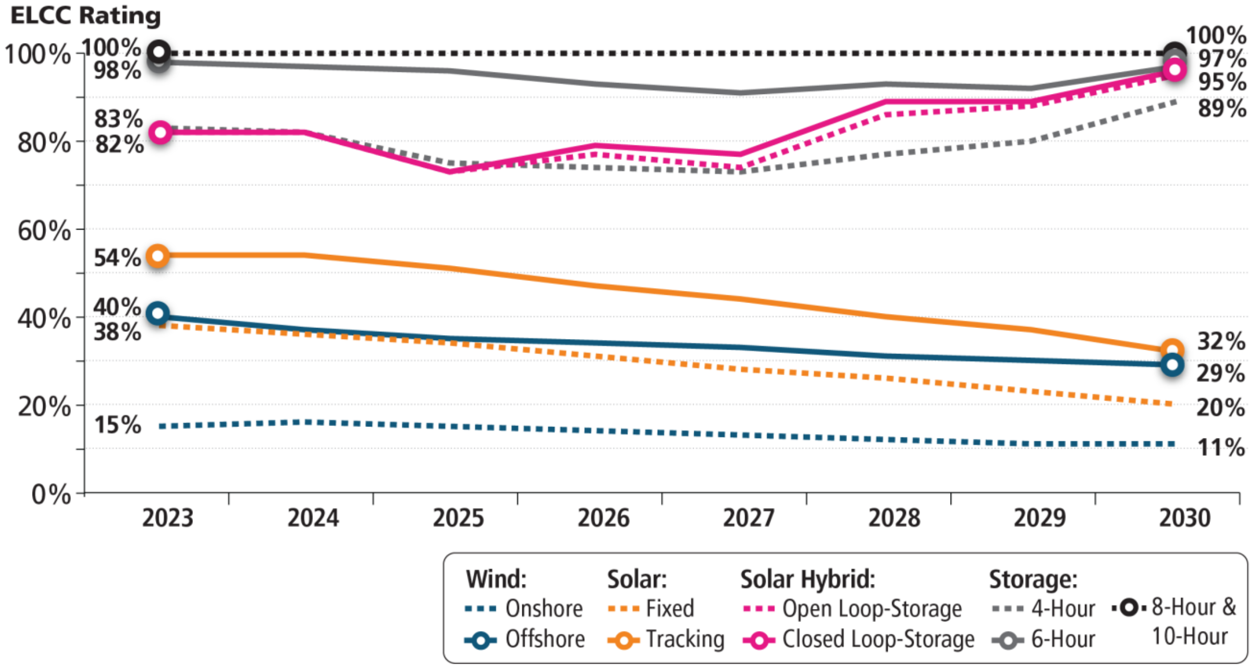
In July 2021, FERC accepted PJM's ELCC methodology for calculating unforced capacity values for intermittent and energy storage capacity resource classes. The ELCC analysis[21] examines load and resource performance uncertainty, and calculates an hourly loss-of-load probability (LOLP) to meet a one-in-10 year loss of load expectation (LOLE) adequacy criteria. The ELCC method examines the alignment of a given resource type's capacity to high risk hours, as well as the change in risk hours proportional to the changes in portfolio size. The adjustments to accredited capacity went into effect in the 2023/2024 BRA executed in June 2022.

This study examined the current renewable generation fleet for the impact of future changes in capacity accreditation. Today, there are approximately 3.5 GW of onshore wind and solar capacity resources participating in the RPM capacity market as intermittent resources. From 2022 to 2030, this accredited capacity is expected to decline by 1.2 GW to 2.3 GW due to portfolio effects resulting in the increase of entry from other intermittent renewable resources.[22] This adjustment is consistent with the renewable expectations presented in the December 2021 Effective Load Carrying Capability (ELCC) Report.

[21] Manual 20, Section 5: PJM Effective Load Carrying Capability Analysis

[22] Approximate nameplate needed to replace 1 MW of thermal generation: Solar – 5.2 MW; Onshore Wind – 14.0 MW; Offshore Wind – 3.9 MW. These are average values.

Figure 5. Effective Load Carrying Capability (ELCC) Rating by Resource Type



Demand Expectations

Load forecasting is an important part of maintaining the reliability of the bulk electric system. Forecasting helps PJM make decisions about how to plan and operate the bulk electric system in a reliable manner, and how to effectively administer competitive power markets. PJM's Resource Adequacy Planning Department publishes an annual Load Forecast Report, which outlines "long-term load forecasts of peak-loads, net energy, load management, distributed solar generation, plug-in electric vehicles and battery storage."

