Department of Energy
Washington, DC 20585

Order No. 202-26-16

Pursuant to the authority vested in the Secretary of Energy by section 202(c) of the Federal Power Act (FPA),[1] and section 301(b) of the Department of Energy Organization Act,[2] and for the reasons set forth below, I hereby determine that an emergency exists in portions of the Midwest region of the United States due to a shortage of electric energy, a shortage of facilities for the generation of electricity, and other causes. Issuance of this Order will meet the emergency and serve the public interest.

BACKGROUND

The J.H. Campbell Generating Plant (Campbell Plant) is a 1,420 MW coal-fired plant primarily owned by Consumers Energy Company (Consumers) and located in West Olive, Michigan. In 2021, Consumers announced that it planned to implement a "speed closure" of the Campbell Plant fifteen years before the end of its scheduled design life.[3] Instead of retiring the Campbell Plant at the end of its design life, Consumers planned to accelerate the Campbell Plant's retirement and discontinue its operations on May 31, 2025.

Order Nos. 202-25-3 and 202-25-7, issued pursuant to FPA section 202(c), each required that the Campbell Plant remain in operation for 90 days, until August 21, 2025, and November 19, 2025, respectively. Subsequently, Order No. 202-25-9, issued pursuant to FPA section 202(c), required that the Campbell Plant remain in operation for 90 days, until February 17, 2026. Those orders were based on my determination that emergency conditions existed in the region served by the Midcontinent Independent System Operator, Inc. (MISO).

Specifically, I determined that MISO likely faced tight reserve margins due to well documented year-round resource adequacy concerns, particularly during periods of high demand or low generation resource output.[4] I determined that the continued operation of the Campbell Plant would provide additional generation capacity during these periods, which would help

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[1] 16 U.S.C. § 824a(c).
[2] 42 U.S.C. § 7151(b).
[3] *See* Consumers Energy, *Consumers Energy Announces Plan to End Coal Use by 2025; Lead Michigan's Clean Energy Transformation* (June 23, 2021), https://www.consumersenergy.com/news-releases/newsrelease-details/2021/06/23/consumers-energy-announces-plan-to-end-coal-use-by-2025-lead-michigans-cleanenergy-transformation.
[4] *See, e.g.*, *Midcontinent Indep. Sys. Operator, Inc., and Consumers Energy Company*, Order No. 202-25-9, at 3-7 (Nov. 18, 2025).

prevent the potential loss of power to homes and local businesses in the areas that might have been affected by curtailments or outages that would otherwise pose a risk to public health and safety.[5] I determined that the continued operation of the Campbell Plant was necessary to alleviate immediate and anticipated threats to reliability.[6] My determination was based on a number of facts.

First, the North American Electric Reliability Corporation (NERC) released its 2025 Summer Reliability Assessment on May 14, 2025. In its assessment, NERC stated that "[d]emand forecasts and resource data indicate that MISO is at elevated risk of operating reserve shortfalls during periods of high demand or low resource output."[7] In particular, NERC explained that the retirement of thermal generation capacity increased the likelihood of electricity supply shortfalls. NERC anticipated that the near-term period of greatest capacity shortfall for MISO would likely occur in August.[8]

Second, multiple generation facilities in Michigan have retired in recent years. According to the U.S. Energy Information Administration (EIA), "[s]ince 2020, about 2,700 megawatts of coal-fired generating capacity have been retired and no new coal-fired facilities are planned."[9] Additionally, EIA stated, "[t]ypically, Michigan's nuclear power plants have supplied about 30% of in-state electricity, but the amount of electricity generated by nuclear power plants in Michigan has declined as plants have been decommissioned."[10] The state's Big Rock Point nuclear power plant shut down in 1997, and the Palisades nuclear power plant closed in 2022. The Palisades plant remains unavailable, although according to a recent news report, "Holtec International expects the Palisades plant in Michigan to resume service early next year . . . ."[11]

Third, the Campbell Plant's retirement would have further decreased available dispatchable generation within MISO's service territory, adding to the loss of the other 1,575 MW of natural gas and coal-fired generation that has retired since the summer of 2024. Although MISO and Consumers have incorporated the planned retirement of the Campbell Plant

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[5] *See, e.g.*, *Id.* at 7-8.

[6] *See, e.g.*, *Id.* at 8.

[7] NERC, *2025 Summer Reliability Assessment*, at 16 (May 2025) (NERC 2025 Summer Reliability Assessment), https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_SRA_2025.pdf.

[8] *Id.*

[9] EIA, *Michigan State Profile and Energy Estimates* (Oct. 17, 2024), https://www.eia.gov/state/print.php?sid=MI.

[10] *Id.*

[11] L.A. TIMES, *Nuclear plants face decadelong timeline to meet AI energy needs* (Nov. 13, 2025), https://www.latimes.com/business/story/2025-11-13/despite-80-billion-commitment-nuclear-plants-face-decade-long-timeline-to-meet-ai-energy-needs.

into their supply forecasts, and Consumers acquired a 1,200 MW natural gas power plant in Covert, Michigan, NERC still anticipates "elevated risk of operating reserve shortfalls."[12]

Fourth, MISO's Planning Resource Auction Results for the 2025-2026 Planning Year, released in April 2025, noted that for the northern and central zones, which include Michigan, "new capacity additions were insufficient to offset the negative impacts of decreased accreditation, suspensions/retirements and external resources."[13] While the results "demonstrated sufficient capacity," the summer months reflected the "highest risk and a tighter supply-demand balance."[14] According to MISO, these results "reinforce the need to increase capacity."[15]

CONTINUING EMERGENCY CONDITIONS

The emergency conditions that necessitated the issuance of Order Nos. 202-25-3, 202-25-7, and 202-25-9 continue, both in the near and long term.[16] The production of electricity from the Campbell Plant will continue to be a critical asset to maintain reliability in MISO. According to the U.S. Environmental Protection Agency's data, from June 2025 through December 2025,[17] the Campbell plant has generated an average of approximately 561,100 MWh per month, providing vital generation capacity to the region. From June 11, 2025 through November 5, 2025, MISO issued dozens of alerts to manage grid reliability in its Central Region in response

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[12] NERC 2025 Summer Reliability Assessment at 16.

[13] MISO, *Planning Resource Auction—Results for Planning Year 2025–2026*, at 13 (May 29, 2025) (MISO 2025– 2026 Planning Resource Auction), https://cdn.misoenergy.org/2025%20PRA%20Results%20Posting%2020250529_Corrections694160.pdf.

[14] *Id.* at 12.

[15] *Id*. at 2. For further information regarding the determination that emergency conditions existed, *see Midcontinent Indep. Sys. Operator, Inc., and Consumers Energy Company*, Order No. 202-25-7 (Aug. 20, 2025).

[16] Further, as noted in Order No. 202-25-7, as a coal-fired facility, it would be difficult for the Campbell Plant to resume operations once it has been retired. Specifically, any stop and start of operation creates heating and cooling cycles that could cause an immediate failure that could take 30-60 days to repair if a unit comes offline. In addition, other practical issues, such as employment, contracts, and permits may greatly increase the timeline for resumption of operations. If Consumers were to begin disassembling the plant or other related facilities, the associated challenges would be greatly exacerbated. Thus, continuous operation is required in such cases so long as the Secretary determines a shortage exists and is likely to persist. *See* Order No. 202-25-7 at 1, n.1.

[17] *See, Custom Data Download, EPA CAMPD (Clean Air Markets Program Data),* *https://campd.epa.gov/data/custom-data-download* *(search criteria to produce these results could include Emissions >> Monthly >> Unit (default) >>Apply >>"2025" and "June, July, August, September, October, November, December."* The data can then be filtered to only include the J.H. Campbell Plant.).

to hot weather, severe weather, high customer load, forced generation outages, and transfer capability limits.

MISO's year-round resource adequacy concerns are well documented. In 2021, MISO requested that the Federal Energy Regulatory Commission (FERC) approve its filing to revise its resource adequacy construct (including the Planning Resource Auction or PRA) to establish capacity requirements for each of the four seasons of the year rather than on an annual basis determined by peak summer demand.[18] MISO justified this revision by explaining that "Reliability risks associated with resource adequacy have shifted from 'Summer only' to a year-round concern."[19] MISO noted that over 60% of all "MaxGen" events (events when MISO initiates emergency procedures because of concerns over the adequacy of available generation) occurred outside of the summer season.[20]

In December of 2023, MISO released its *Attributes Roadmap*, in which it presented "an in-depth look at the challenges of operating a reliable bulk electric system in a rapidly transforming energy landscape."[21] Among other things, this report described changes in the time of year during which the risk of the loss of load was greatest. For the 2023–2024 Planning Year, the greatest risk of loss of load was in the summer, but it is expected that by the summer of 2027, there will be an equal loss of load risk in both the summer and fall seasons.[22] MISO also projected that the risk of loss of load in the winter and spring seasons, although not as high as in the summer or fall, will nevertheless increase over time.[23]

More recently, MISO affirmed the resource adequacy problems occurring outside of its summer season in its 2024 report entitled, *MISO's Response to the Reliability Imperative*.[24] In a section of that report labeled "Risks in Non-Summer Seasons," MISO again stressed that it has resource reliability concerns outside of the summer season.

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[18] MISO, *Midcontinent Independent System Operator, Inc.'s Filing to Include Seasonal and Accreditation Requirements for the MISO Resource Adequacy Construct*, FERC Docket No. ER22-495-000 (Nov. 30, 2021) (MISO Transmittal Letter). This request was approved by FERC on August 31, 2022. *See Midcontinent Independent System Operator, Inc.*, 180 FERC ¶ 61,141 (2022).

[19] MISO Transmittal Letter at 3.

[20] *Id.* at 3-4.

[21] MISO, *Attributes Roadmap* (Dec. 2023), https://cdn.misoenergy.org/2023%20Attributes%20Roadmap631174.pdf.

[22] *Id.* at 11.

[23] *Id.*

[24] MISO, *MISO's Response to the Reliability Imperative* (updated Feb. 2024), https://cdn.misoenergy.org/2024+Reliability+Imperative+report+Feb.+21+Final504018.pdf.

> Widespread retirements of dispatchable resources, lower reserve margins, more frequent and severe weather events and increased reliance on weather-dependent renewables and emergency-only resources have altered the region's highest historic risk profile, creating risks in non-summer months that rarely posed challenges in the past.[25]

These MISO studies indicate that the emergency conditions caused by the loss of generation capacity in MISO extend past the summer season.

In January 2026, NERC released its 2025 Long-Term Reliability Assessment.[26] NERC assessed that the MISO region is at high risk of energy shortfalls over the next five years,[27] stating that it faces significant reliability challenges as "projected resource additions do not keep pace with escalating demand forecasts and announced generator retirements."[28] This determination is based on the combination of accelerating demand growth from new data centers and the retirement of existing thermal generators.[29] The 2025 NERC Long-Term Reliability Assessment notes that "MISO's accredited thermal capacity has decreased by 8.8 GW, driven primarily by reductions in accredited capacity of existing facilities and retirements."[30] The report observes that winter peak periods are a particular concern, with projections showing "shortfalls in planned resources for winter peak periods."[31] However, NERC also concluded that "risks could expand into spring and fall generator maintenance periods when the available dispatchable generation is not enough to counter wind and solar variability when demand is high."[32]

While the 2025–2026 NERC Winter Reliability Assessment found the MISO region to be at normal risk in 2026 and elevated risk in 2027, two earlier winter studies were more critical. The 2023–2024 NERC Winter Reliability Assessment characterized MISO as a region at elevated risk with the "[p]otential for insufficient operating reserves in above-normal conditions."[33] These findings were echoed in NERC's 2024 – 2025 Winter Reliability Assessment, which noted that "[g]enerating capacity is 10 GW lower (-6.8%) compared to the

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[25] *Id.* at 12.

[26] NERC, *2025 Long-Term Reliability Assessment* (Jan. 2026) (2025 NERC Long-Term Reliability Assessment), https://www.nerc.com/globalassets/our-work/assessments/nerc_ltra_2025.pdf.

[27] *Id.* at 7.

[28] *Id.* at 8.

[29] *Id.* at 43.

[30] *Id.* at 15.

[31] *Id*.

[32] *Id*.

[33] NERC, 2023–2024 Winter Reliability Assessment, at 5 (Nov. 2023), https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_WRA_2023.pdf.

prior winter as generators have retired, withdrawn from MISO's capacity market, or received lower winter accredited capacity."[34]

MISO's resource adequacy concerns were most recently demonstrated during Winter Storm Fern, when it operated under a cold weather alert and declared conservative operations from January 23–February 1, 2026. On January 24, MISO declared an Energy Emergency Alert (EEA) 1, as well as an EEA 2 event for MISO's North and Central Regions due to generational outages, high demand, and transfer capability limits.[35]

The evidence indicates that there is also a potential longer term resource adequacy emergency in MISO. When MISO reported the results of its PRA for the 2025–2026 Planning Year, it noted that "new capacity additions were insufficient to offset the negative impacts of decreased accreditation, suspensions/retirements and external resources" in the northern and central zones, which include Michigan.[36]

On June 6, 2025, the Organization of MISO States (OMS) and MISO issued the results of their survey, which has been conducted annually for many years to determine the degree to which expected capacity resources satisfy planning reserve margin requirements.[37] The 2025 OMS-MISO Survey presented projections of resource adequacy for the summer of 2026 and subsequent years. Although the survey projected a potential capacity surplus for the summer of 2026, it also projected that at least 3.1 GW of additional generation capacity beyond currently committed generation capacity must be added to meet the projected planning reserve margin.[38] The 2025 OMS-MISO Survey also projected that there would be insufficient capacity to meet the peak demand for electricity in each of the following four summers, increasing from a deficit of 1.4 GW in 2027 to 8.2 GW in 2030.[39] Similar results were projected for MISO's winter seasons, with a small surplus of generation capacity in 2026, followed by increasing deficits the following four years.[40]

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[34] NERC, *2024–2025 Winter Reliability Assessment*, at 15 (Nov. 2024), https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_WRA_2024.pdf.

[35] *See* MISO Notifications Overview, *Real-Time Operations*, https://www.misoenergy.org/markets-and-operations/notifications/.

[36] MISO 2025 – 2026 Planning Resource Auction at 13.

[37] OMS & MISO, *OMS-MISO Survey Results* (updated June 6, 2025) (2025 OMS-MISO Survey), https://cdn.misoenergy.org/20250606%20OMS%20MISO%20Survey%20Results%20Workshop%20Presentation70 2311.pdf.

[38] *Id.* at 2.

[39] *Id.* at 7.

[40] *Id.* at 9.

The primary reasons for these projected deficits also are shown on the 2025 OMS-MISO Survey. Large amounts of existing generation capacity are projected to be retired each year while, at the same time, the demand for electricity is projected to increase at an accelerating pace.[41] Although the 2025 OMS-MISO Survey projects generation capacity to continue to increase in the coming years with the addition of new potential generation assets, the increase in capacity is largely offset by the projected retirements, and does not keep up with the growth in demand.[42]

MISO has been taking steps to address these projected deficits. For example, on June 6, 2025, MISO submitted a proposal to FERC to establish an Expedited Resource Addition Study (ERAS) process to provide a framework for the expedited study of interconnection requests to address urgent resource adequacy and reliability needs in the near term. This proposal was approved by FERC on July 21, 2025,[43] and the ERAS should help expedite the construction of needed new capacity. However, resources studied under the ERAS will have commercial operation dates that are at least three years away, and are provided an additional three-year grace period to commence commercial operations.[44] In addition, supply chain constraints impeding the acquisition of critical grid components, including large natural gas turbines and transformers, are likely to further hinder rapid construction and exacerbate reliability concerns.[45] Consequently, the new ERAS process is unlikely to result in the addition of any new generation capacity in the next few years.

Order Nos. 202-25-3, 202-25-7, and 202-25-9 were preceded by executive orders on January 20, 2025, and April 8, 2025, in which President Donald J. Trump underscored the dire energy challenges facing the Nation due to growing resource adequacy concerns. President Trump declared a national energy emergency in Executive Order 14156, *Declaring a National Energy Emergency*, in which he determined that the "United States' insufficient energy production, transportation, refining, and generation constitutes an unusual and extraordinary

[41] *Id.* at 7, 9.

[42] *Id.*

[43] *Midcontinent Independent System Operator, Inc.*, 192 FERC ¶ 61,064 (2025).

[44] *Id.* P 84.

[45] *See generally* S&P Global, *US Gas-Fired Turbine Wait Times as Much as Seven Years; Costs Up Sharply* (May 2025), https://www.spglobal.com/energy/en/news-research/latest-news/electric-power/052025-us-gas-fired-turbine-wait-times-as-much-as-seven-years-costs-up-sharply. "With demand for natural gas-fired turbines in the US rapidly accelerating amid power demand growth forecasts driven by AI, manufacturing, and electrification, wait times for turbines are anywhere between one and seven years depending on the model, and costs have increased considerably, experts told Platts."

threat to our Nation's economy, national security, and foreign policy."[46] The Executive Order adds, "hostile state and non-state foreign actors have targeted our domestic energy infrastructure, weaponized our reliance on foreign energy, and abused their ability to cause dramatic swings within international commodity markets."[47] In a subsequent Executive Order 14262, *Strengthening the Reliability and Security of the United States Electric Grid*, President Trump emphasized that "the United States is experiencing an unprecedented surge in electricity demand driven by rapid technological advancements, including the expansion of artificial intelligence data centers and increase in domestic manufacturing."[48]

Further, the Department detailed the myriad challenges affecting the Nation's energy systems in its July 2025 "Resource Adequacy Report: Evaluating the Reliability and Security of the United States Electric Grid," issued pursuant to the President's directive in Executive Order 14262. The Department concluded that "[a]bsent decisive intervention, the Nation's power grid will be unable to meet projected demand for manufacturing, re-industrialization, and data centers driving artificial intelligence (AI) innovation."[49] The prolific growth of data centers for the development of AI, as well as their immense energy needs, presents a new and unexpected source of load growth. This growth is illustrated by the fact that there are more than twenty AI companies operating in Michigan alone.[50] In addition, as just one example, Consumers has announced an additional 1 GW of new power to a planned hyperscale data center and "continue[s] to see positive momentum with data centers within the 9 GW pipeline . . . ."[51]

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[46] Exec. Order No. 14156, 90 Fed. Reg. 8433 (Jan. 20, 2025) (*Declaring a National Energy Emergency*), https://www.whitehouse.gov/presidential-actions/2025/01/declaring-a-national-energy-emergency/.

[47] *Id*.

[48] Exec. Order No. 14262, 90 Fed. Reg. 15521 (Apr. 8, 2025) (*Strengthening the Reliability and Security of the United States Electric Grid*), https://www.whitehouse.gov/presidential-actions/2025/04/strengthening-the-reliabilityand-security-of-the-united-states-electric-grid/.

[49] U.S. Dep't of Energy, *Resource Adequacy Report: Evaluating the Reliability and Security of the United States Electric Grid*, at 1 (July 2025), https://www.energy.gov/sites/default/files/2025-07/DOE%20Final%20EO%20Report%20%28FINAL%20JULY%207%29.pdf.

[50] Ekku Jokinen, *Top 21 Artificial Intelligence Companies in Michigan* (last accessed Aug. 13, 2025), https://www.inven.ai/company-lists/top-21-artificial-intelligence-companies-in-michigan.

[51] *See* Data Center Dynamics, *Michigan utility Consumers Energy to provide 1GW of power to new hyperscale data center* (Aug. 5, 2025) (quoting Consumers CEO Garrick Rochow), https://www.datacenterdynamics.com/en/news/michigan-utility-consumers-energy-toprovide-1gw-of-power-to-new-hyperscale-data-center/.

Grid operators — including MISO itself — have also acknowledged the Nation's current energy crisis. For instance, during a March 25, 2025, hearing before the House Committee on Energy and Commerce, Jennifer Curran, Senior Vice President, Planning and Operations, MISO, testified that "the MISO region faces resource adequacy and reliability challenges due to the changing characteristics of the electric generating fleet, inadequate transmission system infrastructure, growing pressures from extreme weather, and rapid load growth."[52] Ms. Curran also described "much stronger growth [in demand for electricity] from continued electrification efforts, a resurgence in manufacturing, and an unexpected demand for energy-hungry data centers to support artificial intelligence."[53] She added, "[a] growing reliability risk is that the rapid retirement of existing coal and gas power plants threatens to outpace the ability of new resources with the necessary operational characteristics to replace them."[54]

Pursuant to section 202(c)(4)(B) of the FPA, the Department has consulted with the primary Federal agency with expertise in the environmental interest protected by the laws or regulations that may conflict with this Order. The agency did not submit additional conditions for inclusion in this Order.

ORDER

FPA section 202(c)(1) provides that whenever the Secretary of the Department of Energy 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," then the Secretary has the authority "to require by order . . . such generation, delivery, interchange, or transmission of electric energy as in its judgment will best meet the emergency and serve the public interest."[55] This statutory language constitutes a specific grant of authority to the Secretary to require the continued operation of the Campbell Plant when the Secretary has determined that such continued operation will best meet an emergency caused by a sudden increase in the demand for electric energy or a shortage of generation capacity.

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[52] *Keeping the Lights On: Examining the State of Regional Grid Reliability Before the House Committee on Energy and Commerce*, Subcommittee on Energy, 119th Cong., at 5 (Mar. 25, 2025) (statement of Ms. Jennifer Curran, Senior Vice President for Planning and Operations, Midcontinent Independent System Operator), https://democratsenergycommerce.house.gov/sites/evo-subsites/democrats-energycommerce.house.gov/files/evo-mediadocument/witness-testimony_curran_eng_grid-operators_03.25.2025.pdf.

[53] *Id.* at 6.

[54] *Id.* at 7.

[55] Although the text of FPA section 202(c) grants this authority to "the Commission," section 301(b) of the Department of Energy Organization Act transferred this authority to the Secretary of the Department of Energy. *See* 42 U.S.C. § 7151(b).

Such is the case here. As described above, the emergency conditions resulting from the combination of increasing demand for electricity and the capacity shortfall stemming from accelerated retirements of generation facilities supporting the issuance of Order Nos. 202-25-3, 202-25-7, and 202-25-9, will continue in the near term and are also likely to continue in subsequent years. This could lead to the loss of power to homes and local businesses in the areas affected by curtailments or outages, presenting a risk to public health and safety. Given the responsibility of MISO to identify and dispatch generation necessary to meet load requirements, I have determined that, under the conditions specified below, continued additional dispatch of the Campbell Plant is necessary to best meet the increased demand for electricity and mitigate the observed shortage of generation, thus serving the public interest pursuant to FPA section 202(c).

To ensure that the Campbell Plant will be available if needed to address emergency conditions, it shall remain in operation until May 18, 2026.[56]

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

A. From February 17, 2026, MISO and Consumers shall take all measures necessary to ensure that the Campbell Plant is available to operate. For the duration of this Order, MISO is directed to take every step to employ economic dispatch of the Campbell Plant to minimize costs to ratepayers. Following the conclusion of this Order, sufficient time for orderly ramp down is permitted, consistent with industry practices. Consumers is directed to comply with all orders from MISO related to the availability and dispatch of the Campbell Plant.

B. To minimize adverse environmental impacts, this Order limits operation of dispatched units to the times and within the parameters as determined by MISO pursuant to paragraph A. MISO shall provide a daily notification to the Department (via AskCR@hq.doe.gov) reporting whether the Campbell Plant has operated in compliance with the allowances contained in this Order.

C. All operation of the Campbell Plant must comply with applicable environmental requirements, including but not limited to monitoring, reporting, and recordkeeping requirements, to the maximum extent feasible while operating consistent with the emergency conditions.

D. By March 4, 2026, MISO is directed to provide the Department (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 Campbell Plant consistent with this Order. MISO shall also provide such additional information regarding the environmental impacts of this Order and its compliance with the conditions of this Order, in each case as requested by the Department from time to time.

[56] 16 U.S.C. § 824a(c)(4).

E. Consumers is directed to file with FERC tariff revisions or waivers to effectuate this Order, as needed. Rate recovery is available pursuant to 16 U.S.C. § 824a(c).

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

G. Because this Order is predicated on the shortage of facilities for generation of electric energy and other causes, the Campbell Plant shall not be considered a capacity resource.

H. This Order shall be effective on February 17, 2026, through May 18, 2026, with the exception of applicable compliance obligations in paragraph D.

Chris Wright

Chris Wright
Secretary of Energy

cc:

FERC Commissioners

Chairman Laura V. Swett
Commissioner David Rosner
Commissioner Lindsay S. See
Commissioner Judy W. Chang
Commissioner David A. LaCerte

Michigan Public Service Commissioners

Chairman Dan Scripps
Commissioner Katherine Peretick
Commissioner Shaquila Myers

UNITED STATES DEPARTMENT OF ENERGY

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

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

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

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

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MOTION TO INTERVENE

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

Factual Background

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

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

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

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

Adverse Effects

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

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

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

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

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

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

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

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[5] FERC Docket: EL25-90.
[6] *See In the Matter of the Application of Consumers Energy Co. for Approval of Its Integrated Res. Plan Pursuant to Mcl 460.6t & for Other Relief.*, No. U-21090, 2022 WL 2915368, at *73 (June 23, 2022).
[7] *See* Cross-State Air Pollution Rule (CSAPR) and Clean Air Act § 110.

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

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

[9] *Id.*

[10] *Id.*

[11] *Id.*

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

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

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

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

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[14] *Id*.
[15] Illinois State Climatologist, Drought Worsens in a Very Dry June (June 30, 2023), https://stateclimatologist.web.illinois.edu/2023/06/30/drought-worsens-in-a-very-dry-june/ (last visited May 23, 2025).
[16] University of Illinois–Institute of Government & Public Affairs, Preparing for Climate Change in Illinois: An Overview of Anticipated Impacts (2015), https://indigo.uic.edu/articles/report/Preparing_for_Climate_Change_in_Illinois_An_Overview_of_Anticipated_Impacts/15078939/1 (last visited May 23, 2025). See also U.S. Dept. of Agriculture Climate Hubs and Great Lakes Research Integrated Science Assessment, Climate Change Impacts on Illinois Agriculture (2022), https://www.climatehubs.usda.gov/sites/default/files/2022_ClimateChangeImpactsOnIllinoisAgriculture.pdf (last visited May 23, 2025).
[17] Tony Briscoe, Lake Michigan Water Levels Rising at Near Record Rate, CHICAGO TRIBUNE (July 12, 2015), https://www.chicagotribune.com/2015/07/12/lake-michigan-water-levels-rising-at-near-record-rate/ (last visited May 23, 2025).
[18] National Weather Service, July 15, 2024 Derecho Produces Widespread Wind Damage and Numerous Tornadoes, available at https://www.weather.gov/lot/2024_07_15_Derecho#:~:text=With%2032%20tornadoes%2C%20t

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

PETITION FOR REHEARING

I. Overview and Concise Statement of Error

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

The Order

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

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

> **Midcontinent Independent System Operator (MISO):** MISO is expecting to have an existing certain capacity of 142,793 MW in the *2025 SRA*, which is a slight reduction from the 143,866 MW submitted for the *2024 SRA*. The retirement of 1,575 MW of natural gas and coal-fired generation since last summer, combined with a reduction in net firm capacity transfers due to some capacity outside the MISO market opting out of the MISO planning resource auction, is contributing to less dispatchable generation in MISO. With higher demand and less firm resources, MISO is at elevated risk of operating reserve shortfalls during periods of high demand or low resource output. MISO's most recent energy assessment reveals that the period of highest energy shortfall risk has shifted from July to August. This shift is driven by the decline in dispatchable generation and the increasing share that solar and wind resources have in meeting demand. The risk of supply shortfalls increases in late summer as solar output diminishes earlier in the day, leaving variable wind and a more limited amount of dispatchable resources to meet demand.

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

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

Id. at 16.

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

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

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

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

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

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

II. Legal Background

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

> [d]uring the continuance of any war in which the United States is engaged, or whenever the Commission determines that an emergency exists by reason of a sudden increase in the demand for electric energy, or a shortage of electric energy or of facilities for the generation or transmission of electric energy, or of fuel or water for generating facilities, or other causes. . . .

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

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

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

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

Id. at § 824(c)(2).

The applicable regulations define "emergency," as

> an unexpected inadequate supply of electric energy which may result from the unexpected outage or breakdown of facilities for the generation, transmission or distribution of electric power. Such events may be the result of weather conditions, acts of God, or unforeseen occurrences not reasonably within the power of the affected "entity" to prevent. An emergency also can result from a sudden increase in customer demand, an inability to obtain adequate amounts of the necessary fuels to generate electricity, or a regulatory action which prohibits the use of certain electric power supply facilities. Actions under this authority are envisioned *as meeting a specific inadequate power supply situation*.

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

III. Statement of Issues

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

IV. Description of MISO

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

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[21] MISO, *Fact Sheet* (July 2024), available at https://www.misoenergy.org/meetmiso/media-center/2024/corporate-fact-sheet.
[22] MISO, *Electric Grid 101*, available at https://www.misoenergy.org/meet-miso/grid-operations-basics.
[23] MISO, *Interregional Coordination*, available at https://www.misoenergy.org/planning/interregional-coodination/; see also MISO, Historical Net Scheduled Interchange (NSI), at https://www.misoenergy.org/markets-and-operations/real-time--marketdata/ market-reports/ (data found under "Summary" Market Reports).

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

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

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

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[24] MISO, *Transmission and Generation Planning 101*, available at https://www.misoenergy.org/meet-miso/grid_planning_basics.
[25] *See also* MISO, *Approved Generator Retirements (Public) as of June 28, 2024* ("*Approved Retirements 2024*"), https://www.oasis.oati.com/woa/docs/MISO/MISOdocs/OASIS_Posting_of_Approved_Generator_Retirements_(Public)_2024-06-28.pdf).
[26] MISO, *2023 Transmission Expansion Plan*, available at https://cdn.misoenergy.org/MTEP23%20Executive%20Summary630586.pdf.

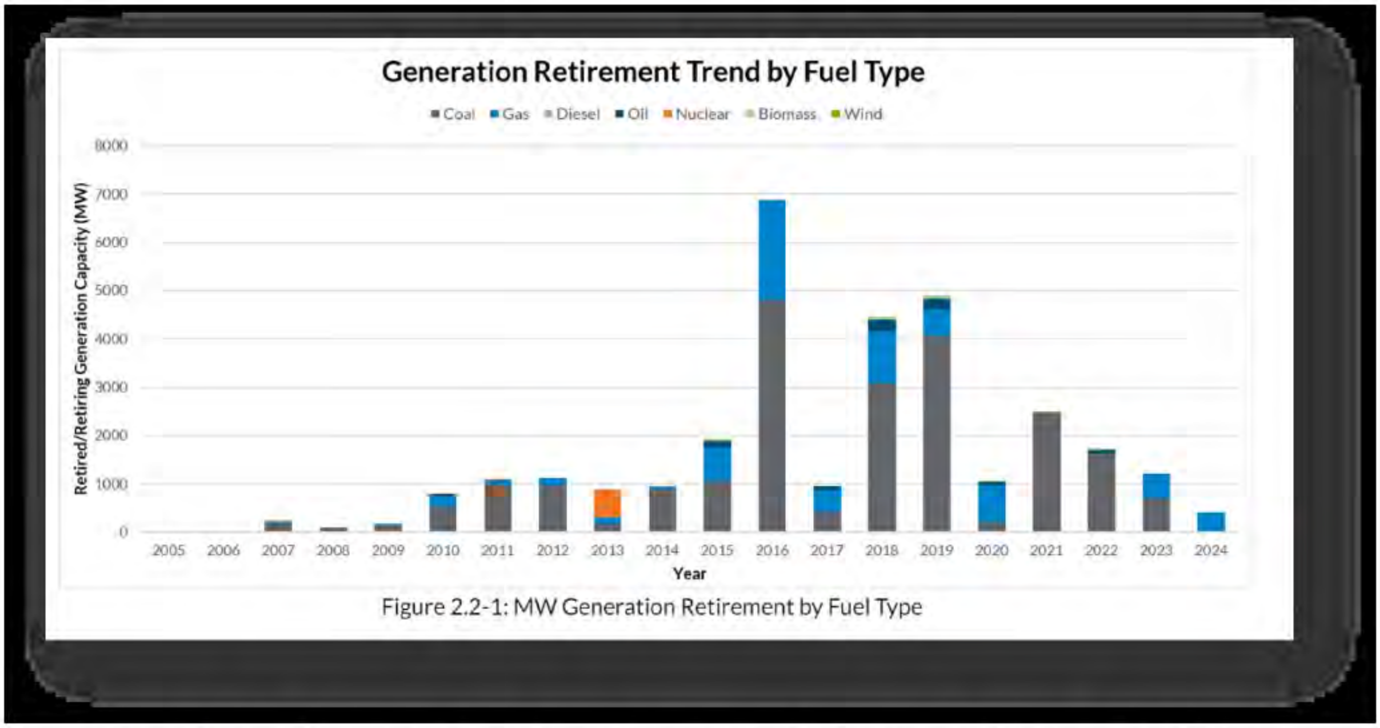

Figure 2.2-1: MW Generation Retirement by Fuel Type

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

V. Argument

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

electric energy which may result from the unexpected outage or breakdown of facilities for the generation, transmission or distribution of electric power. "Such events may be the result of weather conditions, acts of God, or unforeseen occurrences not reasonably within the power of the affected 'entity' to prevent." 10 C.F.R. § 205.371. Further, emergency orders must meet "a specific inadequate power supply situation," and although emergencies with extended periods of insufficient supply could qualify, the impacted entity is supposed to firm up commitments for supply "so that a continuing emergency order is not needed." *Id*

These requirements have been demonstrated by DOE's historic use of 202(c) authority to address natural disasters and specific capacity crises. The most common reason to invoke Section 202(c) authority has been to address natural disasters like hurricanes, cold weather events, and extreme heat. *See* DOE Order Nos. 202-05-1 & -2 (Sept. 28, 2005) (Hurricane Rita); DOE Order No. 20208-1 (Sept. 14, 2008) (Hurricane Ike); DOE Order No. 202-20-1 (Aug. 27, 2020) (Hurricane Laura); DOE Order No. 202-24-1 (Oct. 9, 2024) (Hurricane Milton); DOE Order No. 202-21-1 (Feb. 14, 2021) (Winter Storm Uri); DOE Order No. 202-22-3 (Dec. 23, 2022) (Winter Storm Elliot – Texas ERCOT); DOE Order No. 202-22-4 (Dec. 24, 2022) (Winter Storm Elliot – PJM); DOE Order No. 202-20-2 (Sept. 6, 2020) (extreme heat in California); DOE Order No. 202-21-2 (responding to extreme heat, wildfires and drought in California); DOE Order Nos. 20222-1 & 2 and amendments (same). Indeed, during Winter Storm Elliot, MISO exported power to neighboring regions.[30]

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

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

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

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

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

> On its face, § 202(c) enables the Commission to react to a war or national disaster and order immediate interconnection of the facilities to maintain electrical service during such emergency. . . On the other hand, § 202(b) applies to a crisis which is likely to develop in the foreseeable future but which does not necessitate immediate action on the part of the Commission.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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[37] FERC, *Energy Primer*, https://www.ferc.gov/sites/default/files/2024-01/24_Energy-Markets-Primer_0117_DIGITAL_0.pdf
[38] MISO, *System Planning*, https://www.misoenergy.org/meet-miso/about-miso/industry-foundations/grid_planning_basics/ (last visited June 23, 2025).
[39] *Id*.
[40] *Id*.
[41] MISO, *Resource Adequacy*, https://www.misoenergy.org/planning/resource-adequacy2/resource-adequacy/#t=10&p=0&s=FileName&sd=desc (last visited June 23, 2025).

Michigan's IRP processes, state regulatory proceedings, state judicial proceedings, and state participation in MISO. *See In re Application of Consumers Energy Co. for Approval of Its Integrated Res. Plan Pursuant to Mcl 460.6t & for Other Relief.*, No. U-21090, 2022 WL 2915368, at *73 (June 23, 2022). The MPSC approved of Consumers Energy's plan to replace the capacity that the Campbell Plant would have produced with the purchase of a natural gas plant and extension of two units of natural gas peaking plants. *Id*. at *33. The Michigan Court of Appeals affirmed. *Wolverine Power Supply Coop., Inc. v Michigan Public Service Commission (In re Consumers Energy)*; No. 362294, 2023 WL 2620437 (Mich. Ct. App. March 23, 2023).

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

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

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

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

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

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

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

As discussed in the previous subsection, states retain jurisdiction over facilities used for the generation of electric energy and play a key role in development of MISO's tariff provisions. The Order mandates that to "[t]he extent to which MISO's current Tariff provisions are inapposite to effectuate the dispatch and operation of the units for the reasons specified herein, *the relevant governmental authorities* are directed to take such action and make accommodations as may be necessary to do so." Order ¶ E. As applied to state and local authorities, this mandate is unlawful for several reasons.

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

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

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

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

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

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

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

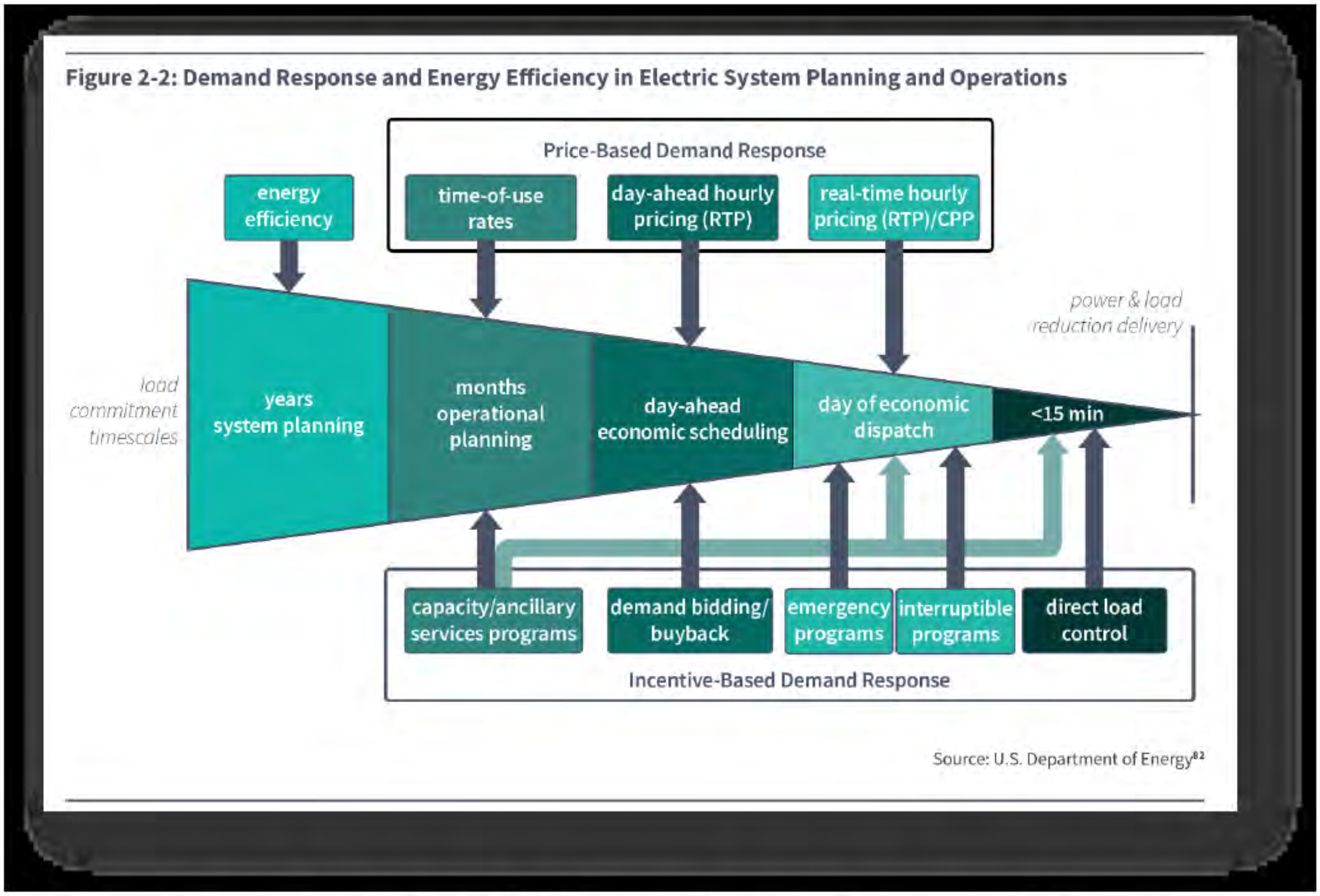

Figure 2-2: Demand Response and Energy Efficiency in Electric System Planning and Operations

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

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

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

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

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

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

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

CONCLUSION

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

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

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Dated: June 23, 2025

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Dated: June 23, 2025

Order No. 202-25-3

Pursuant to the authority vested in the Secretary of Energy by section 202(c) of the Federal Power Act (FPA), 16 U.S.C. § 824a(c), and section 301(b) of the Department of Energy Organization Act, 42 U.S.C. § 7151(b), and for the reasons set forth below, I hereby determine that an emergency exists in portions of the Midwest region of the United States due to a shortage of electric energy, a shortage of facilities for the generation of electric energy, and other causes, and that issuance of this Order will meet the emergency and serve the public interest.

Emergency Situation

The Midcontinent Independent System Operator (MISO) faces potential tight reserve margins during the summer 2025 period, particularly during periods of high demand or low generation resource output. The North American Electric Reliability Corporation (NERC) released its 2025 Summer Reliability Assessment on May 14, 2025. In its assessment, NERC indicated that "[d]emand forecasts and resource data indicate that MISO is at elevated risk of operating reserve shortfalls during periods of high demand or low resource output."[1] In particular, the retirement of thermal generation capacity creates the potential for electricity supply shortfalls. NERC anticipates that the near-term period of highest capacity shortfall for MISO will occur in August.[2]

Multiple generation facilities in Michigan have retired in recent years. According to the U.S. Energy Information Administration (EIA), "[s]ince 2020, about 2,700 megawatts of coal-fired generating capacity have been retired and no new coal-fired facilities are planned."[3] Additionally EIA stated, "[t]ypically Michigan's nuclear power plants have supplied about 30% of in-state electricity, but the amount of electricity generated by nuclear power plants in Michigan has declined as plants have been decommissioned."[4] The state's Big Rock Point nuclear power plant shut down in 1997 and the Palisades nuclear power plant closed in 2022. While the Palisades nuclear power plant may reopen in 2025, it will not be available during the peak demand period this summer.

The 1,560 MW J.H. Campbell coal-fired power plant in West Olive, MI, is scheduled to cease operations on May 31, 2025. Its retirement would further decrease available dispatchable generation within MISO's service territory, removing additional such generation along with the other 1,575 MW of natural gas and coal-fired generation that has retired since the summer of 2024. In 2021, Consumers announced that it planned to "speed closure" of Campbell in 2025, several years before the end of its scheduled design life.[5] Although MISO and Consumers have

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[1] 2025 summer reliability assessment. (May 14, 2025). https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_SRA_2025.pdf
[2] *Id*.
[3] U.S. Energy Information Administration, Michigan State Energy Profile, Oct. 17, 2024, *available at*: https://www.eia.gov/state/print.php?sid=mi.
[4] *Id*.
[5] https://www.consumersenergy.com/news-releases/news-release-details/2021/06/23/consumers-energy-announces-plan-to-end-coal-use-by-2025-lead-michigans-clean-energy-transformation

incorporated the planned retirement into their supply forecasts and acquired a 1,200 MW natural gas power plant in Covert, MI, the NERC Assessment still anticipates "elevated risk of operating reserve shortfalls."

MISO's Planning Resource Auction Results for Planning Year 2025-26, released in April 2025, note that for the northern and central zones, which includes Michigan, "new capacity additions were insufficient to offset the negative impacts of decreased accreditation, suspensions/retirements and external resources." While the results "demonstrated sufficient capacity," the summer months reflected the "highest risk and a tighter supply-demand balance" and the results "reinforce the need to increase capacity."[6]

ORDER

Given the determination that an emergency exists as discussed above, the responsibility of MISO to ensure reliability of its system, and the ability of MISO to identify and dispatch generation necessary to meet load requirements, I have determined that, under the conditions specified below, additional dispatch of the Campbell Plant is necessary to best meet the emergency and serve the public interest for purposes of FPA section 202(c). This determination is based on the insufficiency of dispatchable capacity and anticipated demand during the summer months, and the potential loss of power to homes and local businesses in the areas that may be affected by curtailments or outages, presenting a risk to public health and safety.

This Order is limited in duration to align with the emergency circumstances. Because the additional generation may result in a conflict with environmental standards and requirements, I am authorizing only the necessary additional generation on the conditions contained in this Order, with reporting requirements as described below.

FPA section 202(c) requires the Secretary of Energy to ensure that any 202(c) order that may result in a conflict with a requirement of any environmental law be limited to the "hours necessary to meet the emergency and serve the public interest, and, to the maximum extent practicable," be consistent with any applicable environmental law and minimize any adverse environmental impacts.

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

A. From the time this Order is issued on May 23, 2025, MISO and Consumers Energy shall take all measures necessary to ensure that the Campbell Plant is available to operate. For the duration of this order, MISO is directed to take every step to employ economic dispatch of the Campbell Plant to minimize cost to ratepayers. Following conclusion of this Order, sufficient time for orderly ramp down is permitted, consistent with industry practices. Consumers Energy is directed to comply with all orders from MISO related to the availability and dispatch of the Campbell Plant.

[6] https://cdn.misoenergy.org/2025%20PRA%20Results%20Posting%2020250428694160.pdf

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

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

D. By June 15, 2025, MISO is directed to provide the Department of Energy (via AskCR@hq.doe.gov) with information concerning the measures it has taken and is planning to take to ensure the operational availability and economic dispatch of the Campbell Plant consistent with the public interest. MISO shall also provide such additional information regarding the environmental impacts of this Order and its compliance with the conditions of this Order, in each case as requested by the Department of Energy from time to time.

E. The extent to which MISO's current Tariff provisions are inapposite to effectuate the dispatch and operation of the units for the reasons specified herein, the relevant governmental authorities are directed to take such action and make accommodations as may be necessary to do so.

F. Consumers is directed to file with the Federal Energy Regulatory Commission Tariff revisions or waivers necessary to effectuate this order. Rate recovery is available pursuant to 16 U.S.C. § 824a(c).

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

H. This Order shall be effective upon its issuance, and shall expire at 00:00 EDT on August 21, 2025, with the exception of the reporting requirements in paragraph D and applicable compliance obligations in paragraph E.

I. Issued in Washington, D.C. at 3:15:pm Eastern Daylight Time on this 23rd day of May 2025.

Chris Wright
Secretary of Energy

cc: **<u>FERC Commissioners</u>**
Chairman Mark Christie
Commissioner David Rosner
Commissioner Lindsay S. See
Commissioner Judy W. Chang

<u>Michigan Public Service Commissioners</u>
Chairman Dan Cripps
Commissioner Katherine Peretick
Commissioner Alessandra Carreon

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

2025 Summer Reliability Assessment

May 2025

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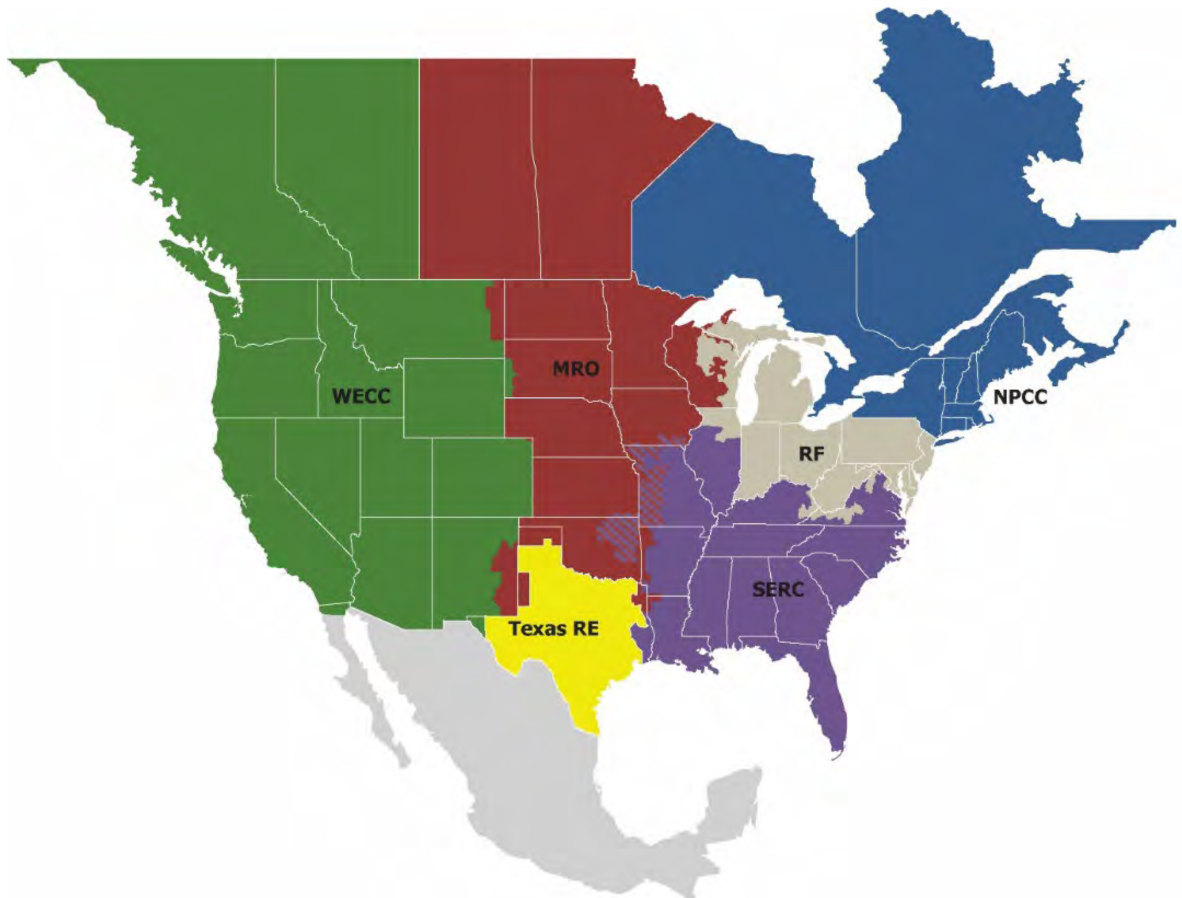
Preface

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

Reliability | Resilience | Security

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

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



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

About this Assessment

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

Key Findings

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

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

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

Resource Adequacy Assessment and Energy Risk Analysis

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

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

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

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

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

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

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

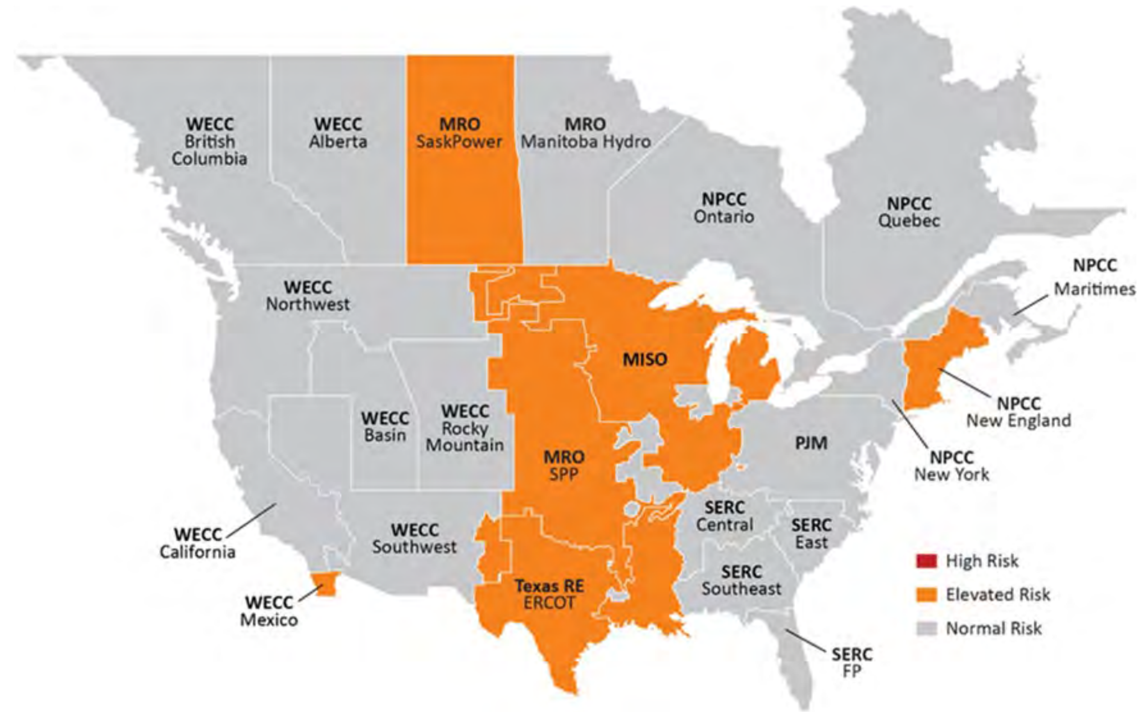


Figure 1: Summer Reliability Risk Area Summary

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

Other Reliability Issues

- **Weather services are expecting above-average summer temperatures across much of North America and continued below-average precipitation in the Northwest and Midwest.** In summer-peaking areas, temperature is one of the main drivers of demand and can also contribute to forced outages for generation and other BPS equipment. Average temperatures last summer across the United States and Canada were not as hot as Summer 2023, but Summer 2024 still managed to rank in the top four hottest recorded summers with certain areas breaking records yet again. Few high-level EEAs were issued between June and September 2024, and there were no supply disruptions that resulted from inadequate resources as Balancing Authorities (BA), Transmission Operators (TOP), and Reliability Coordinators (RC) employed a variety of operational mitigations and demand-side management measures. Natural-gas-fired electricity generation broke records last year—highlighting the criticality of natural gas in meeting electric demand. This continuing trend will be key in operator preparations that help to ensure fuel availability for the coming summer. The **Review of 2024 Capacity and Energy Performance** section describes actual demand and resource levels in comparison with NERC's *2024 SRA* and summarizes 2024 resource adequacy events.
- **Load growth is driving higher peak demand forecasts and contributing to resource and transmission adequacy challenges in many areas.** Fifteen of the 23 assessment areas are expecting an increase in peak summer demand from Summer 2024. Aggregated peak demand across all assessment areas has increased by over 10 GW since 2024. This is more than double the increase in peak demand from 2023 to 2024. One of the largest increases is seen in the U.S. West (+5%), where a new peak demand record was set last summer. Extreme heat is reported as a main reliability concern this year among BAs in WECC. With precipitation expected to be lower than average in the Northwest, natural-gas-fired generation and demand-side management could be important in offsetting any lower-than-normal levels of hydroelectric generation availability. SERC Southeast is also projecting a sizable increase in peak demand of more than 2% from NERC's *2024 SRA.* Entities in the assessment area cite economic growth and increased industrial and data mining loads as the main drivers.
- **Aging generation facilities present increased challenges to maintaining generator readiness and resource adequacy.** Forced outage rates for conventional generators and wind resources have trended toward historically high levels in recent years.[3] System operators face increasing risk of resource shortfalls and operating challenges caused by forced generator outages, especially during periods of high demand or when relatively few conventional resources are dispatched to serve load. The threat to BPS reliability can be compounded in areas where aging resources are further depended upon to provide essential reliability services. In the Southwest, for example, a portion of capacity has been in operation for roughly 60 years. Electric utilities in SERC-Central have also described aging generation as a reliability challenge. Historical performance has demonstrated the need for planning assumptions that account for elevated forced outage rates for these generators. Older generators can also require extensive overhauls, such as generator rewinds, that take resources out of service for extended periods of time as discovery work can lead to additional unplanned maintenance.
- **Battery resource additions are helping reduce energy shortfall risks that can arise from resource variability and peaks in demand.** In Texas, California, and across the U.S. West, the influx of battery energy storage systems (BESS) in recent years has markedly improved the ability to manage energy risks during challenging summer periods. These areas can be exposed to energy shortfalls during hours of peak demand and into evening as solar PV output diminishes, but BESS resources that maintain their charge during the day can help meet peak demand and also overcome energy shortfalls on the system that might otherwise occur with solar down-ramps or variability. Natural-gas-fired generation also continues to play an important role in meeting peak demand and flexibly responding to fluctuations output from variable energy resources (VER).
- **Grid operators need to remain vigilant for the potential of inverter-based resources (IBR) to unexpectedly trip during grid disturbances.** While this near-term challenge persists, NERC continues to work diligently with industry to develop long-term solutions to this issue. In April, NERC published the *Aggregated Report on NERC Level 2 Recommendation to Industry: Findings from Inverter-Based Resource Model Quality Deficiencies Alert*.[4] In the report, NERC summarized the deficiencies identified in the Level 2 alert issued in June 2024. The report's findings were as follows:
  - Many grid operators indicated that they did not have the requested data readily available, supporting the previous finding that data acquisition and management was insufficient.
  - Interconnection process requirements are insufficient.
  - Two-thirds of the protection settings used by grid operators are not set to provide the maximum capability. This creates a significant artificial limitation of overall ride-through capability of BPS-connected solar photovoltaic (PV) facilities.
  - 20% of the surveyed facilities use a facility capability with a 0.95 power factor limit, which means that a significant amount of underused reactive capability exists on the BPS.
  - Dynamic model data is inconsistent.

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

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

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

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

Recommendations

To reduce the risk of electricity shortfalls on the BPS this summer, NERC recommends the following:

- RCs, BAs, and TOPs in the elevated risk areas identified in the key findings should take the following actions:
  - Review seasonal operating plans and protocols for communicating and resolving potential supply shortfalls in anticipation of potentially extreme demand levels.
  - Consider the potential for higher-than-anticipated forced generator outage rates in operating plans due to plant age, operating patterns, or limited pre-seasonal maintenance availability.
  - Employ conservative generation and transmission outage coordination procedures and operate conservatively commensurate with long-range weather forecasts to ensure adequate resource availability. The review of system performance during the January 2025 cold weather event noted that early declaration of conservative operations in advance of extreme conditions helped reduce grid congestion and enhance transfer capability.[8]
  - Engage state or provincial regulators and policymakers to prepare for efficient implementation of demand-side management mechanisms called for in operating plans.
- GOs with solar PV resources should implement recommendations in the IBR performance issues alert that NERC issued in March 2023.[9]
- State regulators and industry should have protocols in place at the start of summer for managing emergent requests from generators for air-quality restriction waivers. If warranted, U.S. Department Energy (DOE) action to exercise emergency authority under the Federal Power Act (FPA) section 202(c) may be needed to ensure that sufficient generation is available during extreme weather conditions.

[5] US sweltered through its 4th-hottest summer on record – National Oceanic and Atmospheric Administration
[6] Short-Term Energy Outlook - U.S. Energy Information Administration (EIA)
[7] Supply shortages and an inflexible market give rise to high power transformer lead times | Wood Mackenzie
[8] See notable operations practices in Appendix 2 of the *January 2025 Arctic Events System Performance Review | FERC, NERC, and its Regional Entities: A Joint Staff Report*, April 2025.

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

Summer Temperature and Drought Forecasts

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

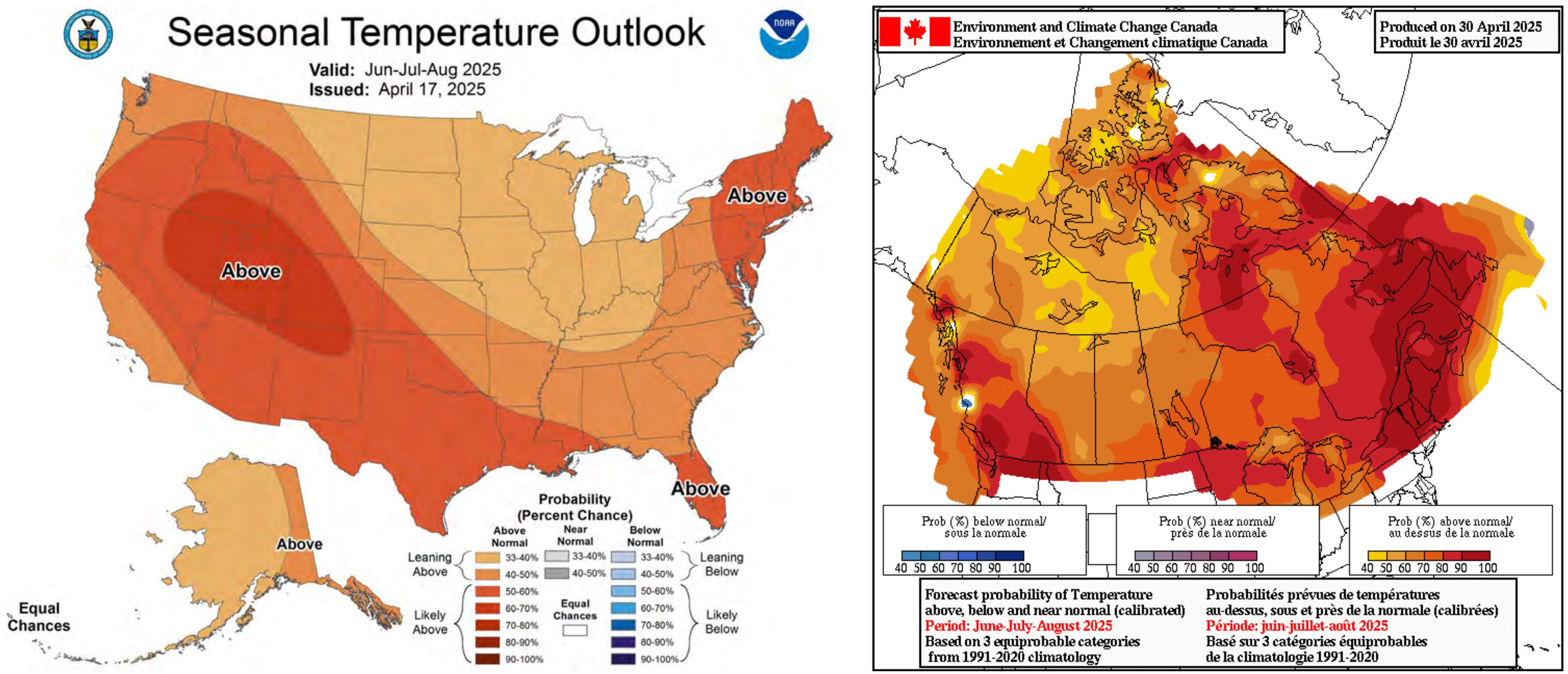


Figure 2: United States and Canada Summer Temperature Outlook[10]

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

Risk Assessment Discussion

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

Table 1: Seasonal Risk Assessment Summary

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

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

Assessment of Planning Reserve Margins and Operational Risk Analysis

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

Table 2: Seasonal Risk Scenario On-Peak Reserve Margins

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

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

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

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

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

Energy Emergency Alerts

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

Energy Emergency Alert Levels

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

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

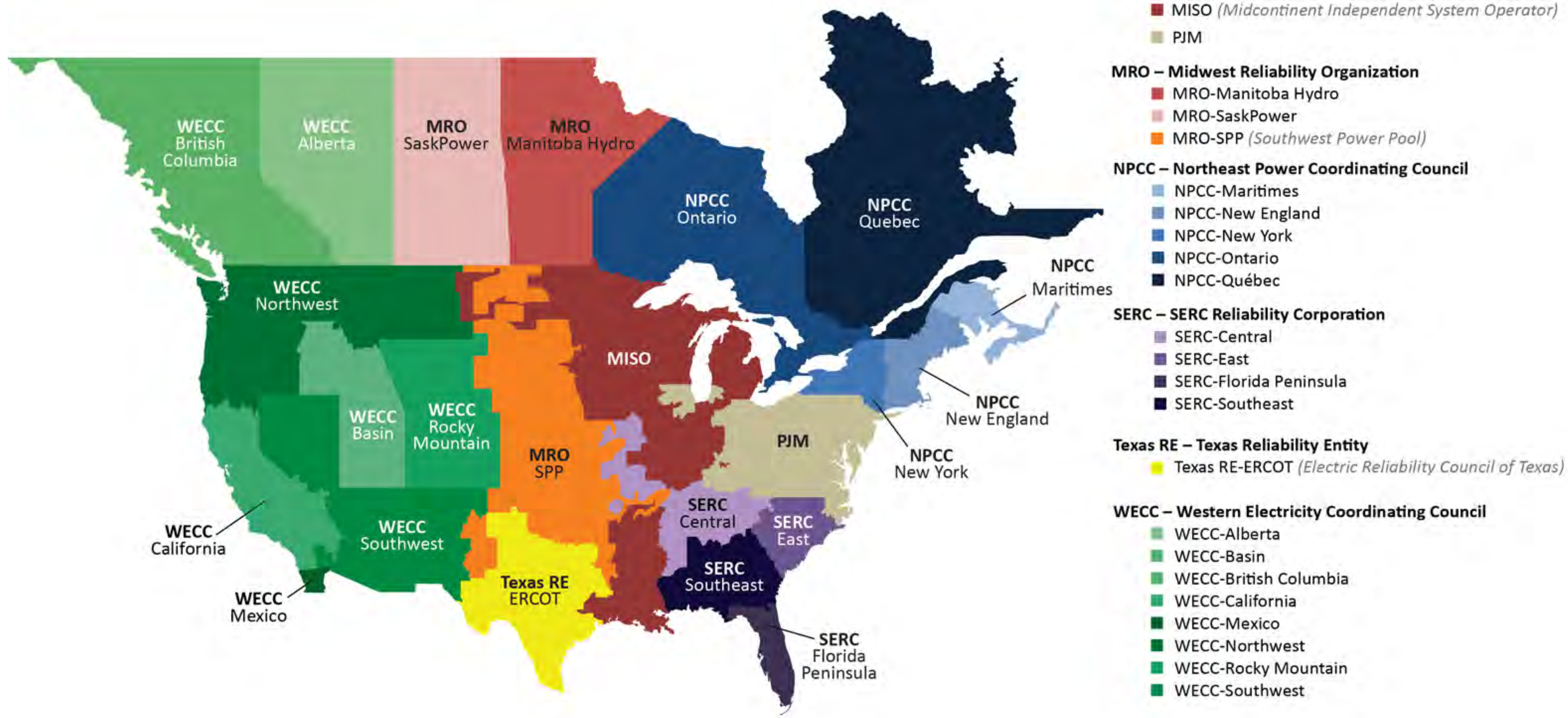
[11] PY 2025–2026 LOLE Study Report

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

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

Regional Assessments Dashboards

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



MISO

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

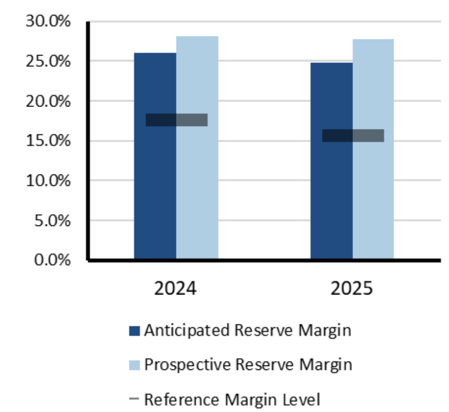
Highlights

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

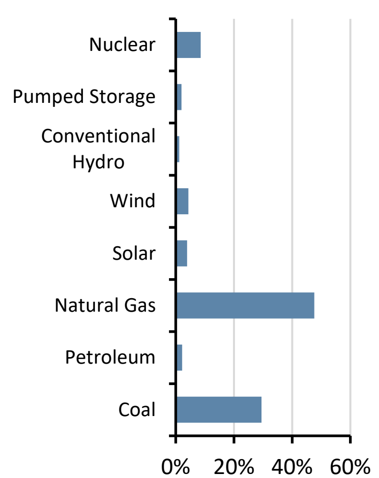
Risk Scenario Summary

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

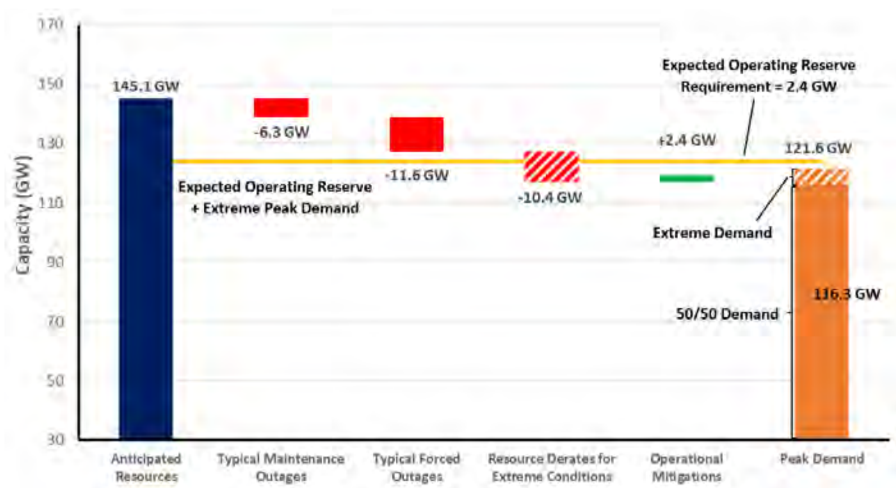
On-Peak Reserve Margin



On-Peak Fuel Mix



2025 Summer Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

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

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

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

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

Extreme Derates: Maximum historical generation outages

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

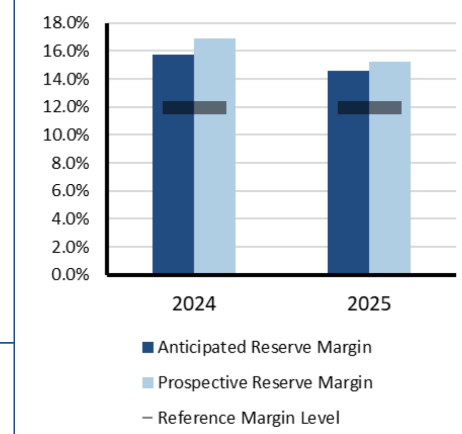
MRO-Manitoba Hydro

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

Highlights

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

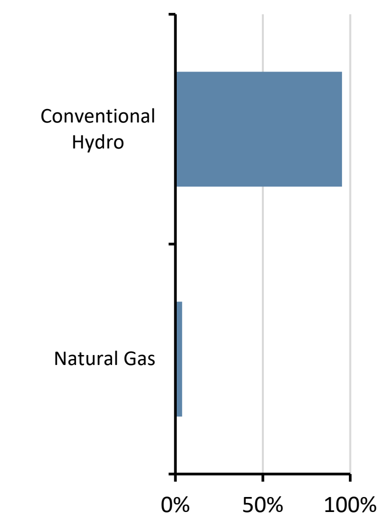
On-Peak Reserve Margin



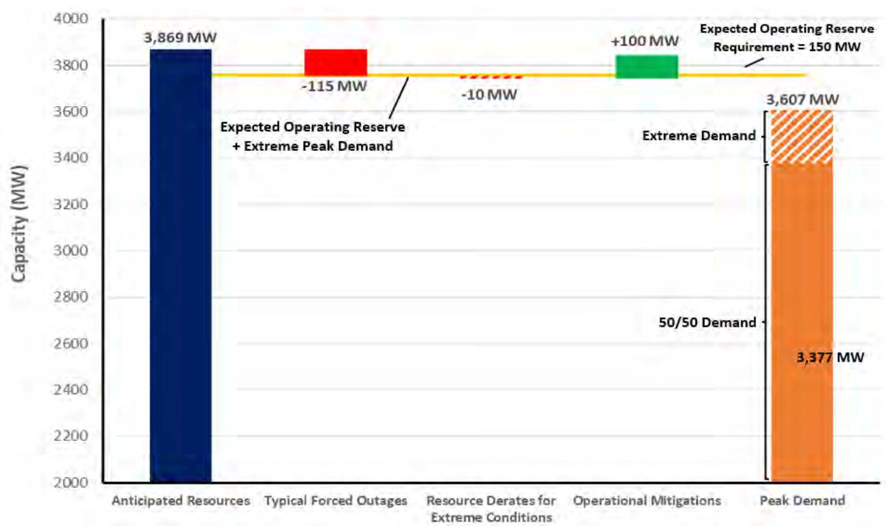
Risk Scenario Summary

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

Forced Outages: Typical forced outages

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

Normal hydro generation expected for this summer.

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

MRO-SaskPower

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

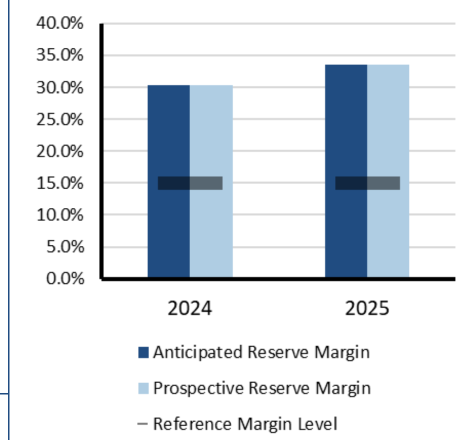
Highlights

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

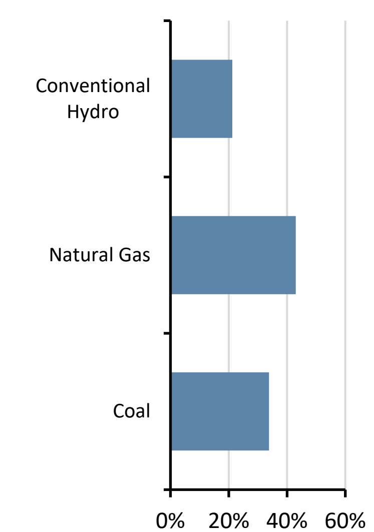
Risk Scenario Summary

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

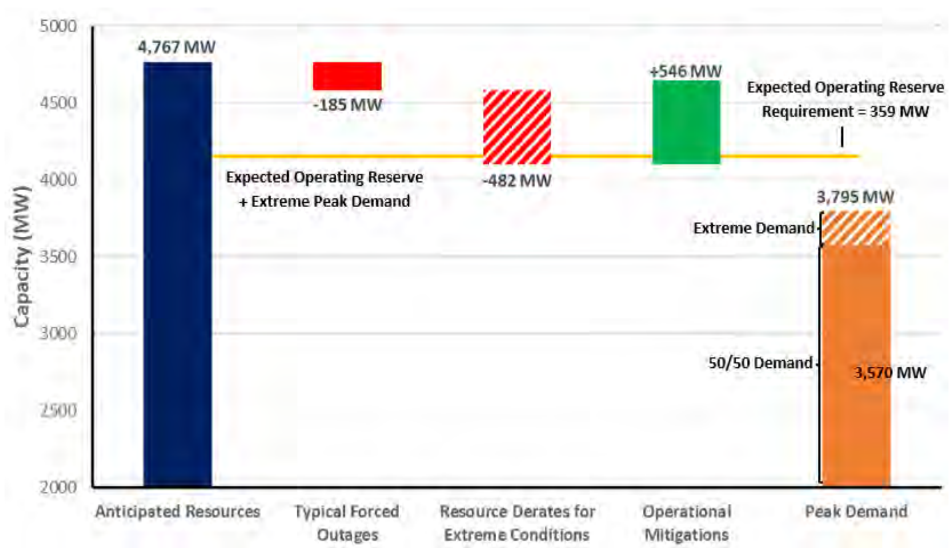
On-Peak Reserve Margin



On-Peak Fuel Mix



2025 Summer Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

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

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

Forced Outages: Estimated by using SaskPower forced outage model

Extreme Derates: Estimated resources unavailable in extreme conditions

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

MRO-SPP

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

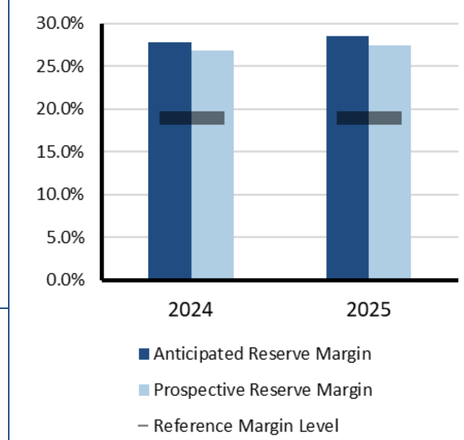
Highlights

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

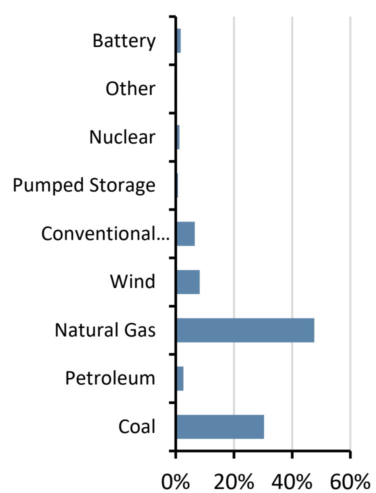
Risk Scenario Summary

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

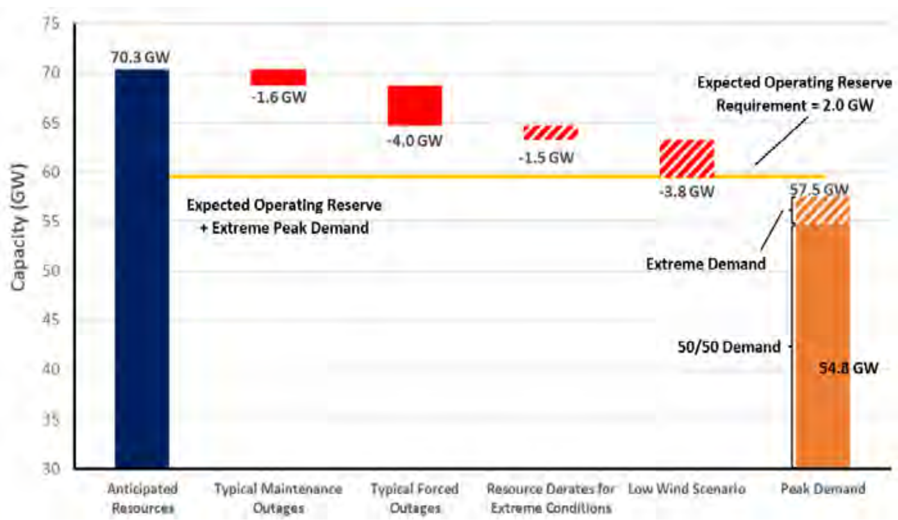
On-Peak Reserve Margin



On-Peak Fuel Mix



2025 Summer Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

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

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

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

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

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

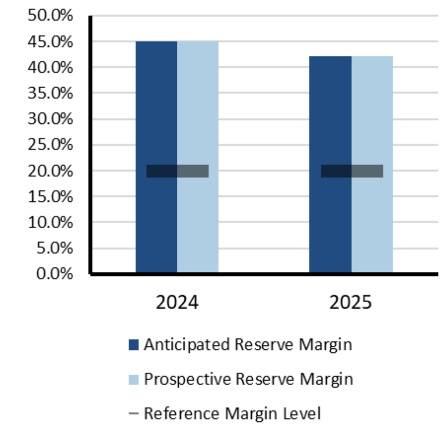
NPCC-Maritimes

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

Highlights

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

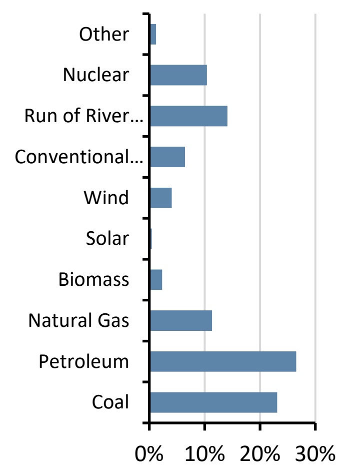
On-Peak Reserve Margin



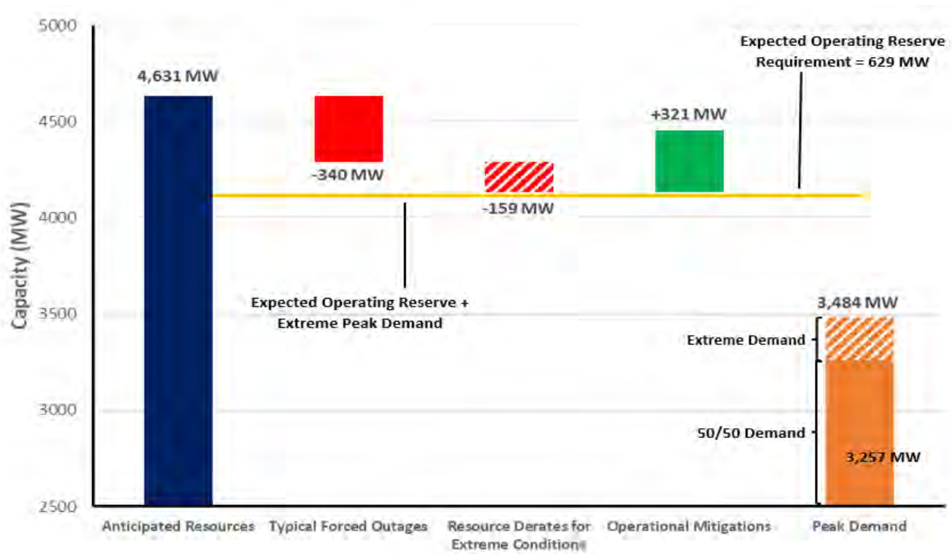
Risk Scenario Summary

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

On-Peak Fuel Mix



2025 Summer Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

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

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

Forced Outages: Based on historical operating experience

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

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

NPCC-New England

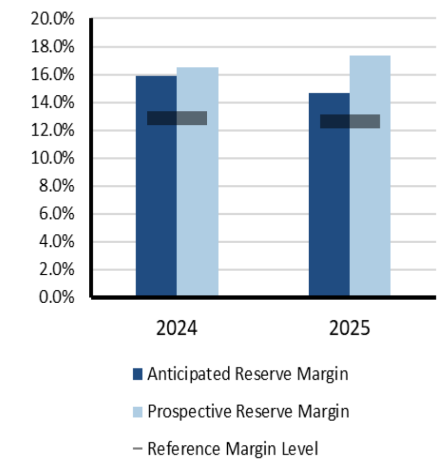
NPCC-New England is an assessment area consisting of the states of Connecticut, Maine, Massachusetts, New Hampshire, Rhode Island, and Vermont that is served by ISO New England (ISO-NE) Inc. ISO-NE is a regional transmission organization that is responsible for the reliable day-to-day operation of New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

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

Highlights

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

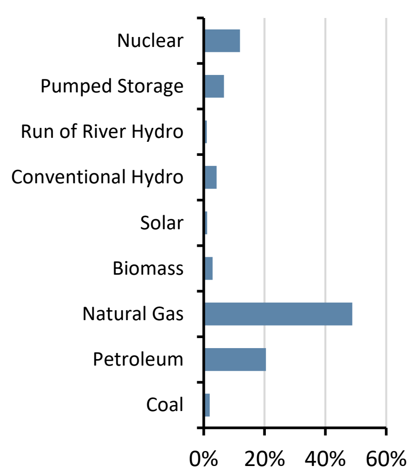
On-Peak Reserve Margin



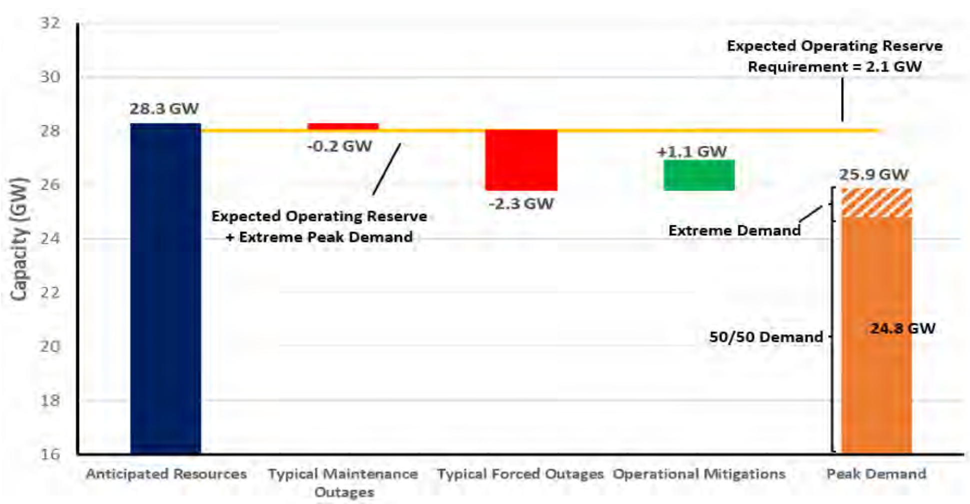
Risk Scenario Summary

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

On-Peak Fuel Mix



2025 Summer Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

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

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

Maintenance Outages: Based on historical weekly averages

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

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

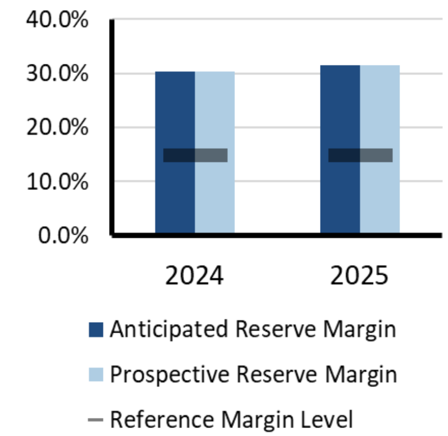
NPCC-New York

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

Highlights

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

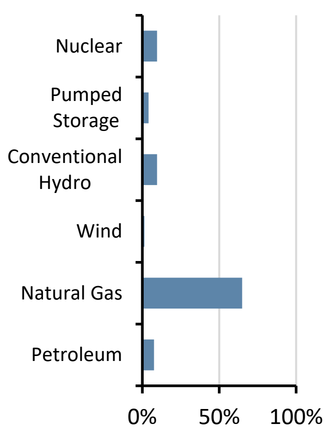
On-Peak Reserve Margin



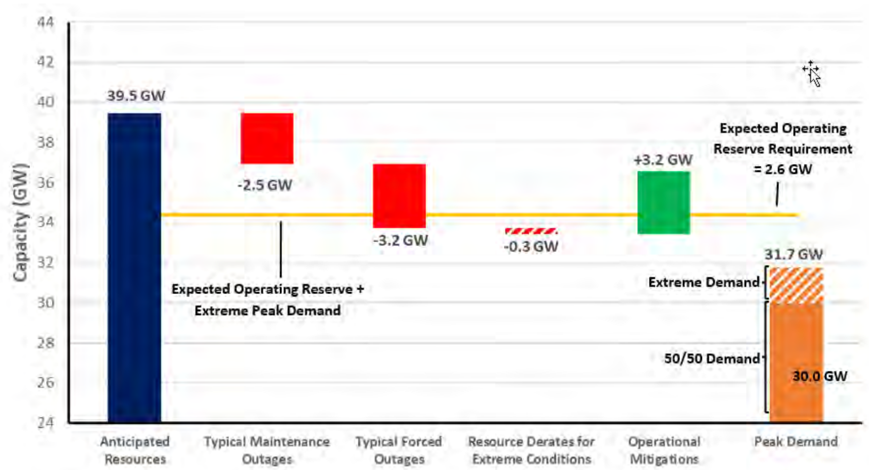
Risk Scenario Summary

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

On-Peak Fuel Mix



2025 Summer Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

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

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

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

Forced Outages: Based on historical five-year averages

Extreme Derates: Estimated resources unavailable in extreme conditions

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

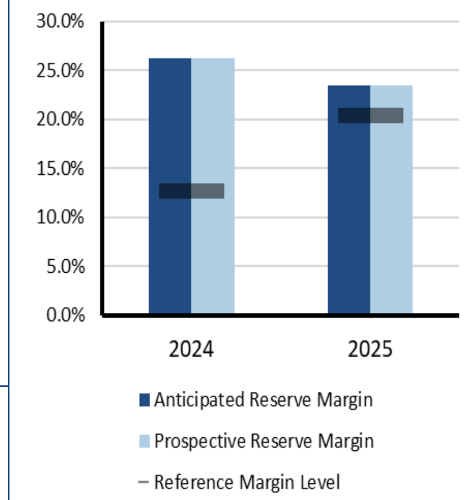
NPCC-Ontario

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

Highlights

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

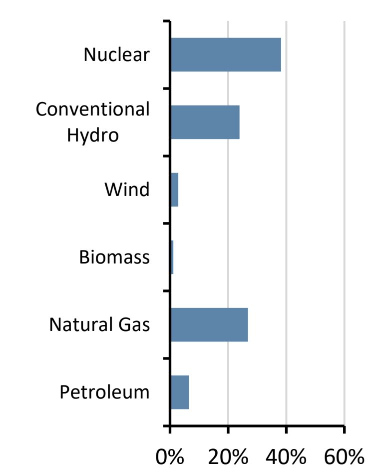
On-Peak Reserve Margin



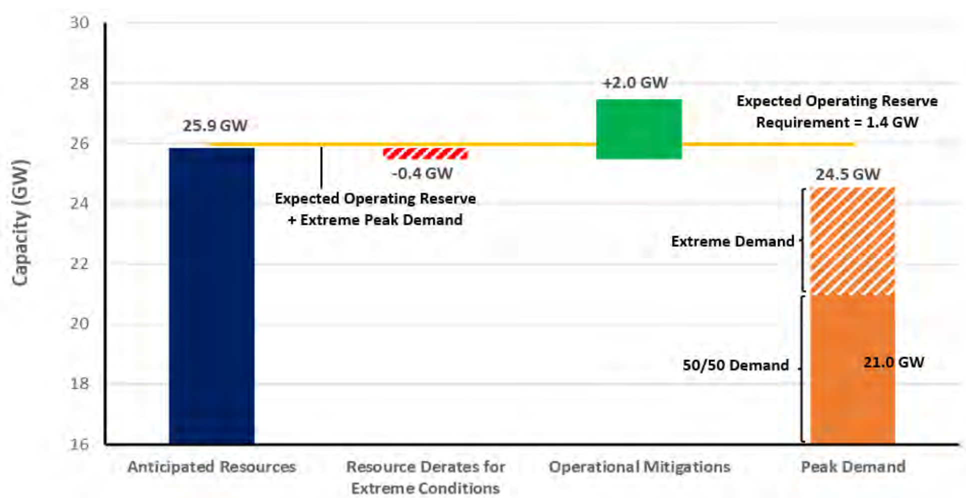
Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed scenarios.

On-Peak Fuel Mix



2025 Summer Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

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

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

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

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

NPCC-Québec

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

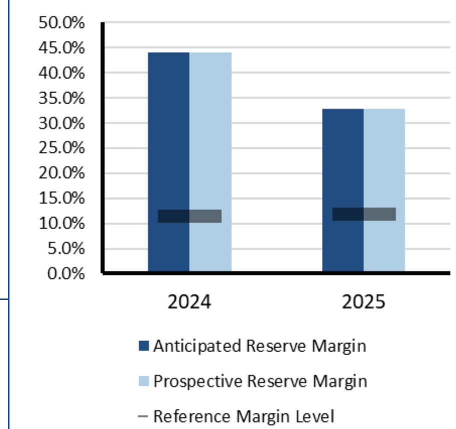
Highlights

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

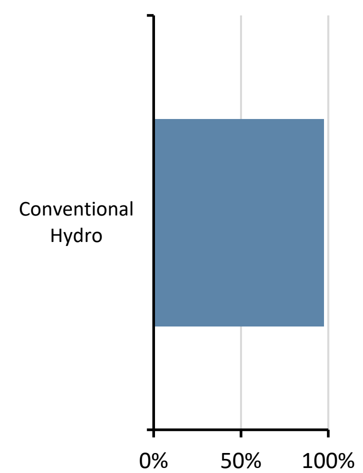
Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed scenarios.

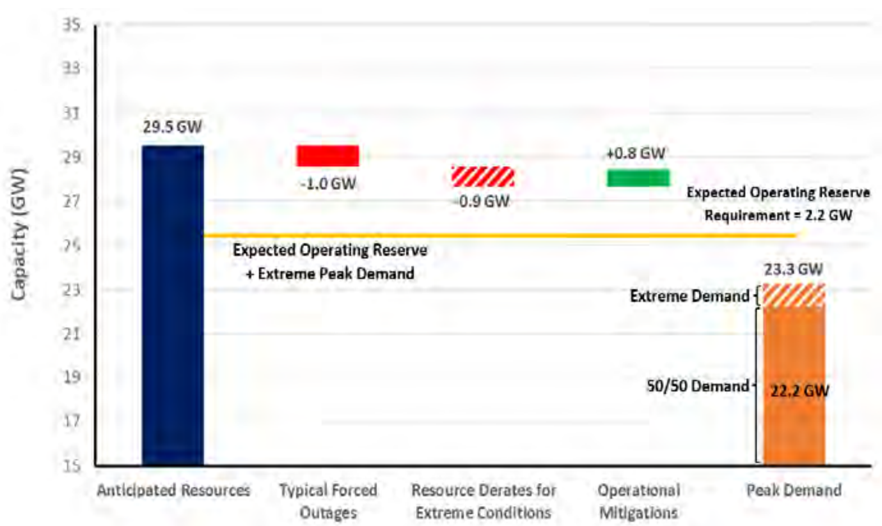
On-Peak Reserve Margin



On-Peak Fuel Mix



2025 Summer Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

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

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

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

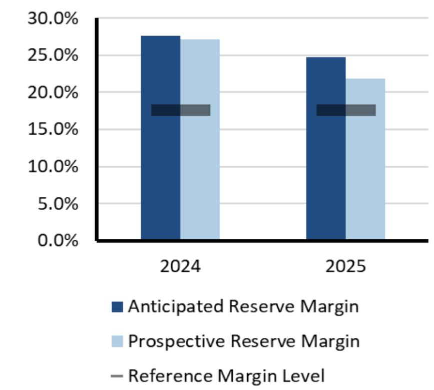
PJM

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

Highlights

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

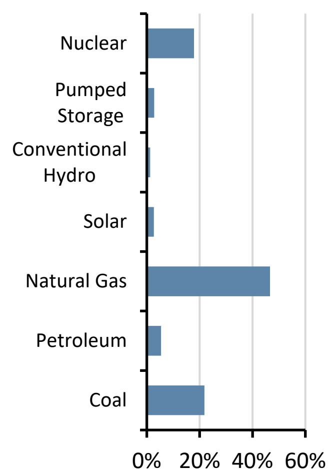
On-Peak Reserve Margin



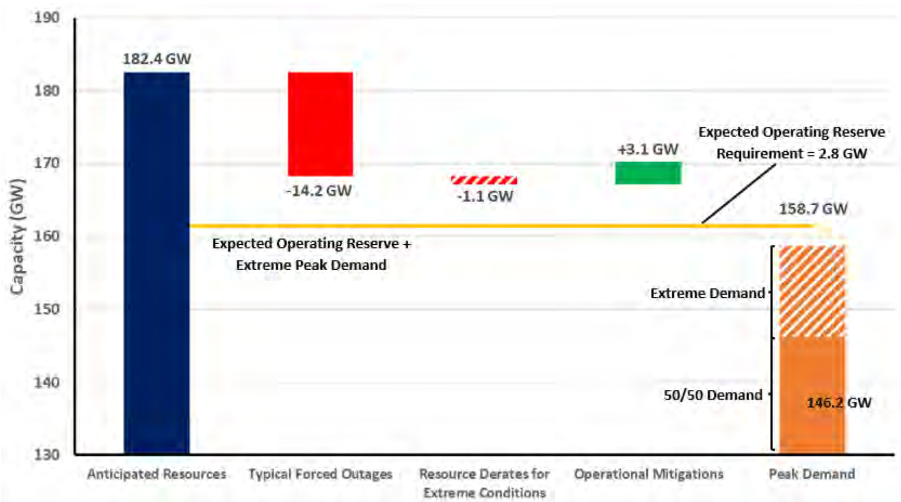
Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed scenarios.

On-Peak Fuel Mix



2025 Summer Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

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

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

Forced Outages: Based on historical data and trending

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

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

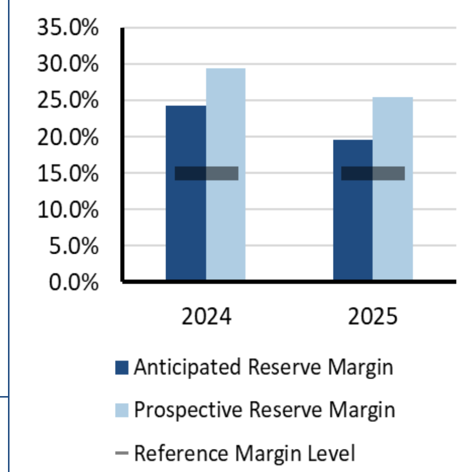
SERC-Central

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

Highlights

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

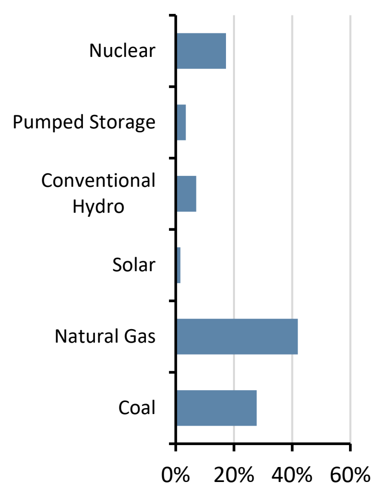
On-Peak Reserve Margin



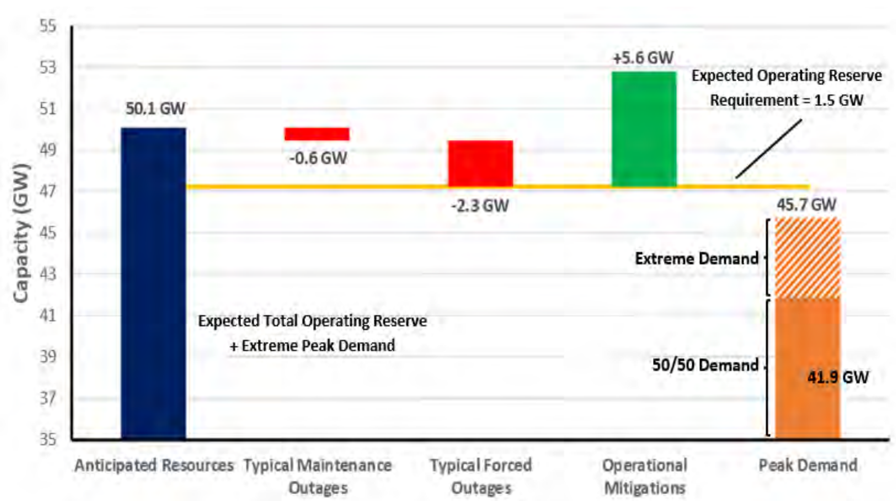
Risk Scenario Summary

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

On-Peak Fuel Mix



2025 Summer Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

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

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

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

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

Operational Mitigations: 5.6 GW based on operational/emergency procedures

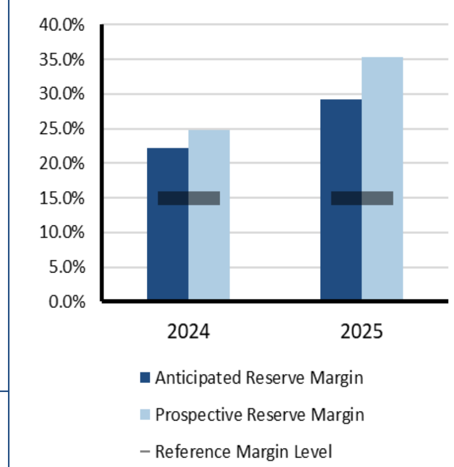
SERC-East

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

Highlights

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

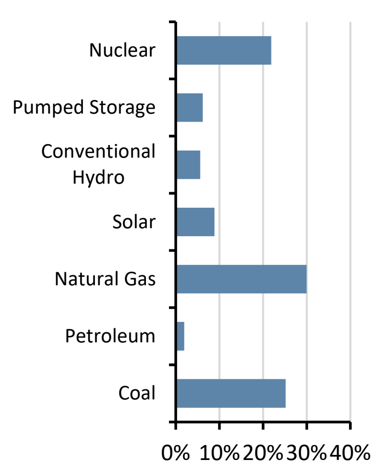
On-Peak Reserve Margin



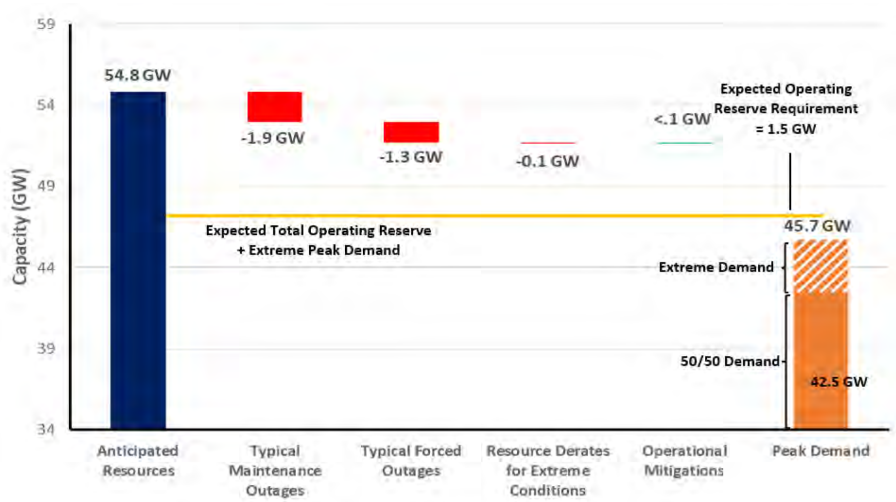
Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed scenarios.