Along with the energy transition, PJM is witnessing a large growth in data center activity. Importantly, the PJM footprint is home to Data Center Alley in Loudoun County, Virginia, the largest concentration of data centers in the world.[23] PJM uses the Load Analysis Subcommittee (LAS) to perform technical analysis to coordinate information related to the forecast of electrical peak demand. In 2022, the LAS began a review of data center load growth and identified growth rates over 300% in some instances.[24] The 2023 PJM Load Forecast Report incorporates adjustments to specific zones for data center load growth, as shown in **Figure 5**.

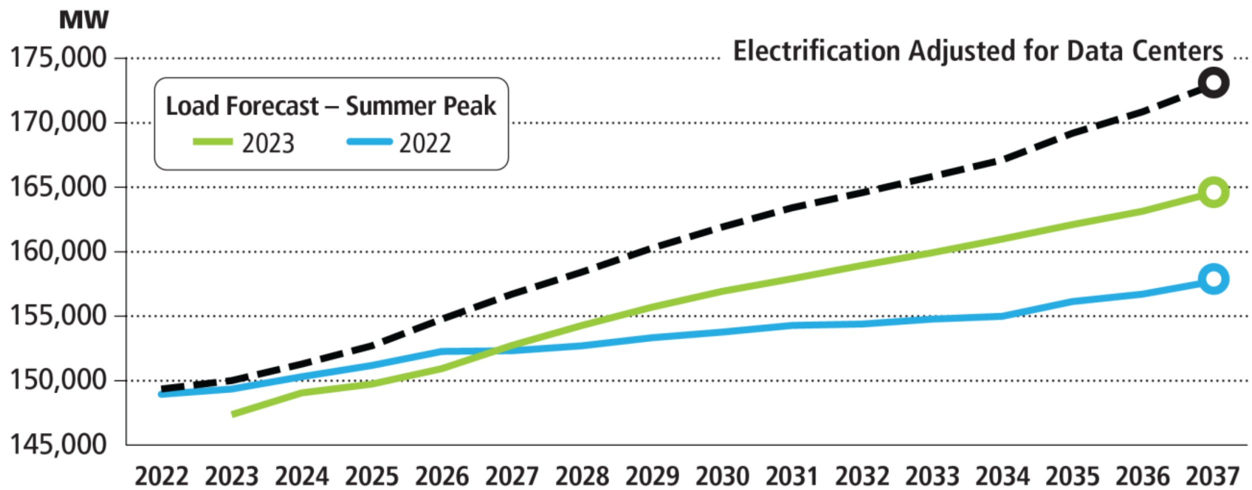
[23] See Loudoun County Department of Economic Development, 2023.

[24] Load Analysis Subcommittee: Load Forecast Adjustment Requests, Andrew Gledhill, Resource Adequacy Planning, Oct. 27, 2022

Additionally, PJM is expecting an increase in electrification resulting from state and federal policies and regulations. The study therefore incorporates an electrification scenario in the load forecast to provide insight on capacity need should accelerated electrification drive demand increases.[25] This accelerated demand increase is consistent with the methodology used in the Emerging Characteristics of a Decarbonizing Grid paper.[26] That paper found electrification to have an asymmetrical impact on demand growth, with demand growth in the winter, mainly due to heating, more than doubling that in the summer. This would move the bulk of the resource adequacy risk from the summer to the winter.

Figure 6 highlights how updated electrification assumptions and accounting for new data center loads have impacted the summer peak between the 2022 and 2023 forecasts.[27]

Figure 6. Impacts of Electrification and Data Center Load on Forecasts



What Does This Mean for Resource Adequacy in PJM?

PJM projects resource adequacy needs through the Reserve Requirement Study (RRS). The purpose of the RRS is to determine the required capacity or Forecast Pool Requirement for future years or delivery years based on load and supply uncertainty. The RRS also satisfies the North America Electric Reliability Corporation/ReliabilityFirst Adequacy Standard BAL-502-RFC-03, Planning Resource Adequacy Analysis, Assessment and Documentation, which requires that the Planning Coordinator performs and documents a resource adequacy analysis that applies a LOLE of one occurrence in 10 years. The RRS establishes the Installed Reserve Margin values for future delivery years. For this study PJM used the most recent 2022 RRS, as well as the 2021 RRS for comparison.

[25] Electrification assumptions are 17 million EVs, 11 million heat pumps, 20 million water heaters, 19 million cooktops in PJM by 2037, built on top of the 2022 Load Forecast.