On-Peak Fuel Mix



2025 Summer Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

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

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

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

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

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

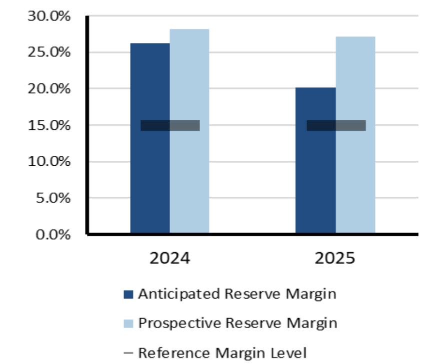
SERC-Florida Peninsula

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

Highlights

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

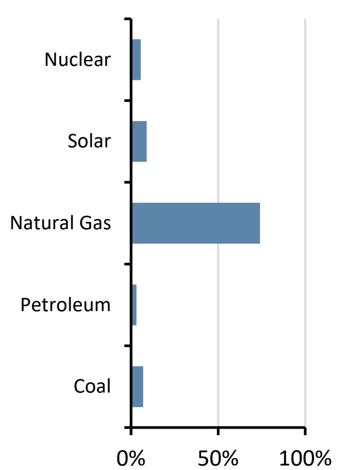
On-Peak Reserve Margin



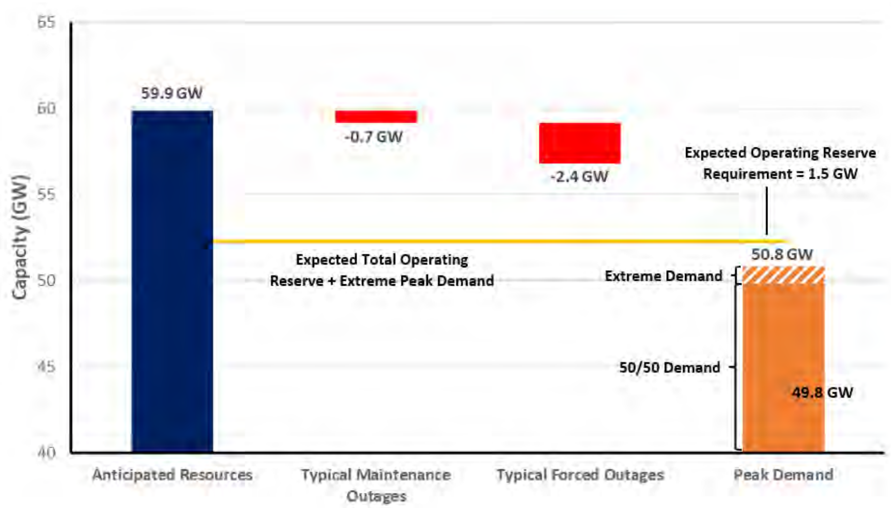
Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed scenarios.

On-Peak Fuel Mix



2025 Summer Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

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

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

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

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

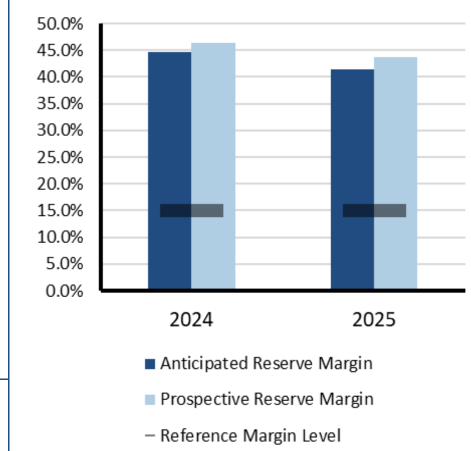
SERC-Southeast

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

Highlights

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

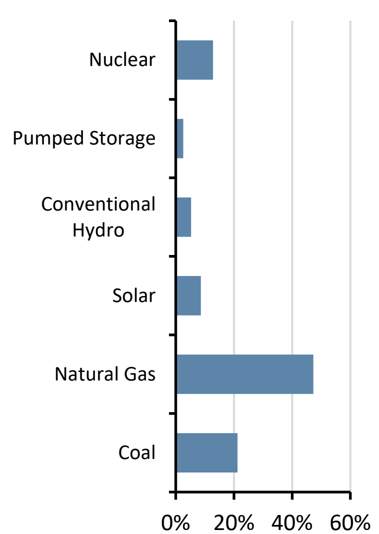
On-Peak Reserve Margin



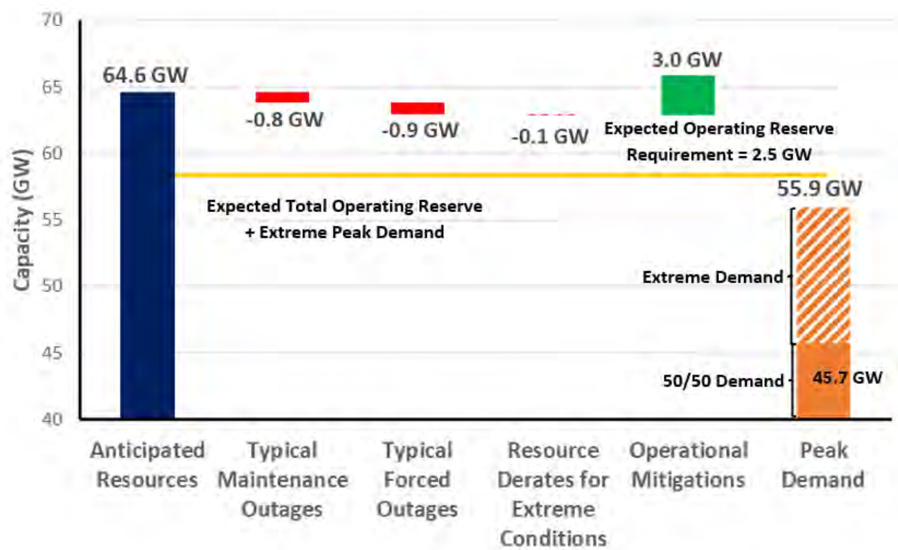
Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed scenarios.

On-Peak Fuel Mix



2025 Summer Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

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

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

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

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

Extreme Derates: Estimated resources unavailable in extreme conditions

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

Texas RE-ERCOT

The Electric Reliability Council of Texas (ERCOT) is the independent system operator (ISO) for the ERCOT Interconnection and is located entirely in the state of Texas; it operates as a single BA. It also performs financial settlement for the competitive wholesale bulk-power market and administers retail switching for nearly 8 million premises in competitive choice areas. ERCOT is governed by a board of directors and subject to oversight by the Public Utility Commission of Texas and the Texas Legislature. ERCOT is summer-peaking, and the forecasted summer peak load month is August. It covers approximately 200,000 square miles, connects over 52,700 miles of transmission lines, has over 1,100 generation units, and serves more than 26 million customers. Texas RE is responsible for the Regional Entity functions described in the Energy Policy Act of 2005 for ERCOT. On November 3, 2022, the Public Utility Commission of Texas issued an order directing ERCOT to assume the duties and responsibilities of the reliability monitor for the Texas grid.

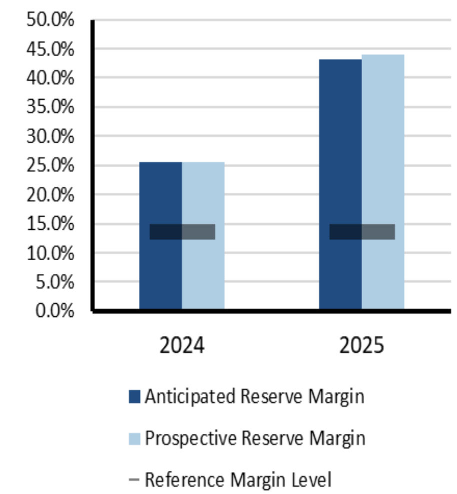
Highlights

- ERCOT expects to have sufficient operating reserves for the August peak load hour given normal summer system conditions.
- ERCOT's probabilistic risk assessment indicates a low risk of having to declare EEAs during the expected August (and summer) peak load day; the EEA probability for the highest-risk hour—hour ending 9:00 p.m.—is 3.6%. The likelihood of an EEA is down significantly from the 2024 SRA due to almost a doubling of battery energy storage capacity and improved energy availability reflecting new battery storage and operational rules.
- Continued robust growth in both loads and intermittent renewable resources drives a higher risk of emergency conditions in the evening hours when solar generation ramps down and loads remain elevated.
- The South Texas IROL continues to present a risk of ERCOT directing system-wide firm load shedding to remain within IROL limits. This risk has been mitigated by updating transmission line dynamic ratings and switching actions to divert power away from the most limiting transmission circuits. The South Texas transmission limits are expected to be needed at least until the San Antonio South Reliability Project is placed in service, which is anticipated to be in Summer 2027.
- ERCOT will release its own August 2025 Monthly Outlook for Resource Adequacy on June 6.

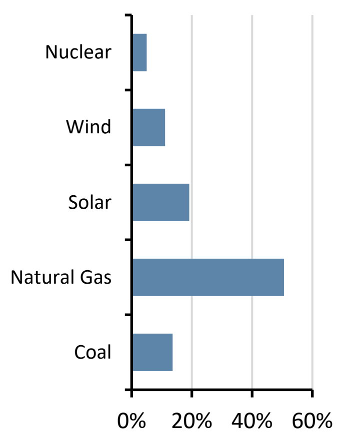
Risk Scenario Summary

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

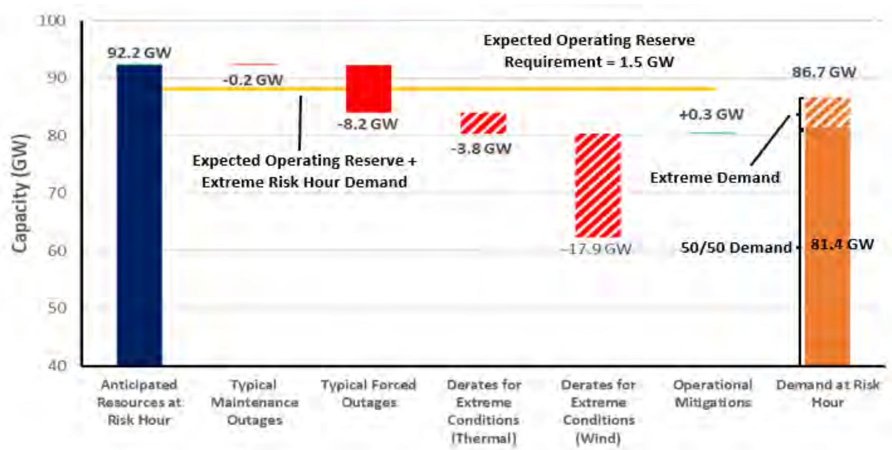
On-Peak Reserve Margin



On-Peak Fuel Mix



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



Scenario Description (See Data Concepts and Assumptions)

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

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

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

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

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

Operational Mitigations: Additional capacity from switchable generation and additional imports

WECC-Alberta

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

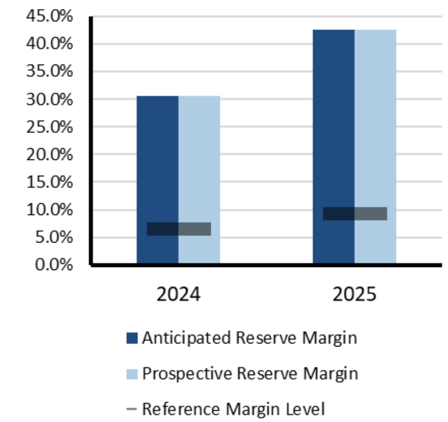
Highlights

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

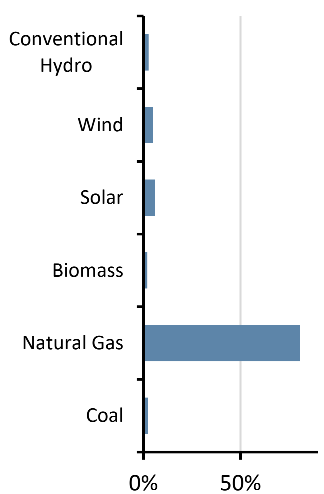
Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed scenarios.

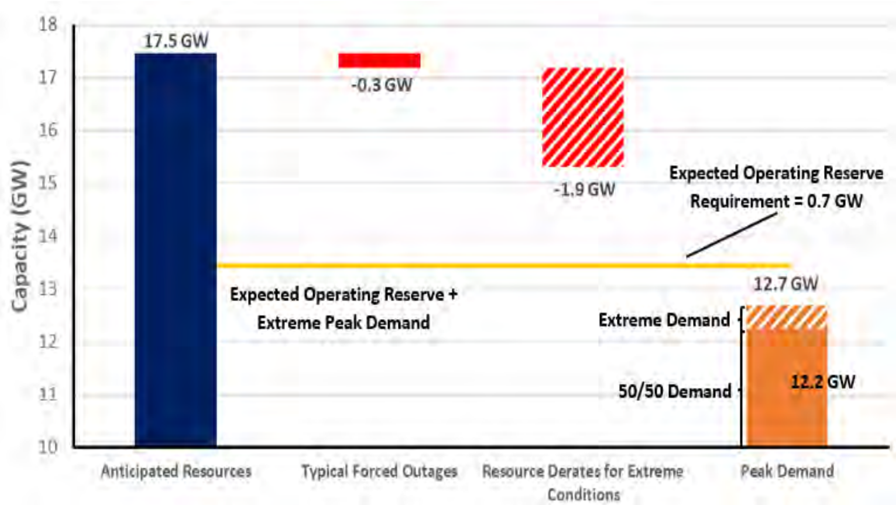
On-Peak Reserve Margin



On-Peak Fuel Mix



2025 Summer Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

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

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

Typical Forced Outages: Average seasonal outages

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

WECC-Basin

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

Highlights

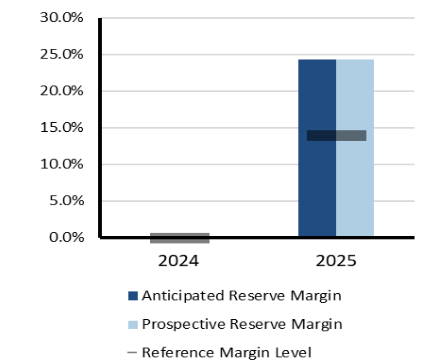
- Total internal expected demand has increased 8% and demand response has increased almost 28% for a net internal demand increase of 7.2%.
- Reserve margins are not anticipated to fall below the reference margin (14%) for the upcoming summer; an early July peak is expected at around 3:00 p.m.
- During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

Risk Scenario Summary

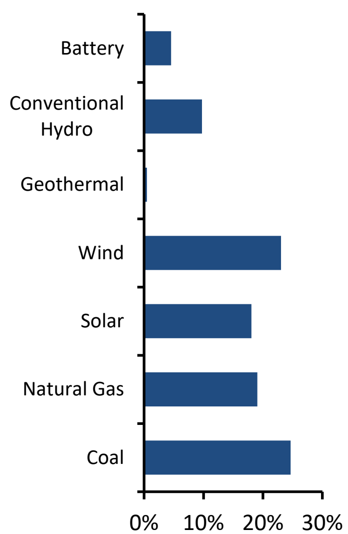
Expected resources meet operating reserve requirements under the assessed scenarios with imports.

On-Peak Reserve Margin

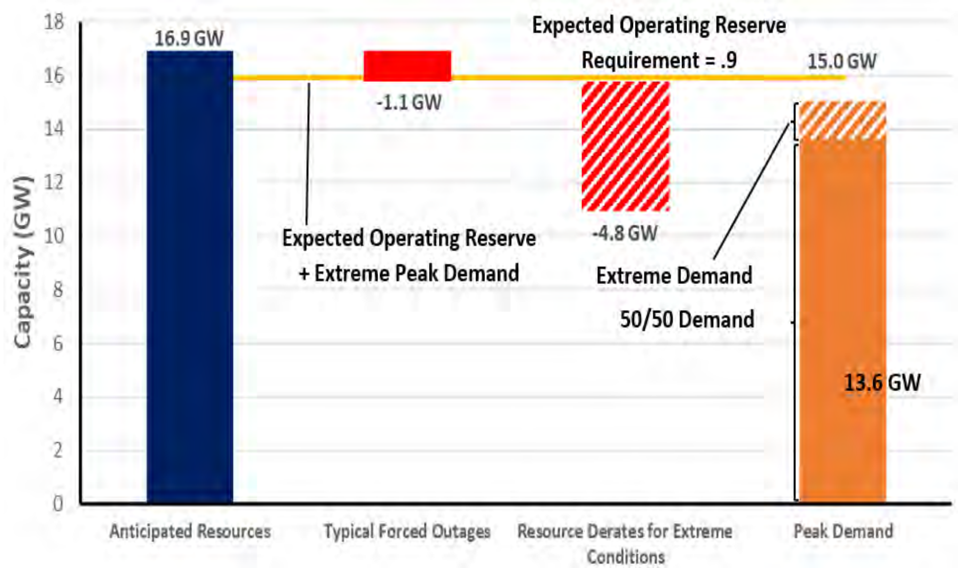
(Note: year comparison not available)



On-Peak Fuel Mix



2025 Summer Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

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

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

Forced Outages: Average seasonal outages

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

WECC-British Columbia

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

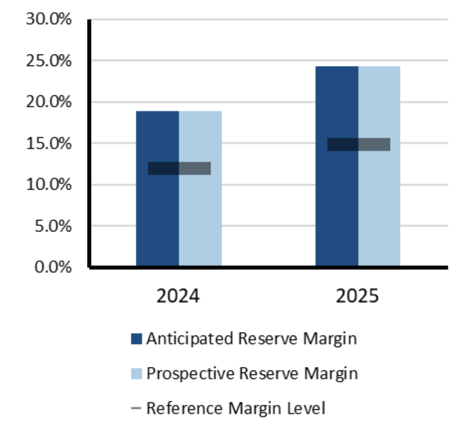
Highlights

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

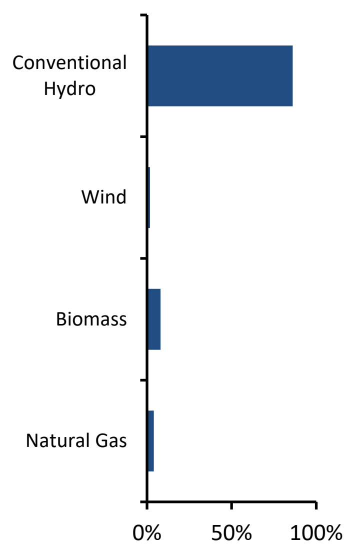
Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed scenarios.

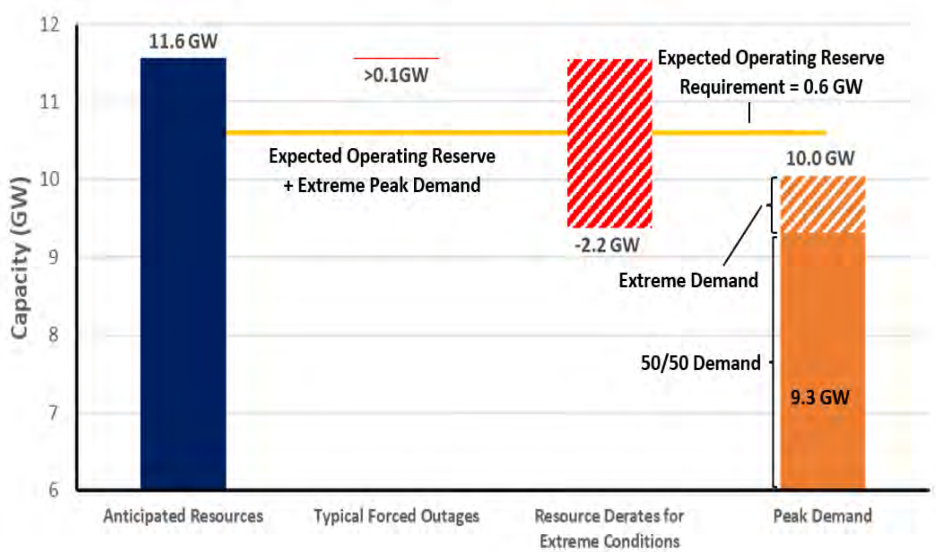
On-Peak Reserve Margin



On-Peak Fuel Mix



2025 Summer Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

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

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

Forced Outages: Average seasonal outages

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

WECC-California

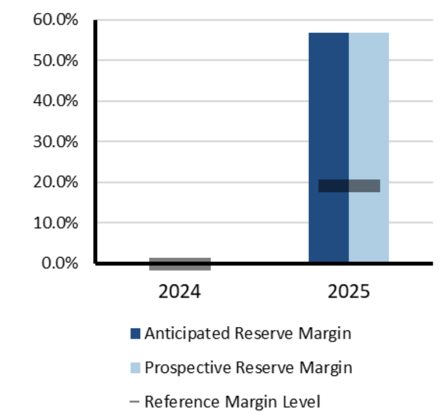
WECC-California is a summer-peaking assessment area in the Western Interconnection that includes most of California and a small section of Nevada. The assessment area has a population of over 42.5 million people. The area includes the California ISO, Los Angeles Department of Water and Power, Turlock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

Highlights

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

On-Peak Reserve Margin

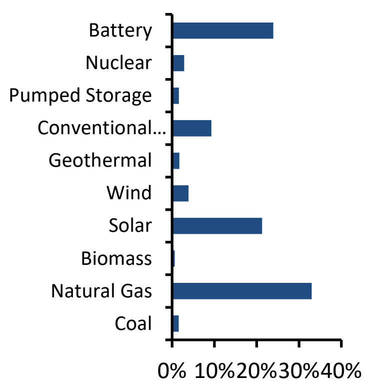
(Note: year comparison not available)



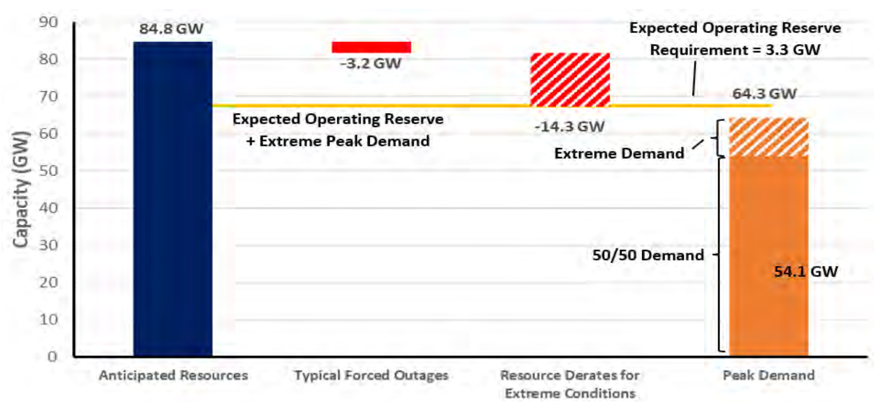
Risk Scenario Summary

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

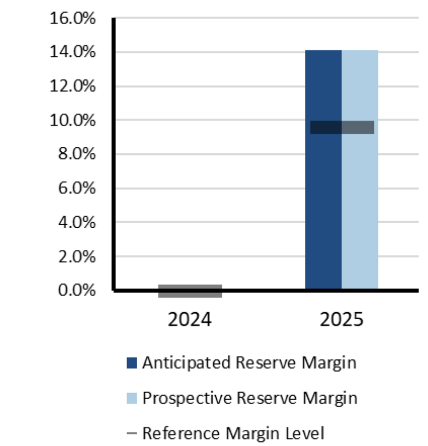
- Total and net internal expected (50/50) demand are up 6.8%, existing-certain capacity is up 29.8% or 989 MW, and Tier 1 planned capacity has fallen 100% to zero, leading to a decrease in the anticipated reserve margin from 22.9% down to 14.1%
- The peak hour is expected to occur in early August around 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

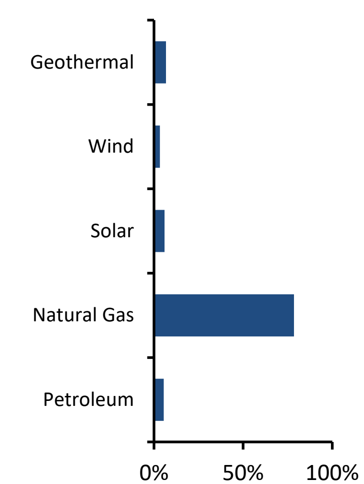
Expected resources at normal peak demand and outage conditions require some imports to maintain operating reserves. Thus, above-normal demand, high forced outage conditions, or transmission derates in the neighboring area could place WECC-Mexico in an energy emergency.

On-Peak Reserve Margin

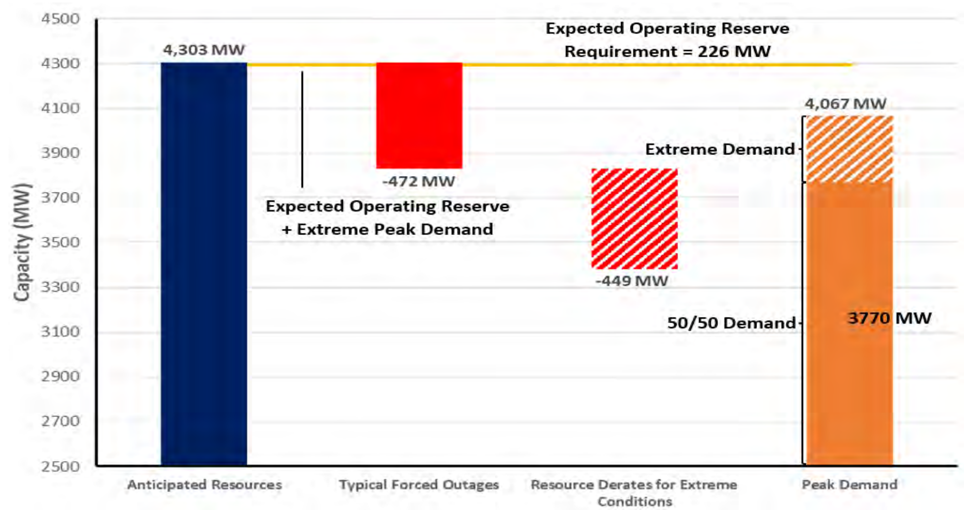
(Note: year comparison not available)



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.*

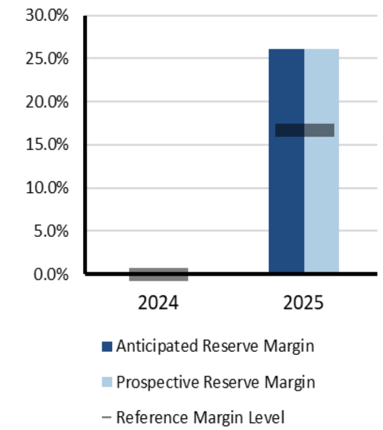
Highlights

- 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

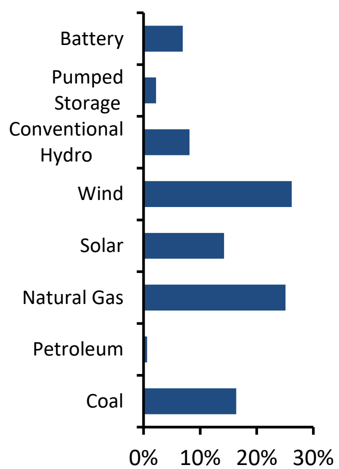
Expected resources meet operating reserve requirements under assessed scenarios with imports.

On-Peak Reserve Margin

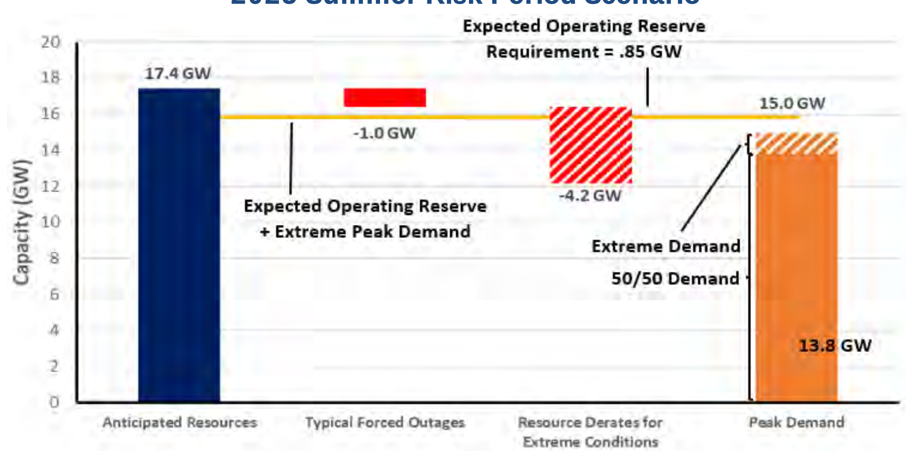


(Note: year comparison not available)

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

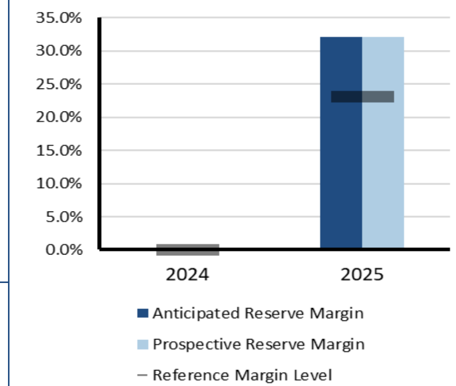
- The reserve margins (existing-certain 29% and anticipated and prospective 32%) are not anticipated to fall below the reference margin (23%) for the upcoming summer. An extreme summer peak load may be around 32,740 MW.
- Typical forced outages are forecast to be 771 MW, with derates for thermal under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

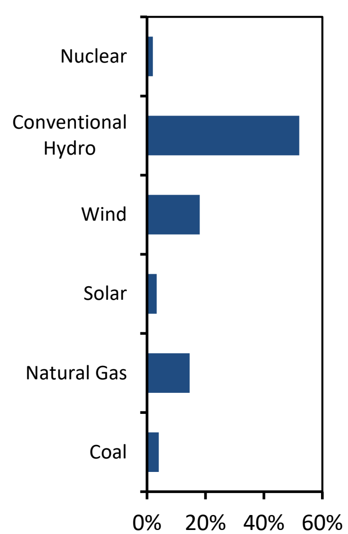
Expected resources meet operating reserve requirements under assessed scenarios with imports.

On-Peak Reserve Margin

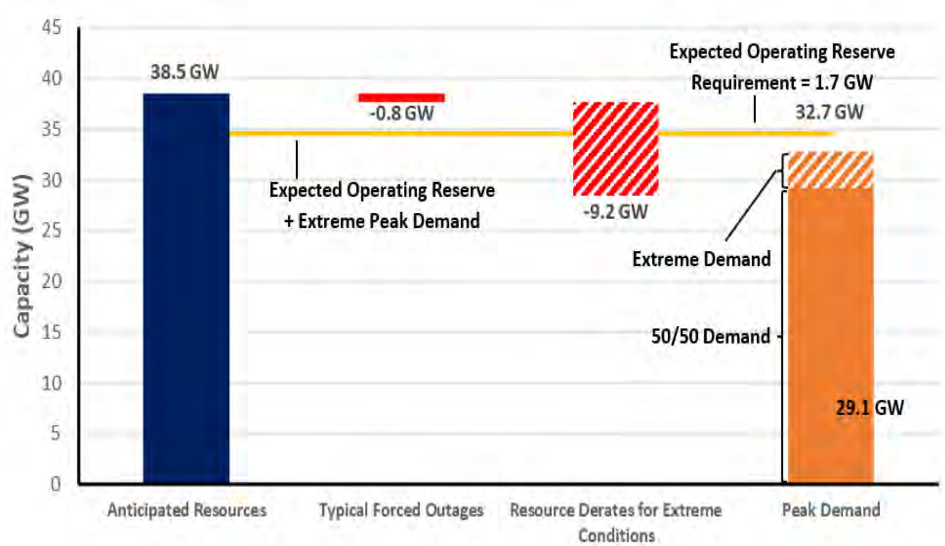
(Note: year comparison not available)



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

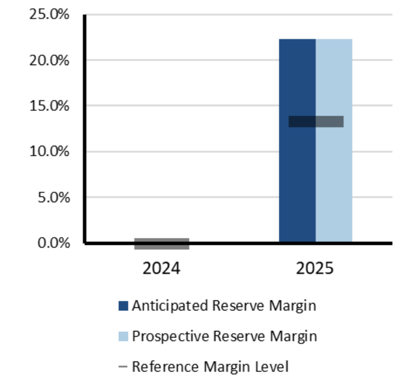
- Anticipated Reserve Margins for the summer are 22%, exceeding the Reference Margin Level for reliability calculated by WECC.
- WECC's probabilistic analysis indicates that the area is not expected to encounter LOLH or EUE under a range of demand and resource conditions.
- The peak hour is expected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

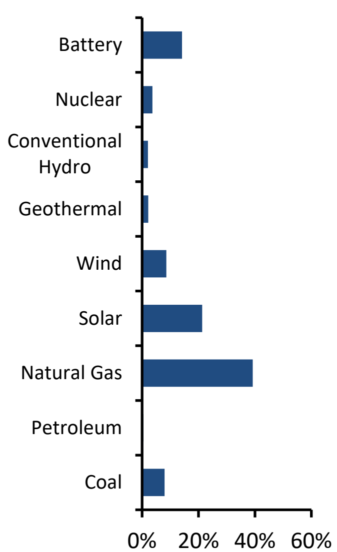
Expected resources meet operating reserve requirements under assessed scenarios with imports.

On-Peak Reserve Margin

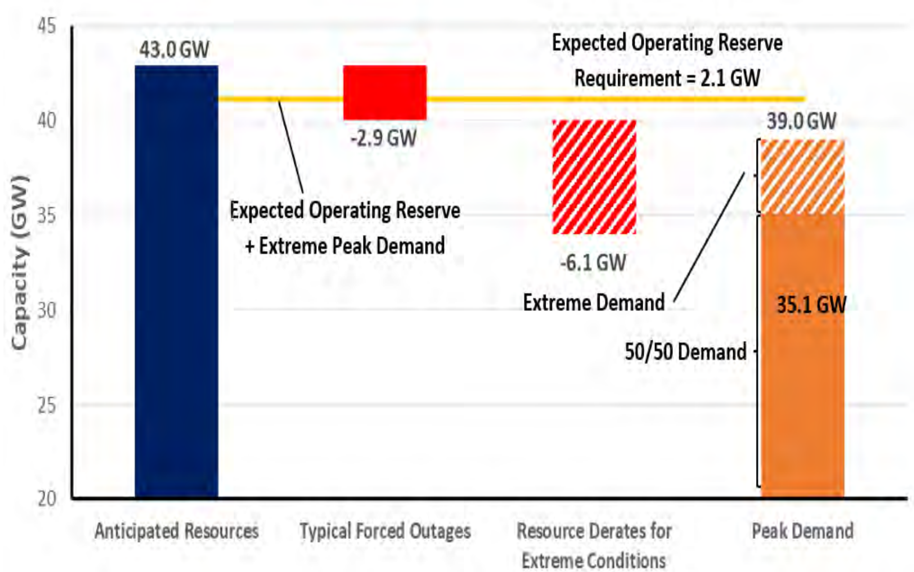
(Note: year comparison not available)



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**.

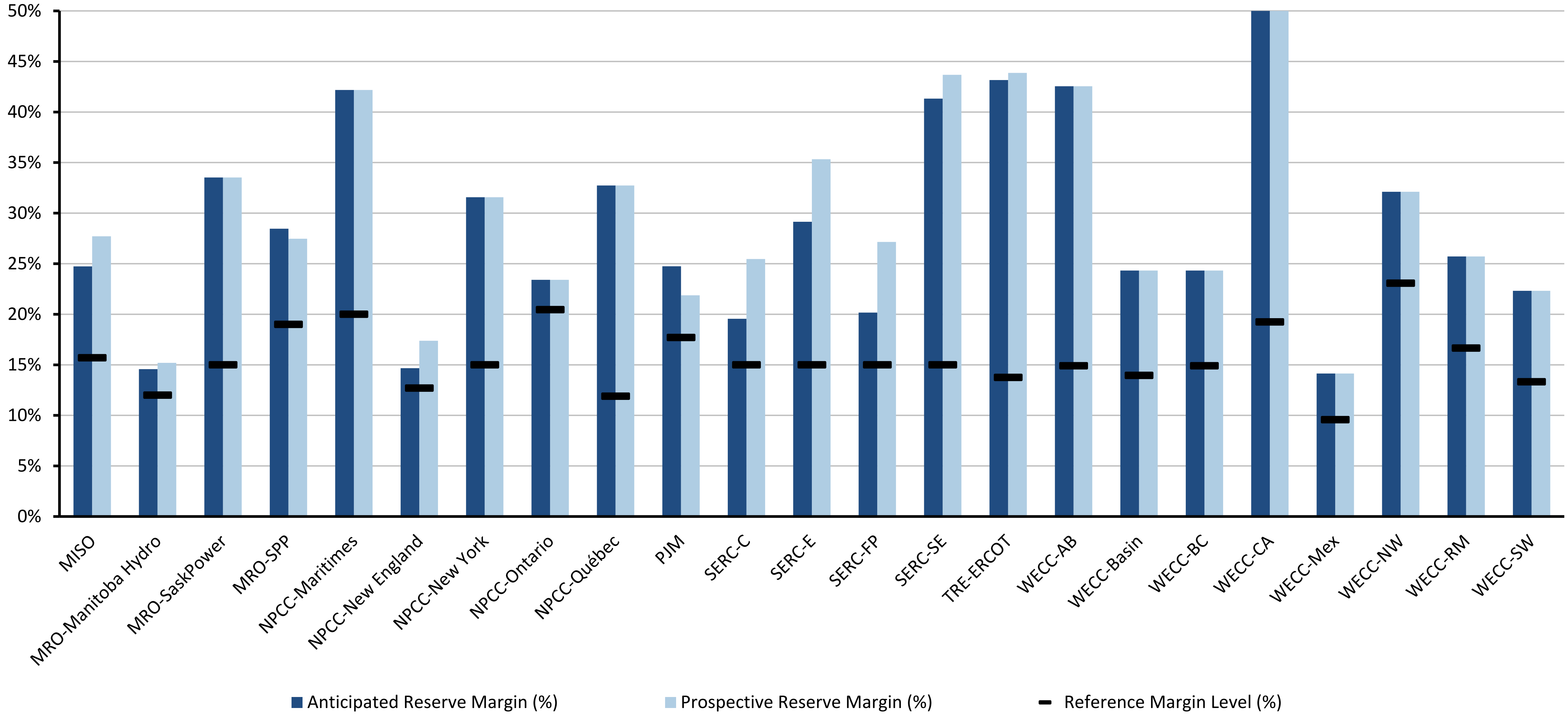


Figure 4: Summer 2025 Anticipated/Prospective Reserve Margins Compared to Reference Margin Level

[16] Generally, anticipated resources include generators and firm capacity transfers that are expected to be available to serve load during electrical peak loads for the season. Prospective resources are those that could be available but do not meet criteria to be counted as anticipated resources. Refer to the **Data Concepts and Assumptions** section for additional information on Anticipated/Prospective Reserve Margins, anticipated/prospective resources, and RMLs.

Changes from Year to Year

Figure 5 provides the relative change in the forecast ARMs from the 2024 Summer to the 2025 Summer. A significant decline can signal potential operational issues for the upcoming season. Additional details for each assessment area are provided in the Data Concepts and Assumptions and Regional Assessments Dashboards sections.

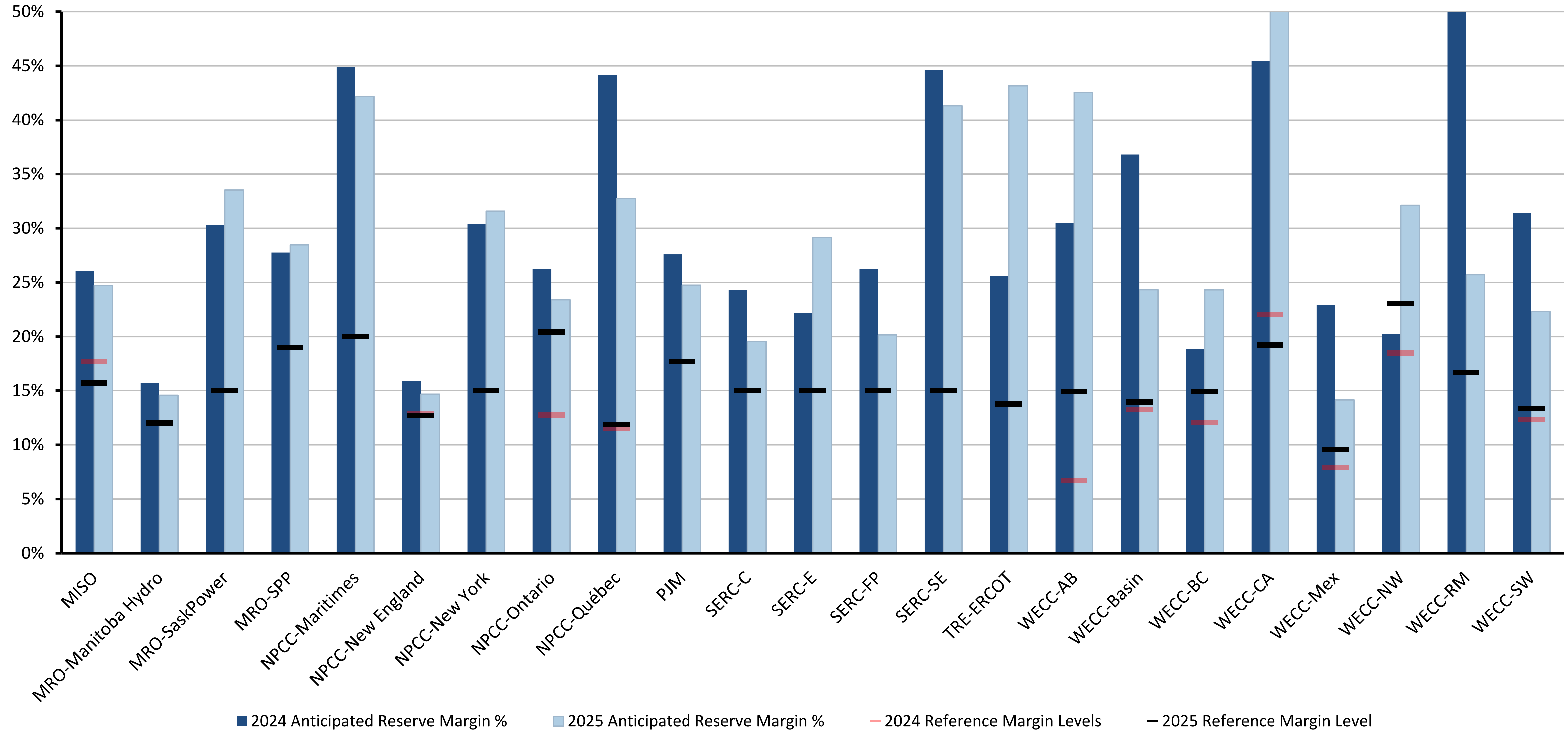


Figure 5: Summer 2024 and Summer 2025 Anticipated Reserve Margins Year-to-Year Change

Note: Yearly trends are not available for new WECC assessment areas in the United States and Baja California, Mexico.

Net Internal Demand

The changes in forecasted net internal demand for each assessment area are shown in **Figure 6**.[17] Assessment areas develop these forecasts based on historic load and weather information as well as other long-term projections.

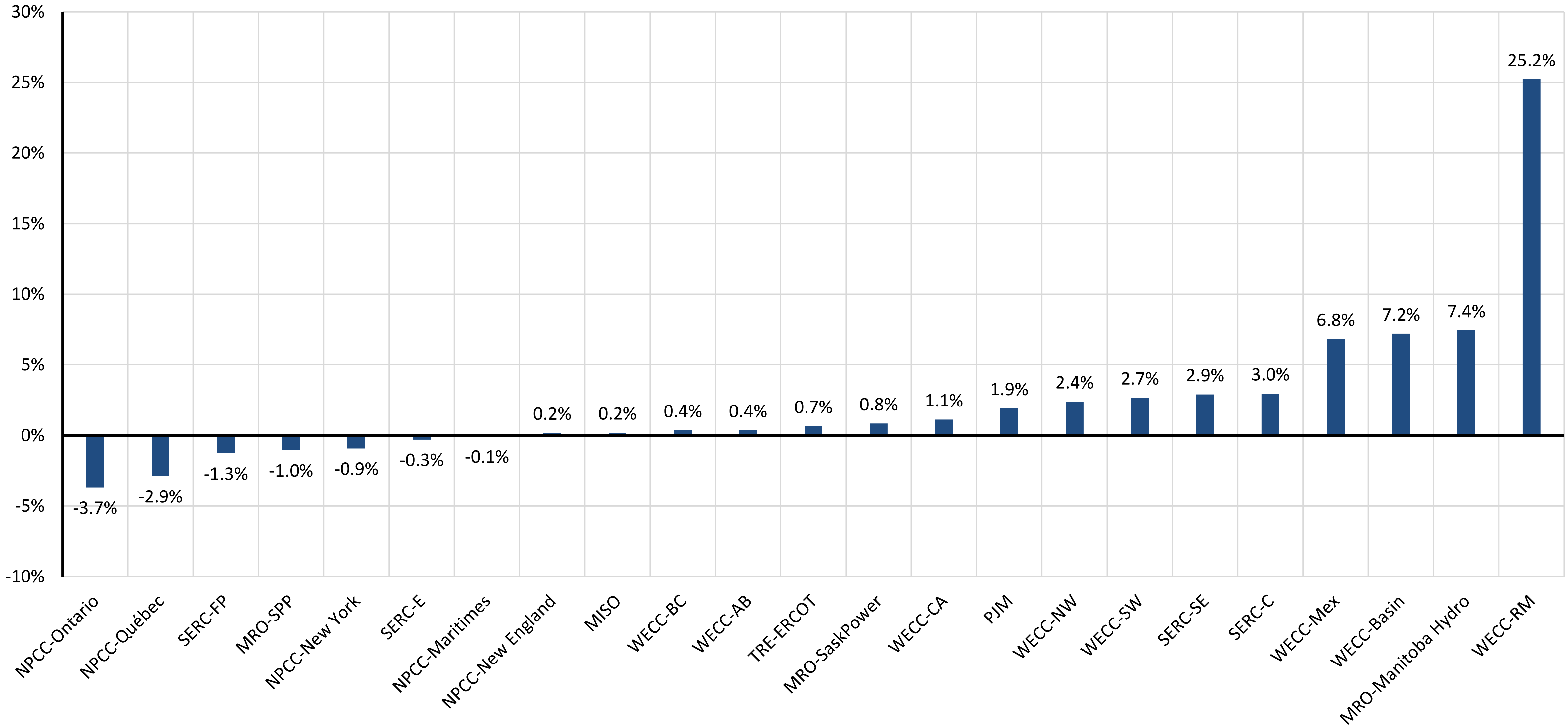


Figure 6: Changes in Net Internal Demand—Summer 2024 Forecast Compared to Summer 2025 Forecast

[17] Changes in modeling and methods are contributing to year-to-year changes in forecasted net internal demand projections in NPCC Maritimes and NPCC Ontario. See assessment area dashboards.

Demand and Resource Tables

Peak demand and supply capacity data—resource adequacy data—for each assessment area are as follows in each table (in alphabetical order).

MISO			
Demand, Resource, and Reserve Margins	**2024 SRA**	**2025 SRA**	**2024 vs. 2025 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	124,830	125,313	0.4%
Demand Response: Available	8,750	9,004	2.9%
Net Internal Demand	116,079	116,309	0.2%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	143,866	142,793	-0.7%
Tier 1 Planned Capacity	0	0	-
Net Firm Capacity Transfers	2,471	2,280	-7.7%
Anticipated Resources	146,337	145,073	-0.9%
Existing-Other Capacity	1,833	1,190	-35.1%
Prospective Resources	148,740	148,543	-0.1%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	26.1%	24.7%	-1.3
Prospective Reserve Margin	28.1%	27.7%	-0.4
Reference Margin Level	17.7%	15.7%	-2.0

MRO-Manitoba Hydro			
Demand, Resource, and Reserve Margins	**2024 SRA**	**2025 SRA**	**2024 vs. 2025 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	3,143	3,377	7.4%
Demand Response: Available	0	0	-
Net Internal Demand	3,143	3,377	7.4%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	5,615	5,583	-0.6%
Tier 1 Planned Capacity	0	0	-
Net Firm Capacity Transfers	-1,978	-1,714	-13.3%
Anticipated Resources	3,637	3,869	6.4%
Existing-Other Capacity	37	21	-42.9%
Prospective Resources	3,674	3,890	5.9%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	15.7%	14.6%	-1.1
Prospective Reserve Margin	16.9%	15.2%	-1.7
Reference Margin Level	12.0%	12.0%	0.0

MRO-SaskPower			
Demand, Resource, and Reserve Margins	**2024 SRA**	**2025 SRA**	**2024 vs. 2025 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	3,590	3,620	0.8%
Demand Response: Available	50	50	0.0%
Net Internal Demand	3,540	3,570	0.8%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	4,323	4,477	3.6%
Tier 1 Planned Capacity	0	0	-
Net Firm Capacity Transfers	290	290	0.0%
Anticipated Resources	4,613	4,767	3.3%
Existing-Other Capacity	0	0	-
Prospective Resources	4,613	4,767	3.3%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	30.3%	33.5%	3.2
Prospective Reserve Margin	30.3%	33.5%	3.2
Reference Margin Level	15.0%	15.0%	0.0

MRO-SPP			
Demand, Resource, and Reserve Margins	**2024 SRA**	**2025 SRA**	**2024 vs. 2025 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	56,316	56,168	-0.3%
Demand Response: Available	979	1,408	43.8%
Net Internal Demand	55,337	54,760	-1.0%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	70,855	70,549	-0.4%
Tier 1 Planned Capacity	0	0	-
Net Firm Capacity Transfers	-157	-201	27.5%
Anticipated Resources	70,698	70,348	-0.5%
Existing-Other Capacity	0	0	-
Prospective Resources	70,151	69,801	-0.5%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	27.8%	28.5%	0.7
Prospective Reserve Margin	26.8%	27.5%	0.7
Reference Margin Level	19.0%	19.0%	0.0

NPCC-Maritimes			
Demand, Resource, and Reserve Margins	**2024 SRA**	**2025 SRA**	**2024 vs. 2025 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	3,586	3,584	-0.1%
Demand Response: Available	327	327	0.0%
Net Internal Demand	3,259	3,257	-0.1%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	4,660	4,348	-6.7%
Tier 1 Planned Capacity	0	220	-
Net Firm Capacity Transfers	63	63	0.0%
Anticipated Resources	4,723	4,631	-1.9%
Existing-Other Capacity	0	0	-
Prospective Resources	4,723	4,631	-1.9%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	44.9%	42.2%	-2.7
Prospective Reserve Margin	44.9%	42.2%	-2.7
Reference Margin Level	20.0%	20.0%	0.0

NPCC-New York			
Demand, Resource, and Reserve Margins	**2024 SRA**	**2025 SRA**	**2024 vs. 2025 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	31,541	31,471	-0.2%
Demand Response: Available	1,281	1,487	16.1%
Net Internal Demand	30,260	29,984	-0.9%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	37,867	37,682	-0.5%
Tier 1 Planned Capacity	0	0	-
Net Firm Capacity Transfers	1,585	1,769	11.6%
Anticipated Resources	39,452	39,451	0.0%
Existing-Other Capacity	0	0	-
Prospective Resources	39,452	39,451	0.0%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	30.4%	31.6%	1.2
Prospective Reserve Margin	30.4%	31.6%	1.2
Reference Margin Level	15.0%	15.0%	0.0

NPCC-New England			
Demand, Resource, and Reserve Margins	**2024 SRA**	**2025 SRA**	**2024 vs. 2025 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	25,294	25,202	-0.4%
Demand Response: Available	661	399	-39.6%
Net Internal Demand	24,633	24,803	0.7%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	27,255	27,054	-0.7%
Tier 1 Planned Capacity	0	0	-
Net Firm Capacity Transfers	1,297	1,245	-4.0%
Anticipated Resources	28,552	28,299	-0.9%
Existing-Other Capacity	138	668	384.1%
Prospective Resources	28,690	28,967	1.0%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	15.9%	14.1%	-1.8
Prospective Reserve Margin	16.5%	16.8%	0.3
Reference Margin Level	12.9%	12.7%	-0.2

NPCC-Ontario			
Demand, Resource, and Reserve Margins	**2024 SRA**	**2025 SRA**	**2024 vs. 2025 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	22,753	21,955	-3.5%
Demand Response: Available	996	998	0.2%
Net Internal Demand	21,757	20,957	-3.7%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	26,856	24,760	-7.8%
Tier 1 Planned Capacity	9	413	4568.6%
Net Firm Capacity Transfers	600	689	14.8%
Anticipated Resources	27,465	25,862	-5.8%
Existing-Other Capacity	0	0	-
Prospective Resources	27,465	25,862	-5.8%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	26.2%	23.4%	-2.8
Prospective Reserve Margin	26.2%	23.4%	-2.8
Reference Margin Level	12.8%	20.5%	7.7

NPCC-Québec			
Demand, Resource, and Reserve Margins	**2024 SRA**	**2025 SRA**	**2024 vs. 2025 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	22,922	23,283	1.6%
Demand Response: Available	0	1,020	-
Net Internal Demand	22,922	22,263	-2.9%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	35,731	32,132	-10.1%
Tier 1 Planned Capacity	0	0	-
Net Firm Capacity Transfers	-2,689	-2,582	-4.0%
Anticipated Resources	33,042	29,550	-10.6%
Existing-Other Capacity	0	0	-
Prospective Resources	33,042	29,550	-10.6%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	44.1%	32.7%	-11.4
Prospective Reserve Margin	44.1%	32.7%	-11.4
Reference Margin Level	11.5%	11.9%	0.4

SERC-Central			
Demand, Resource, and Reserve Margins	**2024 SRA**	**2025 SRA**	**2024 vs. 2025 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	42,636	42,765	0.3%
Demand Response: Available	1,941	864	-55.5%
Net Internal Demand	40,695	41,900	3.0%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	47,674	46,949	-1.5%
Tier 1 Planned Capacity	332	592	78.1%
Net Firm Capacity Transfers	2,578	2,554	-0.9%
Anticipated Resources	50,584	50,095	-1.0%
Existing-Other Capacity	2,075	2,475	19.2%
Prospective Resources	52,659	52,570	-0.2%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	24.3%	19.6%	-4.7
Prospective Reserve Margin	29.4%	25.5%	-3.9
Reference Margin Level	15.0%	15.0%	0.0

PJM			
Demand, Resource, and Reserve Margins	**2024 SRA**	**2025 SRA**	**2024 vs. 2025 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	151,247	154,144	1.9%
Demand Response: Available	7,756	7,898	1.8%
Net Internal Demand	143,491	146,246	1.9%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	183,690	186,638	1.6%
Tier 1 Planned Capacity	0	0	-
Net Firm Capacity Transfers	-607	-4,200	591.9%
Anticipated Resources	183,083	182,438	-0.4%
Existing-Other Capacity	0	0	-
Prospective Resources	182,476	178,238	-2.3%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	27.6%	24.7%	-2.8
Prospective Reserve Margin	27.2%	21.9%	-5.3
Reference Margin Level	17.7%	17.7%	0.0

SERC-East			
Demand, Resource, and Reserve Margins	**2024 SRA**	**2025 SRA**	**2024 vs. 2025 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	43,567	44,015	1.0%
Demand Response: Available	985	1,558	58.2%
Net Internal Demand	42,582	42,457	-0.3%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	51,304	54,665	6.5%
Tier 1 Planned Capacity	122	17	-86.0%
Net Firm Capacity Transfers	593	150	-74.7%
Anticipated Resources	52,019	54,832	5.4%
Existing-Other Capacity	1,131	2,628	132.3%
Prospective Resources	53,150	57,459	8.1%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	22.2%	29.1%	7.0
Prospective Reserve Margin	24.8%	35.3%	10.5
Reference Margin Level	15.0%	15.0%	0.0

SERC-Florida Peninsula			
Demand, Resource, and Reserve Margins	**2024 SRA**	**2025 SRA**	**2024 vs. 2025 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	53,293	52,987	-0.6%
Demand Response: Available	2,824	3,158	11.8%
Net Internal Demand	50,469	49,829	-1.3%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	63,199	59,395	-6.0%
Tier 1 Planned Capacity	34	102	197.8%
Net Firm Capacity Transfers	491	381	-22.4%
Anticipated Resources	63,724	59,878	-6.0%
Existing-Other Capacity	972	3,482	258.2%
Prospective Resources	64,696	63,360	-2.1%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	26.3%	20.2%	-6.1
Prospective Reserve Margin	28.2%	27.2%	-1.0
Reference Margin Level	15.0%	15.0%	0.0

Texas RE-ERCOT			
Demand, Resource, and Reserve Margins	**2024 SRA**	**2025 SRA**	**2024 vs. 2025 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	84,818	85,151	0.4%
Demand Response: Available	3,496	3,292	-5.8%
Net Internal Demand	81,323	81,859	0.7%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	99,541	112,321	12.8%
Tier 1 Planned Capacity	2,578	4,854	88.3%
Net Firm Capacity Transfers	20	20	0.0%
Anticipated Resources	102,139	117,195	14.7%
Existing-Other Capacity	0	0	-
Prospective Resources	102,167	117,770	15.3%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	25.6%	43.2%	17.6
Prospective Reserve Margin	25.6%	43.9%	18.2
Reference Margin Level	13.75%	13.75%	0.0

SERC-Southeast			
Demand, Resource, and Reserve Margins	**2024 SRA**	**2025 SRA**	**2024 vs. 2025 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	46,021	47,049	2.2%
Demand Response: Available	1,599	1,338	-16.3%
Net Internal Demand	44,422	45,711	2.9%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	63,693	64,111	0.7%
Tier 1 Planned Capacity	1,738	0	-100.0%
Net Firm Capacity Transfers	-1,192	489	-141.0%
Anticipated Resources	64,238	64,600	0.6%
Existing-Other Capacity	785	1,077	37.1%
Prospective Resources	65,024	65,676	1.0%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	44.6%	41.3%	-3.3
Prospective Reserve Margin	46.4%	43.7%	-2.7
Reference Margin Level	15.0%	15.0%	0.0

WECC-AB			
Demand, Resource, and Reserve Margins	**2024 SRA**	**2025 SRA**	**2024 vs. 2025 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	12,201	12,246	0.4%
Demand Response: Available	0	0	-
Net Internal Demand	12,201	12,246	0.4%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	13,941	17,176	23.2%
Tier 1 Planned Capacity	1,981	281	-85.8%
Net Firm Capacity Transfers	0	0	-
Anticipated Resources	15,922	17,457	9.6%
Existing-Other Capacity	0	0	-
Prospective Resources	15,922	17,457	9.6%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	30.5%	42.6%	12.1
Prospective Reserve Margin	30.5%	42.6%	12.1
Reference Margin Level	6.7%	9.0%	2.7

WECC-BC			
Demand, Resource, and Reserve Margins	**2024 SRA**	**2025 SRA**	**2024 vs. 2025 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	9,275	9,309	0.4%
Demand Response: Available	0	0	-
Net Internal Demand	9,275	9,309	0.4%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	11,022	11,313	2.6%
Tier 1 Planned Capacity	0	260	-
Net Firm Capacity Transfers	0	0	-
Anticipated Resources	11,022	11,573	5.0%
Existing-Other Capacity	0	0	-
Prospective Resources	11,022	11,573	5.0%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	18.8%	24.3%	5.5
Prospective Reserve Margin	18.8%	24.3%	5.5
Reference Margin Level	12.0%	14.9%	2.9

WECC-California			
Demand, Resource, and Reserve Margins	**2024 SRA**	**2025 SRA**	**2024 vs. 2025 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	54,267	54,797	1.0%
Demand Response: Available	816	746	-8.6%
Net Internal Demand	53,451	54,051	1.1%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	71,564	75,726	5.8%
Tier 1 Planned Capacity	5,998	8,470	41.2%
Net Firm Capacity Transfers	197	598	203.6%
Anticipated Resources	77,759	84,794	9.0%
Existing-Other Capacity	0	0	-
Prospective Resources	77,759	84,794	9.0%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	45.5%	56.9%	11.4
Prospective Reserve Margin	45.5%	56.9%	11.4
Reference Margin Level	22.0%	19.2%	-2.8

WECC-Southwest			
Demand, Resource, and Reserve Margins	**2024 SRA**	**2025 SRA**	**2024 vs. 2025 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	34,629	35,321	2.0%
Demand Response: Available	422	199	-52.9%
Net Internal Demand	34,207	35,122	2.7%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	37,716	40,300	6.9%
Tier 1 Planned Capacity	4,272	1,966	-54.0%
Net Firm Capacity Transfers	2,957	695	-76.5%
Anticipated Resources	44,945	42,961	-4.4%
Existing-Other Capacity	0	0	-
Prospective Resources	44,945	42,961	-4.4%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	31.4%	22.3%	-9.1
Prospective Reserve Margin	31.4%	22.3%	-9.1
Reference Margin Level	12.4%	13.3%	1.0

WECC-Northwest			
Demand, Resource, and Reserve Margins	**2024 SRA**	**2025 SRA**	**2024 vs. 2025 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	28,475	29,157	2.4%
Demand Response: Available	30	30	0.0%
Net Internal Demand	28,445	29,127	2.4%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	33,164	36,388	9.7%
Tier 1 Planned Capacity	201	844	319.9%
Net Firm Capacity Transfers	838	1,249	49.0%
Anticipated Resources	34,203	38,481	12.5%
Existing-Other Capacity	0	0	-
Prospective Resources	34,203	38,481	12.5%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	20.2%	32.1%	11.9
Prospective Reserve Margin	20.2%	32.1%	11.9
Reference Margin Level	18.5%	23.1%	4.6

WECC-Basin			
Demand, Resource, and Reserve Margins	**2024 SRA**	**2025 SRA**	**2024 vs. 2025 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	13,165	14,214	8.0%
Demand Response: Available	485	620	27.8%
Net Internal Demand	12,680	13,594	7.2%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	13,534	14,923	10.3%
Tier 1 Planned Capacity	2,436	704	-71.1%
Net Firm Capacity Transfers	1,376	1,274	-7.4%
Anticipated Resources	17,346	16,901	-2.6%
Existing-Other Capacity	0	0	-
Prospective Resources	17,346	16,901	-2.6%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	36.8%	24.3%	-12.5
Prospective Reserve Margin	36.8%	24.3%	-12.5
Reference Margin Level	13.3%	14.0%	0.7

WECC-Rocky Mountain			
Demand, Resource, and Reserve Margins	**2024 SRA**	**2025 SRA**	**2024 vs. 2025 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	11,313	14,098	24.6%
Demand Response: Available	281	284	1.1%
Net Internal Demand	11,032	13,814	25.2%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	17,345	17,262	-0.5%
Tier 1 Planned Capacity	55	104	89.1%
Net Firm Capacity Transfers	0	0	-
Anticipated Resources	17,400	17,366	-0.2%
Existing-Other Capacity	0	0	-
Prospective Resources	17,400	17,366	-0.2%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	57.7%	25.7%	-32.0
Prospective Reserve Margin	57.7%	25.7%	-32.0
Reference Margin Level	18.0%	16.7%	-1.3

WECC-Mexico			
Demand, Resource, and Reserve Margins	**2024 SRA**	**2025 SRA**	**2024 vs. 2025 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	3,529	3,770	6.8%
Demand Response: Available	0	0	-
Net Internal Demand	3,529	3,770	6.8%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	3,314	4,303	29.8%
Tier 1 Planned Capacity	874	0	-100.0%
Net Firm Capacity Transfers	150	0	-100.0%
Anticipated Resources	4,338	4,303	-0.8%
Existing-Other Capacity	0	0	-
Prospective Resources	4,338	4,303	-0.8%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	22.9%	14.1%	-8.8
Prospective Reserve Margin	22.9%	14.1%	-8.8
Reference Margin Level	7.9%	9.6%	1.6

Variable Energy Resource Contributions

Because the electrical output of VERs (e.g., wind, solar PV) depends on weather conditions, on-peak capacity contributions are less than nameplate capacity. The following table shows the capacity contribution of existing wind and solar PV resources at the peak demand hour for each assessment area. Resource contributions are also aggregated by Interconnection and across the entire BPS. For NERC's analysis of risk periods after peak demand (e.g., U.S. assessment areas in WECC), lower contributions of solar PV resources are used because output is diminished during evening periods.

BPS Variable Energy Resources by Assessment Area

	Wind			Solar PV			Hydro			Energy Storage Systems (ESS)		
Assessment Area / Interconnection	Nameplate Wind	Expected Wind	Expected Share of Nameplate (%)	Nameplate Solar PV	Expected Solar PV	Expected Share of Nameplate (%)	Nameplate Hydro	Expected Hydro	Expected Share of Nameplate (%)	Nameplate ESS	Expected ESS	Expected Share of Nameplate (%)
MISO	30,992	6,039	19%	18,246	9,123	50%	1,572	1,467	93%	3,159	3,107	98%
MRO-Manitoba Hydro	259	48	19%	-	-	0%	202	60	30%	-	-	0%
MRO-SaskPower	816	310	38%	30	9	29%	848	686	81%	-	-	0%
NPCC-Maritimes	1,230	314	26%	147	-	0%	1,313	1,313	100%	12	6	50%
NPCC-New England	1,546	142	9%	3,266	1,412	43%	575	175	31%	192	110	57%
NPCC-New York	2,586	446	17%	609	243	40%	976	478	49%	32	17	53%
NPCC-Ontario	4,943	742	15%	478	66	14%	8,862	5,320	60%	-	-	0%
NPCC-Québec	4,024	885	22%	10	-	0%	444	444	100%	-	-	0%
PJM	12,465	1,855	15%	13,731	6,244	45%	2,505	2,505	100%	310	288	93%
SERC-Central	1,324	370	28%	1,810	1,053	58%	4,991	3,418	68%	100	100	100%
SERC-East	-	-	0%	7,097	5,022	71%	3,078	3,008	98%	19	8	41%
SERC-Florida Peninsula	-	-	0%	8,295	5,749	54%	-	-	0%	631	631	100%
SERC-Southeast	-	-	0%	8,507	7,728	91%	3,258	3,308	102%	115	105	92%
SPP	35,613	5,556	16%	1,159	492	42%	114	56	49%	182	41	23%
Texas RE-ERCOT	40,102	9,396	23%	31,473	22,962	73%	572	439	77%	15,291	12,190	80%
WECC-AB	5,712	796	14%	2,174	1,480	68%	894	456	51%	250	235	94%
WECC-BC	747	149	20%	2	-	0%	16,918	10,181	60%	-	-	0%
WECC-Basin	4,859	911	19%	2,648	2,231	84%	2,637	2,022	77%	120	118	98%
WECC-CA	7,836	1,207	15%	25,059	14,756	59%	14,565	6,518	45%	11,459	11,115	97%
WECC-Mexico	300	50	17%	350	227	65%	-	-	0%	-	-	0%
WECC-NW	9,199	3,107	34%	1,349	666	49%	33,068	20,145	61%	11	10	91%
WECC-RM	5,681	1,359	24%	2,523	1,669	66%	3,251	2,446	75%	242	235	97%
WECC-SW	4,848	1,091	23%	9,288	4,293	46%	1,316	845	64%	4,187	3,982	95%
EASTERN INTERCONNECTION	91,773	15,822	17%	67,138	37,886	56%	28,294	21,794	77%	4,752	4,413	93%
QUÉBEC INTERCONNECTION	4,024	885	22%	10	-	0%	444	444	100%	-	-	0%
TEXAS INTERCONNECTION	40,102	9,396	23%	31,473	22,962	73%	572	439	77%	15,291	12,190	80%
WECC INTERCONNECTION	39,182	8,670	22%	43,393	25,322	58%	72,649	42,613	59%	16,269	15,695	96%
All INTERCONNECTIONS	**175,081**	**34,774**	**20%**	**142,014**	**86,170**	**61%**	**101,959**	**65,290**	**64%**	**36,311**	**32,298**	**89%**

Review of 2024 Capacity and Energy Performance

The summer of 2024 was the fourth hottest on record for both the contiguous United States[18] and Canada,[19] with some areas experiencing their hottest summer ever. The result was record electricity demand in the United States as well as in Canada, which was particularly pronounced in the Western Interconnection. While peak demand exceeded normal summer forecasts in most areas, only one area experienced demand that met or exceeded a 90/10 demand scenario as defined in the prior year's *SRA*. In addition, Hurricane Helene, the deadliest Atlantic hurricane to strike the US mainland since 2005, made landfall in Florida in September and led to widespread flooding and power outages from Florida to North Carolina. Helene was one of five hurricanes to impact the US last summer, joining other extreme weather incidents such as drought across the West and wildfires in the Southwest. To manage the challenging grid conditions brought about by heat domes and these other extreme weather events, grid operators across North America used various operating mitigations up to, and including, the issuance of EEAs. No disruptions to the BPS occurred due to inadequate resources. The following section describes actual demand and resource levels in comparison with NERC's *2024 SRA* and summarizes 2024 resource adequacy events.

Eastern Interconnection–Canada and Québec Interconnection

During the June heat wave that extended across the eastern half of the United States and Canada, system operators in Ontario and the Maritimes provinces followed conservative operating protocols and issued energy emergencies. A late-summer heat wave resulted in an energy emergency in Maritimes.

Eastern Interconnection–United States

MISO experienced peak electricity demand during late August. Demand was between the normal and 90/10 summer peak forecast levels. Wind and solar resource output at the time of peak demand were near expectations for summer on-peak contributions. Forced outages of thermal units, however, were lower than expected. On the day prior to MISO's peak demand, operators issued advisories to maximize generation. Similar advisories were issued earlier in the summer, coinciding with above-normal temperatures and periods of high generator forced outages.

In SPP, summer electricity demand peaked in mid-July at a level below normal 50/50 forecasts. Above-normal wind performance and sufficient generator availability contributed to sufficient electricity supplies during peak conditions. In late August, however, SPP operators issued an EEA1 due to high load forecasts, generator outages, and forecasts for low wind output. The period coincided with MISO's peak demand period, making excess supplies for import uncertain. Also in August during a period of high demand and low resource availability, operators issued public appeals for conservation when a 345 kV line outage caused a transmission emergency. During other summer periods, SPP operators responded to forecasts for high demand and low resource conditions with resource advisories intended to maximize available generators.

Like SPP, PJM also experienced peak electricity demand in mid-July and issued an EEA in August. Peak demand in July was near 90/10 forecast levels. Generator outages were below normal at the time of peak demand. In late August, PJM operators issued an EEA1 in expectation of extreme demand.

A period of unseasonably high demand in early summer brought on by high temperatures in the Northeast contributed to an EEA1 in NPCC-New England when a large thermal generator encountered a forced outage. Peak demand in New England occurred in mid-July at a near-normal summer peak demand level. At the time of peak demand, generator outages were below historical averages.

Peak demand in the NPCC-New York area occurred in early July at a level below the normal summer peak demand forecast. Generator outages were below historical levels for peak summer conditions.

[18] US sweltered through its 4th-hottest summer on record – National Oceanic and Atmospheric Administration
[19] Climate Trends and Variations Bulletin – Summer 2024 – Government of Canada

Systems in the U.S. Southeast saw successive heat waves beginning prior to the official start to summer and extending to early fall. Operators in the SERC region used conservative operations and resource advisories to maximize generation and transmission network availability and issued EEAs when warranted by conditions. In some instances, EEAs were issued when generator outages threatened supplies needed for high demand. Peak demand in all assessment areas within the SERC region exceeded normal summer peak demand levels and approached 90/10 demand forecasts.

Texas Interconnection–ERCOT

Peak demand in ERCOT was at or near record levels last summer, as load growth and extreme temperatures contributed to escalating summer electricity needs. Demand peaked in August well above the 90/10 demand forecast. At the time of peak demand, wind generation was below expected levels for peak demand periods, while output from solar generation was near forecasted levels. Forced generator outages were well below historical average levels for peak demand, helping to meet the extreme electricity demand. Unlike the prior summer, ERCOT did not issue any conservation appeals to customers to reduce demand during high-demand periods. New solar generation, battery resources, and some thermal generation additions since Summer 2023 boosted electricity supplies, enabling operators to meet demand records without demand-side management.

Western Interconnection

In July, the Western Interconnection set a new peak demand record of 167,988 MW. Operators in United States and Canada employed procedures throughout summer to manage challenging grid conditions from extended extreme heat and wildfires.

Western Interconnection–Canada

In the province of Alberta, the electric system operator issued an EEA3 in early July as high temperatures contributed to elevated demand that coincided with a forced generator outage. A new summer peak demand record was set in Alberta later in July at 12.2 MW (up from 11.5 GW in summer 2023). Alberta’s demand peak was slightly higher than the normal demand peak scenario projected in the spring of last year.

In British Columbia, peak demand reached 9.4 GW (up from 9.2 GW the previous year), also slightly above the normal peak demand that was projected last year.

In both Alberta and British Columbia, peak demand was still below the extreme peak demand scenarios previously projected, which lowered the risk profile of those provinces over Summer 2024.

Western Interconnection–United States

Demand peaked in July in the U.S. Northwest at a level below the normal summer peak demand. During a period of high demand in July, operators at a BA in the U.S. Northwest issued an EEA1 to address forecasted conditions.

The California-Mexico assessment area, which consists of the CAISO, Northern California, and CENACE BAs, experienced system peak electricity demand in early September at a level nearing the 90/10 peak demand forecast. The extreme demand contributed to localized supply concerns and led CAISO to declare a transmission emergency and use conservative operations protocols to posture the system. Despite the extreme demand, operators were able to maintain sufficient supply without resorting to public appeals, as was required in prior summers. New battery resources were instrumental in providing energy to meet high demand during late afternoon and early evenings. Natural-gas-fired generators also performed well and were important to meeting high demand during these same periods. Dry conditions from early summer prompted operators in CA/MX to frequently employ public safety power shutoff (PSPS) procedures beginning in June. Active wildfires led transmission operators to de-energize transmission lines in Northern California and declare transmission emergencies that affected operations across CAISO.

The U.S. Southwest experienced extended heat conditions and demand levels that exceeded 90/10 peak summer forecasts, with peak occurring in early August. Higher-than-expected wind and solar output and low generator outages helped maintain sufficient supplies.

2024 Summer Demand and Generation Summary at Peak Demand							
Assessment Area	Actual Peak Demand[1] (GW)	SRA Peak Demand Scenarios[2] (GW)	Wind – Actual[1] (MW)	Wind – Expected[3] (MW)	Solar – Actual[1] (MW)	Solar – Expected[3] (MW)	Forced Outages Summary[4] (MW)
MISO	118.6	116.1 125.8	4,565	5,599	5,858	4,981	4,412
MRO-Manitoba Hydro	3.6	3.1 3.3	50	48	0	0	290
MRO-SaskPower	3.7	3.5 3.7	170	208	22	6	0
MRO-SPP	54.3	55.3 57.5	10,869	5,876	442	486	6,046
NPCC-Maritimes	3.5	3.3 3.6	428	262	21	-	777
NPCC-New England	24.3	24.6 26.5	174	122	167	1,111	1,496
NPCC-New York	29	30.3 32	130	340	0	53	1,451
NPCC-Ontario	23.9	21.8 23.7	915	720	260	66	1,174
NPCC-Québec	23	22.9 24	2,270	-	0	-	10,500*
PJM	153.1	143.5 156.9	3,366	1,703	2,709	5,694	6,402
SERC-C	42.3	40.7 43.9	312	172	813	996	959
SERC-E	44	42.6 44.7	0	-	3,009	2,405	1,878
SERC-FP	52.4	50.5 53.6	0	-	5,376	5,643	
SERC-SE	44.9	44.4 45.3	0	-	3,507	7,217	1,007
TRE-ERCOT	85.5	81.3 82.3	6,286	9,070	17,566	17,797	3,622
WECC-AB	12.2	12.2 12.7	1,091	666	1,114	786	-**
WECC-BC	9.4	9.3 9.8	257	140	0.94	0	-**

2024 Summer Demand and Generation Summary at Peak Demand							
Assessment Area	**Actual Peak Demand[1] (GW)**	**SRA Peak Demand Scenarios[2] (GW)**	**Wind – Actual[1] (MW)**	**Wind – Expected[3] (MW)**	**Solar – Actual[1] (MW)**	**Solar – Expected[3] (MW)**	**Forced Outages Summary[4] (MW)**
WECC-CA/MX	58.9	53.2 61.6	1,633	1,124	10,112	13,147	921
WECC-NW	59.7	63 69.7	4,694	2,964	6,339	2,595	3,655
WECC-SW	30.8	26.4 28.8	1,179	542	3,357	1,294	2,042
Highlighting Notes	Actual peak demand in the highlighted areas met or exceeded extreme scenario levels.		Actual wind output in highlighted areas was significantly below seasonal forecast.		Actual solar output in highlighted areas was significantly below seasonal forecast.		Actual forced outages above or below forecast by factor of two

Table Notes:

[1] Actual demand, wind, and solar values for the hour of peak demand in U.S. areas were obtained from EIA From 930 data. For areas in Canada, this data was provided to NERC by system operators and utilities.

[2] See NERC *2024 SRA* demand scenarios for each assessment area (pp. 14–33). Values represent the normal summer peak demand forecast and an extreme peak demand forecast that represents a 90/10, or once-per-decade, peak demand. Some areas use other basis for extreme peak demand.

[3] Expected values of wind and solar resources from the *2024 SRA*.

[4] Values from NERC Generator Availability Data System for the 2024 summer hour of peak demand in each assessment area. Highlighted areas had actual forced outages that were more than twice the value for typical forced outage rates used in the 2024 summer risk period scenarios in the *2024 SRA*.

*Values include both maintenance and forced outages.

**Canadian assessment areas report to the NERC Generator Availability Data System on a voluntary basis, which can contribute to the absence of some values in certain assessment areas.

Planning Resource Auction

Results for Planning Year 2025-26

April 2025

CORRECTIONS

Reposted 05/29/25

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

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

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

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

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

In the 2025 PRA, the RBDC…

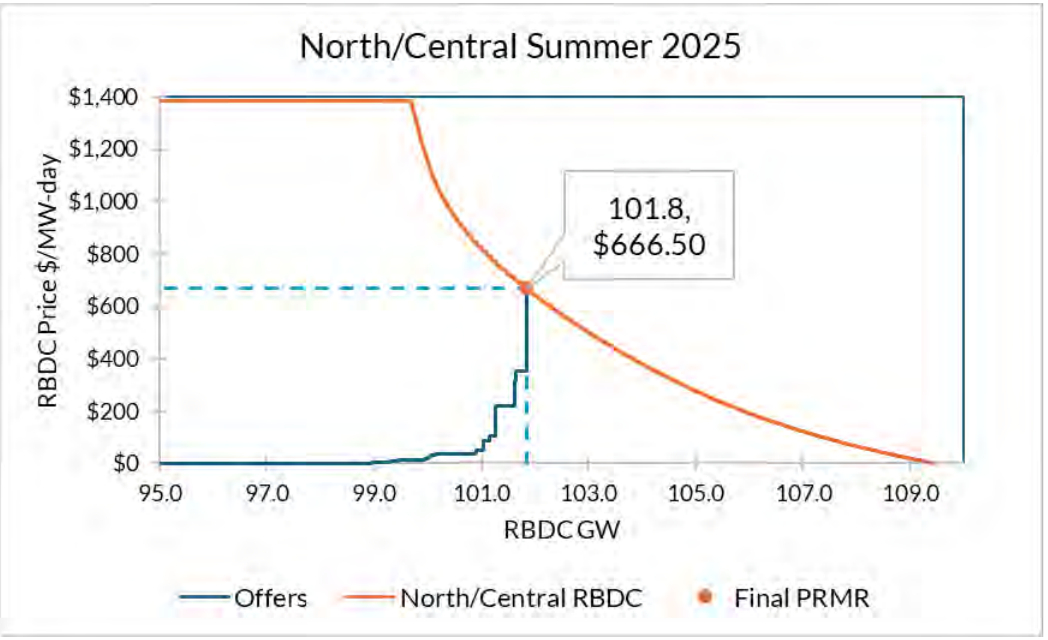
- Delivers competitive prices aligned with seasonal risks and tightening surplus
  - Prioritizes summer availability, the system's highest-risk season (based on 1-in-10 LOLE)
- Values incremental capacity above and below the LOLE target based on its reliability
  - Clears capacity above target Planning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

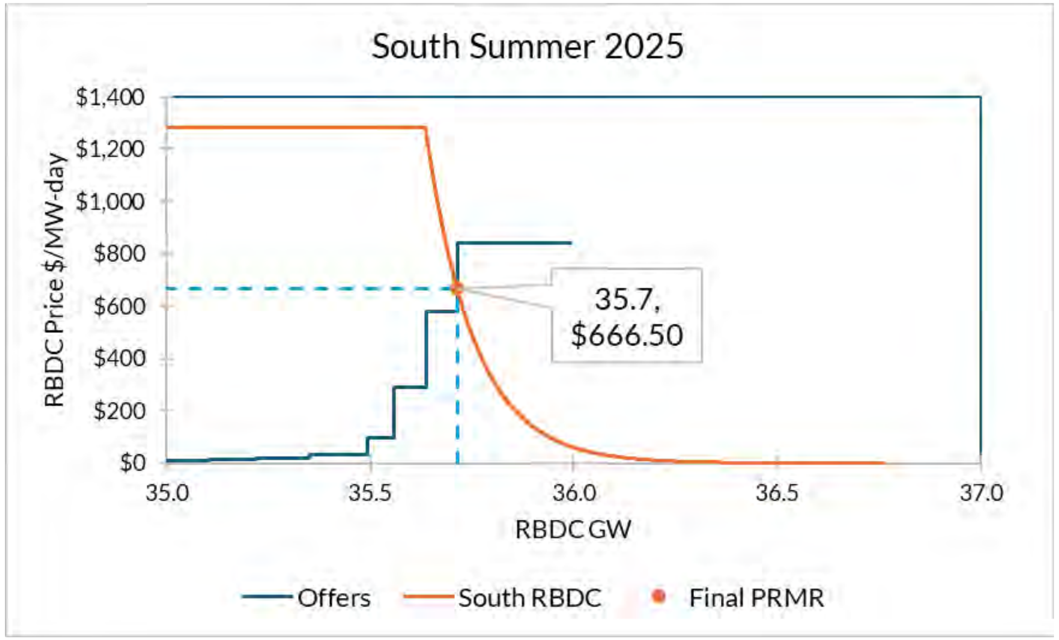
Why it Matters

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

LOLE: Loss of Load Expectation

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





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

LOLE: Loss of Load Expectation

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

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

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

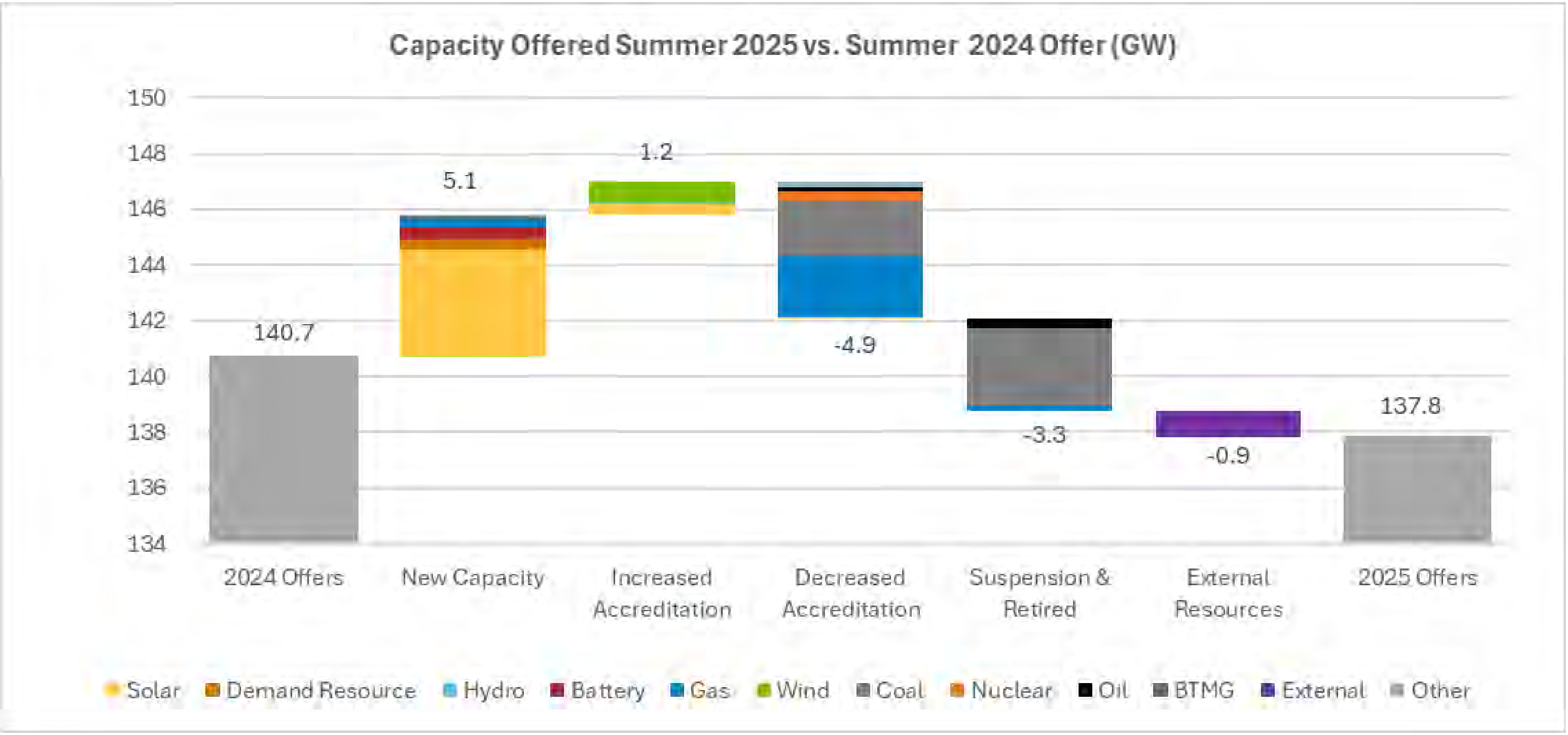
Annualized
$217 (North/Central)
$212 (South)

PRM: Planning Reserve Margin

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

MISO

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



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

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

Ongoing Challenges

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

Completed Initiatives

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

Initiatives In Progress

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

Next Steps

April 28

2025 PRA Results Posted

May 21

Zonal deliverability benefits available at the May RASC

—

MISO publishes cleared Load Modifying Resources to Operations tools

May 28

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

June 1

2025 PRA prices go into affect

—

New Planning Year starts

Appendix

Table of Contents

Acronyms

ACP: Auction Clearing Price

ARC: Aggregator of Retail Customers

BTMG: Behind the Meter Generator

CIL: Capacity Import Limit

CEL: Capacity Export Limit

CONE: Cost of New Entry

CPF: Coincident Peak Forecast

DLOL: Direct Loss-of-Load

DR: Demand Resource

ELCC: Effective Load Carrying Capability

EE: Energy Efficiency

ER: External Resource

ERAS: Expedited Resource Addition Study

ERZ: External Resource Zones

FRAP: Fixed Resource Adequacy Plan

ICAP: Installed Capacity

IMM: Independent Market Monitor

LBA: Load Balancing Authority

LCR: Local Clearing Requirement

LOLE: Loss of Load Expectation

LMR: Load Modifying Resource

LRR: Local Reliability Requirement

LRZ: Local Resource Zone

LSE: Load Serving Entity

OMS: Organization of MISO States

PO: Planned Outage

PRA: Planning Resource Auction

PRM: Planning Reserve Margin

PRMR: Planning Reserve Margin Requirement

RASC: Resource Adequacy Sub-Committee

RBDC: Reliability-Based Demand Curve

SAC: Seasonal Accredited Capacity

SREC: Sub-Regional Export Constraint

SRIC: Sub-Regional Import Constraint

SRPBC: Sub-Regional Power Balance Constraint

SS: Self Schedule

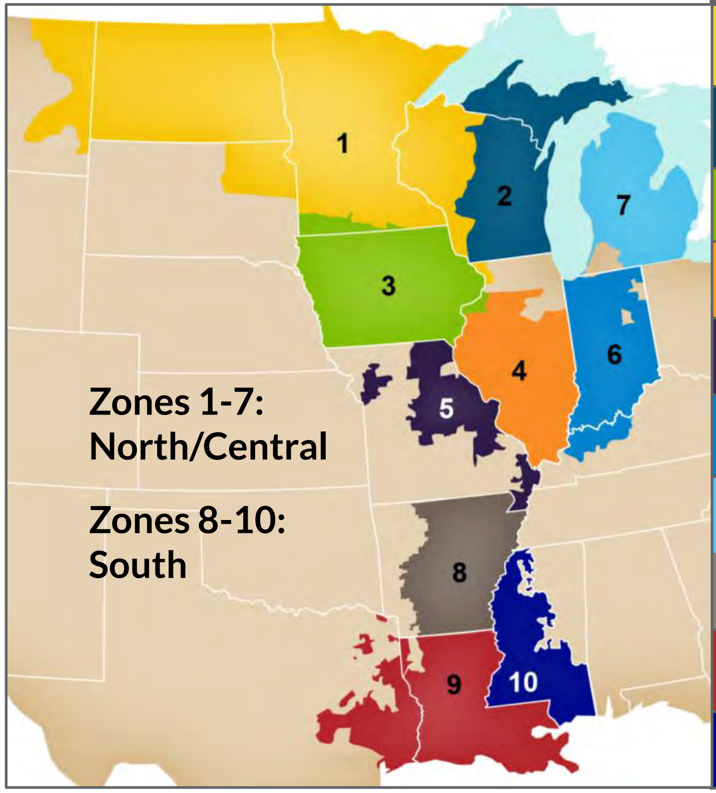
UCAP: Unforced Capacity

ZIA: Zonal Import Ability

ZRC: Zonal Resource Credit

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

MISO Resource Adequacy Zones



2025 PRA Results

<table>
<tr><th rowspan="2"></th><th colspan="4">Price/MW-Day</th></tr>
<tr><th>Summer</th><th>Fall</th><th>Winter</th><th>Spring</th></tr>
<tr><td>1</td><td rowspan="10">$666.50</td><td rowspan="7">$91.60</td><td rowspan="10">$33.20</td><td rowspan="10">$69.88</td></tr>
<tr><td>2</td></tr>
<tr><td>3</td></tr>
<tr><td>4</td></tr>
<tr><td>5</td></tr>
<tr><td>6</td></tr>
<tr><td>7</td></tr>
<tr><td>8</td><td rowspan="3">$74.09</td></tr>
<tr><td>9</td></tr>
<tr><td>10</td></tr>
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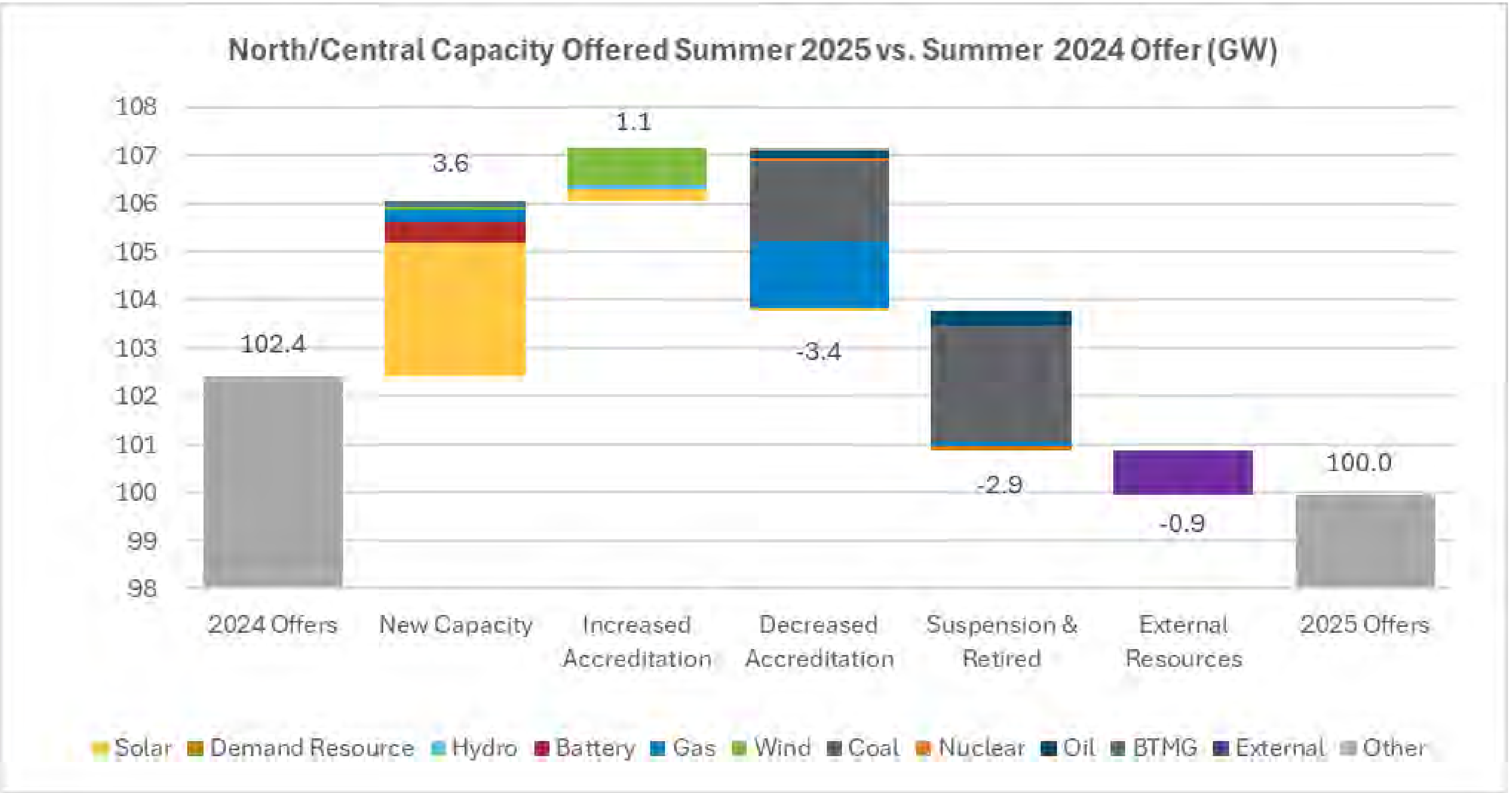
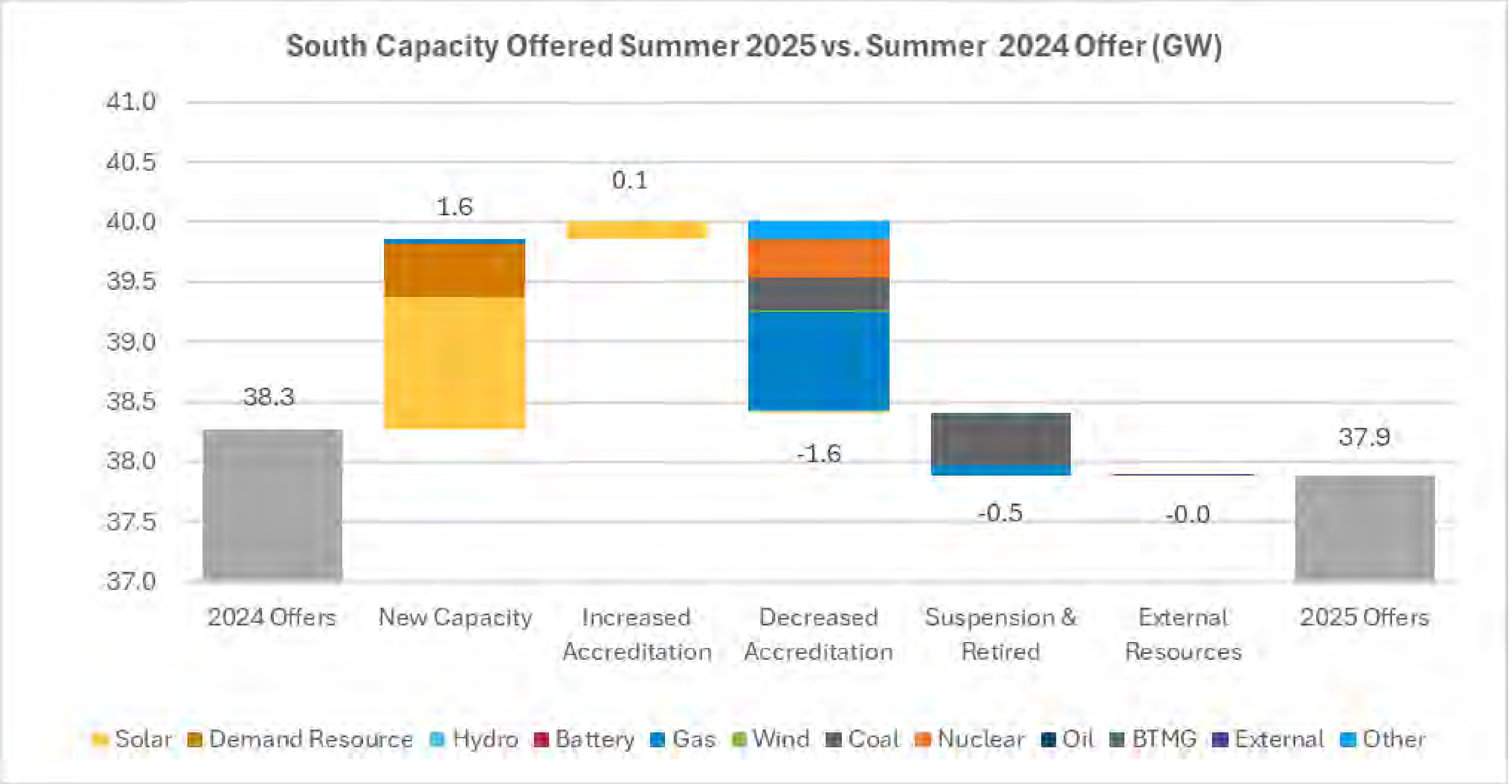
Annualized
$217 (North/Central)
$212 (South)

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



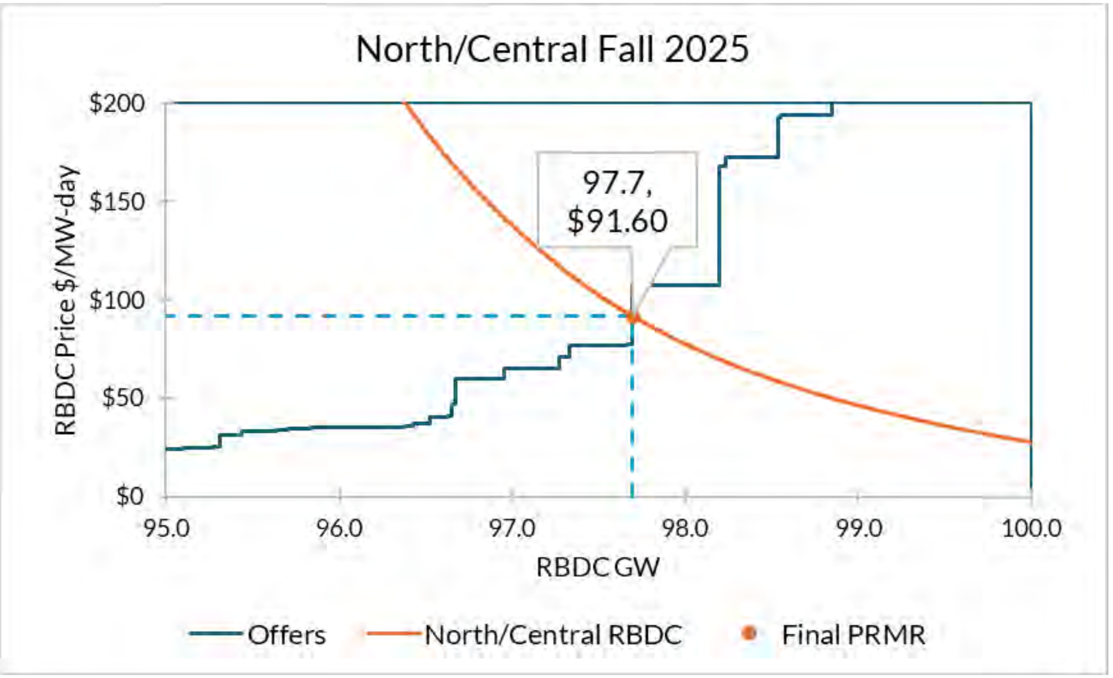
BTMG: Behind the Meter Generation | Capacity indicated is offered accredited value