[26] Energy Transition in PJM: Emerging Characteristics of a Decarbonizing Grid, May 17, 2022.

[27] 2023 Load Forecast Supplement, PJM Resource Adequacy Planning Department, January 2023.

Combining the resource exit, entry and increases in demand, summarized in **Figure 7**, the study identified some areas of concern. Approximately 40 GW PJM's fossil fuel fleet resources may be pressured to retire as load grows into the 2026/2027 Delivery Year. At current low rates of renewable entry, the projected reserve margin would be 15%, as shown in **Table 1**. The projected total capacity from generating resources would not meet projected peak loads, thus requiring the deployment of demand response. By the 2028/2029 Delivery Year and beyond, at Low New Entry scenario levels, projected reserve margins would be 8%, as projected demand response may be insufficient to cover peak demand expectations, unless new entry progresses at a levels exhibited in the High New Entry scenario. This will require the ability to maintain needed existing resources, as well as quickly incentivize and integrate new entry

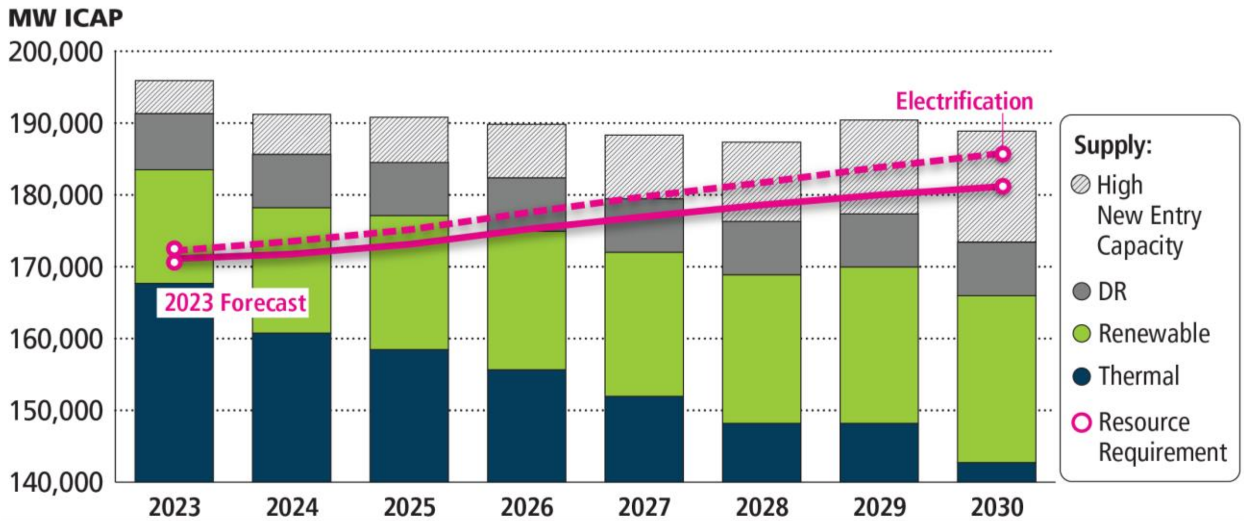
Table 1. Reserve Margin Projections Under Study Scenarios

Reserve Margin	2023	2024	2025	2026	2027	2028	2029	2030
Low New Entry								
2023 Load Forecast	23%	19%	17%	15%	11%	8%	8%	5%
Electrification	22%	18%	16%	13%	10%	7%	6%	3%
High New Entry								
2023 Load Forecast	26%	23%	21%	19%	17%	16%	17%	15%
Electrification	25%	22%	20%	18%	15%	14%	14%	12%

As witnessed during the rapid transition from coal resources to natural gas resources last decade, PJM markets provide incentives for capacity resources. The challenge will be integrating the level of additional resources envisioned to meet this demand, and therefore addressing issues such as resource capacity accreditation is critical in the near term. The low entry rates shown in our Low New Entry scenario are illustrative of recent completion history applied to the current queue. RTO capacity prices in recent auctions have been low for several delivery years, and capacity margins have historically reached around 28% of peak loads. As capacity reserve levels tighten, the markets will clear higher on the VRR curves, sending price signals to build new generation for reliability needs.

The 2024/2025 BRA, which executed in December 2022, highlighted another area of uncertainty. Queue capacity with approved ISAs/WMPAs is currently very high, approximately 35 GW-nameplate, but resources are not progressing into construction. There has only been about 10 GW-nameplate moving to in service in the past three years. There may still be risks to new entry, such as semiconductor supply chain disruptions or pipeline supply restrictions, which are preventing construction despite resources successfully navigating the queue process.