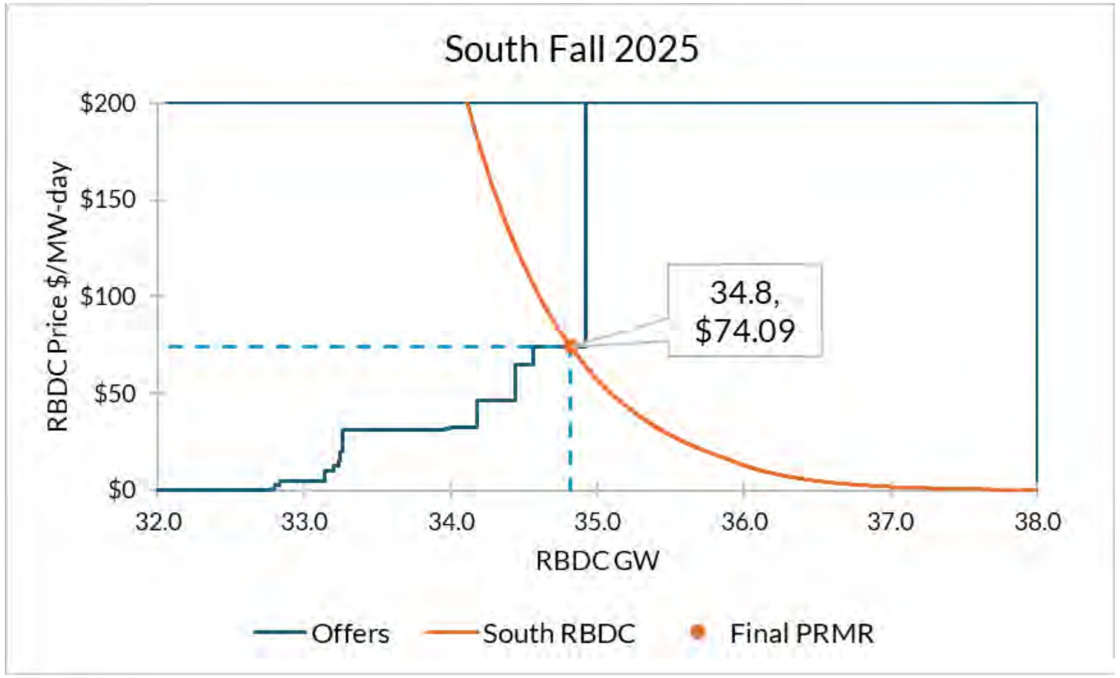
For the South, new capacity additions nearly offset the negative impacts of decreased accreditation, suspensions/retirements



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

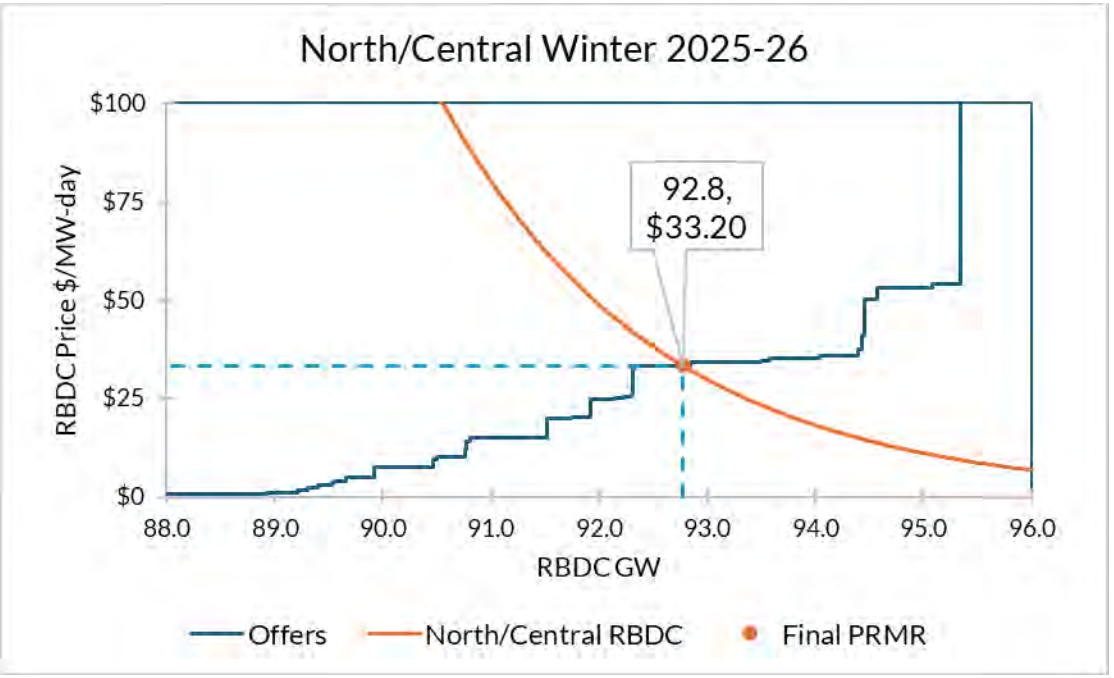
Fall 2025 Reliability-Based Demand Curve, Offer Curves and Auction Clearing Prices

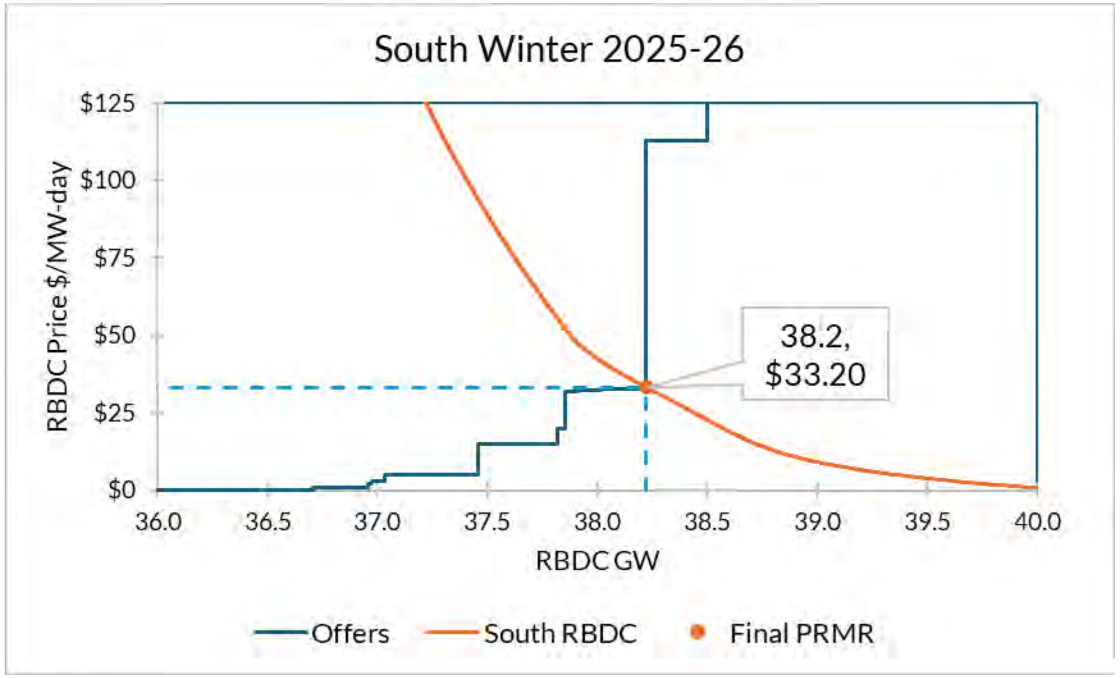




- Subregional RBDCs are determining clearing for both subregions
- Subregional Power Balance Constraint (SRPBC), South to North, is binding resulting in price separation between North/Central and South subregions in Fall season
  - ACP for North subregion is $91.60, and $74.09 South subregion
  - A marginal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

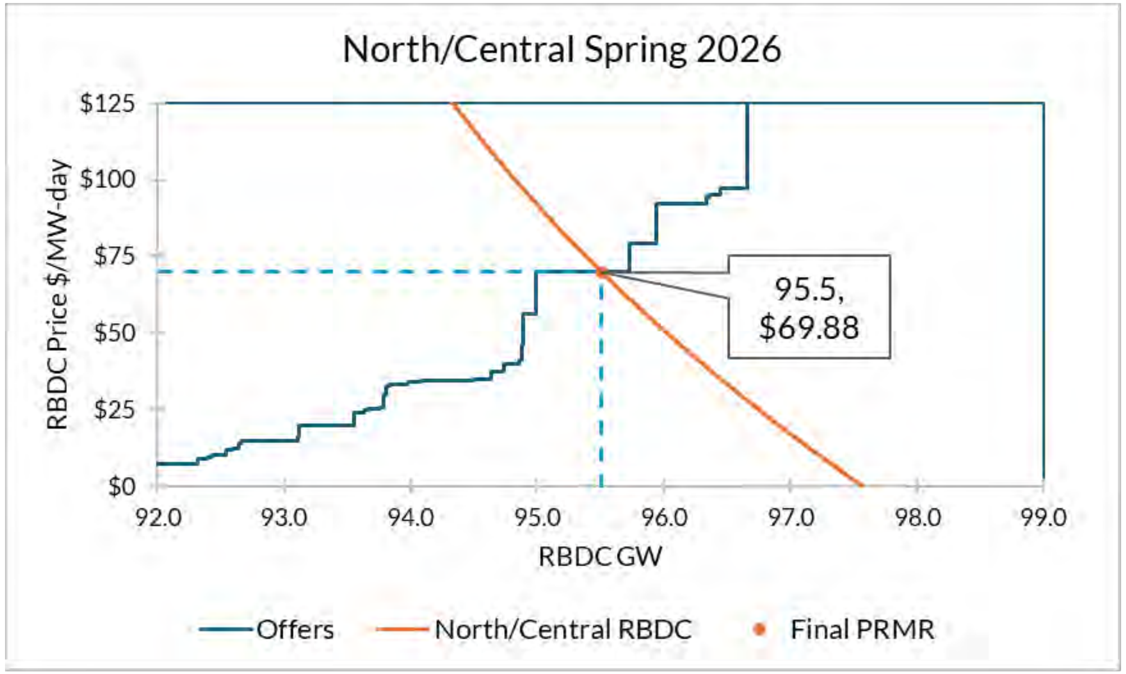
Winter 2025/26 Reliability-Based Demand Curve, Offer Curves and Auction Clearing Prices

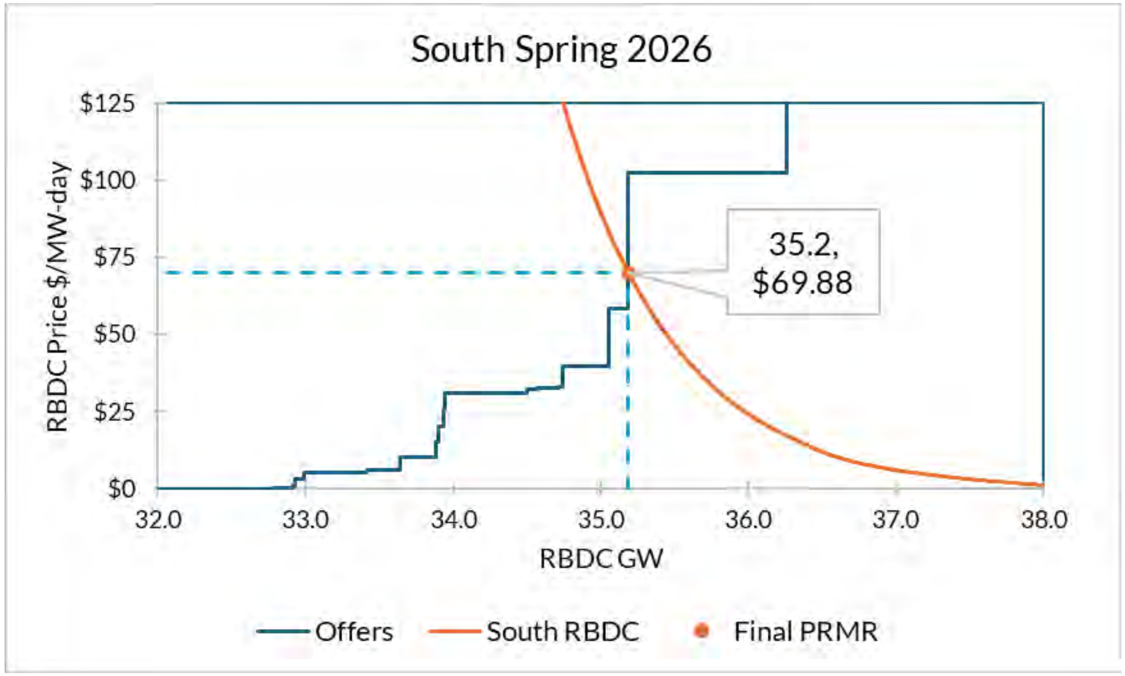




- Subregional RBDCs are determining clearing for both subregions
- No price separation between North/Central and South subregions in winter
  - ACP for both subregions is $33.20
  - Multiple marginal resources, cleared *pro rata*, sets the price
- In winter, “effective” margin for North/Central subregion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

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





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

Summer 2025 PRA Results by Zone

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

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

Fall 2025 PRA Results by Zone

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

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

Winter 2025/26 PRA Results by Zone

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

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

Spring 2026 PRA Results by Zone

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

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

Summer Supply Offered and Cleared Comparison Trend

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

ZRC: Zonal Resource Credit

Fall Supply Offered and Cleared Comparison Trend

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

ZRC: Zonal Resource Credit

Winter Supply Offered and Cleared Comparison Trend

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

ZRC: Zonal Resource Credit

Spring Supply Offered and Cleared Comparison Trend

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

ZRC: Zonal Resource Credit

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

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

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

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

ERZ: External Resource Zones

Historical Summer Auction Clearing Price Comparison

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

- Auction Clearing Prices shown in $/MW-Day

ERZ: External Resource Zones

Fall Auction Clearing Price Comparison

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

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

ERZ: External Resource Zones

Winter Auction Clearing Price Comparison

PY	Zone 1	Zone 2	Zone 3	Zone 4	Zone 5	Zone 6	Zone 7	Zone 8	Zone 9	Zone 10	ERZs
Winter 2023-24	$2.00								$18.88	$2.00	
Winter 2024-25	$0.75										
Winter 2025-26	$33.20										

- Auction Clearing Prices shown in $/MW-Day

ERZ: External Resource Zones

Spring Auction Clearing Price Comparison

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

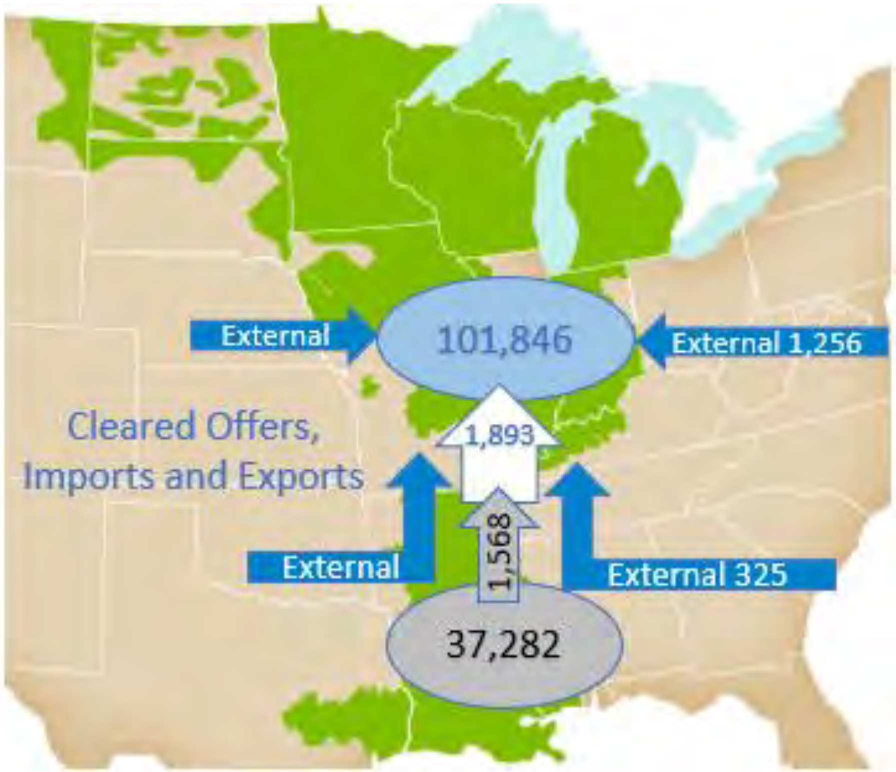
- Auction Clearing Prices shown in $/MW-Day

ERZ: External Resource Zones

Summer 2025 Capacity

Offered Capacity & Final PRMR (MW)

Cleared Capacity, Imports & Exports (MW)



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

Fall 2025 Capacity

Offered Capacity & Final PRMR (MW)

Cleared Capacity, Imports & Exports (MW)

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

Winter 2025/26 Capacity

Offered Capacity & Final PRMR (MW)

Cleared Capacity, Imports & Exports (MW)

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

Spring 2026 Capacity

Offered Capacity & Final PRMR (MW)

Cleared Capacity, Imports & Exports (MW)

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

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

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

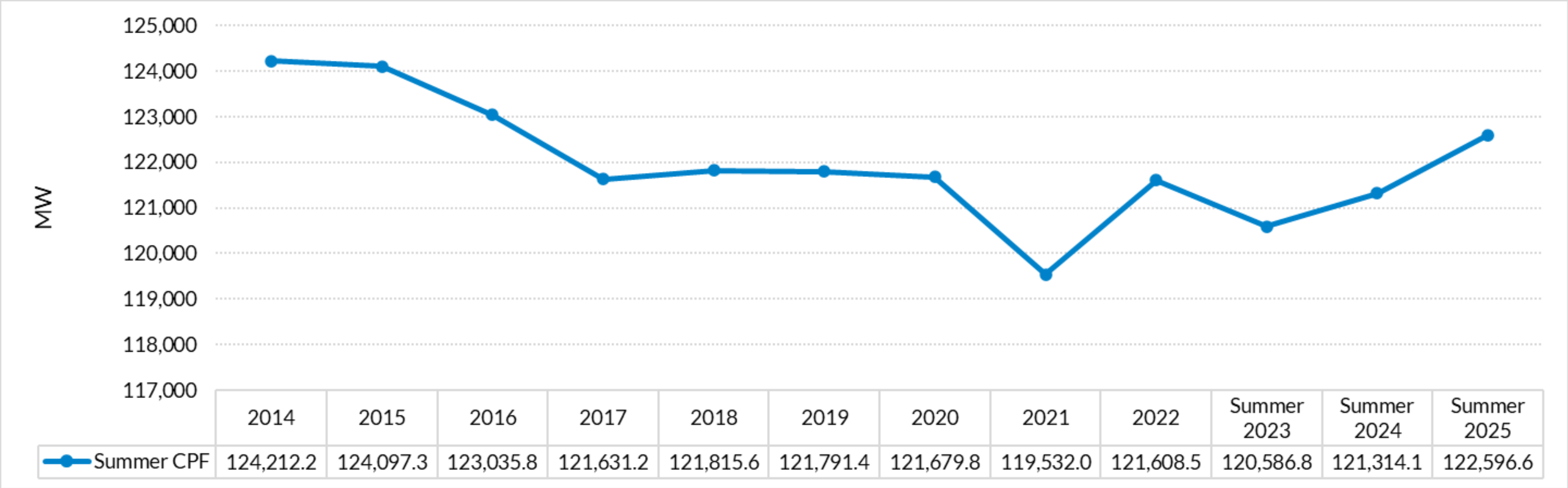
- Resource offers in the auction were comparable to "High Certainty" values projected in the OMS-MISO Survey
- Incremental accreditation reductions in the auction were offset by incremental increases in new resource additions
- Notably, initial PRMR was lower (5.5 GW) than projected in the OMS-MISO Survey

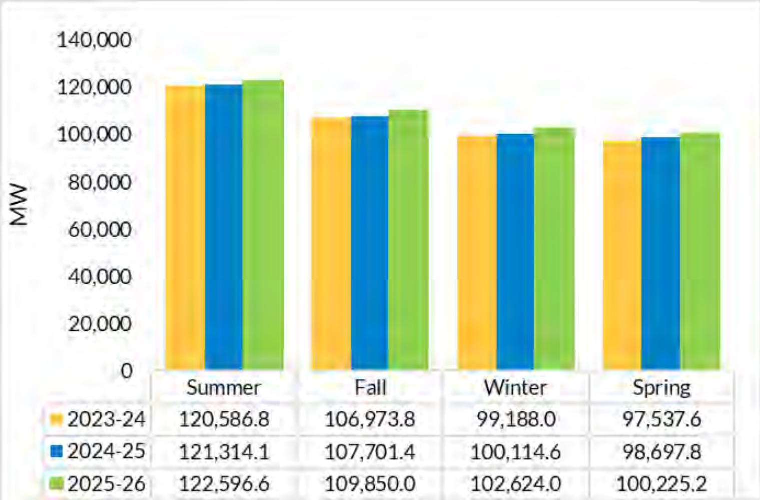
2024 OMS-MISO Survey Projection vs. 2025 PRA Actual PRMR Surplus (MW)

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

Coincident Peak Forecast

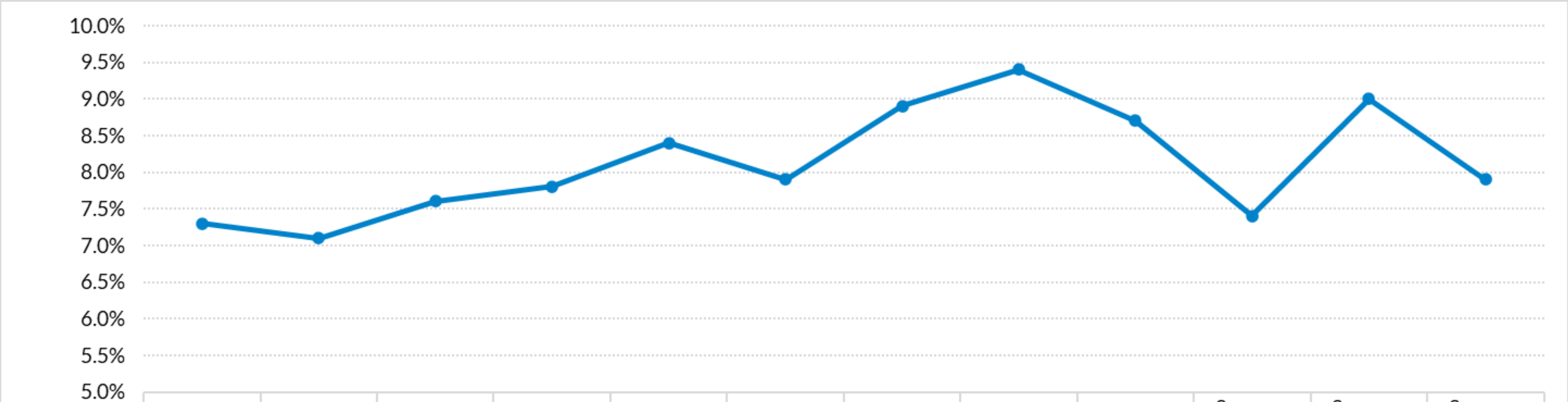
Year over year the Summer CPF (+1.3 GW), PRM (-1.1%) and Final PRMR (+1.5 GW) are higher.



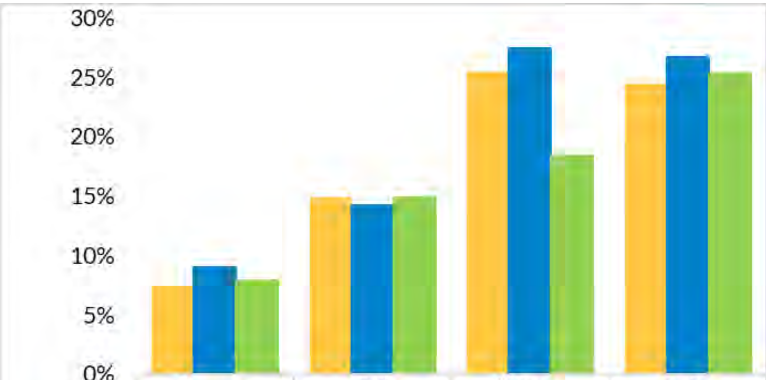


PRMR: Planning Reserve Margin Requirement

Planning Reserve Margin (%)

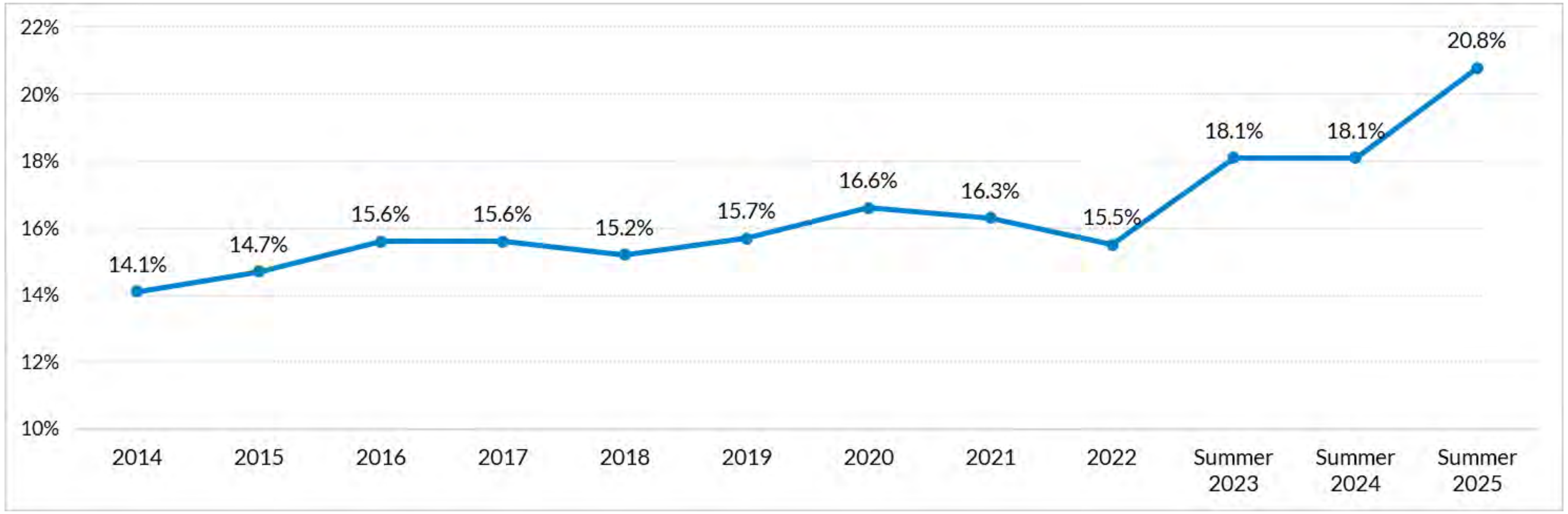


	2014	2015	2016	2017	2018	2019	2020	2021	2022	Summer 2023	Summer 2024	Summer 2025
PRM	7.3%	7.1%	7.6%	7.8%	8.4%	7.9%	8.9%	9.4%	8.7%	7.4%	9.0%	7.9%



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

Wind Effective Load Carrying Capacity (%)

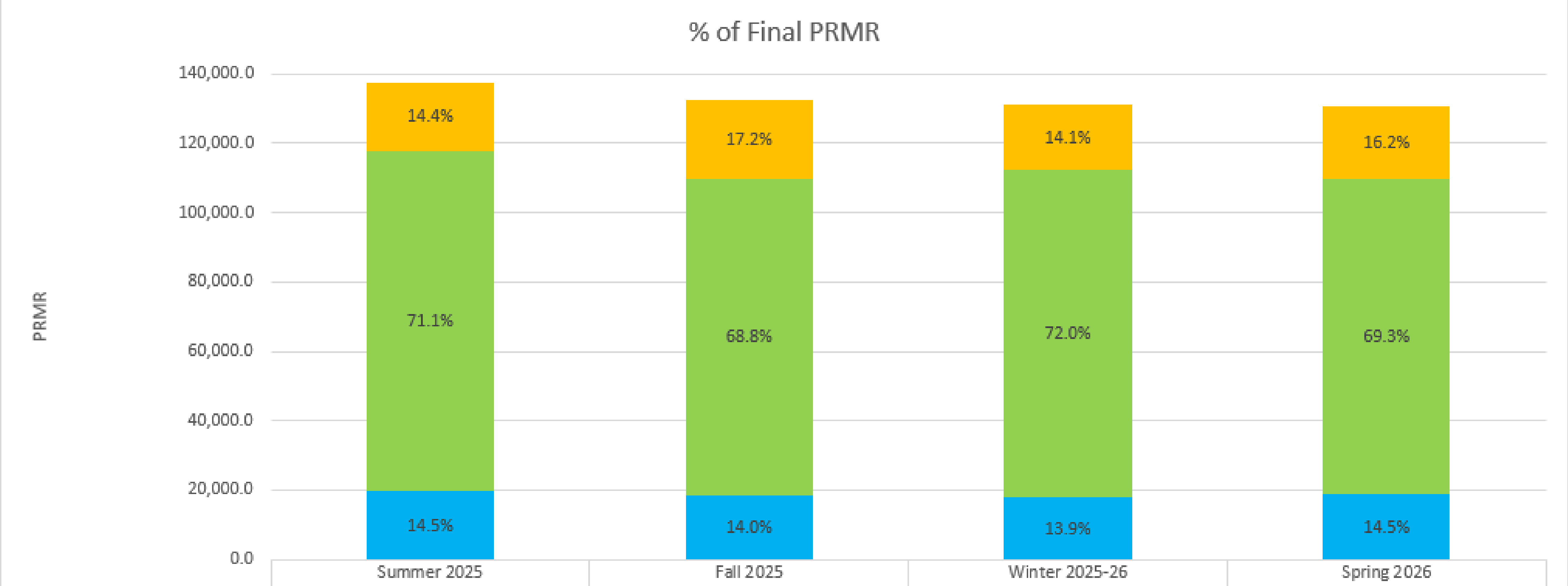


	Summer	Fall	Winter	Spring
2023-24	18.1%	23.1%	40.3%	23.0%
2024-25	18.1%	15.6%	53.1%	18.0%
2025-26	20.8%	30.7%	29.0%	25.3%

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

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

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

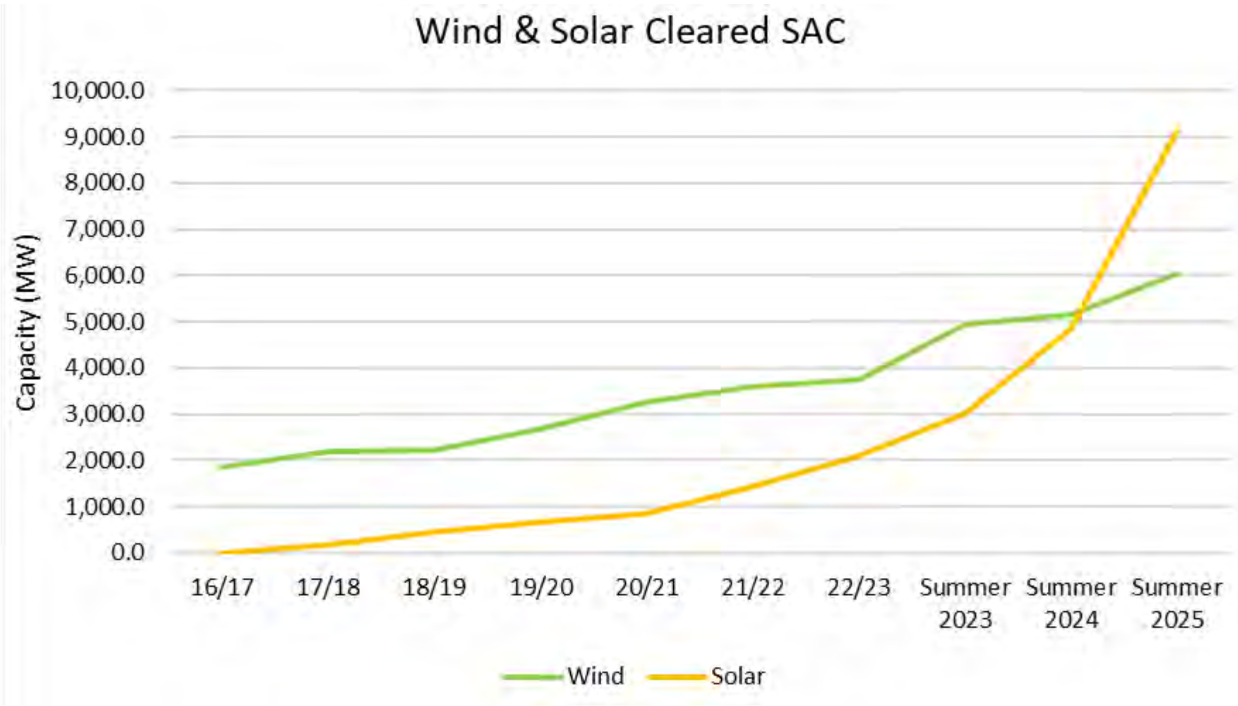


	Summer 2025	Fall 2025	Winter 2025-26	Spring 2026
Cleared Non-Self Scheduled	19,800.6	22,768.8	18,510.0	21,151.5
Self Scheduled	97,811.7	91,206.8	94,316.0	90,582.4
FRAP	19,947.0	18,540.2	18,173.5	18,965.6

PRMR: Planning Reserve Margin Requirement

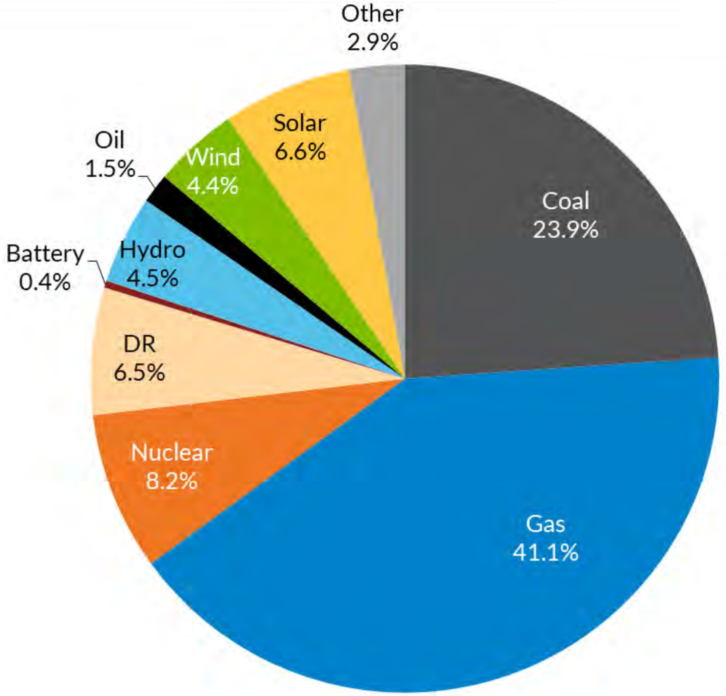
Although conventional generation still comprises most of the capacity, wind and solar continue to grow

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



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

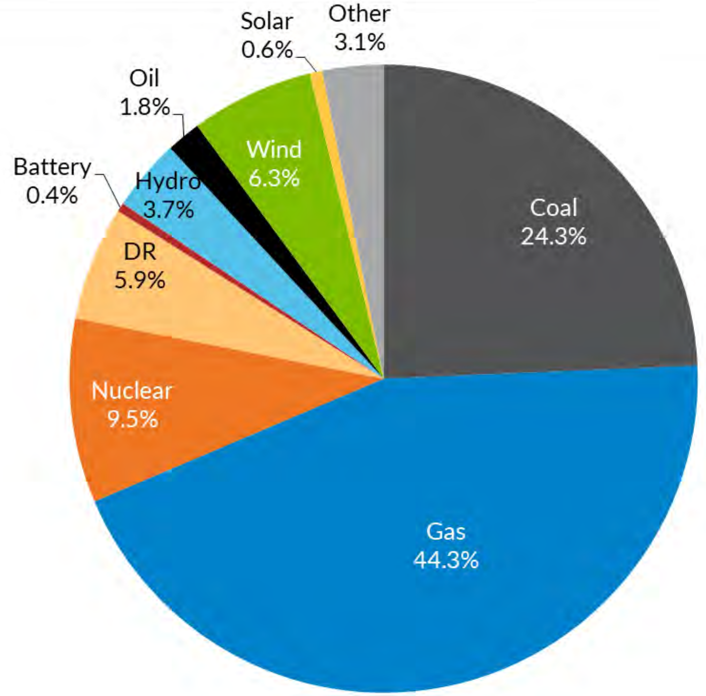
Summer 2025



MISO-wide

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

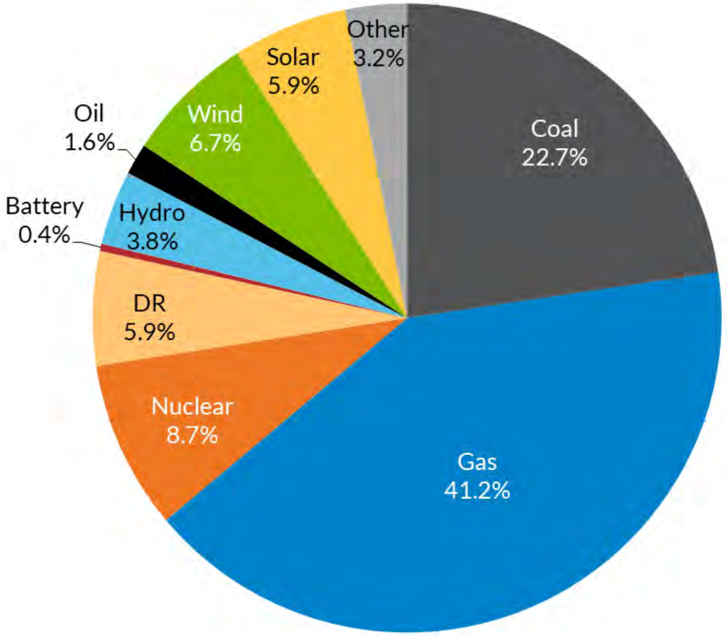
Winter 2025/26



PRMR: Planning Reserve Margin Requirement

Fall 2025 and Spring 2026 - Cleared ZRCs and Final PRMR

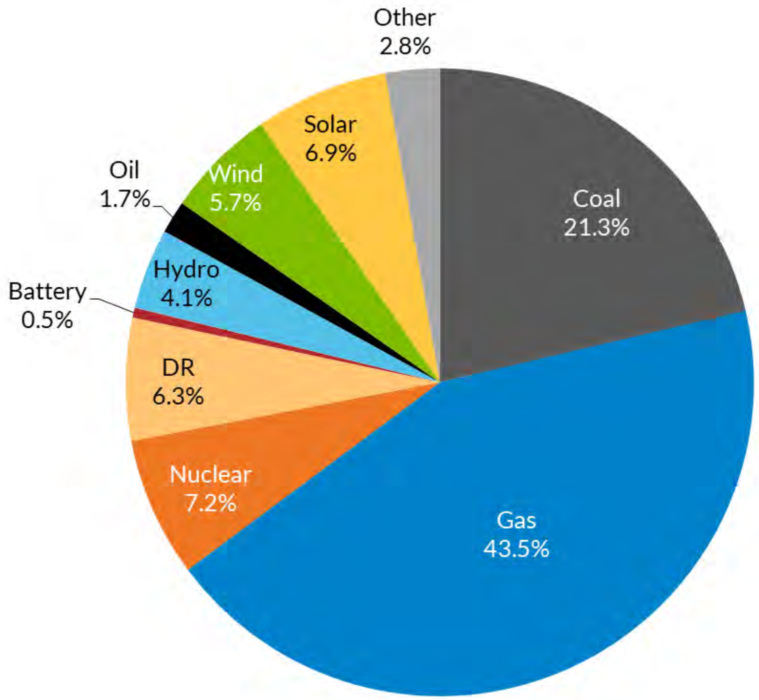
Fall 2025



MISO-Wide

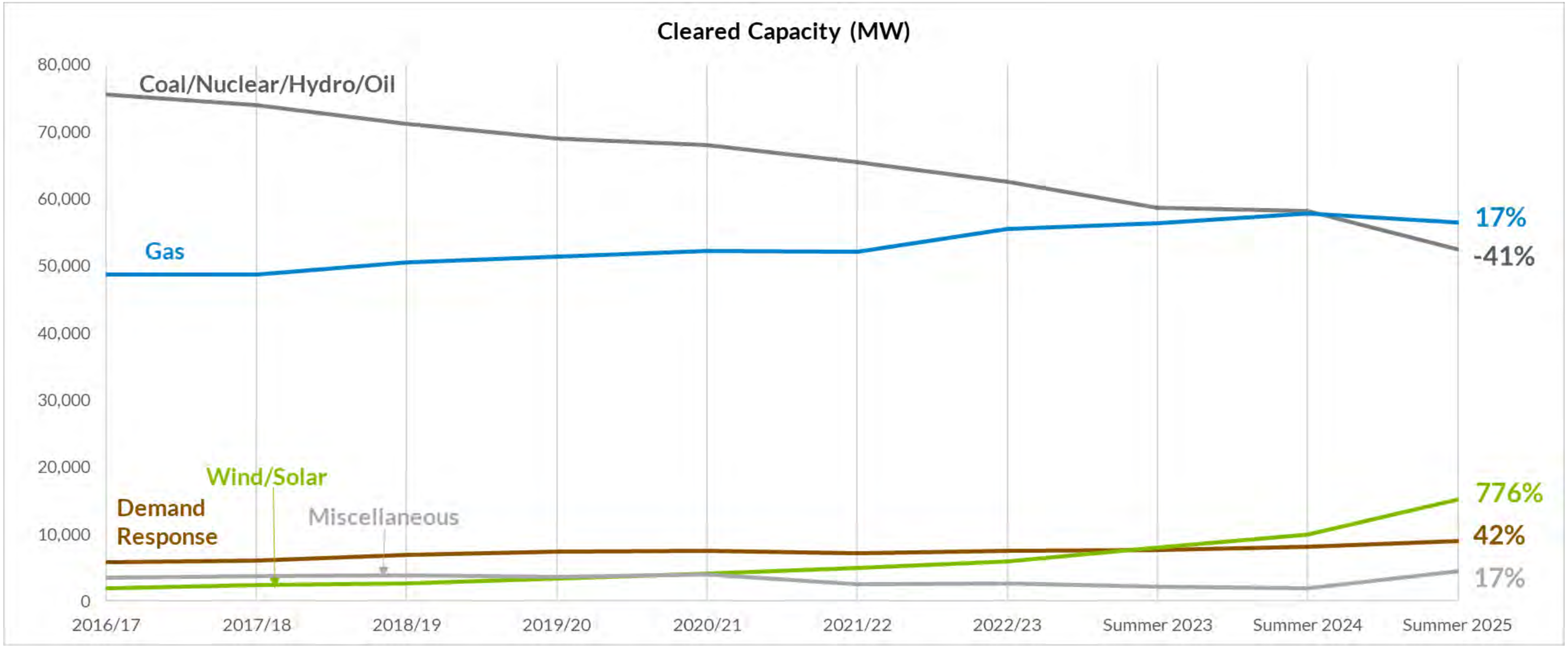
Cleared ZRC	Fall 2025	Spring 2026
Coal	30,038.9	27,886.8
Gas	54,636.4	56,820.7
Nuclear	11,482.1	9,405.4
DR	7,767.8	8,240.5
Battery	497.9	663.3
EE	28.1	30.5
Hydro	5,047.4	5,415.8
Oil	2,123.8	2,190.4
Wind	8,864.8	7,438.0
Solar	7,843.8	8,975.1
Misc	4,184.8	3,633.0
PRMR	132,515.8	130,699.5

Spring 2026

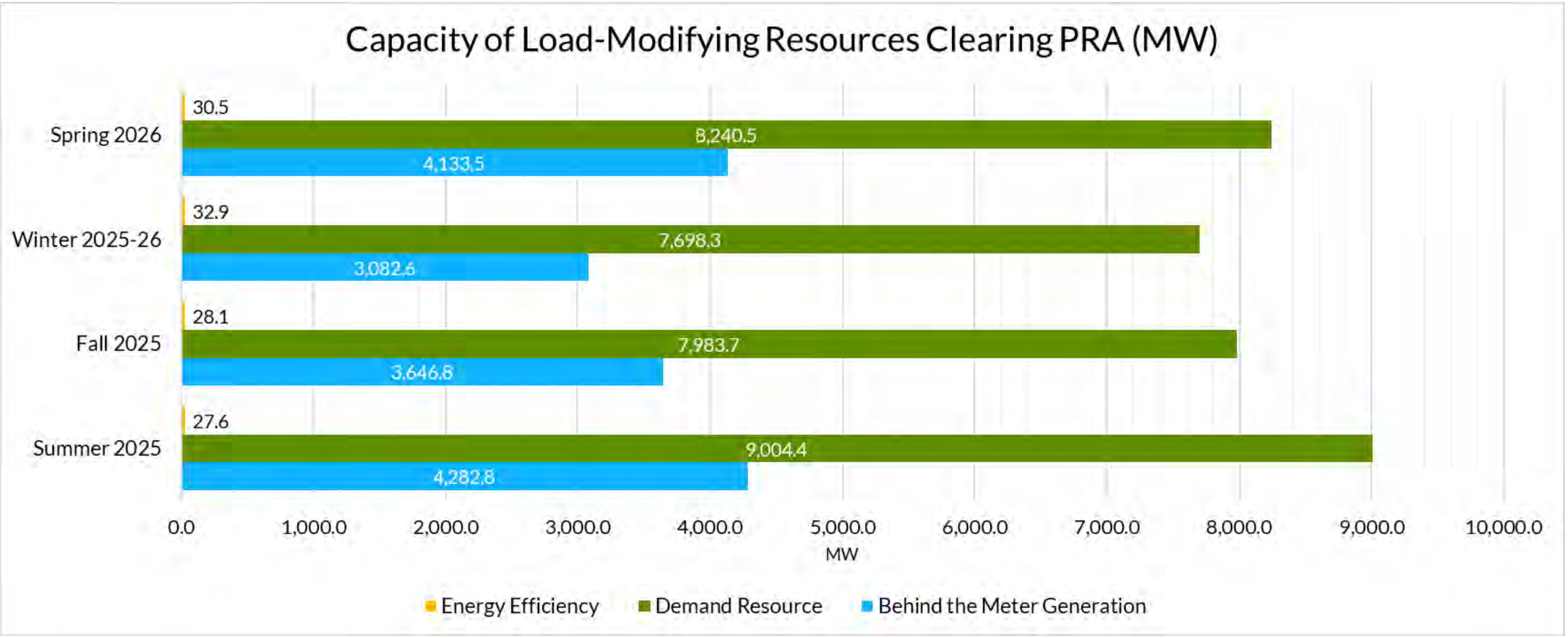


PRMR: Planning Reserve Margin Requirement

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



2025/26 Seasonally Cleared Load Modifying Resources Comparison



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

MISO’s Planning Resource Auction indicates sufficient resources

Improved pricing signal more accurately highlights reliability risk

For Immediate Release

April 28, 2025

Media Contact

Brandon Morris

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

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

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

The seasonal Auction Clearing Prices are:

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

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

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

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

##

MEDIA CONTACT:
Brandon D. Morris

About MISO

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

News Release Link

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:

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

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

1.2.1 Perform an analysis for Year One.

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

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

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

1.3.1 Load forecast characteristics:

1.3.1.1 Median (50:50) forecast peak Load.

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

1.3.1.3 Load diversity.

1.3.1.4 Seasonal Load variations.

1.3.1.5 Daily demand modeling assumptions (firm, interruptible).

1.3.1.6 Contractual arrangements concerning curtailable/Interruptible Demand.

1.3.2 Resource characteristics:

1.3.2.1 Historic resource performance and any projected changes

1.3.2.2 Seasonal resource ratings

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

1.3.2.4 Resource planned outage schedules, deratings, and retirements.

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

1.3.2.6 Criteria for including planned resource additions in the analysis

1.3.3 Transmission limitations that prevent the delivery of generation reserves

1.3.3.1 Criteria for including planned Transmission Facility additions in the analysis

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

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

1.4.1 Availability and deliverability of fuel.

1.4.2 Common mode outages that affect resource availability

1.4.3 Environmental or regulatory restrictions of resource availability.

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

1.4.5 Sensitivity to resource outage rates.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

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

1.2. Evidence Retention

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

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

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

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

1.3. Compliance Monitoring and Assessment Processes

Compliance Audit
Self-Certification
Spot Checking

Compliance Investigation
Self-Reporting
Complaint

1.4. Additional Compliance Information

None

Table of Compliance Elements

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

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

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

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

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

D. Regional Variances

None

E. Interpretations

None

F. Associated Documents

None

Version History

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

ECONOMIC DISPATCH

OF

ELECTRIC GENERATION CAPACITY

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

United States Department of Energy

February 2007

ECONOMIC DISPATCH

OF

ELECTRIC GENERATION CAPACITY

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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[4] EPAct, Section 1298.
[5] Federal Energy Regulatory Commission, "Security Constrained Economic Dispatch: Definition, Practices, Issues and Recommendations – A Report to Congress Regarding the Recommendations of Regional Joint Boards For the Study of Economic Dispatch Pursuant to Section 223 of the Federal Power Act as Added by Section 1298 of the Energy Policy Act of 2005," July 31, 2006, at http://www.ferc.gov/industries/electric/indus-act/joint-boards/final-cong-rpt.pdf .
[6] *Ibid.* at 10.

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

Other Activities and Issues Related to Economic Dispatch

FERC Reform of Open Access Transmission Tariff

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

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

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

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

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

Load forecasting

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

[8] Federal Energy Regulatory Commission, "Preventing Undue Discrimination and Preference in Transmission Services," Notice of Inquiry, September 16, 2005, and comments, found at http://www.ferc.gov/industries/electric/indus-act/oatt-reform.asp .
[9] Federal Energy Regulatory Commission, news release regarding Order 890, February 15, 2007.

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

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

Private Sector Initiatives

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

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

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[10] Energy Information Administration," Monthly Flash Estimates of Electric Power Data", September 19, 2006, Data for July 2006.
[11] California ISO, "Conservation Works! More Conservation Needed as Peak Demand Skyrockets to Critical Peak Monday," July 23, 2006.
[12] See http://www.nbc5i.com/news/8794207/detail.html?rss=dfw&psp=news and other local news sources.
[13] The term "bus" is used in the electricity industry to refer to a node in an electrical transmission network where one or more elements are connected together.

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

Conclusions

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

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

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

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

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

ORDER ESTABLISHING TASK FORCE AND SOLICITING NOMINATIONS

(Issued June 17, 2021)

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

I. <u>Task Force</u>

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

[1] 16 U.S.C. § 824h(b).

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

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

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

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

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

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

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

II. Issue Statement

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

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

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

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

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

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

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

III. Next Steps

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

By the Commission. Commissioner Chatterjee is not participating.

(S E A L)

Kimberly D. Bose,
Secretary.

NEWS RELEASES

FERC, NARUC Establish Federal-State Current Issues Collaborative

March 21, 2024

Items E-5

Docket Nos. AD21-15, AD24-7

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

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

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

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

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

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

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

R24-12

Contact Information

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This page was last updated on March 21, 2024

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

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

ANSWER OF THE
MIDCONTINENT INDEPENDENT SYSTEM OPERATOR, INC.

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

1 *See* Rules 206 and 213 of the Rules of Practice and Procedure of the Federal Energy Regulatory Commission ("FERC" or "Commission"), 18 C.F.R. § 385.206(f) (2025); 18 C.F.R. § 385.213 (2025).
2 U.S. Department of Energy, Order No. 202-25-3, at 2 (May 23, 2025) ("DOE Order").
3 DOE Order at 1.
4 DOE Order at 2.

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

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

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

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

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

I. BACKGROUND

The Secretary of Energy issued the DOE Order on May 23, 2025.[8] The DOE Order identifies an "emergency situation" in the MISO region and states that MISO "faces potential tight reserve margins during the summer 2025 period, particularly during periods of high demand or low generation resource output."[9] The DOE Order notes that the Campbell Plant is scheduled to cease operations on May 31, 2025," and concludes that the Campbell Plant's retirement "would further decrease available dispatchable generation within MISO's service territory[.]"[10] The DOE Order states that, although MISO and Consumers Energy incorporated the Campbell Plant's planned retirement into their supply forecasts and acquired a 1,200 MW natural gas plant in Covert, MI, the North American Electric Reliability Corporation's ("NERC") analysis still anticipates an "elevated risk of operating reserve shortfalls."[11] The DOE Order concludes that "additional dispatch of the Campbell Plant is necessary to best meet the emergency and serve the public interest for purposes of FPA section 202(c)."[12]

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

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

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

The DOE Order states that, to "[t]he extent to which MISO's current Tariff provisions are inapposite to effectuate the dispatch and operation of the units for the reasons specified herein, the relevant governmental authorities are directed to take such action and make accommodations as may be necessary to do so."[15] The Order further provides that "Consumers [Energy] is directed to file with the Federal Energy Regulatory Commission Tariff revisions or waivers necessary to effectuate this order."[16] The DOE Order states that "[r]ate recovery is available pursuant to 16 U.S.C. § 824a(c)."[17]

II. ANSWER

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

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

[14] DOE Order at 2-3.
[15] DOE Order at 3.
[16] DOE Order at 3.
[17] DOE Order at 3.
[18] Complaint at 18.

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

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

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

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

III. ADMISSIONS AND DENIALS; AFFIRMATIVE DEFENSES

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

IV. COMMUNICATIONS

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

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

V. CONCLUSION

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

Respectfully submitted,

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CERTIFICATE OF SERVICE

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

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

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

Dated: June 19, 2025

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

By Amanda Durish Cook

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Why This Matters

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

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

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

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

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

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

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

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Federal Power Act: The Department of Energy's Emergency Authority

June 12, 2025

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CRS REPORT
Prepared for Members and
Committees of Congress

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

History of Section 202(c)

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

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

DOE may execute this authority during war or at any other time it "determines that an emergency exists by reason of a sudden increase in the demand for electric energy, or a shortage of electric energy or of facilities for the generation or transmission of electric energy, or of fuel or water for generating facilities, or other causes." This report focuses on the authority as used during emergencies, not war, and it focuses on DOE's authority—it does not discuss other energy emergency authorities.[1]

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

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

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

DOE Implementation

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

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

[2] 10 C.F.R. §§205.370-205.379.

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

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

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

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

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

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

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

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

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

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

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

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

Trump Administration Actions

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

The E.O. additionally directs DOE to develop a protocol to identify generation resources that are critical to system reliability. The protocol must "include all mechanisms available under applicable law, including Section 202(c) of the Federal Power Act, to ensure any generation resource identified as critical within an at-risk region is appropriately retained." Further, the protocol must prevent, "as the Secretary of Energy deems appropriate and consistent with applicable law," identified resources from "leaving the bulk-power system" or converting fuels in such a way that reduces their accredited capacity. An example of fuel conversion that could reduce accredited capacity is replacing a coal-fired power plant with a solar farm.

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

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

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

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

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

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

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

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

Issues for Congress

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

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

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

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

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

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

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

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

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

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

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

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

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

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Disclaimer

U.S. Government Accountability Office

Electricity: Information on Peak Demand Power Plants

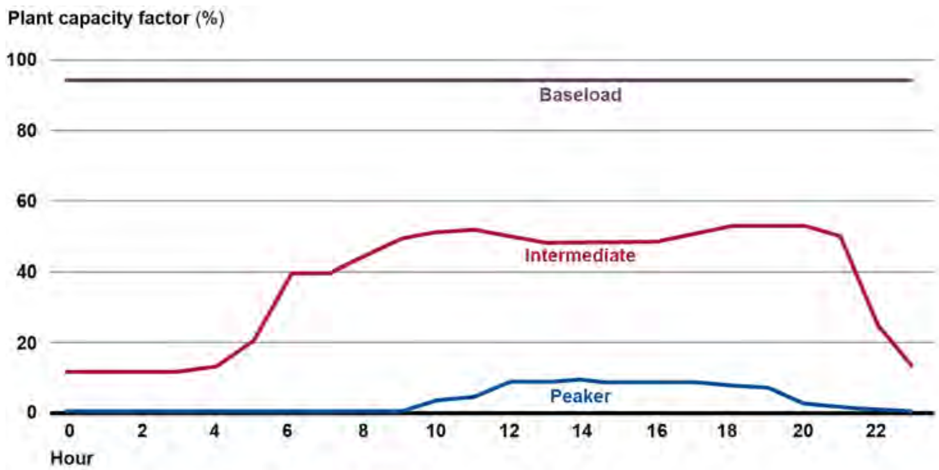
GAO-24-106145
Q&A Report to Congressional Requesters

May 21, 2024

Why This Matters

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

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



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

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

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

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

Key Takeaways

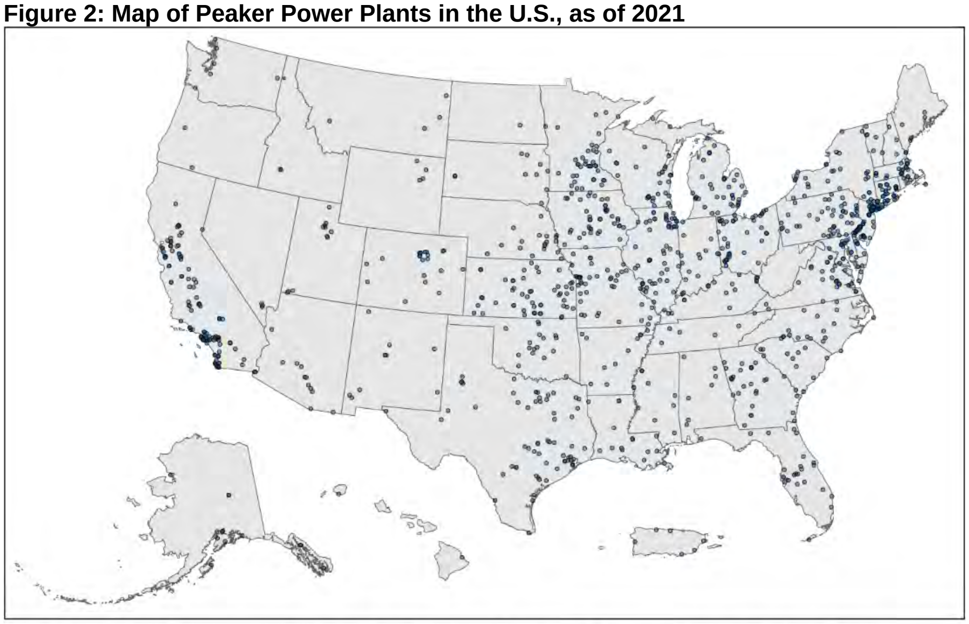
- Historically disadvantaged racial or ethnic communities tend to be closer to peakers.

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

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

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

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



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

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

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

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

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

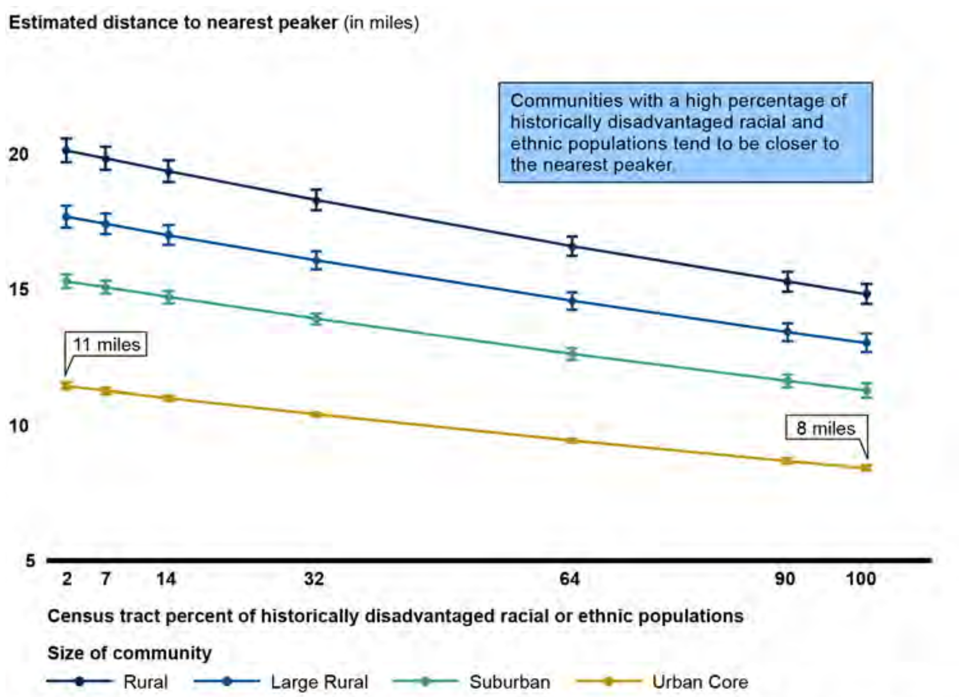
Note: We define peakers as fossil-fueled power plants that have a capacity factor of 15 percent or less and a nameplate capacity of greater than 10 megawatts of electricity.

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

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

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

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

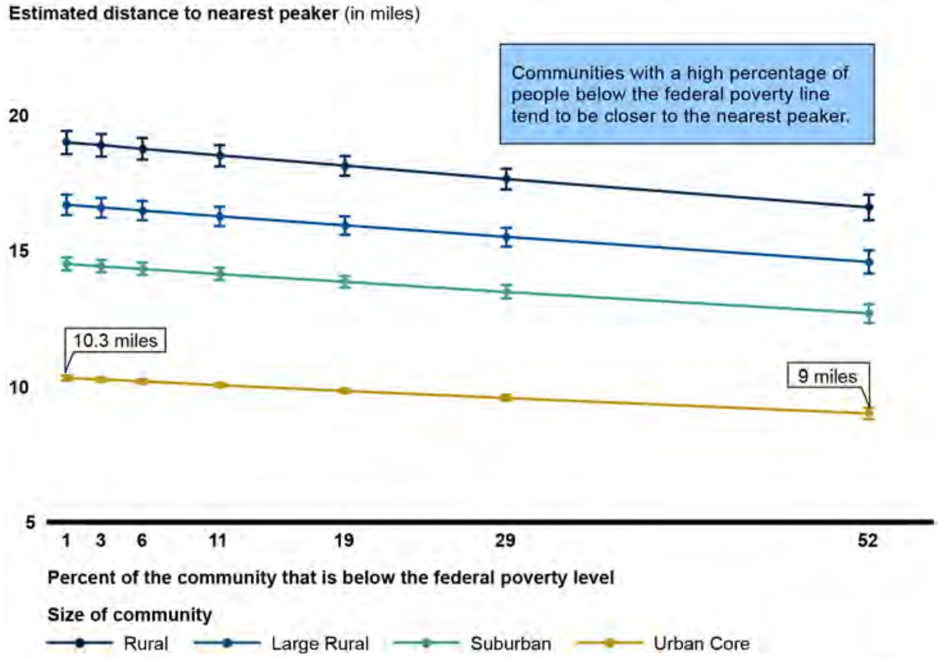


Source: GAO analysis of Census Bureau American Community Survey, Department of Agriculture Economic Research Services, National Oceanic and Atmospheric Administration National Weather Service, and Energy Information Administration data. | GAO-24-106145

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

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

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



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

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

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

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

Pollutants

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

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

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

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

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

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

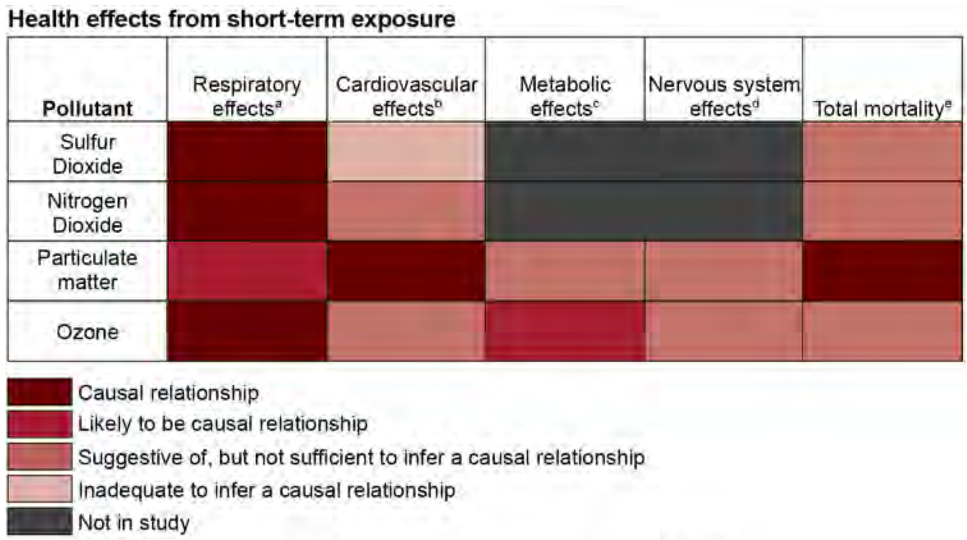
In addition to sulfur dioxide and nitrogen oxides, ground-level ozone and particulate matter are pollutants related to the operation of peaker plants. Ground-level ozone is formed through chemical reactions between nitrogen oxides—emitted by peakers—and volatile organic compounds. Particulate matter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

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

Health effects

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

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



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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

What are the potential challenges of replacing peakers?

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

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

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

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

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

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

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

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

Agency Comments

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

How GAO Did This Study

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

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

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

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

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

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

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

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

List of Addressees

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

The Honorable Alexandria Ocasio-Cortez
House of Representatives

The Honorable Yvette D. Clarke
House of Representatives

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

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Appendix I: Technical Appendix

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

The resulting coefficients from our model allowed us to

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

Model Variables/Data Sources

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

- We associated the 2019 USDA ERS tract codes with 2020 U.S. Census tracts using the U.S Census tract relationship files between the 2020 census tract entities and the 2010 tract entities.
- In cases where there is more than one record for a 2020 tract, we select the tract that has the largest area of intersection.

- Definition of peakers. We identified plants as peakers using each of the four definitions described and ran separate models for each definition. To capture potential variation within a plant in recent years, the peaker status in our regression is based on 2018–2021 Environmental Protection Agency (EPA) data.

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

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

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

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

Endnotes

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

[16]See appendix I for additional details.

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

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

UNITED STATES DEPARTMENT OF ENERGY

Midcontinent Independent System Operator	Order No. 202-25-7

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

Pursuant to section 202(c) of the Federal Power Act, 16 U.S.C. §§ 824a(c), 825l, the States of Minnesota and Illinois ("the States") move to intervene and petition for rehearing of the Department of Energy's ("DOE") May 23, 2025, Order No. 202-25-7 ("Renewed Order," Ex. A)[1] directing the Midcontinent Independent System Operator ("MISO") and Consumers Energy Company ("Consumers Energy") to take all measures necessary to ensure that the coal-burning J.H. Campbell Plant ("Campbell Plant") in West Olive, Michigan "is available to operate" and "to take every step to employ economic dispatch of the Campbell Plant." The Renewed Order is in effect from 00:00 Eastern Daylight Time (EDT) on August 21,2025, and expires at 00:00 EDT on November 19, 2025.

This Renewed Order is dated August 20, 2025, and continues the prior DOE Order No. 202-25-3, which directed MISO and Consumers Energy to keep the Campbell Plant available to provide economic dispatch from its planned retirement date through August 20, 2025, expiring at 00:00h on August 21, 2025 (the "Original Campbell Order)."

Pursuant to the Federal Power Act ("the Act") and Department procedures applying it to

[1] All Exhibits are lettered and attached; to be submitted in separate serial emails to the DOE's AskCR <askcr@hq.doe.gov> account.

petitions for rehearing, the States hereby file this timely request for rehearing of DOE's Renewed Order. The Renewed Order extends the Original Order, perpetuating the Original Order's flawed analyses, faulty conclusion that an emergency exists for the MISO Regional Transmission Organization ("RTO") for the summer months of 2025, and unlawful directives. This Order exceeds DOE's legal authority in several respects. And even if an emergency did exist and DOE had the legal authority to issue an Order, this Order is not rationally related to meet the purported need. It should be rescinded.

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MOTION TO INTERVENE

The States[2] move to intervene in this proceeding and thereby to become parties for purposes of Section 313l of the Act, 16 U.S.C. § 825l. The States have an interest in and are aggrieved by the Renewed Order (Ex. A) in several ways and seek to intervene and petition for rehearing. *FDR v. R.J. Reynolds Vapor Co.*, 606 U.S. ___ (2025) (slip op., at 3–8) (defining an "adversely affected or aggrieved" party within the APA as "anyone even 'arguably within the zone of interests to be protected or regulated by the statute . . . in question.'" (quoting *Ass'n of Data Processing Svc. Orgs. v. Camp*, 397 U. S. 150, 153 (1970))).

Factual Background

The utilities regulated by the States are members of MISO, the electric grid operator for the central United States. MISO covers the largest geographical range of any independent system operator ("ISO") in the U.S. The 15 states covered by MISO are: Arkansas, Illinois, Indiana, Iowa, Kentucky, Louisiana, Michigan, Minnesota, Mississippi, Missouri, Montana, North Dakota, South Dakota, Texas, and Wisconsin. As the ISO of the electric grid in this region, MISO manages the flow of electricity across the high-voltage, long-distance power lines. To do so, MISO develops rules so that the wholesale electricity transmission system operates reliably and safely. MISO has described this as being like the "air traffic controller" for the grid in its territory,[3] meaning that MISO seeks to resolve power congestion (traffic) issues in real-time through its control room and has processes in place to anticipate and avoid emergencies that could lead to the loss of power.

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

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

On May 23, 2025, the DOE issued the Original Campbell Order pursuant to section 202(c) of the Federal Power Act to MISO. *See* Ex. B; *see also* 16 U.S.C. § 824(c)(1). The Order directed MISO, in coordination with Consumers Energy, the owner of the plant, to ensure that the Campbell Plant remained available for operation during the summer season; expiring on August 20, 2025. *Id.*

This eleventh-hour Original Campbell Order disrupted a longstanding planning sequence handled by state authorities and submitted to MISO. Consumers Energy had already announced its plan to retire the Campbell Plant in 2021, and MISO approved that retirement plan three years ago, in March 2022.[4]

Minnesota and Illinois timely submitted a Petition for Rehearing of the Original Order on June 23, 2025. Ex. D. DOE did not act on that petition within 30 days; and later issued that it had been denied by operation of law given the passage of time. Ex. C. Minnesota and Illinois filed a Petition for Review in the D.C. Circuit Court of Appeals (No. 25-1162, consolidated with 25-1159 and 25-1160) on July 28, 2025.

On August 20, 2025, the DOE issued the Renewed Order requiring MISO and Consumers Energy to ensure that the Campbell Plant "is available to operate" and "to take every step to employ economic dispatch of the Campbell Plant." The Renewed Order is in effect from 00:00 Eastern Daylight Time (EDT) on August 21,2025, and expires at 00:00 EDT on November 19, 2025.

On September 8, 2025, DOE issued a document fashioned as "ORDER ADDRESSING ARGUMENTS RAISED ON REHEARING." Ex. E.

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

Adverse Effects

The States will be adversely affected by the Renewed Order in many of the same ways that they were harmed by the Original Campbell Order. The Renewed Order prevents the planned retirement of the Campbell Plant, with consequent negative impacts on the States.

First, households and businesses in the States, and the States as consumers in their own right, will pay higher electricity bills as a result of the Renewed Order's imposition of costs and cost-recovery to the States. By ordering the Campbell Plant to take all steps necessary to be available and ordering MISO to take all steps necessary for the Campbell Plant to provide economic dispatch, costs are already being incurred and more costs will continue to be generated. Notably, the age of the units is concerning for costs, and Consumers Energy projected in 2021 that retiring Campbell in 2025 would avoid $365,008,000 in capital expenditures and major maintenance costs.[5] The Renewed Order would likely require at least a portion of capital expenditures and major maintenance costs, which will drive up costs and impact ratepayer bills. This would be in addition to the cost of rehiring operators and obtaining more coal, among other expenses.

Although the precise amount is not yet known, the Renewed Order provides that cost recovery is available to Consumers Energy through Federal Energy Regulatory Commission ("FERC") proceedings, (¶E). Consumers Energy already initiated a cost recovery complaint before FERC on the Original Campbell Order,[6] asking to allocate costs (net of market revenues) across

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

[6] FERC Docket: EL25-90.

all of MISO Zones 1 through 7 (which includes Minnesota and Illinois). Consumers Energy asked that these costs be apportioned according to load, which would assign costs to the States. MISO filed its answer indicating its general support for adjusting its tariff to account for Consumers Energy's cost recovery petition, meaning the costs will be charged to the States according to their respective share of load. FERC granted cost recovery on August 15, 2025.

The Renewed Order will have substantially the same impact, and more if additional maintenance—deferred or otherwise—needs to be performed to keep the aging (and greatly deteriorated) Campbell Plant units online.

Second, the States will suffer environmental harms as a result of the Order. The Campbell Plant is a significant source of particulate matter, nitrogen oxides, sulfur oxides, and carbon dioxide,[7] among other pollutants. By extending the operations of the Campbell Plant beyond its planned retirement date, the Order increases the amount of pollution emitted in the state of Michigan and other MISO States, causing harm to the public health and welfare.[8] The States of Minnesota and Illinois share the upper Midwest region and Great Lakes environment with Michigan. Depending on weather, air emissions in Michigan impact conditions in Minnesota and Illinois. Further, Minnesota and Illinois have an interest in the Great Lakes ecosystem into which pollutants from coal-burning power plants such as mercury are deposited. Such pollution is harmful to state economies including fisheries and recreation, human health, and the environment in general. The Campbell Plant is situated on the shores of Lake Michigan across from Illinois, including the highly populated Chicago metropolitan area. Thus Minnesota and Illinois have an

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[7] See In the Matter of the Application of Consumers Energy Co. for Approval of Its Integrated Res. Plan Pursuant to Mcl 460.6t & for Other Relief., No. U-21090, 2022 WL 2915368, at *73 (June 23, 2022).
[8] *See* Cross-State Air Pollution Rule (CSAPR) and Clean Air Act § 110.

economic, public health, and ecological interest in protecting their environment and natural resources from unnecessary pollution emanating from the Campbell plant. Minnesota and Illinois are harmed because the Order results in the unnecessary consumption of fuel that generates such pollution.

Coal-fired power plants also contribute to regional, national, and global greenhouse gas emissions, which cause global climate change. Climate change directly harms the States by imposing significant additional costs for responsive actions, disaster recovery, and resiliency programs. Increased emissions threaten state climate goals and the States' ability to comply with federal and state air pollution requirements.

Minnesota, for example, is experiencing rapid changes including higher winter temperatures and larger, more frequent extreme precipitation events, extreme heat, and drought.[9] Each of Minnesota's top-ten combined warmest and wettest years on record have occurred since 1998, with 2024 standing as the warmest year on record and 2019 the wettest.[10] Minnesota is already suffering from a significant uptick in devastating, large-area extreme rain events, threatening the state with ever greater frequency and intensity.[11] These events damage streets, wastewater facilities, businesses, homes, farms, and natural resources, costing local governments, business owners, and residents millions of dollars in cleanup, repairs, and adaptation expenses.[12] Wildfires are also becoming larger and more frequent, including a rash of devastating fires in the spring of 2025 that consumed more than 32,000 acres and destroyed an estimated 150 structures.

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

The spring of 2024 included heavy precipitation and extreme rainfall events, leading to extensive flooding and federal disaster declarations for large parts of the state.[13] From 1980 to 2024, the annual average for billion-dollar weather and climate disasters in Minnesota is 1.4 events per year, but the annual average from 2020 to 2024 is 4.6 events.[14] The "Lost Winter" of 2023-2024 was the warmest on record, with temperatures averaging 10.9°F above 1991-2020 averages, greatly harming Minnesota's recreational economy.[15] These impacts will continue, and emissions from the Campbell Plant contribute to them.

Climate change is affecting Illinois in a number of ways. Illinois' farming industry is vulnerable to cycles of extreme drought and extreme precipitation caused by climate change. In 2023, a severe drought dried up soil throughout the state, with extreme dryness extending down to 20 inches below the surface in some areas.[16] In other years, extreme precipitation has threatened Illinois' agriculture. For instance, January to June of 2013 was the wettest period ever recorded in Illinois, causing widespread flooding in farmland that forced farmers to delay planting and lose

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

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

[15] *Id*.

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

revenue.[17] Climate change is also intensifying catastrophic extreme weather events. In 2024, the Illinois State Climatologist recorded strong wind, hail, and tornadoes across all of Illinois' 102 counties and the state logged 142 tornadoes—a new annual record.[18] These storms included a July 15, 2024 "derecho" that produced 100 mile-per-hour winds and 48 separate tornados.[19] In the Chicago area alone, the derecho produced 32 tornados, breaking the previous records set by the July 2014 "double derecho" and a March 2023 storm.

Moreover, the States have an interest given their primary responsibility for resource planning and ensuring that there will be adequate and reliable electricity generation. The processes that States employ to ensure reliability—which takes into account planned retirements, new generation projects, transmission infrastructure, and meeting consumer demand—are both sophisticated and robust. The Renewed Order harms Minnesota and Illinois by usurping the traditional role that states play in generation planning and resource adequacy.

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

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

[19] National Weather Service, July 15, 2024, Derecho Produces Widespread Wind Damage and Numerous Tornadoes, available at https://www.weather.gov/lot/2024_07_15_Derecho#:~:text=With%2032%20tornadoes%2C%20the%20July,March%2031%2C%202023%20tornado%20outbreaks. (last visited May 25, 2025). *See also* David Struett, Tornado Record Broken with 27 Chicago Area Twisters July 15—Spawned by 'Ring of Fire', WBEZ CHICAGO, available at https://www.wbez.org/weather/2024/07/24/chicago-weather-tornado-record-derecho-july-15 (last accessed May 23, 2025)

PETITION FOR REHEARING

I. Overview and Concise Statement of Error

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

The challenged Renewed Order is premised on an incomplete recitation of MISO's planned capacity and reserves for the summer of 2025.

It first relies on the Original Order, which was fundamentally flawed and misstated the purported "evidence" on which it relied for all of the reasons set forth in the States' Petition for Rehearing, filed June 23, 2025. Ex. D.

The Renewed Order continues to misconstrue the source material on which it relies and still concludes only that there is a <u>possibility</u> of shortfalls. But it does not cite or rely on any evidence that there is any likelihood or probability that they will occur during the relevant timeframe of the Renewed Order.

The Renewed Order concludes that the evidence collected (and discussed below) supports the issuance of Order No. 202-25-3. It contends that the purported emergency will continue in the near term and is likely to continue in subsequent years. It declares—without any evidence identifying an emergency in the August 20 to November 19 timeframe—that the alleged emergency "<u>could</u> lead to the <u>potential</u> 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." Ex.

A at 7 (emphasis added). It then orders that MISO and Consumers Energy shall take "all measures necessary to ensure that the Campbell Plant is available to operate." And MISO must "take every step to employ economic dispatch of the Campbell Plant to minimize cost to ratepayers." Further, it orders that the Campbell Plant operate according to times as determined by MISO. Importantly, the Renewed Order prohibits the Campbell Plant from being considered a capacity resource.

The Renewed Order was issued in error. The DOE did not have substantial evidence or engage in reasoned decision-making in declaring the existence of an emergency in general, be it far into the future or even in the August 20 to November 19, 2025, timeframe.

It starts from the proposition that there is only a "potential" for insufficient capacity that "could" result in a need for mitigation, which does not present an actual existing or imminent emergency. Section 202(c)'s plain terms limit DOE to actual emergencies—not the potential that emergencies might arise. Section 202(c) is also limited in the type of conduct it allows DOE to order, such as directing the generation, delivery, or transmission of electric energy. This Renewed Order, however, requires the Campbell Plant to be "available to operate." Nothing in section 202(c) grants DOE authority to order a plant be available to operate without any demonstrated need identified by the states with primary resource planning authority, the utility operating the resource, or grid operator responsible for forecasting and coordinating adequate and reliable supply.

Even if an emergency did exist and DOE had the legal authority to issue the Renewed Order, directing the Campbell Plant to participate in the bidding market using economic dispatch would not rationally "best" meet the purported need (because there is no evidence the Campbell Plant can reasonably address any given future emergency need. This is because emergency responses do not require economic evaluation, and because the Campbell Plant takes so long to ramp up). The Renewed Order should be rescinded.

II. Legal Background

Under section 202(c) of the Federal Power Act, the Commission[20] has authority to issue an order:

> [d]uring the continuance of any war in which the United States is engaged, or whenever the Commission determines that an emergency exists by reason of a sudden increase in the demand for electric energy, or a shortage of electric energy or of facilities for the generation or transmission of electric energy, or of fuel or water for generating facilities, or other causes. . . .

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

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

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

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

Id. at § 824(c)(2).

The applicable regulations define "emergency," as

> an unexpected inadequate supply of electric energy which may result from the unexpected outage or breakdown of facilities for the generation, transmission or distribution of electric power. Such events may be the result of weather conditions, acts of God, or unforeseen occurrences not reasonably within the power of the affected "entity" to prevent. An emergency also can result from a sudden increase in customer demand, an inability to obtain adequate amounts of the necessary fuels to generate electricity, or a regulatory action which prohibits the use of certain electric power supply facilities. Actions under this authority are envisioned *as meeting a specific inadequate power supply situation*.

10 C.F.R. § 205.371[21] (emphasis added).

III. Statement of Issues

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

No. DOE relied on evidence that did not identify any likelihood or probability that there would be a shortfall during the relevant timeframe of the Renewed Order's requirements—August 20 to November 19, 2025. Further, DOE failed to consider substantial countervailing evidence, including the MISO States' Integrated Resource Plans and MISO's PRA for the summer of 2025. The Renewed Order fails to identify any reasoned basis for concluding an

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

actual emergency exists or is imminent, much less one that will occur between August 20 and November 19.

Issue B: Section 202(c)(1) allows DOE to issue temporary emergency orders in times of actual or impending emergencies such as war, sudden demand for electric energy, shortage of fuel or water, or other similar conditions creating a specific inadequate power supply situation. Did DOE exceed this authority where its Renewed Order is based on the nonspecific possibility that such a situation might occur over a period of several months—or in the 2027-2030 timeframe, well outside of the Renewed Order's applicability?

Yes. An actual "emergency" is a sudden occurrence requiring immediate response action or a concrete need for energy to be produced; conversely, it is not the mere potential that an emergency might occur. 16 U.S.C. § 824a(c); 10 C.F.R. § 205.371. Emergency orders must respond to "a specific inadequate power supply situation." 10 C.F.R. § 205.371. The Renewed Order does not address any sudden occurrence needing imminent response, nor does it identify any actual and specific insufficient supply situation. Instead, the Renewed Order focuses on vague non-summer needs and the potential for shortfalls several years away. Because the Renewed Order is not directed to any emergency at all, much less one occurring in the August 20 to November 19 timeframe, DOE lacks authority, and the Renewed Order is contrary to law.

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

Yes. DOE's emergency powers allow it to order the generation, delivery, interchange, or transmission of electric energy. Section 202(c)(1) does not give the DOE the authority to order that a plant be available (absent a showing of why that is needed), nor does it give the DOE authority to order MISO to engage in potential economic dispatch. 42 U.S.C. §16432(b). Because the Order does not adhere to the types of actions allowed under section 202(c)(1), DOE lacks authority, and the Renewed Order is contrary to law.

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

Yes. The statutory language requires an emergency order be limited to only those hours necessary to meet the emergency and minimize adverse environmental impacts. 16 U.S.C. § 824a(c)(2). The Renewed Order does not establish any limited hours for operation, instead deferring to MISO. The Renewed Order also does not meaningfully take steps to minimize adverse environmental impacts. Because the Renewed Order does not set any specific hours the Campbell Plant must run, and does not meaningfully minimize adverse environmental impacts, the Renewed Order violates the requirements of section 202(c)(2). The DOE is without authority, and the Renewed Order is contrary to law.

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

Yes. Section 201(a) of the Federal Power Act explicitly provides that federal regulation over generation and transmission is related to matters of interstate commerce and extends "only to those matters which are not subject to regulation by the States." 16 U. S. C. § 824(a). States retain jurisdiction "over facilities used for the generation of electric energy." 16 U.S.C. § 824(b)(1). DOE's Order exceeds its authority by contradicting Michigan's resource plans. It also exceeds DOE's authority by purporting to engage in long-term resource planning for the years 2027-2030, which is a role reserved to the states. For both reasons, the Renewed Order is contrary to law.

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

No. Section 202(c) contemplates emergency orders that are precisely tailored to "best" meet the specific emergency. 16 U.S.C. § 824a(c). The Order's specific requirement for MISO to take steps to effectuate "economic dispatch" of the Campbell Plant is not rationally related to the emergency it purports to address. Even during the peak days in June of 2025, MISO had adequate resources to generate power without the Campbell Plant's output—with capacity to spare. The Renewed Order does not explain how keeping the Campbell Plant available to run will meet any particular need when MISO has adequate resources at its disposal without the Campbell Plant. The Renewed Order, therefore, is without substantial evidence and lacks reasoned decision-making.

Issue G: Federal law prohibits agencies from prejudging the outcome of an action. Did the Secretary of Energy and the federal administration improperly prejudge the need for the Renewed Order?

Yes. As evidenced by public statements, the purported emergency is pretext for an improperly-prejudged outcome to preserve coal as a fuel for electrical generation.

IV. MISO's Robust Capacity and Planning Projections are Adequate to Ensure Reliability.

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

[22] MISO, *Fact Sheet* (July 2024), available at https://www.misoenergy.org/meetmiso/media-center/2024/corporate-fact-sheet.
[23] MISO, *Electric Grid 101*, available at https://www.misoenergy.org/meet-miso/grid-operations-basics.

works to coordinate generation and transmission of electricity with other RTOs, exporting power at times and at others allowing electricity to be imported to MISO.[24] MISO uses advanced modeling and thorough research to coordinate short and long-term planning for the benefit of generating units and consumers.[25]

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

The long-planned retirement of the Campbell Plant is not an impediment to summer reliability in the MISO region. Since 2010, MISO has experienced the retirement of 30.8 gigawatts (GW) of generation capacity, a large proportion of which (21.9 GW) was coal-fired generating

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[24] MISO, *Interregional Coordination*, available at https://www.misoenergy.org/planning/interregional-coodination/; see also MISO, Historical Net Scheduled Interchange (NSI), at https://www.misoenergy.org/markets-and-operations/real-time--marketdata/ market-reports/ (data found under "Summary" Market Reports).
[25] MISO, *Transmission and Generation Planning 101*, available at https://www.misoenergy.org/meet-miso/grid_planning_basics.

units.[26] That trend is shown below in the bar graph (from MISO's 2023 Transmission Expansion Plan Report,[27] Ex. G at 35), which displays the retired capacity by generation type over time:

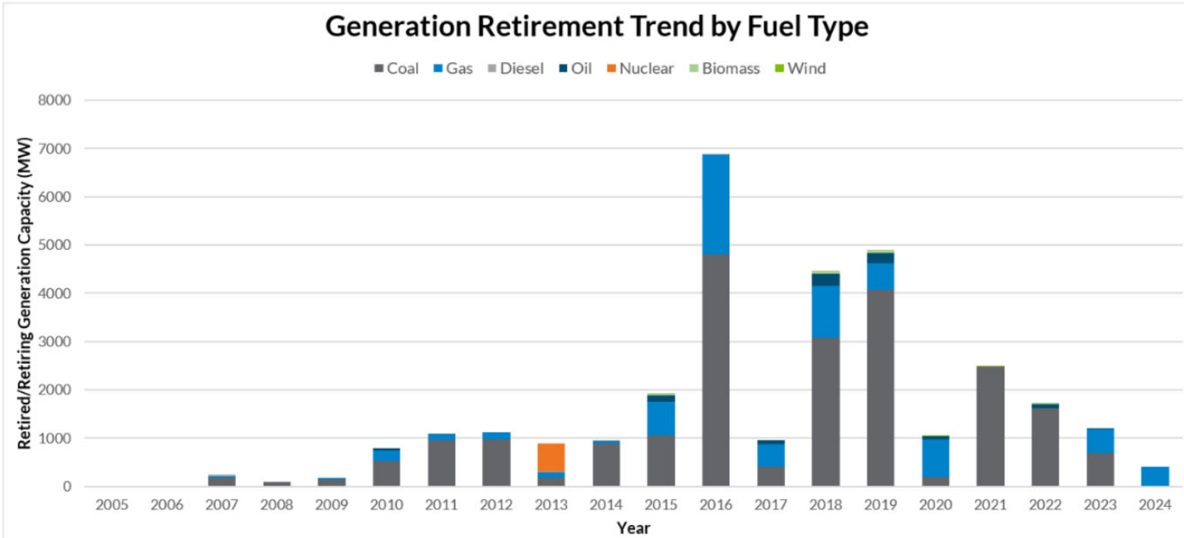

Figure 2.2-1: MW Generation Retirement by Fuel Type

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

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

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

V. Argument

A. The Renewed Order is not supported by substantial evidence demonstrating the existence of an actual emergency and does not demonstrate reasoned decision-making.

The DOE failed to provide substantial evidence that an unexpected emergency presently exists, as required by 16 U.S.C. § 824a(c)(5). The relevant standard is whether the DOE's determination is supported by substantial evidence. 16 U.S.C. § 824a(c)(5) refers to the possibility of judicial review under 16 U.S.C. § 825l. After an objection has been brought before DOE, the Court may consider it with the understanding that "[t]he finding of the Commission as to the facts, if supported by substantial evidence, shall be conclusive." 16 U.S.C. § 825l. Substantial evidence means "such relevant evidence as a reasonable mind might accept as adequate to support a conclusion." *Duke Energy Corp. v. FERC*, 892 F.3d 416, 420 (2018). This standard implies deference to an agency's factual determinations. *See, e.g., id.*

DOE failed to point to substantial evidence of a current and unexpected emergency in the August 20 to November 19, 2025, timeframe during which the Renewed Order is in effect. The evidence DOE provided does, however, prove that there is currently no energy emergency and that there will not be an "unexpected emergency" that warrants this Renewed Order. MISO is well situated to deliver reliable power throughout its area in the fall of 2025.

In declaring the contrary, DOE relied on a NERC assessment that identified an elevated risk for <u>potential</u> capacity exceedance <u>if</u> an extreme weather event were to occur**.** But the Renewed Order makes too much out of too little—the "elevated" category is hardly a call for immediate and unnecessary emergency action. As the NERC assessment points out, MISO expects to have an existing certain capacity of 142,783 MW during the summer—which already factored in the assumption that the Campbell Plant would be retired and unavailable for the summer of 2025. That projection also exceeds both expected demand and the reserve margin.[28] While retirements and fewer suppliers meant that MISO would have fewer firm resources and dispatchable generation, that was no cause for alarm. To the contrary, NERC concluded that all areas were projected to have "adequate anticipated resources for normal summer peak load conditions." *Id*. And nothing in the NERC assessment determined that MISO's interconnection with other RTOs would be insufficient to cover any needs that could arise.

The "elevated risk" category is not tantamount to an emergency. Even though NERC used the term "elevated risk" for the possibility that there could be an operating reserve shortfall, NERC did not apply the "high risk" category to MISO and did not call for any retired plants to be brought back online. Ex. H. at 5. Moreover, the "elevated risk" designation means the probabilistic indices <u>are low but not negligible</u>. *Id*. at 10, Table 1. And further, the MISO-specific "dashboard" concludes that MISO's expected resources meet operating reserve requirements under normal peak-demand scenarios. At worst, operating mitigations "could" be necessary for above-normal summer peak load and extreme generator outage conditions. *Id*. at 16.

Perhaps most simply, the "elevated risk" designation is far from unusual; it has never required an emergency order before, and the grid has remained stable. MISO has been designated an "elevated" risk in every NERC Summer Reliability Assessment since NERC initiated the practice of designating regions as "high," elevated," or "normal" risk in 2021.[29] NERC has also designated MISO as "elevated" risk in every Winter Reliability Assessment since 2021. *Id*. Yet no

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[28] MISO PRA, Results for Planning Year 2025-26 at 18 (Corrected May 29, 2025).
[29] *See* NERC*, Reliability Assessments,* https://www.nerc.com/pa/RAPA/ra/Pages/default.aspx (last visited June 23, 2025).

energy shortage has occurred, and DOE has never imposed an emergency declaration until now (see *infra* regarding prejudgment and pretext).

In fact, the evidence before DOE cuts against the Renewed Order. This includes MISO's PRA for the summer of 2025, which found sufficient capacity throughout the region for the summer 2025 season. The PRA provides a strong conclusion that supply will be adequate. Ex. F. The press release announcing the PRA, (Ex. I), confirms "adequate resources are available to maintain reliability during the upcoming planning year (June 2025 – May 2026)." Ex. I. And while "the 2025 auction prices reflect a tightening supply-demand balance during the summer months, there is sufficient capacity throughout the MISO footprint." *Id*. The PRA was based on NERC's standard BAL-502-RF-03 (Ex. J), requiring assessment of "one day in ten year" loss of load expectation principles. In short, the NERC standard that MISO applied to conduct the PRA demonstrated that MISO <u>will</u> have sufficient capacity through the summer of 2025. Exs. F, I. J. MISO's PRA results show that there will be enough capacity in the summer planning year, and MISO notes that the summer auction price provides a signal to the market to add more capacity for future auction years. DOE appears to have cherry-picked certain phrases from the PRA but does not give it full consideration.

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

And beyond the lack of supporting evidence, DOE also acted arbitrarily and capriciously by ignoring well-known and readily-accessible contrary information. For example, DOE failed to consider recent comments by MISO's Independent Market Monitor to the Markets Committee of the MISO Board of Directors dispelling NERC's purported concerns—these comments were cited in the States Petition for Rehearing of the Original Campbell Order. Ex. L. The Independent Market Monitor is charged with ensuring adequate supply markets for the MISO region. He criticized a separate NERC long-term reliability assessment (which has since been revised[30]) that included capacity shortfalls in 2025, noting that NERC's assessment compared the wrong numbers. In doing so, the Independent Market Monitor declared MISO capacity to be "more than adequate," and that he had "no material concerns" over MISO's resource adequacy for the upcoming summer.

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

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

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

1. *The materials cited in the Original Order do not support the existence of an emergency.*

The evidence supporting the Original Campbell Order does not support the Renewed Order. The Renewed Order continues to rely on some of the same evidence that DOE cited in the Original Campbell Order, including the North American Electric Reliability Corporation's ("NERC") 2025 Summer Reliability Assessment. Ex. H. That report does not identify any war, fuel shortage, or natural disaster. *Id*. Rather, it evaluates generation resource and transmission system adequacy as well as energy sufficiency to meet projected summer peak demands and operating reserves. Ex. H at 5. Here are NERC's main conclusions regarding MISO:

> **Midcontinent Independent System Operator (MISO):** MISO is expecting to have an existing certain capacity of 142,793 MW in the *2025 SRA*, which is a slight reduction from the 143,866 MW submitted for the *2024 SRA*. The retirement of 1,575 MW of natural gas and coal-fired generation since last summer, combined with a reduction in net firm capacity transfers due to some capacity outside the MISO market opting out of the MISO planning resource auction, is contributing to less dispatchable generation in MISO. With higher demand and less firm resources, MISO is at elevated risk of operating reserve shortfalls during periods of high demand or low resource output. MISO's most recent energy assessment reveals that the period of highest energy shortfall risk has shifted from July to August. This shift is driven by the decline in dispatchable generation and the increasing share that solar and wind resources have in meeting demand. The risk of supply shortfalls increases in late summer as solar output diminishes earlier in the day, leaving variable wind and a more limited amount of dispatchable resources to meet demand.

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

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

Id. at 16.

Second, the Renewed Order describes a sequence of resource retirements without acknowledging the replacement capacity that came online (or that is/was planned to come online) to offset those retirements. Ex. A at 2. In any event, NERC's 2025 Summer Reliability Assessment analysis already factored in an assumption that included those retirements <u>including</u> the Campbell Plant' slated retirement for the summer of 2025. Ex. H at 5, 16.

Third, the Renewed Order cites NERC's "elevated risk" determination. But the Campbell Plant's retirement was well known to MISO operators who accounted for the retirement in their robust resource planning processes (described in further detail herein). Indeed, the Renewed Order acknowledges that the retirement was already factored into MISO's own supply forecasts. *Id*. at 2. MISO's PRA (Ex. F), cited in the Original Campbell Order, confirms adequate margin. *Id*. In fact, for the fall 2025 timeframe, the auction results exceeded MISO's Reserve Margin Requirement by 2.6%. That means MISO entered the fall with more resources than necessary to ensure grid reliability. Ex. F at 19.

And as the States' Petition for Rehearing on the Original Campbell Order explains, the "elevated risk" designation that DOE cites is relatively common and has never presented an emergency before. Ex. D at 19-20. In fact, NERC concluded that all areas were projected to have "adequate anticipated resources for normal summer peak load conditions." Ex. H at 5. And nothing in the NERC assessment determined that MISO's interconnection with other RTOs would be insufficient for additional capacity if needed. Nonetheless, the Renewed Order relies on the NERC

Summer Assessment, and that "additional dispatch of the Campbell Plant is necessary," Ex. A at 2, even though the Campbell Plant was not included in any of the MISO forecasts finding sufficient capacity.

Fourth, the Renewed Order cites the PRA by cherry-picking reference to capacity offset while simultaneously acknowledging its conclusion that the results "demonstrated sufficient capacity." Ex. A at 2. Sufficient capacity, by definition, is not an emergency.

All this evidence was improperly credited when DOE issued the Original Campbell Order, and the Renewed Order compounds that error by reasserting the same flaws and mischaracterizations. This is even more troubling since the petitions challenging the Original Order placed DOE squarely on notice of the fundamental flaws in these sources. Rather than identifying and responding to an emergency, both orders together demonstrate that DOE instead started with a desired result (keeping a coal-fired plant online) and worked backwards to justify that outcome.