Figure 7. The Balance Sheet



For the first time in recent history, PJM could face decreasing reserve margins, as shown in **Table 1**, should these trends – high load growth, increasing rates of generator retirements, and slower entry of new resources – continue. The amount of generation retirements appears to be more certain than the timely arrival of replacement generation resources, given that the quantity of retirements is codified in various policy objectives, while the impacts to the pace of new entry of the Inflation Reduction Act, post-pandemic supply chain issues, and other externalities are still not fully understood.

The findings of this study highlight the importance of PJM's ongoing stakeholder initiatives (Resource Adequacy Senior Task Force, CAPSTF, Interconnection Process Subcommittee), continued efforts between PJM and state and federal agencies to manage reliability impacts of policies and regulations, and the urgency for coordinated actions to shape the future of resource adequacy.

The potential for an asymmetrical pace within the energy transition, where resource retirements and load growth exceed the pace of new entry, underscores the need for better accreditation, qualification and performance requirements for capacity resources.

The composition and performance characteristics of the resource mix will ultimately determine PJM's ability to maintain the reliability of the bulk electric system. Managing the energy transition through collaborative efforts of PJM stakeholders, state and federal agencies, and consumers will ensure PJM has the tools and resources to maintain reliability.

ReliabilityFirst 2025 Summer Reliability Assessment

By **Tim Fryfogle** (https://www.rfirst.org/authors/tim-fryfogle/), Principal Engineer – Resources, Engineering and System Performance

ReliabilityFirst annually conducts seasonal reliability assessments, analyzing resource adequacy in our region using data provided by MISO and PJM. The Summer Reliability Assessment is published each June at the onset of the period of warmer weather experienced across the summer months in the RF region.

Return to Resource Center (/resource-center)

ReliabilityFirst (RF) projects both the MISO and PJM areas to have adequate resources to serve normal electric demand in the upcoming summer season, including during expected periods in which certain generation resources become unavailable. This analysis is based on data provided by MISO and PJM, which we use to perform our annual summer resource adequacy assessment.

While these 50/50 demand forecasts project MISO and PJM to have adequate resources to satisfy their respective planning reserve requirements, if resource outages and/or demand are experienced beyond the established projections, there is an increased likelihood that corrective actions (like Load Modifying Resources and Operating Reserves) would need to be utilized to serve forecasted load. The 50/50 demand forecast projects a 50% likelihood that demand exceeds projected load and 50% likelihood that it is below.

This risk of resource unavailability requiring corrective actions to be taken is elevated in the MISO area compared to the PJM area. When resource outages and/or demand are experienced beyond the established projections, PJM is at low risk while MISO is at an elevated risk for the summer of 2025.

MISO does anticipate issuing Maximum Generation alerts to call on their demand response programs. These alerts provide an early warning that system conditions may require the use of MISO's generation emergency procedures. These resources are only eligible to be used after all other online callable and dispatchable generation has maxed out.

The availability of MISO wind energy resources will also play a key role in determining whether MISO will need assistance from external (non-firm) resources during periods of more extreme demand levels. MISO has more than 31,000 MW of installed wind capacity, however historically these resources produce approximately 5,616 MW of on-peak capacity.

Capacity and reserves

PJM's planning reserve margin requirement is 17.7% for the 2025 planning year, while its forecasted reserve margin comes in above that figure at 24.7%. As a result, PJM is considered a low risk of electricity supply shortages this summer.

MISO's planning reserve margin requirement is 15.7% for the 2025 planning year. Its forecasted reserve margin is above that value at 24.7%, meaning the MISO area has sufficient resources to meet the anticipated demand this summer period. However, as discussed in the next section of this article, MISO does have an increased likelihood of capacity shortfalls if unplanned outages and demand are higher than anticipated.