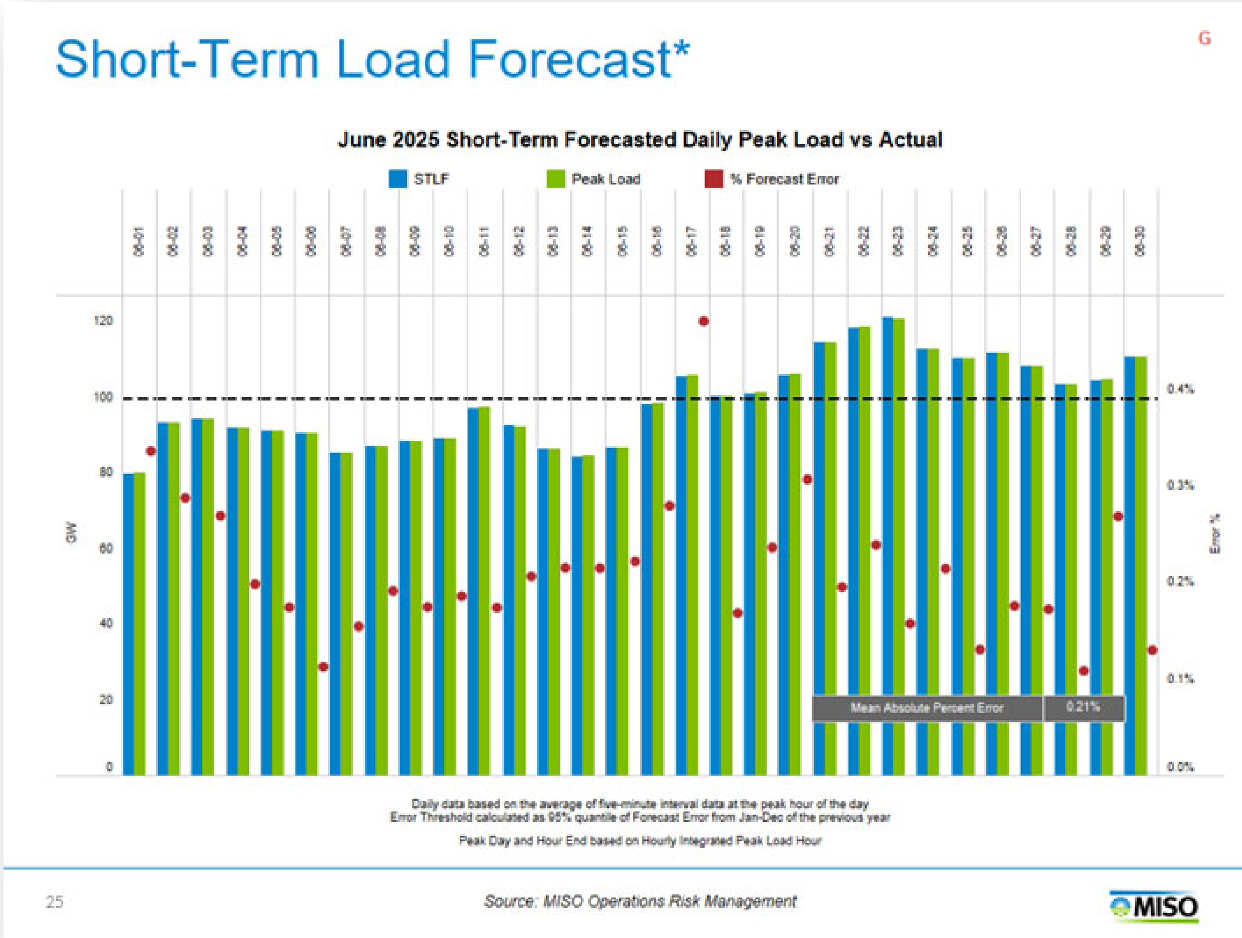
2. *The additional evidence cited in the Renewed Order does not demonstrate a continuing emergency.*

A continuing emergency condition does not exist, especially during the Renewed Order's applicable timeframe. After recounting the same purported evidence supplied in the Original Campbell Order, the Renewed Order then enters into a section entitled "Continuing Emergency Conditions" which presents several additional flaws, cherry-picked and out-of-context citations, and unsupported or illogical conclusions:

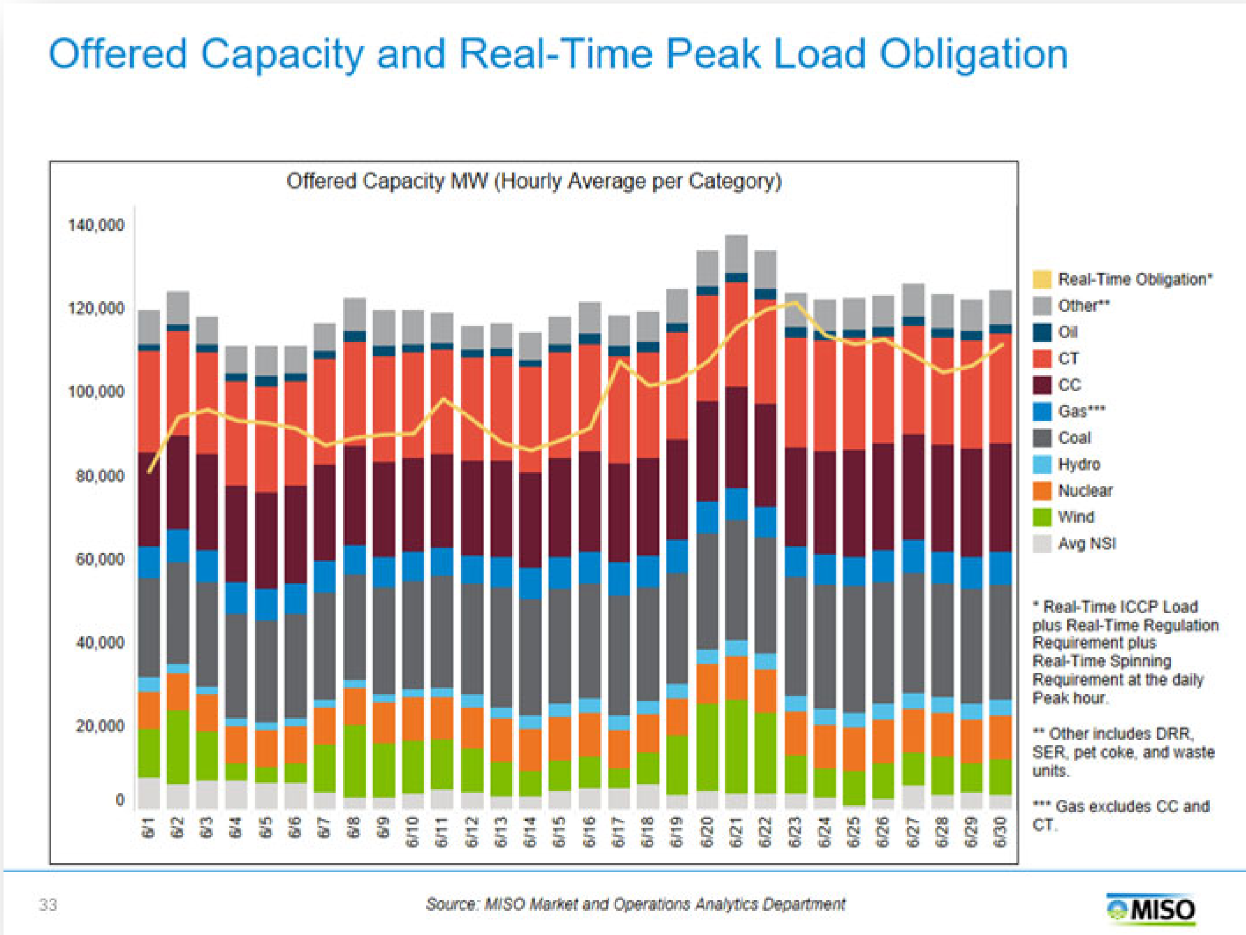
It declares that the "summer season has not yet ended" (Ex. A. at 2), but this fails to acknowledge multiple critical points. These include that peak demand is historically in June and July, not late August, that the Renewed Order was issued just days before the start of the meteorological fall, and that the Renewed Order remains in place through late November.

The Renewed Order describes how MISO called on the Campbell Plant to run in June 2025 (Ex. A at 3) without acknowledging: (1) that the Campbell Plant was only available because of the Original Order in the first place, or (2) that other resources could have supplied the capacity that the Campbell plant provided, or (3) that there was sufficient capacity within MISO even without the Campbell Plant operating, or (4) that there is no reason for DOE to conclude that the Campbell Plant's operation in June indicated any need to respond to a heat wave in September, October, or November of 2025 while the Renewed Order remains in effect.

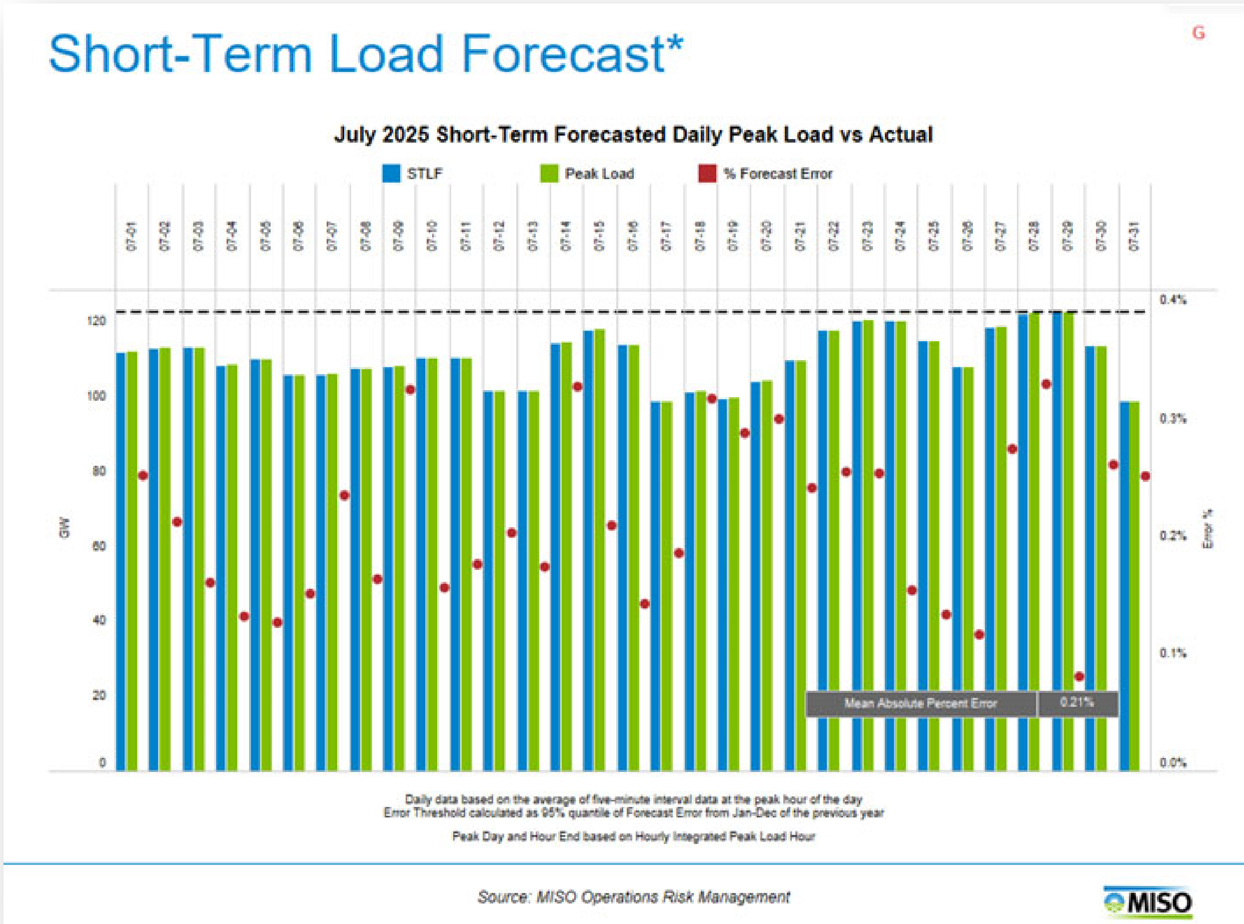
The Renewed Order attempts to justify its emergency finding by observing that MISO issued various alerts over the course of the summer (Ex. A at 3) without acknowledging: (1) that such alerts are common mechanisms for managing peak load demand every summer, and have been used for decades without any need for Section 202(c) emergency orders by DOE to keep a resource that had been slated for retirement online, or (2) that the alerts responded to summer conditions that will not be present in September, October, or November of 2025 while the Renewed Order remains in effect. Moreover, even in the peak-demand timeframe of June (Ex. M) and July (Ex. N.), when actual demand reached 120 GW on June 23, MISO had more than enough offered capacity:


Short-Term Load Forecast*
June 2025 Short-Term Forecasted Daily Peak Load vs Actual
STLF
Peak Load
% Forecast Error
GW
Error %
Mean Absolute Percent Error
0.21%
Daily data based on the average of five-minute interval data at the peak hour of the day
Error Threshold calculated as 95% quantile of Forecast Error from Jan-Dec of the previous year
Peak Day and Hour End based on Hourly Integrated Peak Load Hour
25
Source: MISO Operations Risk Management
MISO

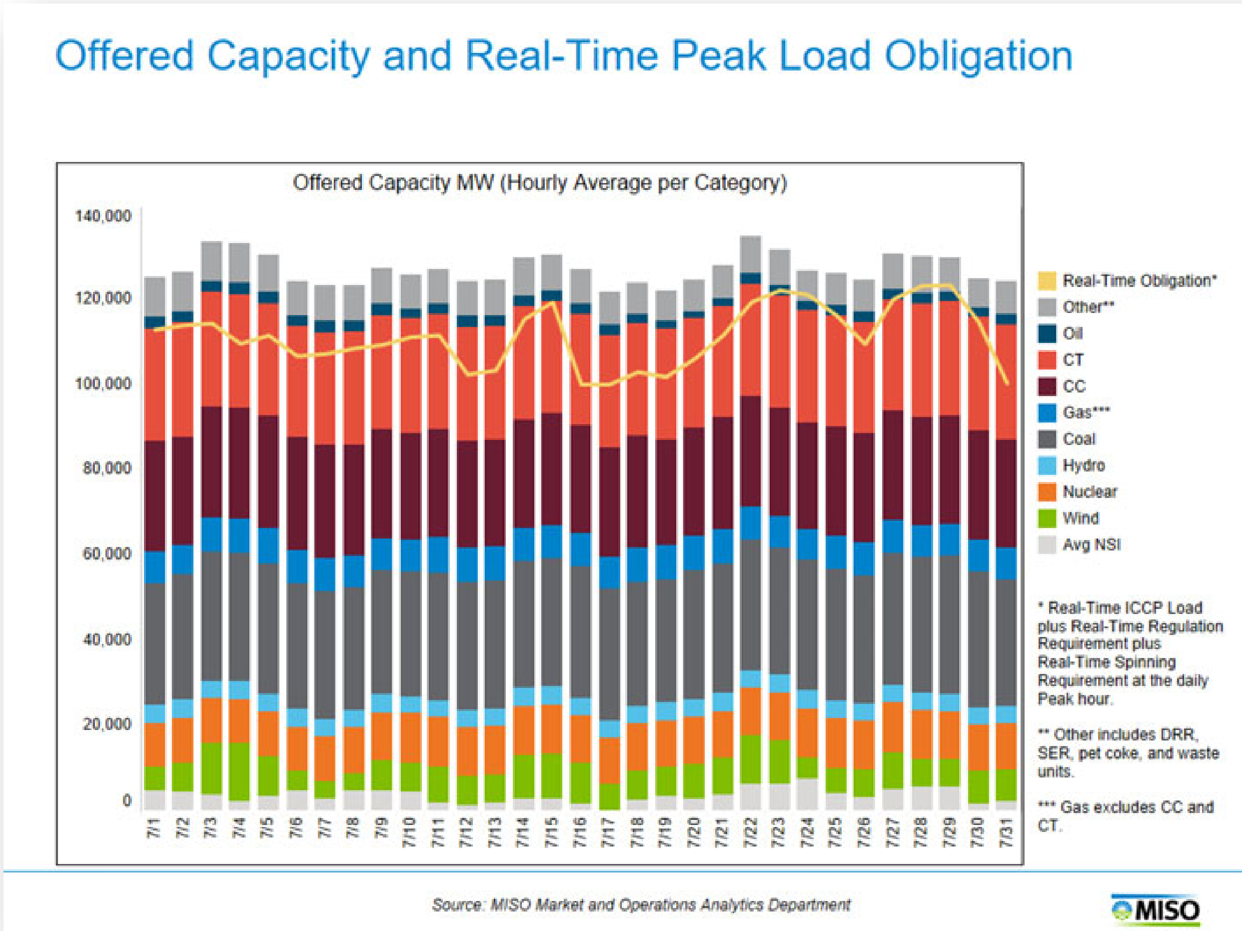
Ex. M at 25.


Offered Capacity and Real-Time Peak Load Obligation
Offered Capacity MW (Hourly Average per Category)
140,000
120,000
100,000
80,000
60,000
40,000
20,000
0
6/1
6/2
6/3
6/4
6/5
6/6
6/7
6/8
6/9
6/10
6/11
6/12
6/13
6/14
6/15
6/16
6/17
6/18
6/19
6/20
6/21
6/22
6/23
6/24
6/25
6/26
6/27
6/28
6/29
6/30
Real-Time Obligation*
Other**
Oil
CT
CC
Gas***
Coal
Hydro
Nuclear
Wind
Avg NSI
* Real-Time ICCP Load plus Real-Time Regulation Requirement plus Real-Time Spinning Requirement at the daily Peak hour.
** Other includes DRR, SER, pet coke, and waste units.
*** Gas excludes CC and CT.
33
Source: MISO Market and Operations Analytics Department
MISO

Ex. M at 33.


Short-Term Load Forecast*
July 2025 Short-Term Forecasted Daily Peak Load vs Actual
STLF
Peak Load
% Forecast Error
GW
Error %
Mean Absolute Percent Error
0.21%
Daily data based on the average of five-minute interval data at the peak hour of the day
Error Threshold calculated as 95% quantile of Forecast Error from Jan-Dec of the previous year
Peak Day and Hour End based on Hourly Integrated Peak Load Hour
Source: MISO Operations Risk Management
MISO

Ex. N at 24.



Ex. N at 32. These charts do not include more than 7000MW in headroom available to MISO beyond the offered capacity shown.[31]

The Renewed Order then cites MISO's three-year-old 2022 application to revise its resource adequacy construct to argue that the alleged "emergency" that the Renewed Order purports to address in the fall of 2025 is a year-round phenomenon. Ex. A at 3. But DOE's reliance on the application fails to acknowledge that MISO has been operating through 2025 without any

[31] *See* Public Interest Organization's Petition for Rehearing submitted to DOE on September 8, 2025, Exhibit 70 at ¶¶ 16-19.

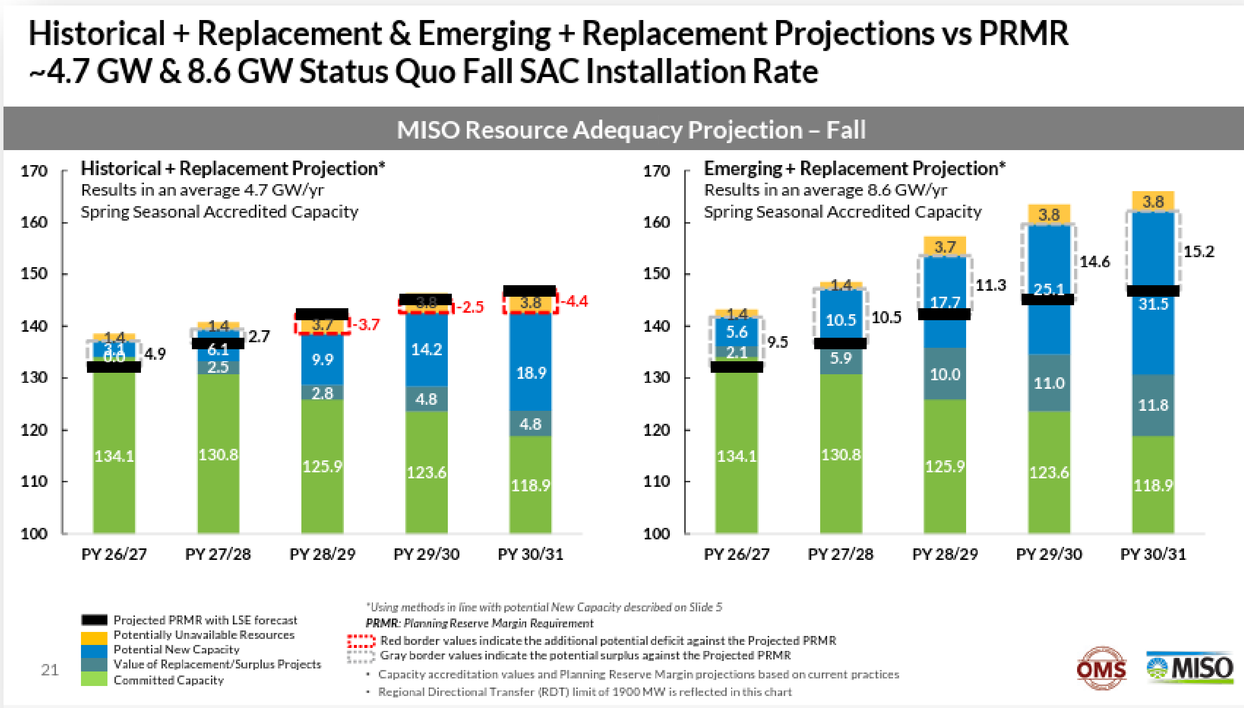
need for a Section 202(c) emergency order (other than 202-25-3) by engaging in its robust planning process that ensures adequacy and reliability.

The Renewed Order also cites MISO's 2023 Attributes Roadmap for the proposition that by the summer of 2027, there will be an equal loss of load risk in both the summer and fall seasons. The Renewed Order does not explain how a Section 202(c) order directed to the August to November 2025 timeframe will address that eventuality several years away.

The Renewed Order also cites MISO's Response to the Reliability Imperative, concluding that MISO purportedly has "resource reliability concerns" and quotes a passage acknowledging "risks in non-summer months" that were not historically of concern. Ex. A at 4. But the Renewed Order fails to identify how generalized discussion of non-summer "concerns" and potential "risks" demonstrate any particular emergency, much less a specific one that is posed for the August to November 2025 timeframe. To the contrary, the MISO Response to the Reliability Imperative describes the risks posed by non-summer operations in the context of explaining the steps it is taking to address these risks to ensure adequate capacity and overall system reliability. Ex. O at 11. It specifically describes four pillars of approaches that MISO intends to deploy, (Ex. O at 12–24), and concludes with a "Roadmap" for how it will deploy its strategy. Ex. O at Appendix A-1. Nothing in the Renewed Order contends that these measures are inadequate or that there is an emergency despite MISO's robust efforts. *Contra* Ex. A.

The Renewed Order also cites (again) the 2025-2026 PRA results, which included a statement that "new capacity additions were insufficient to offset the negative impacts of decreased accreditation, suspensions/retirements and external resources." Ex. A at 4; Ex. F at 13. Again, the actual document, in its full context, <u>confirms adequate margin</u> for reliability.

The Renewed Order further cites the Organization of MISO states and MISO's joint publication of a survey dated June 6, 2025. Ex. A at 4–5. But as the Renewed Order confirms, the survey confirms a surplus through the summer of 2026, well beyond the scope of the Renewed Order's timeframe. In fact, the survey shows a fall 2026 surplus using seasonally-accredited capacity against the planning reserve margin requirement:



Ex. P at 21. The Renewed Order then relies on the survey results to identify potential forecast deficits (which are not emergencies) in the 2027-2030 timeframe—but that is well outside the fall 2025 timeframe in which the Renewed Order will be in effect, and fails to account for the "Emerging + Replacement Projection" metrics throughout the document showing surpluses against the projected Planning Reserve Margin Requirement. *Id.* at 7, 9, 19–26.

The Renewed Order further cites the development of the AI industry in general, including citing the existence of 21 AI companies in Michigan. Ex. A at 6.[32] But a company's business address is not necessarily the same as where its data centers might be located, and the Renewed Order does not identify whether any of the listed companies have or intend to build data centers that would be served by the Campbell Plant's output. To the contrary, the cited article confirms that many of them have a predominance of foreign employment.[33]

The Renewed Order further cites the DOE's 2025 July 2025 Resource Adequacy Report. Ex. A at 6; Ex. Q. But that Report uses the <u>wrong data</u> for MISO, as the Renewal Order explicitly acknowledges. Ex. Q at 20, fn25 ("Following the initial data collection for this report, MISO issued its 2025 Summer Reliability Assessment. Based on that report, NERC revised evaluations from its 2024 LTRA and reclassified the MISO footprint from being an 'elevated risk' to 'high risk' in the 2028–2031 timeframe, depending on new resource additions/retirements. <u>While DOE's analysis is based on the previously reported figures, DOE is committed to assessing the implications of updated data</u> on overall resource adequacy and providing technical updates on findings, as appropriate." (emphasis added).). The Renewed Order fails to explain how data that the Report has yet to even consider can support a finding that an emergency exists in the fall of 2025.

The DOE Report also defines a shortfall, even where there is a 3%-6% operating <u>surplus</u>. Ex. Q at 12. And the report completely fails to apply a "perfect capacity" estimate for MISO. Ex.

[32] Ekku Jokinen, *Top 21 Artificial Intelligence Companies in Michigan*, (last accessed Sep. 15, 2025), https://www.inven.ai/company-lists/top-21-artificial-intelligence-companies-in-michigan.
[33] These include: Soothsayer Analytics: 65% of employees in India; Netlink Software Group America Inc: 65% of employees in India; Suneratech: 82% of employees in India; Ventuit: 51% of employees in India; Verdai: 100% of employees in Italy; Communication Valley Reply: 100% of employees in Italy; Altair RapidMiner: 44% in Hungary, 29% in Germany; and LENS Corporation: 100% of employees in India

Q at 20. Instead, the Report confirms that its work was done by hand with a limited number of iterations, acknowledging an incomplete analysis that explicitly should not be relied upon. *Id.* at 19 ("As the work was done by hand with a limited number of iterations (15), this should not be considered the minimum possible capacity to accomplish these targets." (emphasis added)). Yet the Renewed Order relies upon it.

The Renewed Order further cites testimony by MISO's Senior Vice President of Planning and Operations, Jennifer Curran. Ex. A at 6. But the Renewed Order (apparently intentionally) omits a critical sentence from the passage it cites, which provides important context: "A growing reliability risk is that the rapid retirement of existing coal and gas power plants threatens to outpace the ability of new resources with the necessary operational characteristics to replace them. This can be addressed by letting local reliability requirements determine the pace of retirement of existing power plants." Ex. R at 7 (emphasis added). Further testimony undermines the very proposition for which the Renewed Order purports to rely on Ms. Curran's testimony. She also repeatedly confirmed that resource planning is the purview of individual states and utilities in the MISO region, which can be used to mitigate the risk:

- "More work remains to be done… Let reliability needs help inform the pace of retirement of existing electric generating resources, ensuring they aren't retired before adequate new electric generation is available." Ex. R. at 2.
- "The MISO region predominantly consists of vertically integrated utilities with responsibility for providing adequate electric generation to meet needed load for their area and states having jurisdiction over electric resource adequacy decisions." Ex. R at 4.

- "Two of our most important tools are the Futures Planning Scenarios, which are MISO projections capturing a range of potential system conditions over a 20-year horizon, and the annual Organization of MISO States and MISO survey, a voluntary survey of generation owners to assess available resource capacity to serve the projected load over the next five years. These regularly updated studies provide the basis for long-term transmission planning efforts and help inform the electric resource planning decisions, which are the purview of the states and utilities in the MISO region." Ex. R at 6.

In total, none of this evidence demonstrates that there is any emergency, much less one that might occur in the August 20 to November 19 timeframe. To be sure, there are normal capacity considerations including some that pose some degree of potential risk, but not one of the sources cited in the Renewed Order evidences any lack of adequate planning to address those risks, much less any likelihood of a shortfall between August 20 and November 19, 2025.

Instead, the robust and comprehensive planning processes undertaken by the prime authorities—the individual states, the utilities, and MISO—have comprehensively planned for resource adequacy and system reliability during the fall 2025 and beyond.

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

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

DOE exceeds its authority because the Renewed Order does not address any actual emergency or sudden occurrence needing imminent response, and because it has not identified any actual and specific insufficient supply situation, for the August 20 to November 19 timeframe. Thus the Renewed Order is without authority and contrary to law.

As the statutes make clear, an actual "emergency" is a sudden occurrence requiring immediate responsive action; conversely, it is not the mere potential that an emergency might occur. 16 U.S.C. § 824a(c). And Department regulations define "emergency" to mean an unexpected inadequate supply of electric energy which may result from the unexpected outage or breakdown of facilities for the generation, transmission or distribution of electric power. "Such events may be the result of weather conditions, acts of God, or unforeseen occurrences not reasonably within the power of the affected 'entity' to prevent." 10 C.F.R. § 205.371. Further, emergency orders must meet "a specific inadequate power supply situation," and although emergencies with extended periods of insufficient supply could qualify, the impacted entity is supposed to firm up commitments for supply "so that a continuing emergency order is not needed." *Id*

These requirements have been demonstrated by DOE's historic use of 202(c) authority to address natural disasters and specific capacity crises. The most common reason to invoke Section 202(c) authority has been to address natural disasters like hurricanes, cold weather events, and extreme heat. *See* DOE Order Nos. 202-05-1 & -2 (Sept. 28, 2005) (Hurricane Rita); DOE Order No. 20208-1 (Sept. 14, 2008) (Hurricane Ike); DOE Order No. 202-20-1 (Aug. 27, 2020) (Hurricane Laura); DOE Order No. 202-24-1 (Oct. 9, 2024) (Hurricane Milton); DOE Order No. 202-21-1 (Feb. 14, 2021) (Winter Storm Uri); DOE Order No. 202-22-3 (Dec. 23, 2022) (Winter Storm Elliot – Texas ERCOT); DOE Order No. 202-22-4 (Dec. 24, 2022) (Winter Storm Elliot – PJM); DOE Order No. 202-20-2 (Sept. 6, 2020) (extreme heat in California); DOE Order No. 202-21-2 (responding to extreme heat, wildfires and drought in California); DOE Order Nos. 20222-1

& 2 and amendments (same). Indeed, during Winter Storm Elliot, MISO exported power to neighboring regions.[34]

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

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

Indeed, the statutory structure of the Federal Power Act confirms the short-term nature of emergency approaches. That is because long-term planning authority appears in an entirely different Section of the Federal Power Act – Section 215—which indicates that the emergency authority of Section 202(c) is a different authority altogether. 16 U.S.C. § 824o. Given all the procedures attendant to resource planning, this statutory structure confirms that emergency orders are not the proper mechanism to engage in resource planning five years into the future. *See FDA v. Brown & Williamson Tobacco Corp.*, 529 U.S. 120, 142, 149 (2000); s*ee also Cal.*

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

Indep. Sys. Operator Corp. v. FERC, 372 F.3d 395, 401–02 (D.C. Cir. 2004) (DOE's authority in one Section of the Federal Power Act "is strong evidence" that a separate Section does not confer the same authority on the agency).

Courts have also recognized Section 202(c)'s limitation to actual or imminent crises. For example, in *Richmond Power and Light v. FERC*, the D.C. Circuit noted that the statute "speaks of 'temporary' emergencies, epitomized by wartime disturbances, and is aimed at situations in which demand for electricity exceeds supply." 574 F.2d 610, 615 (D.C. Cir. 1978). And in *Otter Tail Power Co. v. Fed. Power Comm'n*., the Eighth Circuit noted that 202(c) provides authority to "react to a war or national disaster and order immediate interconnection. . . to maintain electrical service during such emergency." 429 F.2d 232, 234 (8th Cir. 1970). In *Otter Tail*, the Eighth Circuit distinguished between an emergency that is likely to occur and one that is actually occurring, concluding that a separate provision, section 202(b) [35] applies to the former, while section 202(c) applies to the latter:

> On its face, § 202(c) enables the Commission to react to a war or national disaster and order immediate interconnection of the facilities to maintain electrical service during such emergency. . . On the other hand, § 202(b) applies to a crisis which is likely to develop in the foreseeable future but which does not necessitate immediate action on the part of the Commission.

[35] Section 202(b) refers to 16 U.S.C. § 824a(b), which states "[w]henever the Commission, upon application of any State commission or of any person engaged in the transmission or sale of electric energy, and after notice to each State commission and public utility affected and after opportunity for hearing, finds such action necessary or appropriate in the public interest it may by order direct a public utility" if the utility would not face an undue burden. The DOE's authority is much more limited in these situations. Further, 42 U.S.C. § 7172(a)(1)(B) vests this power in FERC, not the Secretary.

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

Statutory text and structure, past practice, and caselaw are therefore all clear: for DOE to have any authority under section 202(c), the emergency must be actual and not merely a broadly asserted projected risk. With no such actual or even imminent emergency, the Renewed Order is unlawful.

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

The Renewed Order also is unlawful because it purports to require actions not within DOE's statutory authority.

DOE's authority is limited to issuing orders that require connections or the generation, delivery, interchange, or transmission of electric energy. 16 U.S.C. § 824a(c). This authority does not cover mandating general plant <u>availability</u> untethered to meeting any specific need, nor does it allow for <u>potential</u> economic dispatch (which is not an apt solution for an actual emergency anyway—more on this in Section G below). Section 202(c)(1) does not allow for preemptive measures just in case an emergency might occur and specifically does not allow for the Department to order availability without a specific need to be available.[36] Plus, "economic dispatch" is not equivalent to the generation of electric energy. Economic dispatch is constrained by statute to mean only the lowest-cost option under the Energy Policy Act of 2005 Section 1234(c). 42 U.S.C. §16432(b). MISO's determination of lowest-cost sources may not result in the Campbell Plant producing *any* generation whatsoever during the fall of 2025. (Or if it does, it could be as a result of the Original Campbell Order or the Renewed Order being in place rather than an external need.) Thus, the DOE is without authority, and the Renewed Order is contrary to law.

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

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

The Renewed Order addresses only the potential for an emergency, but it does not identify a need for the Campbell Plant to generate electricity to meet it. By the same token, the Renewed Order does not establish any limited hours or other parameters for the Campbell Plant to follow to ensure it meets the purported emergency, only that it always be available. Thus, the DOE is without authority, and the Renewed Order is contrary to law, because it allows the Campbell Plant to generate electricity during times there are not even "elevated risks." Allowing a coal plant to generate electricity and pollute beyond the purported emergency needs would increase the

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

environmental impacts that, by law, the Renewed Order must strive to minimize. 16 U.S.C. § 824a(c)(2). Thus, the DOE is without authority, and THE Renewed Order is contrary to law.

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

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

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

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

States are responsible for developing and approving power generation plans, typically through public commissions like the Minnesota Public Utilities Commission[37] and the Wisconsin Public Service Commission.[38] These bodies oversee the development of Integrated Resource Plans ("IRPs"), or Strategic Energy Assessments, which are the blueprints for how a utility plans to generate sufficient electric power to meet its expected demand. *E.g.*, Minn. Stat. § 216B.2422 (Minnesota's IRP statute). An IRP can consider and adopt plans with myriad inputs and considerations and impact overall electricity rates, the specific communities or areas where power plants are located, determinations of which power plants might be built or retired and the fuels that they will use, overall electric system reliability (like the likelihood of power outages and how quickly the lights come back on), and the environment.[39] Such processes can be rigorous and commissions will open a docket to publicly vet a proposed plan, receive comments, and make an informed decision that is in the best interest of the states and its ratepayers.[40]

MISO, in turn, is one of the country's largest RTO, which was formed to develop transmission systems, trading markets, and attendant procedures.[41] MISO works collaboratively

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[37] Minnesota Public Utilities Commission, *Utility Planning*, https://mn.gov/puc/activities/economic-analysis/planning/ (last visited June 23, 2025).
[38] Wis. Stat. Ann. § 196.491 (West).
[39] *Id*.
[40] Minnesota Public Utilities Commission, *Electric Integrated Resource Planning (EILRP)*, https://mn.gov/puc/activities/economic-analysis/planning/irp/ (last visited June 23, 2025).
[41] FERC, *Energy Primer*, https://www.ferc.gov/sites/default/files/2024-01/24_Energy-Markets-Primer_0117_DIGITAL_0.pdf

with its member states to ensure resource adequacy throughout its service area.[42] This means that it ensures there is sufficient generation capacity to meet future electricity demands, including forecasting demand growth, assessing existing generation assets, and planning for new generation resources.[43] MISO works with utilities during their development of submissions to state regulators for the IRPs that that the regulators ultimately approve. And MISO then accounts for the final IRPs in its planning and analyses forecasting the balance between load and capacity. MISO also operates a capacity auction where utilities and other load-serving entities can procure the necessary generation capacity to meet projected demand. This incentivizes the development and maintenance of adequate generation resources.[44] MISO works with utilities, local regulators, and other stakeholders to maintain resource adequacy, including through its annual PRA, which procures sufficient resources and allows market participants to buy and sell capacity via an auction. MISO determines the capacity requirements in its region for each season covering the June 1 to May 31 time period.[45]

The Campbell Plant's planned retirement is subject to precisely such state regulation and MISO integration. The plan to retire the plant received intense scrutiny over years before being approved and worked into MISO's projections—all under the auspices of state law including Michigan's IRP processes, state regulatory proceedings, state judicial proceedings, and state participation in MISO. *See In re Application of Consumers Energy Co. for Approval of Its Integrated Res. Plan Pursuant to MCL 460.6t & for Other Relief.*, No. U-21090, 2022 WL

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[42] MISO, *System Planning*, https://www.misoenergy.org/meet-miso/about-miso/industry-foundations/grid_planning_basics/ (last visited June 23, 2025).
[43] *Id*.
[44] *Id*.
[45] MISO, *Resource Adequacy*, https://www.misoenergy.org/planning/resource-adequacy2/resource-adequacy/#t=10&p=0&s=FileName&sd=desc (last visited June 23, 2025).

2915368, at *73 (June 23, 2022). The Michigan Public Services Commission approved Consumers Energy's plan to replace the capacity that the Campbell Plant would have produced with the purchase of a natural gas plant and extension of two units of natural gas peaking plants. *Id*. at *33. The Michigan Court of Appeals affirmed. *Wolverine Power Supply Coop., Inc. v. Mich. Pub. Surv. Comm'n (In re Consumers Energy)*; No. 362294, 2023 WL 2620437 (Mich. Ct. App. March 23, 2023).

MISO also reviews planned plant retirements to ensure resource adequacy and grid reliability. Section 38.2.7 of MISO's Open Access Transmission, Energy, and Operating Reserve Markets Tariff requires an operator to provide 26 weeks of advance notice of a planned retirement. MISO then performs a Reliability Study to determine whether retirement will pose any concern for grid reliability.[46]

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

DOE did not adequately consult with the state, much less account for or incorporate the findings of MISO when it approved Consumer's Energy's Attachment Y submission. Michigan state regulators have primary jurisdiction over IRPs, siting, and cost recovery for utilities operating in their states including the Campbell Plant. *Zibelman*, 906 F.3d at 50. DOE's failure to consult violates the principles behind FERC and DOT policies to involve the states in light of the statutory

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

reservation of state authority in federal-state regulatory balance, 16 U.S.C. § 824(b)(1). It avoids 209(b) of the Federal Power Act regarding federal-state collaboration and upends FERC's historic practice of seeking to develop a robust dialogue between regulators. 16 U.S. Code § 824h(b). And it flouts Section 103 of the Department of Energy Organization Act which requires consultation with relevant state officials—consultation was absolutely "practicable" here given the lack of an imminent emergency. The Renewed Order did not give <u>any</u> consideration (much less due consideration) to Michigan's IRP, in violation of law. 42 U.S.C. § 7113.

In the Renewed Order's focus on longer-term risks, including the growth of data centers and the projections out into the 2027-2030 timeframe, DOE is improperly inserting itself into long-term resource planning, usurping a role belonging to the respective states. The DOE cannot use short-term emergency orders to serve a purpose for which DOE's emergency authority was not designed: to supplant the states' primary authority in the long-term resource planning arena.

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

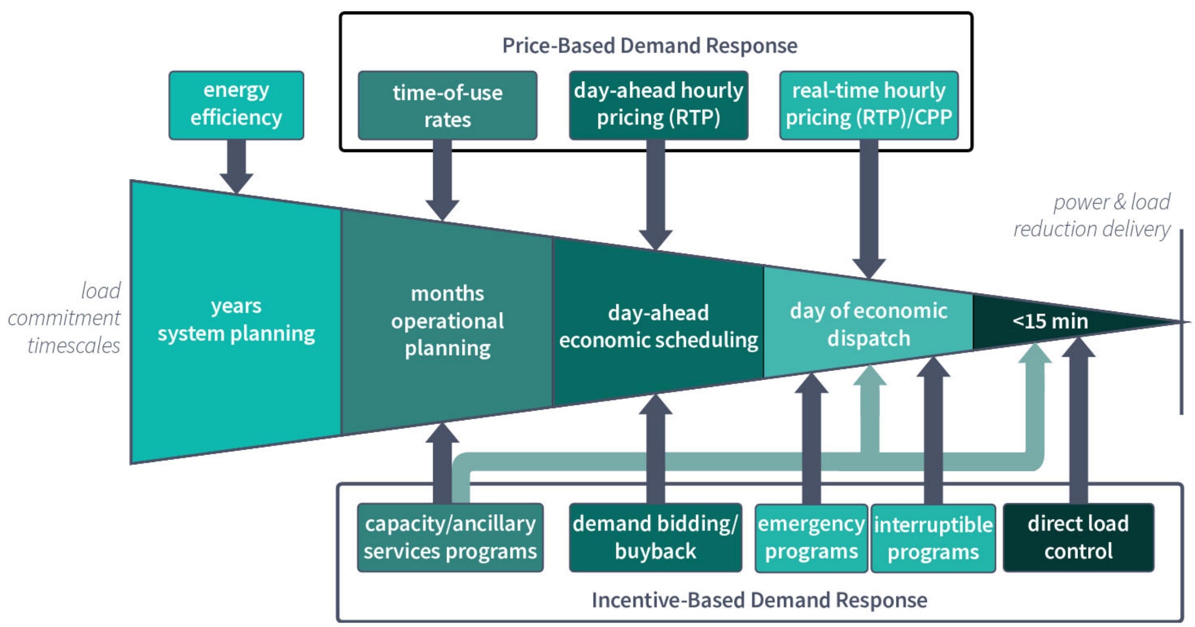
F. The Renewed Order is unreasoned, arbitrary, and capricious because its directive for "economic dispatch" is inherently contradictory with the needs to meet an actual emergency.

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

The Order's specific requirement for MISO to take steps to effectuate "economic dispatch" of the Campbell Plant undermines its determination that an emergency exists and cannot "best meet" the purported emergency. Economic dispatch is a term of art for the procedure by which

MISO selects generators to add electric energy to the grid. It is designed to ensure that the electricity generated matches the demand in its service area in the most cost-effective way. "Economic dispatch," by definition, is awarded to the lowest-cost option (all else being equal). Ex. V. That is because much of the base load planning takes place years or months ahead of time and is comprised of the must-run units. Additional capacity is then called upon in the day-ahead or day-of markets for which additional generation is required:

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



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

Ex. V at 43. Most of the generation available to meet load in real time for economic dispatch is identified and scheduled the day before, based upon the day-ahead load forecast used in the security-constrained unit commitment process. Ex. W at 6–7, 13, 51. As recently as 2021, the vast majority of peaking plants operated on natural gas and oil which can be dispatched in much shorter order; only 3.3 percent of all peakers nationwide burned coal. See Ex. X at 2.

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

The Renewed Order's proposed solution for "economic dispatch" of the Campbell Plant is thus inherently incompatible with addressing emergency operation (likely because there is no emergency in the first place). In a true emergency, even <u>uneconomic</u> plants receive cost-of-service payments when they are required to run to alleviate the emergency condition. The RTO does not require the emergency generator to bid into the market and *then* make a determination about whether it will be selected to run as with economic dispatch. Rather, the emergency generator becomes a "price taker" using MISO's "must run" classification. Thus, the Order's directive to use "economic dispatch" is irrational: actual emergencies are not addressed with economic dispatch, and economic dispatch is a necessarily ineffective method to address an actual emergency.[47]

Moreover, the Renewed Order's requirement that the Campbell Plant be "available to operate" does not accord with 202(c)(1)'s requirement that DOE select the temporary measure that will "best meet the emergency and serve the public interest." Section 202(c)(1)'s use of the term "best" shows that the Commission cannot require temporary power generation from the Campbell Plant when better means are available to meet the alleged emergency and serve the public interest.

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[47] Campbell's situation illustrates this inefficiency. Coal is an expensive fuel type in our current energy mix. The inefficiency of running a coal plant makes it uneconomic in general, which is one of the reasons why this specific Campbell plant was slated for retirement. *See In re Application of Consumers Energy*, No. U-21090, 2022 WL 2915368, at *73.

Entergy Corp. v. Riverkeeper, Inc., 556 U.S. 208, 218 (2009) ("Best" means what is "most advantageous." (Quoting Webster's New International Dictionary 258 (2d ed.1953))). DOE's decision to require the Campbell Plant to be available disregarded its obligation to consider alternatives and select the best one.

Although DOE need not consider every conceivable alternative, it must consider those that are obvious and viable. *See Dep't of Homeland Sec. v. Regents of the Univ. of Calif.*, 591 U.S. 1, 30 (2020); *Motor Vehicle Manufs. Ass'n of the U.S. v. State Farm Mut. Auto. Ins. Co.*, 463 U.S. 29, 51 (1983); *Nat'l Shooting Sports Found., Inc. v. Jones*, 716 F.3d 200, 215 (D.C. Cir. 2013). Intervenors and the public may also introduce information that requires the Department to evaluate alternatives and reconsider its decision to impose or maintain a requirement. *See, e.g.*, *Chamber of Com. of the U.S. v. Secs. & Exch. Comm'n*, 412 F.3d 133, 144 (D.C. Cir. 2005) (evaluating agency failure to consider alternative raised by dissenting Commissioners and introduced by commenters); *cf.* 10 C.F.R. § 205.370 (stating ability to cancel, modify, or otherwise change an order). Indeed, DOE's regulations specify information it shall consider when deciding to issue an order under section 202(c). 10 C.F.R. § 205.373. The specified information includes "conservation or load reduction actions," "efforts . . . to obtain additional power through voluntary means," and "available imports, demand response, and identified behind-the-meter generation resources selected to minimize an increase in emissions." *Id*. § 205.373(g)–(h); Ex. Y at 4 (DOE Order No. 202-22-4). DOE has not explained why ordering the Campbell Plant to remain "available" meets any of these criteria, especially considering alternatives such as power pooling and utility coordination.

DOE has not explained why its Renewed Order "best" meets the emergency, because it does not. Again, the Renewed Order alleges only that the Campbell Plant should remain available because a need *might* arise in the future (and even then, most likely years from now, not in the August to November timeframe). Given the speculative nature of the alleged emergency, it is incorrect as a matter of fact that ordering the Campbell Plant to remain available is the best means of addressing it. DOE's failure to consider alternatives other than the inefficient and incapable Campbell Plant does not meet section 202(c) requirement for DOE to use its judgment to choose the best temporary source of emergency energy.

First, if an emergency need occurs in the day-of or real-time markets, the Campbell Plant will not be able to spool up in time to meet that need. That is because it takes over 12 hours to reach peak load. Ex. Z.[48]

Second, even if there was adequate notice for the Campbell Plant to deliver energy in an emergency, its age and unreliability make it a poor choice to rely on for emergency services.[49] The Campbell Plant's unreliability was one of the reasons it was slated for retirement. In 2023 and 2024, Campbell experienced long, recurring outages that demonstrated it should not be relied on as an emergency power source. For example, in 2023, Unit 2 experienced four outages totaling 3,445 hours—nearly 40 percent of the year—due to a pump failure, and in 2024, Unit 3 experienced an outage totaling 1,104 hours due to a failure in one of the turbine's gears.[50] Even during the June 23, 2025, peak load event during the heat wave, Campbell did not run two of its three units. *Id*.

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

[49] *See* Public Interest Organization's Petition for Rehearing submitted to DOE on September 8, 2025, Exhibits 103-104.

[50] *Id*. Exhibit 3.

Even if there was adequate transmission and lead time, the Campbell Plant's expensive fuel source means that its bid to provide electricity would be higher than other lower-cost dispatchable alternatives (natural gas, storage, or renewables), which would prevent it from being selected as the most economic resource to meet the need. Again, even during the peak load in June of 2025, only one of the Campbell Plant's units was online, and it produced only 761MW of power. Ex. AA.[51] That represents a small fraction of the remaining margin that MISO had available and demonstrates that the Campbell Plant is not an efficient means of meeting an emergency energy demand.

Finally, if, for example, there was a need for additional electricity in North Dakota in October of 2025, it is unlikely that there would be sufficient transmission infrastructure across the Great Lakes to deliver electricity from the Campbell Plant to meet that need.

Rather than ordering the Campbell Plant to remain available, DOE was required to consider obvious alternatives that MISO has available and uses as part of its role as a regional transmission grid operator. The Department has long recognized that power pools and utility coordination "are a basic element in resolving electric energy shortages." *Emergency Interconnection of Elec. Facilities and the Transfer of Elec. to Alleviate an Emergency Shortage of Elec. Power,* 46 Fed. Reg. 39,984, 39,985–86 (Aug. 6, 1981). And recent history bears out the important role of transmission connectivity along with imports and exports.[52] The fact that DOE has intruded on

[51] *Sourced from* https://campd.epa.gov/data/custom-data-download.
[52] *See, e.g.*, Public Interest Organization's Petition for Rehearing submitted to DOE on September 8, 2025, Exhibit 43 at § III.A.3.b (Winter Storm Elliott System Operations Inquiry) ("Despite tightening conditions on the MISO system . . . MISO maintained steadily increasing exports to TVA throughout the day."); Exhibit 44 at 43 (PJM Elliott Report) (describing PJM exports of between 8 and 11 GW to TVA and other neighboring regions), 83–84 (describing PJM power exports to MISO and graphically depicting those exports over time); Exhibit 36 at 6 (MISO Elliott Max. Gen. Event Overview) ("MISO consistently exported power to southern

MISO's role of planning for and meeting fluctuations in demand without considering these viable and obvious alternatives shows that it did not comply with section 202(c).

Section 202(c)(2) requires the emergency measures to be tailored the actual need; yet here, the Renewed Order improperly imposes measures that are not tailored to anything. All the while, the Order imposes costs on the States to bring the Campbell Plant to operational status beyond its planned retirement, adds potentially expensive generation to the mix if it were to run in the August 20-November 19 timeframe, and generates harmful pollution at the same time. Thus, the Renewed Order requiring the Campbell Plant to remain available and for MISO to take steps to use the Campbell Plant for economic dispatch is irrational and arbitrary where the Campbell Plant is unlikely to be a good candidate to serve either economic dispatch or emergency-need functions—especially where it is unclear what need it is supposed to meet in the first place.

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

G. The purported emergency is pretext for a prejudged outcome.

The Renewed Order is not a good faith effort to carry out DOE's duties under the Federal Power Act. Rather, the materials supporting the Renewed Order demonstrate a pretextual effort to further the administration's policy support for fossil fuels, and in particular coal electricity generation.

Where the conduct of the agency shows an "unalterably closed mind on matters critical to the disposition of th[is] proceeding," it requires either disqualification of the administrator or

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neighbors with a maximum value of nearly 5 GW."); *and* Exhibit 7 at 1 (DOE Order No. 202-02-1) (providing for usage of interregional transmission).

withdrawal of the proposal. *Ass'n of Nat'l Advertisers v. FTC*, 627 F.2d 1151, 1170 (D.C. Cir. 1979); *Nehemiah Corp. of Am. v. Jackson*, 546 F.Supp. 2d 830, 847 (E.D. Cal. 2008) (describing the appropriate remedies when an agency official has prejudged the outcome of a particular matter). A preexisting internal directive to reach a particular result is strong evidence that the official is not "free, both in theory and in reality, to change his mind" in the agency proceedings. *Nat'l Advertisers*, 627 F.2d at 1172; *see Int'l Snowmobile Mfrs. Ass'n v. Norton*, 340 F. Supp. 2d 1249, 1260 (D. Wyo. 2004).

The Renewed Order cites a bevy of Executive Orders declaring an energy emergency. Even if these Executive Orders are taken at face value, they are incoherent with the President's other actions to <u>reduce</u> capacity of new energy generation, such as from ongoing and nearly-completed wind projects. *Temporary Withdrawal of All Areas on the Outer Continental Shelf From Offshore Wind Leasing and Review of the Federal Government's Leasing and Permitting Practices for Wind Projects* 90 Fed. Reg. 8,363 (Jan. 20, 2025); *Ending Market Distorting Subsidies for Unreliable, Foreign-Controlled Energy Sources*, 90 Fed. Reg. 30,821 (Jul. 10, 2025).

Further, the administration has declared a preference for coal energy. *Executive Order 14261: Reinvigorating America's Beautiful Clean Coal Industry and Amending Executive Order 14241*, 90 Fed. Reg. 15,517 (Apr. 8, 2025). The express mandate of Executive Order 14261 declared it to be the national policy "to support the domestic coal industry by removing Federal regulatory barriers that undermine coal production, encouraging the utilization of coal to meet growing domestic energy demands, increasing American coal exports, and ensuring that Federal policy does not discriminate against coal production or coal-fired electricity generation."