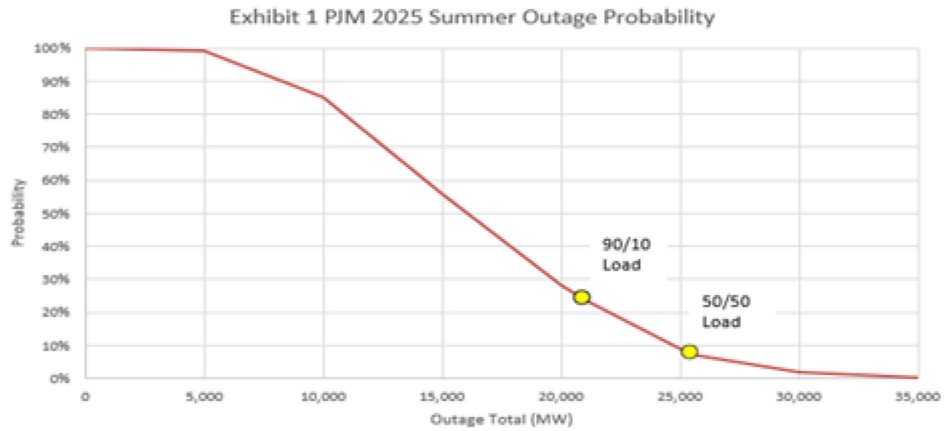
Since PJM and MISO are both projected to have adequate resources to satisfy their respective forecasted reserve margin requirements, the RF footprint as a whole is projected to have sufficient resources for the 2025 summer period.

Likelihood of generation unavailability

RF's summer assessment also evaluated the likelihood associated with different levels of generation unavailability for PJM and MISO[1], shown in Exhibits 1 and 2 below[2].

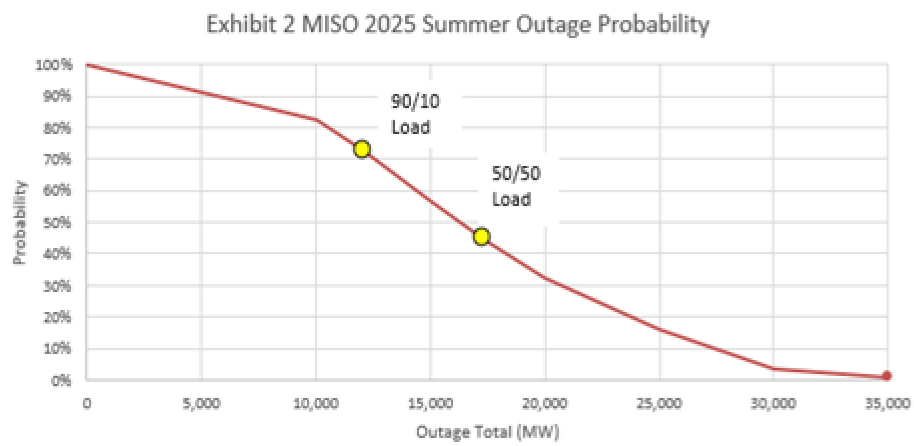
Exhibit 1 shows the probability of PJM's outage likelihood based on different generation outage levels within PJM. The yellow load dots indicate where available resources are no longer sufficient to serve the projected load, including their use of demand response and operating reserves.

The 90/10 demand forecast is a more extreme load profile than the 50/50 demand forecast. Looking at Exhibit 1, for the 90/10 demand forecast, it is projecting a 22% chance that demand exceeds extreme load which may require the operator to begin mitigating actions to prevent firm load shed (i.e., this includes using operating reserves, interchange transactions, and demand response).



For PJM's 50/50 demand forecast, 25,500 MW of generation unavailability may require operator mitigating actions. This analysis indicates that there's a very low likelihood (less than 10%) of this amount of generation outages occurring, making PJM a low risk for the upcoming summer.

Exhibit 2 shows MISO's summer outage likelihood based on different generation outage levels. The 90/10 demand forecast projects a greater than 70% chance that demand exceeds extreme load which may require the operator to begin mitigating actions to prevent firm load shed.



For MISO's 50/50 demand forecast, this analysis indicates there's a nearly 50% chance that demand exceeds load requiring the operator to begin mitigating actions to prevent firm load shed. Since there is a lower amount of generator outages that need to occur before MISO operators need to take corrective action to stop firm load shed, MISO is at an elevated risk for the upcoming summer.

Footnotes:

1. *This analysis uses historical GADS data from a rolling five-year period, which provided a range of outages that occur during the summer period (i.e., May through September) of 2020 through 2024 (note: the distribution of random outages used for this assessment is not linear throughout the range of outages observed).*

2. *When reviewing Exhibits 1 and 2, the outage total across the horizontal axis of the graph is the number of outages that could occur during the five-year timeframe examined based on historical GADS data. The probabilities on the vertical axis are not based on a true statistical analysis of the available daily random outage data. Instead, these values represent the proportion of outages compared to the total resources available, then determines how often this proportion occurred within the five-year historical summer period.*