But this was not a simple policy preference—the administration had already predetermined that it would resort to emergency authority to reopen or forestall closure of coal plants before it ever issued the Original Campbell Order or the Renewed Order. On April 8, 2025, President Trump gave remarks during the signing ceremony for Executive Order 14261. In those remarks, he noted that the administration would take action to reopen coal plants.[53] Also on April 8, 2025, the Department of Energy announced several initiatives directed to increasing coal production.[54]

During a Bloomberg TV interview in February 2025, Secretary Wright declared that the United States should stop the closure of coal power plants, and asserted that DOE had the authority to do so.[55]

On July 7, 2025, Secretary Wright was quoted as saying, "I think our biggest impact by far is going to be — there are like 40 coal plants that are supposed to close this year — and our biggest impact is going to be to stop the closure of most of those."[56]

On July 11, 2025, the DOE posted a video Secretary Wright to the department's social media accounts with the chyron, "BIG BEAUTIFUL CLEAN COAL. This is the largest source of global electricity and third largest source of electricity in the U.S."[57]

The DOE's social media feeds are full of clips from Secretary Wright media appearances extoling coal plants, promising to increase the use of coal for energy production, and asserting that DOE had the authority to forestall closures.

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[53] https://www.presidency.ucsb.edu/documents/remarks-domestic-coal-production ("And all those plants that have been closed are going to be opened if they're modern enough." And "From now on, we'll ensure that our Nation's critically needed coal plants, as an example, remain online and fully operational. They're always going to be operational.")
[54] https://www.energy.gov/articles/energy-department-acts-unleash-american-coal-strengthening-coal-technology-and-securing
[55] https://www.bloomberg.com/news/articles/2025-02-11/us-should-stop-closure-of-coal-fired-power-plants-wright-says.
[56] https://www.wvnews.com/statejournal/news/top_story/energy-secretary-chris-wright-future-of-u-s-coal-is-long-and-bright/article_4ffcdad0-9030-4e6f-8ca7-0816e1786cbc.html
[57] *E.g.*, https://www.facebook.com/energy/videos/big-beautiful-clean-coal-this-is-the-largest-source-of-global-electricity-and-th/1468968367585884/.

The administration, and DOE in particular, engaged in prejudgment of the Renewed Order. Knowing that it needed to effectuate the administration's policy preference to keep coal plants open, DOE worked backwards from that preferred result and justified it using post-hoc rationalizations. Secretary Wright demonstrated an "unalterably closed mind on matters critical to the disposition" of the use of emergency authority, requiring the Renewed Order to be set aside. *Nat'l Advertisers*, 627 F.2d at 1170; *Nehemiah Corp.*, 546 F. Supp. 2d at 847.

CONCLUSION

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

KEITH ELLISON
ATTORNEY GENERAL
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Dated: September 19, 2025

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ATTORNEY GENERAL OF
THE STATE OF ILLINOIS

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Dated: September 19, 2025

UNITED STATES DEPARTMENT OF ENERGY

Midcontinent Independent System Operator	Order No. 202-25-9

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

Pursuant to section 202(c) of the Federal Power Act, 16 U.S.C. §§ 824a(c), 825l, the States of Minnesota and Illinois ("the States") move to intervene and apply for rehearing of the Department of Energy's ("DOE") November 18, 2025, Order No. 202-25-9 ("Campbell Order III," Ex. A)[1] directing the Midcontinent Independent System Operator ("MISO") and Consumers Energy Company ("Consumers Energy") to take all measures necessary to ensure that the coal-burning J.H. Campbell Plant ("Campbell Plant") in West Olive, Michigan "is available to operate" and "to take every step to employ economic dispatch of the Campbell Plant to minimize cost to ratepayers." The Campbell III Order is in effect from 00:00 Eastern Standard Time ("EST") on November 19, 2025, and expires at 00:00 EST on February 17, 2026.[2] This is the third in a series of orders directing MISO to take the same actions for the same facility and based on the same alleged statutory authority and factual circumstances.

The States have an interest in and are aggrieved by Campbell Order III. *FDA v. R.J. Reynolds Vapor Co.*, 606 U.S. 226, 232–36 (2025) (defining an "adversely affected or aggrieved"

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[1] All Exhibits are lettered and attached.
[2] This petition is being submitted to DOE's AskCR <askcr@hq.doe.gov> account as DOE instructs.

party within the APA as “anyone even ‘arguably within the zone of interests to be protected or regulated by the statute . . . in question.’” (quoting *Ass’n of Data Processing Svc. Orgs. v. Camp*, 397 U. S. 150, 153 (1970))).

The Campbell III Order continues the pattern established by two prior DOE Orders numbered 202-25-3 (“Campbell I”) and 202-25-7 (“Campbell II”) that also directed MISO and Consumers Energy to keep the Campbell Plant available to provide economic dispatch from its planned retirement date of June 1, 2025, through November 18, 2025.

The States requested rehearing of the Campbell I and II Orders and described the applicable facts, with record support, in those challenges. Exs. B-C (nested exhibits omitted). Campbell III is almost identical to Campbell II, which in turn extended Campbell I. Because the legal and factual issues here directly overlap and repeat the same matters previously raised, the States hereby incorporate by reference the petitions for rehearing of the Campbell I and II Orders, including all arguments, exhibits, and other referenced materials, and reassert them as grounds for rehearing of the Campbell III Order.

The States will be adversely affected by the Campbell III Order in the same ways they were harmed by the Campbell I and II Orders, but Campbell III also compounds and increases those harms through ongoing, cumulative emissions and related impacts. The negative effects on the States were described in the prior challenges and are hereby incorporated by reference.[3]

[3] The harms include economic harm to ratepayers in the States who are saddled with the increased costs associated with operating the inefficient, coal-burning Campbell Plant, the environmental harms of operating the coal plant, and the harm caused by usurping the States’ role in planning resource adequacy and generation.

The Campbell III Order compounds the errors of the prior orders for all of the reasons set forth in the States' Petitions for Rehearing filed June 23, 2025 (Campbell I) and September 19, 2025 (Campbell II).

As with the Campbell I and II Orders, the Campbell III Order should be rescinded because it lacked reasoned decisionmaking, exceeded DOE's authority, was not rationally tailored to meet the purported emergency, and demonstrated impermissible prejudgment of the relevant issues.

In addition to the grounds laid out in the requests for rehearing on the Campbell I and II Orders, Consumers Energy Company filed its most recent 10-Q and 8-K reports with the Securities and Exchange Commission on October 30, 2025. Consumers Energy reported that for the period from May 23, 2025 through September 30, 2025, the costs of keeping Campbell online were $164 million, but the plant made only $84 million in revenue from the sale of its output, netting an $80 million loss. Exs. D (summary of contents), E (copy of 10-Q). Specifically,

> During the initial emergency order period, the net financial impact of compliance was $53 million after applying MISO revenues of $67 million. For the second emergency order period through September 30, 2025, the net financial impact of compliance was $27 million after applying MISO revenues of $17 million.

Ex. E. at 62. Consumers Energy concluded that it would seek to recover the $80 million in net losses from ratepayers through FERC tariff proceedings. *Id*. These real-world figures confirm that the plant cannot be effectively used for "economic dispatch" because it is uneconomical and runs at a loss when operated as the Campbell III Order requires. They also confirm that operating Campell plant as ordered has not and will not "minimize cost to ratepayers" where net losses will be charged to them. Thus, the Consumers Energy SEC filings demonstrate that the Campbell III Order cannot be fulfilled according to its own terms. Ex. A at 8.

In addition to the Exhibits (A through E) attached to this request for rehearing, DOE is already in possession of the exhibits the States submitted in support of their petitions for rehearing of the Campbell I and II Orders. The States are not resubmitting those same documents since they are incorporated by reference into the record for this petition. If DOE needs additional copies of any documents, please contact any of the signatories to this request.

KEITH ELLISON
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Dated: December 18, 2025

KWAME RAOUL
ATTORNEY GENERAL OF
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Dated: December 18, 2025

UNITED STATES SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549
FORM 10-K

☒ **ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**
For the fiscal year ended December 31, 2025

OR

☐ TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the transition period from _____to_____

Commission File No.	Registrant; State of Incorporation; Address; and Telephone Number	IRS Employer Identification No.
1-9513	**CMS ENERGY CORPORATION** (A Michigan Corporation) One Energy Plaza, Jackson, Michigan 49201 (517) 788-0550	38-2726431
1-5611	**CONSUMERS ENERGY COMPANY** (A Michigan Corporation) One Energy Plaza, Jackson, Michigan 49201 (517) 788-0550	38-0442310

Securities registered pursuant to Section 12(b) of the Act:

Title of each class	**Trading Symbol(s)**	**Name of each exchange on which registered**
CMS Energy Corporation Common Stock, $0.01 par value	CMS	New York Stock Exchange
CMS Energy Corporation 5.625% Junior Subordinated Notes due 2078	CMSA	New York Stock Exchange
CMS Energy Corporation 5.875% Junior Subordinated Notes due 2078	CMSC	New York Stock Exchange
CMS Energy Corporation 5.875% Junior Subordinated Notes due 2079	CMSD	New York Stock Exchange
CMS Energy Corporation Depositary Shares, each representing a 1/1,000th interest in a share of 4.200% Cumulative Redeemable Perpetual Preferred Stock, Series C	CMS PRC	New York Stock Exchange
Consumers Energy Company Cumulative Preferred Stock, $100 par value: $4.50 Series	CMS-PB	New York Stock Exchange

Securities registered pursuant to Section 12(g) of the Act: None

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act.
CMS Energy Corporation: Yes ☒ No ☐ **Consumers Energy Company:** Yes ☒ No ☐

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act.
CMS Energy Corporation: Yes ☐ No ☒ **Consumers Energy Company:** Yes ☐ No ☒

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days.
CMS Energy Corporation: Yes ☒ No ☐ **Consumers Energy Company:** Yes ☒ No ☐

Indicate by check mark whether the registrant has submitted electronically every Interactive Data File required to be submitted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit such files).
CMS Energy Corporation: Yes ☒ No ☐ **Consumers Energy Company:** Yes ☒ No ☐

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, a smaller reporting company, or an emerging growth company. See the definitions of "large accelerated filer," "accelerated filer," "smaller reporting company," and "emerging growth company" in Rule 12b-2 of the Exchange Act.

CMS Energy Corporation:		**Consumers Energy Company:**	
Large accelerated filer	☒	Large accelerated filer	☐
Non-accelerated filer	☐	Non-accelerated filer	☒
Accelerated filer	☐	Accelerated filer	☐
Smaller reporting company	☐	Smaller reporting company	☐
Emerging growth company	☐	Emerging growth company	☐

If an emerging growth company, indicate by check mark if the registrant has elected not to use the extended transition period for complying with any new or revised financial accounting standards provided pursuant to Section 13(a) of the Exchange Act.
CMS Energy Corporation: ☐ **Consumers Energy Company:** ☐

Indicate by check mark whether the registrant has filed a report on and attestation to its management's assessment of the effectiveness of its internal control over financial reporting under Section 404(b) of the Sarbanes-Oxley Act (15 U.S.C. 7262(b)) by the registered public accounting firm that prepared or issued its audit report.
CMS Energy Corporation: ☒ **Consumers Energy Company:** ☒

If securities are registered pursuant to Section 12(b) of the Act, indicate by check mark whether the financial statements of the registrant included in the filing reflect the correction of an error to previously issued financial statements.
CMS Energy Corporation: ☐ **Consumers Energy Company:** ☐

Indicate by check mark whether any of those error corrections are restatements that required a recovery analysis of incentive-based compensation received by any of the registrant's executive officers during the relevant recovery period pursuant to §240.10D-1(b).
CMS Energy Corporation: ☐ **Consumers Energy Company:** ☐

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act).
CMS Energy Corporation: Yes ☐ No ☒ **Consumers Energy Company:** Yes ☐ No ☒

The aggregate market value of CMS Energy voting and non-voting common equity held by non-affiliates was $20.644 billion for the 297,980,694 CMS Energy Corporation Common Stock shares outstanding on June 30, 2025 based on the closing sale price of $69.28 for CMS Energy Corporation Common Stock, as reported by the New York Stock Exchange on such date. There were no shares of Consumers common equity held by non-affiliates as of June 30, 2025.

There were 306,420,901 shares of CMS Energy Corporation Common Stock outstanding on January 16, 2026. On January 16, 2026, CMS Energy held all 84,108,789 outstanding shares of common stock of Consumers.

Documents incorporated by reference in Part III: CMS Energy's and Consumers' proxy statement relating to their 2026 Annual Meetings of Shareholders to be held May 8, 2026.

CMS Energy Corporation
Consumers Energy Company
Annual Reports on Form 10-K to the Securities and Exchange Commission for the Year Ended December 31, 2025

Table of Contents

Glossary

Certain terms used in the text and financial statements are defined below.

2023 Energy Law
Michigan's Public Acts 229, 230, 231, 233, 234, and 235 of 2023

ABATE
Association of Businesses Advocating Tariff Equity

ABO
Accumulated benefit obligation; the liabilities of a pension plan based on service and pay to date, which differs from the PBO in that it does not reflect expected future salary increases

AFUDC
Allowance for borrowed and equity funds used during construction

AOCI
Accumulated other comprehensive income (loss)

ARO
Asset retirement obligation

ASC 715
Financial Accounting Standards Board Accounting Standards Codification Topic 715, Compensation—Retirement Benefits

ASC 740
Financial Accounting Standards Board Accounting Standards Codification Topic 740, Income Taxes

ASP
Appliance Service Plan

ASU
Financial Accounting Standards Board Accounting Standards Update

Audit Committee
The Audit Committee of the Board, which is composed entirely of independent directors.

Aviator Wind
Aviator Wind Holdings, LLC, a VIE in which Aviator Wind Equity Holdings holds a Class B membership interest

Aviator Wind Equity Holdings
Aviator Wind Equity Holdings, LLC, a VIE in which Grand River Wind, LLC, a wholly owned subsidiary of NorthStar Clean Energy, has a 51-percent interest

Bay Harbor
A residential/commercial real estate area located near Petoskey, Michigan, in which CMS Energy sold its interest in 2002

Bcf
Billion cubic feet

BG Solar Holdings
BG Solar Holdings, LLC, a VIE in which BG Solar Holdings I, LLC, a wholly owned subsidiary of Grand River Solar, LLC, a wholly owned subsidiary of NorthStar Clean Energy, holds a Class B membership interest

Board
Board of Directors of CMS Energy and Consumers

CAO
Chief Accounting Officer

CCR
Coal combustion residual

CEO
Chief Executive Officer

CERCLA
Comprehensive Environmental Response, Compensation, and Liability Act of 1980, as amended

CFO
Chief Financial Officer

CIO
Chief Information Officer

City-gate contract
An arrangement made for the point at which a local distribution company physically receives gas from a supplier or pipeline

Clean Air Act
Federal Clean Air Act of 1963, as amended

Clean Water Act
Federal Water Pollution Control Act of 1972, as amended

CMS Capital
CMS Capital, L.L.C., a wholly owned subsidiary of CMS Energy

CMS Energy
CMS Energy Corporation and its consolidated subsidiaries, unless otherwise noted; the parent of Consumers and NorthStar Clean Energy

CMS ERM
CMS Energy Resource Management Company a wholly owned subsidiary of NorthStar Clean Energy

CMS Gas Transmission
CMS Gas Transmission Company, a wholly owned subsidiary of NorthStar Clean Energy

CMS Land
CMS Land Company, a wholly owned subsidiary of CMS Capital, L.L.C., a wholly owned subsidiary of CMS Energy

Consumers
Consumers Energy Company and its consolidated subsidiaries, unless otherwise noted; a wholly owned subsidiary of CMS Energy

Consumers 2014 Securitization Funding
Consumers 2014 Securitization Funding LLC, a wholly owned consolidated bankruptcy-remote subsidiary of Consumers and special-purpose entity organized for the sole purpose of purchasing and owning securitization property, issuing securitization bonds, and pledging its interest in securitization property to a trustee to collateralize the securitization bonds

Consumers 2023 Securitization Funding
Consumers 2023 Securitization Funding LLC, a wholly owned consolidated bankruptcy-remote subsidiary of Consumers and special-purpose entity organized for the sole purpose of purchasing and owning securitization property, issuing securitization bonds, and pledging its interest in securitization property to a trustee to collateralize the securitization bonds

Covert Generating Station
A 1,200-MW natural gas-fueled generation station that was acquired by Consumers in 2023 from New Covert Generating Company, LLC, a non-affiliated company

Craven
Craven County Wood Energy Limited Partnership, a VIE in which HYDRA-CO Enterprises, Inc., a wholly owned subsidiary of NorthStar Clean Energy, has a 50-percent interest

CSAPR
Cross-State Air Pollution Rule of 2011, as amended

DB Pension Plan A
Defined benefit pension plan of CMS Energy and Consumers, including certain present and former affiliates and subsidiaries, created as of December 31, 2017 for active employees who were covered under the defined benefit pension plan that closed in 2005

DB Pension Plan B
Defined benefit pension plan of CMS Energy and Consumers, including certain present and former affiliates and subsidiaries, amended as of December 31, 2017 to include only retired and former employees who were covered under the defined benefit pension plan that closed in 2005

DB Pension Plans
Defined benefit pension plans of CMS Energy and Consumers, comprising DB Pension Plan A and DB Pension Plan B

DB SERP
Defined Benefit Supplemental Executive Retirement Plan

DCCP
Defined Company Contribution Plan

DC SERP
Defined Contribution Supplemental Executive Retirement Plan

Delta Solar Equity Holdings
Delta Solar Equity Holdings, LLC, a VIE in which Grand River Solar, LLC, a wholly owned subsidiary of NorthStar Clean Energy, has a 50-percent interest

DIG
Dearborn Industrial Generation, L.L.C., a wholly owned subsidiary of Dearborn Industrial Energy, L.L.C., a wholly owned subsidiary of NorthStar Clean Energy

Dodd-Frank Act
Dodd-Frank Wall Street Reform and Consumer Protection Act of 2010

DOE
U.S. Department of Energy

DTE Electric
DTE Electric Company, a non-affiliated company

EEI
Edison Electric Institute, an association representing all U.S. investor-owned electric companies

EGLE
Michigan Department of Environment, Great Lakes, and Energy

Electric Supply Plan
Consumers’ long-term strategy for delivering safe, reliable, affordable, clean, and equitable energy to its customers; this plan is outlined in Consumers’ integrated resource plan and incorporates the Renewable Energy Plan

Endangered Species Act
Federal Endangered Species Act of 1973, as amended

EnerBank
EnerBank USA, a wholly owned subsidiary of CMS Capital until October 1, 2021

Energy waste reduction
The reduction of energy consumption through energy efficiency and demand-side energy conservation, as established under Michigan law

EPA
U.S. Environmental Protection Agency

EPS
Earnings per share

ERCOT
Electric Reliability Council of Texas

ERP
Enterprise Resource Planning software

Exchange Act
Securities Exchange Act of 1934

Federal Power Act
Federal Power Act of 1920

FERC
Federal Energy Regulatory Commission

First Mortgage Bond Indenture
Indenture dated as of September 1, 1945 between Consumers and The Bank of New York Mellon, as Trustee, as amended and supplemented

FTR
Financial transmission right

GAAP
U.S. Generally Accepted Accounting Principles

GCC
Gas Customer Choice, which allows gas customers to purchase gas from alternative suppliers

GCR
Gas cost recovery

Genesee
Genesee Power Station Limited Partnership, a VIE in which HYDRA-CO Enterprises, Inc., a wholly owned subsidiary of NorthStar Clean Energy, has a 50-percent interest

Grayling
Grayling Generating Station Limited Partnership, a VIE in which HYDRA-CO Enterprises, Inc., a wholly owned subsidiary of NorthStar Clean Energy, has a 50-percent interest

GW
Gigawatt, a unit of energy equal to 1 billion watts

GWh
Gigawatt-hour, a unit of energy equal to 1 billion watt-hours

Internal Revenue Code
Internal Revenue Code of 1986, as amended

IRS
Internal Revenue Service

IT
Information technology

J.H. Campbell

J.H. Campbell Generating Complex, a three-unit coal-fueled electric generating facility comprised of Units 1 and 2, which are wholly owned by Consumers, and Unit 3, which Consumers jointly owns with the Michigan Public Power Agency, holding a 4.80-percent interest, and Wolverine Power, holding a 1.89-percent interest, each a non-affiliated company

kV

Thousand volts, a unit used to measure the difference in electrical pressure along a current

kVA

Thousand volt-amperes, a unit used to reflect the electrical power capacity rating of equipment or a system

kWh

Kilowatt-hour, a unit of energy equal to 1,000 watt-hours

Ludington

Ludington pumped-storage plant, jointly owned by Consumers and DTE Electric

MATS

Mercury and Air Toxics Standards, which limit mercury, acid gases, and other toxic pollution from coal-fueled and oil-fueled power plants

MCV Facility

A 1,647-MW natural gas-fueled, combined-cycle cogeneration facility operated by the MCV Partnership

MCV Partnership

Midland Cogeneration Venture Limited Partnership, a non-affiliated company

MCV PPA

PPA between Consumers and the MCV Partnership

METC

Michigan Electric Transmission Company, LLC, a non-affiliated company

MGP

Manufactured gas plant

Migratory Bird Treaty Act

Migratory Bird Treaty Act of 1918, as amended

MISO

Midcontinent Independent System Operator, Inc.

MISO Tariff
MISO Open Access Transmission, Energy, and Operating Reserve Markets Tariff

Mothball
To place a generating unit into a state of extended reserve shutdown in which the unit is inactive and unavailable for service for a specified period, during which the unit can be brought back into service after receiving appropriate notification and completing any necessary maintenance or other work; generation owners in MISO must request approval to mothball a unit, and MISO then evaluates the request for reliability impacts

MPSC
Michigan Public Service Commission

MRV
Market-related value of plan assets

MW
Megawatt, a unit of power equal to 1 million watts

MWh
Megawatt-hour, a unit of energy equal to 1 million watt-hours

NAAQS
National Ambient Air Quality Standards

Natural Gas Act
Natural Gas Act of 1938

NERC
North American Electric Reliability Corporation, a non-affiliated company responsible for developing and enforcing reliability standards, monitoring the bulk power system, and educating and certifying industry personnel

Newport Solar Holdings
Newport Solar Holdings III, LLC, a VIE in which Newport Solar Equity Holdings LLC, a wholly owned subsidiary of Grand River Solar, LLC, a wholly owned subsidiary of NorthStar Clean Energy, holds a Class B membership interest

NorthStar Clean Energy
NorthStar Clean Energy Company and its consolidated subsidiaries, unless otherwise noted; a wholly owned subsidiary of CMS Energy

NOx
Nitrogen oxides

NPDES
National Pollutant Discharge Elimination System, a permit system for regulating point sources of pollution under the Clean Water Act

NREPA
Part 201 of Michigan's Natural Resources and Environmental Protection Act of 1994, as amended

NWO Holdco
NWO Holdco, L.L.C., a VIE in which NWO Holdco I, LLC, a wholly owned subsidiary of NWO Wind Equity Holdings, LLC, holds a Class B membership interest

NWO Wind Equity Holdings
NWO Wind Equity Holdings, LLC, a VIE in which Grand River Wind, LLC, a wholly owned subsidiary of NorthStar Clean Energy, has a 50-percent interest

OBBBA
Federal One Big Beautiful Bill Act of 2025

OPEB
Other post-employment benefits

OPEB Plan
Postretirement health care and life insurance plans of CMS Energy and Consumers, including certain present and former affiliates and subsidiaries

OSHA
Occupational Safety and Health Administration

PBO
Projected benefit obligation

PCB
Polychlorinated biphenyl

PFAS
Per- and polyfluoroalkyl substances

PISP
Performance Incentive Stock Plan

PJM
PJM Interconnection Inc.

PPA
Power purchase agreement

PSCR
Power supply cost recovery

PURPA
Public Utility Regulatory Policies Act of 1978

RCRA
Federal Resource Conservation and Recovery Act of 1976

REC
Renewable energy credit

Reliability Roadmap
Consumers' five-year strategy to improve its electric distribution system and the reliability of the grid; this plan was filed with the MPSC in 2023, and is an update to Consumers' previous Electric Distribution Infrastructure Investment Plan filed in 2021

ROA
Retail Open Access, which allows electric generation customers to choose alternative electric suppliers pursuant to Michigan's Public Acts 141 and 142 of 2000, as amended

S&P
Standard & Poor's Financial Services LLC

SEC
U.S. Securities and Exchange Commission

Securitization
A financing method authorized by statute and approved by the MPSC which allows a utility to sell its right to receive a portion of the rate payments received from its customers for the repayment of securitization bonds issued by a special-purpose entity affiliated with such utility

SOFR
Secured overnight financing rate calculated and published by the Federal Reserve Bank of New York

TAES
Toshiba America Energy Systems Corporation, a non-affiliated company

TBJH
TBJH Inc., a non-affiliated company

TCJA
Tax Cuts and Jobs Act of 2017

Term SOFR
The rate per annum that is a forward-looking term rate based on SOFR

T.E.S. Filer City
T.E.S. Filer City Station Limited Partnership, a VIE in which HYDRA-CO Enterprises, Inc., a wholly owned subsidiary of NorthStar Clean Energy, has a 50-percent interest

Toshiba
Toshiba Corporation, a non-affiliated company

Toshiba International
Toshiba International Corporation, a non-affiliated company

USW
United Steel, Paper and Forestry, Rubber, Manufacturing, Energy, Allied Industrial and Service Workers International Union, AFL-CIO-CLC

UWUA
Utility Workers Union of America, AFL-CIO

VEBA trust
Voluntary employees' beneficiary association trusts accounts established specifically to set aside employer-contributed assets to pay for future expenses of the OPEB Plan

VIE
Variable interest entity

Wolverine Power
Wolverine Power Supply Cooperative, Inc., a non-affiliated company

Filing Format

This combined Form 10-K is separately filed by CMS Energy and Consumers. Information in this combined Form 10-K relating to each individual registrant is filed by such registrant on its own behalf. Consumers makes no representation regarding information relating to any other companies affiliated with CMS Energy other than its own subsidiaries.

CMS Energy is the parent holding company of several subsidiaries, including Consumers and NorthStar Clean Energy. None of CMS Energy, NorthStar Clean Energy, nor any of CMS Energy's other subsidiaries (other than Consumers) has any obligation in respect of Consumers' debt securities or preferred stock and holders of such securities should not consider the financial resources or results of operations of CMS Energy, NorthStar Clean Energy, nor any of CMS Energy's other subsidiaries (other than Consumers and its own subsidiaries (in relevant circumstances)) in making a decision with respect to Consumers' debt securities or preferred stock. Similarly, neither Consumers nor any other subsidiary of CMS Energy has any obligation in respect of securities of CMS Energy.

Forward-looking Statements and Information

This Form 10-K and other CMS Energy and Consumers disclosures may contain forward-looking statements as defined by the Private Securities Litigation Reform Act of 1995. The use of "anticipates," "assumes," "believes," "could," "estimates," "expects," "forecasts," "goals," "guidance," "intends," "may," "might," "objectives," "plans," "possible," "potential," "predicts," "projects," "seeks," "should," "targets," "will," and other similar words is intended to identify forward-looking statements that involve risk and uncertainty. This discussion of potential risks and uncertainties is designed to highlight important factors that may impact CMS Energy's and Consumers' businesses and financial outlook. CMS Energy and Consumers have no obligation to update or revise forward-looking statements regardless of whether new information, future events, or any other factors affect the information contained in the statements. These forward-looking statements are subject to various factors that could cause CMS Energy's and Consumers' actual results to differ materially from the results anticipated in these statements. These factors include, but are not limited to, the following, all of which are potentially significant:

- the impact and effect of recent events, such as worsening trade relations, geopolitical tensions, war, acts of terrorism, and the responses to these events, and related economic disruptions including, but not limited to, inflation, energy price volatility, tariffs, and supply chain disruptions
- the impact of new or modified regulation by the MPSC, FERC, and other applicable governmental proceedings and regulations, including any associated impact on electric or gas rates or rate structures
- potentially adverse regulatory treatment, effects of a failure to receive timely regulatory orders that are or could come before the MPSC, FERC, or other governmental authorities, or effects of a government shutdown
- changes in the performance of or regulations applicable to MISO, METC, pipelines, railroads, vessels, or other service providers that CMS Energy, Consumers, or any of their affiliates rely on to serve their customers
- federal or executive actions, the adoption of or challenges to federal or state laws or regulations or changes in applicable laws, rules, regulations, principles, or practices, or in their interpretation, such as those related to energy policy, ROA, the Public Utility Regulatory Policies Act of 1978, infrastructure integrity or security, cybersecurity, gas pipeline safety, gas pipeline capacity, energy waste reduction, the financial compensation mechanism, the environment, regulation or

deregulation, reliability, health care reforms, taxes, tax credits, accounting matters, tariffs, climate change, air emissions, renewable energy, the Dodd-Frank Act, and other business issues that could have an impact on CMS Energy's, Consumers', or any of their affiliates' businesses or financial results

- factors affecting, disrupting, interrupting, or otherwise impacting CMS Energy's or Consumers' facilities, utility infrastructure, operations, or backup systems, such as costs and availability of personnel, equipment, and materials; weather and climate, including catastrophic weather-related damage and extreme temperatures; natural disasters; fires; smoke; scheduled or unscheduled equipment outages; maintenance or repairs; contractor performance; environmental incidents; failures of equipment or materials; electric transmission and distribution or gas pipeline system constraints; interconnection requirements; political and social unrest; general strikes; the government and/or paramilitary response to political or social events; changes in trade policies, regulations, or tariffs; accidents; explosions; physical disasters; global pandemics; cyber incidents; physical or cyber attacks; vandalism; war or terrorism; and the ability to obtain or maintain insurance coverage for these events

- the ability of CMS Energy and Consumers to execute cost-reduction strategies and/or convert economic development opportunities

- potentially adverse regulatory or legal interpretations or decisions regarding environmental matters, or delayed regulatory treatment or permitting decisions that are or could come before agencies such as EGLE, the EPA, FERC, and/or the U.S. Army Corps of Engineers, and potential environmental remediation costs associated with these interpretations or decisions, including those that may affect Consumers' coal ash management or routine maintenance, repair, and replacement classification under New Source Review, a construction-permitting program under the Clean Air Act

- changes in energy markets, including availability, price, and seasonality of electric capacity and energy and the timing and extent of changes in commodity prices and availability and deliverability of coal, natural gas, natural gas liquids, electricity, oil, gasoline, diesel fuel, and certain related products

- the price of CMS Energy common stock, the credit ratings of CMS Energy and Consumers, capital and financial market conditions, and the effect of these market conditions on CMS Energy's and Consumers' interest costs and access to the capital markets, including availability of financing to CMS Energy, Consumers, or any of their affiliates

- the ability of CMS Energy and Consumers to execute their financing strategies

- the investment performance of the assets of CMS Energy's and Consumers' pension and benefit plans, the discount rates, mortality assumptions, and future medical costs used in calculating the plans' obligations, and the resulting impact on future funding requirements

- the impact of the economy, particularly in Michigan, and potential future volatility in the financial and credit markets on CMS Energy's, Consumers', or any of their affiliates' revenues, ability to collect accounts receivable from customers, or cost and availability of capital

- changes in the economic and financial viability of CMS Energy's and Consumers' suppliers, customers, and other counterparties and the continued ability of these third parties, including those in bankruptcy, to meet their obligations to CMS Energy and Consumers

- population changes in the geographic areas where CMS Energy and Consumers conduct business
- national, regional, and local economic, competitive, and regulatory policies, conditions, and developments
- loss of customer demand for electric generation supply to alternative electric suppliers, the creation of municipal utilities, increased use of self-generation including distributed generation, energy waste reduction, or energy storage
- loss of customer demand for natural gas due to alternative technologies or fuels or electrification
- the ability of Consumers to meet increased renewable energy demand due to customers seeking to meet their own sustainability goals in a timely and cost-efficient manner
- the reputational or other impact on CMS Energy and Consumers of the failure to meet the renewable or clean energy standards required by the 2023 Energy Law or to achieve or make timely progress on their greenhouse gas reduction goals related to reducing their impact on climate change
- adverse consequences of employee, director, or third-party fraud or non-compliance with codes of conduct or with laws or regulations
- federal regulation of electric sales, including periodic re-examination by federal regulators of CMS Energy's and Consumers' market-based sales authorizations
- any event, change, development, occurrence, or circumstance that could impact the implementation of the Electric Supply Plan, including any action by a regulatory authority or other third party to prohibit, delay, or impair the implementation of the Electric Supply Plan
- the ability to meet increases in electric demand associated with data centers, or alternatively, the risk that anticipated demand growth from data center expansion may not materialize as expected
- changes associated with artificial intelligence technologies and related sectors, including the risk that a significant decline in investor confidence could lead to broader economic disruption, reductions in customer demand, tightening of capital markets, higher financing costs, or other downstream impacts
- the availability, cost, coverage, and terms of insurance, the stability of insurance providers, and the ability of Consumers to recover the costs of any insurance from customers
- the effectiveness of CMS Energy's and Consumers' risk management policies, procedures, and strategies, including strategies to hedge risk related to interest rates and future prices of electricity, natural gas, and other energy-related commodities
- factors affecting development of electric generation projects, gas transmission, and gas and electric distribution infrastructure replacement, conversion, and expansion projects, including factors related to project site identification, construction material availability, quality, and pricing, tariffs, embargoes on equipment, supply chain disruptions, schedule delays, interconnection delays, availability of qualified construction personnel, permitting, acquisition of property rights, community opposition, environmental regulations, performance of contractors and counterparties, and government actions
- changes or disruption in fuel supply, including but not limited to supplier bankruptcy and delivery disruptions

- potential costs, lost revenues, reputational harm, or other consequences resulting from misappropriation of assets or sensitive information, corruption of data, or operational disruption in connection with a cyberattack or other cyber incident
- potential disruption to, interruption or failure of, or other impacts on IT backup or disaster recovery systems
- technological developments in energy production, storage, delivery, usage, and metering
- the ability to implement and integrate technology successfully, including artificial intelligence
- the impact of CMS Energy's and Consumers' integrated business software system and its effects on their operations, including utility customer billing and collections
- adverse consequences resulting from any past, present, or future assertion of indemnity or warranty claims associated with assets and businesses previously owned by CMS Energy or Consumers, including claims resulting from attempts by foreign or domestic governments to assess taxes on or to impose environmental liability associated with past operations or transactions
- the outcome, cost, and other effects of any legal or administrative claims, proceedings, investigations, or settlements
- the reputational impact on CMS Energy and Consumers of operational incidents, violations of corporate policies, regulatory violations, inappropriate use of social media, and other events
- restrictions imposed by various financing arrangements and regulatory requirements on the ability of Consumers and other subsidiaries of CMS Energy to transfer funds to CMS Energy in the form of cash dividends, loans, or advances
- earnings volatility resulting from the application of fair value accounting to certain energy commodity contracts or interest rate contracts
- changes in financial or regulatory accounting principles or policies or interpretation of principles or policies
- other matters that may be disclosed from time to time in CMS Energy's and Consumers' SEC filings, or in other public documents

All forward-looking statements should be considered in the context of the risk and other factors described above and as detailed from time to time in CMS Energy's and Consumers' SEC filings. For additional details regarding these and other uncertainties, see Item 1A. Risk Factors; Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations—Outlook; and Item 8. Financial Statements and Supplementary Data—Notes to the Consolidated Financial Statements—Note 3, Regulatory Matters and Note 4, Contingencies and Commitments.

Part I
Item 1. Business

General

CMS Energy

CMS Energy was formed as a corporation in Michigan in 1987 and is an energy company operating primarily in Michigan. It is the parent holding company of several subsidiaries, including Consumers, an electric and gas utility, and NorthStar Clean Energy, primarily a domestic independent power producer and marketer. Consumers' customer base consists of a mix of primarily residential, commercial, and diversified industrial customers. NorthStar Clean Energy, through its subsidiaries and equity investments, is engaged in domestic independent power production, including the development and operation of renewable generation, and the marketing of independent power production.

CMS Energy manages its businesses by the nature of services each provides, and operates principally in three business segments: electric utility; gas utility; and NorthStar Clean Energy, its non-utility operations and investments. Consumers' consolidated operations account for the substantial majority of CMS Energy's total assets, income, and operating revenue. CMS Energy's consolidated operating revenue was $8.5 billion in 2025, and $7.5 billion in 2024 and 2023.

For further information about operating revenue, income, and assets and liabilities attributable to all of CMS Energy's business segments and operations, see Item 8. Financial Statements and Supplementary Data—CMS Energy Consolidated Financial Statements and Notes to the Consolidated Financial Statements.

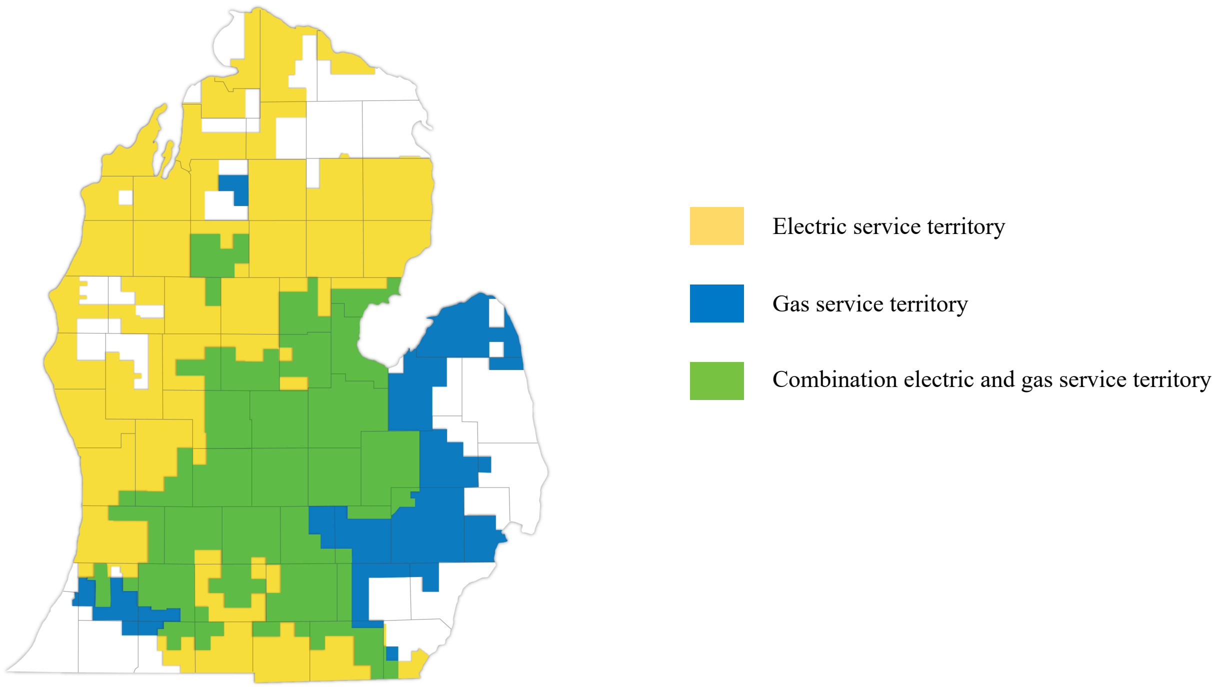
Consumers

Consumers has served Michigan customers since 1886. Consumers was incorporated in Maine in 1910 and became a Michigan corporation in 1968. Consumers owns and operates electric generation and distribution facilities and gas transmission, storage, and distribution facilities. It provides electricity and/or natural gas to 6.8 million of Michigan's 10 million residents. Consumers' rates and certain other aspects of its business are subject to the jurisdiction of the MPSC and FERC, as well as to NERC reliability standards, as described in CMS Energy and Consumers Regulation.

Consumers' consolidated operating revenue was $8.1 billion in 2025, and $7.2 billion in 2024 and 2023. For further information about operating revenue, income, and assets and liabilities attributable to Consumers' electric and gas utility operations, see Item 8. Financial Statements and Supplementary Data—Consumers Consolidated Financial Statements and Notes to the Consolidated Financial Statements.

Consumers owns its principal properties in fee, except that most electric lines, gas mains, and renewable generation projects are located below or adjacent to public roads or on land owned by others and are accessed by Consumers through easements, leases, and other rights. Almost all of Consumers' properties are subject to the lien of its First Mortgage Bond Indenture. For additional information on Consumers' properties, see Business Segments—Consumers Electric Utility—Electric Utility Properties and Consumers Gas Utility—Gas Utility Properties.

In 2025, Consumers served 1.9 million electric customers and 1.8 million gas customers in Michigan's Lower Peninsula. Presented in the following map are Consumers' service territories:



CMS Energy and Consumers—The Triple Bottom Line

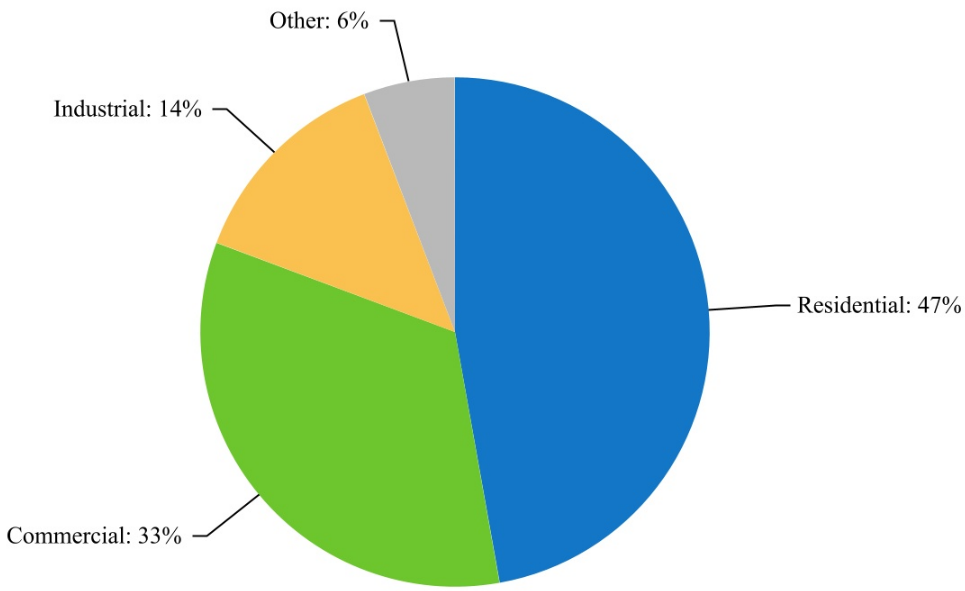
For information regarding CMS Energy's and Consumers' purpose and impact on the "triple bottom line" of people, planet, and prosperity, see Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations—Executive Overview.

Business Segments

Consumers Electric Utility

Electric Utility Operations: Consumers' electric utility operations, which include the generation, purchase, distribution, and sale of electricity, generated operating revenue of $5.6 billion in 2025, $5.1 billion in 2024, and $4.7 billion in 2023. Consumers' electric utility customer base consists of a mix of primarily residential, commercial, and diversified industrial customers in Michigan's Lower Peninsula.

Presented in the following illustration is Consumers’ 2025 electric utility operating revenue of $5.6 billion by customer class:

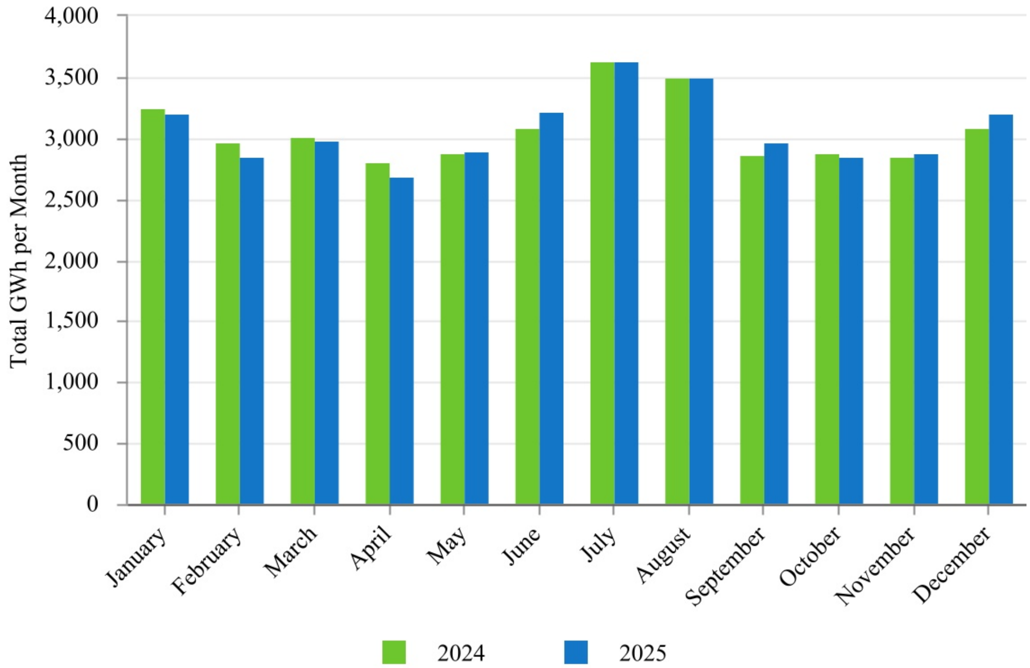


Consumers’ electric utility operations are not dependent on a single customer, or even a few customers, and the loss of any one or even a few of Consumers’ largest customers is not reasonably likely to have a material adverse effect on Consumers’ financial condition.

In 2025, Consumers’ electric deliveries were 37 billion kWh, which included ROA deliveries of 3 billion kWh, resulting in net bundled sales of 34 billion kWh. In 2024, Consumers’ electric deliveries were 37 billion kWh, which included ROA deliveries of 4 billion kWh, resulting in net bundled sales of 33 billion kWh.

Consumers’ electric utility operations are seasonal. The consumption of electric energy typically increases in the summer months, due primarily to the use of air conditioners and other cooling equipment.

Presented in the following illustration are Consumers' monthly weather-normalized electric deliveries (deliveries adjusted to reflect normal weather conditions) to its customers, including ROA deliveries, during 2025 and 2024:



Consumers' 2025 summer peak demand was 8,500 MW, which included ROA demand of 552 MW. For the 2024-2025 winter season, Consumers' peak demand was 5,755 MW, which included ROA demand of 449 MW. As required by MISO reserve margin requirements, Consumers owns or controls, through long-term PPAs, short-term capacity purchases, and auction capacity purchases, all of the capacity required to supply its projected firm peak load and necessary reserve margin for summer 2026.

Electric Utility Properties: Consumers owns and operates electric generation and distribution facilities. For details about Consumers' electric generation facilities, see the Electric Utility Generation and Supply Mix section that follows this Electric Utility Properties section. Consumers' distribution system consists of:

- 263 miles of high-voltage distribution overhead lines operating at 138 kV
- 4 miles of high-voltage distribution underground lines operating at 138 kV
- 4,619 miles of high-voltage distribution overhead lines operating at 46 kV and 69 kV
- 18 miles of high-voltage distribution underground lines operating at 46 kV
- 82,854 miles of electric distribution overhead lines
- 10,027 miles of underground distribution lines
- 1,102 substations with an aggregate transformer capacity of 29 million kVA

Consumers is interconnected to the interstate high-voltage electric transmission system owned by METC and operated by MISO. Consumers is also interconnected to neighboring utilities and to other transmission systems.

Electric Utility Generation and Supply Mix: Consumers' Electric Supply Plan, its long-term strategy for delivering safe, reliable, affordable, clean, and equitable energy to its customers, is outlined in its integrated resource plan and incorporates Consumers' Renewable Energy Plan. The Electric Supply Plan is Consumers' blueprint for compliance with Michigan's 2023 Energy Law and for advancing sustainability objectives.

To meet these objectives, Consumers is executing a multi-faceted strategy. This strategy involves taking steps to end the use of coal, including the retirement of the D.E. Karn coal-fueled generating units, totaling 515 MW of nameplate capacity, in 2023 and obtaining MPSC approval to retire J.H. Campbell, totaling 1,407 MW of nameplate capacity. The retirement of J.H. Campbell is subject to temporary extensions under emergency orders issued by the U.S. Secretary of Energy. For a more detailed discussion of the emergency orders, see Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations—Outlook—Consumers Electric Utility Outlook and Uncertainties—J.H. Campbell Emergency Orders and Item 8. Financial Statements and Supplementary Data—Notes to the Consolidated Financial Statements—Note 3, Regulatory Matters.

To continue providing controllable sources of electricity to customers, Consumers purchased the Covert Generating Station, representing 1,200 MW of nameplate capacity, in 2023 and has solicited additional capacity from controllable sources of electricity to customers.

Consumers' updates to its Renewable Energy Plan include up to 9,000 MW of both purchased and owned solar energy resources and up to 4,000 MW of wind energy resources. Coupled with updates to its integrated resource plan, these actions position Consumers to achieve 60-percent renewable energy by 2035 and 100-percent clean energy by 2040. For further information on Consumers' progress towards reducing carbon emissions and towards meeting the requirements of the 2023 Energy Law, see Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations—Executive Overview and Outlook—Consumers Electric Utility Outlook and Uncertainties.

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Presented in the following table are details about Consumers' 2025 electric generation and supply mix:

Name and Location (Michigan)	Number of Units and Year Entered Service	2025 Generation Capacity [1] (MW)	2025 Electric Supply (GWh)
Coal steam generation			
J.H. Campbell 1 & 2 – West Olive[2]	2 Units, 1962-1967	—	2,568
J.H. Campbell 3 – West Olive[2,3]	1 Unit, 1980	—	4,752
		—	7,320
Oil/Gas steam generation			
D.E. Karn 3 & 4 – Essexville	2 Units, 1975-1977	1,189	106
Hydroelectric			
Ludington – Ludington	6 Units, 1973	1,119 [4]	(360) [5]
Conventional hydro generation[6]	35 Units, 1906-1949	75	344
		1,194	(16)
Gas combined cycle			
Covert Generating Station – Covert	3 Units, 2004	1,090	7,357
Jackson – Jackson	1 Unit, 2002	531	1,979
Zeeland – Zeeland	3 Units, 2002	534	3,952
		2,155	13,288
Gas combustion turbines			
Zeeland (simple cycle) – Zeeland	2 Units, 2001	314	1,373
Wind generation			
Crescent Wind Farm – Hillsdale County	2021	150	362
Cross Winds® Energy Park – Tuscola County	2014-2019	231	728
Gratiot Farms Wind Project – Gratiot County	2020	150	345
Heartland Farms Wind Project – Gratiot County	2023	200	470
Lake Winds® Energy Park – Mason County	2012	101	251
		832	2,156
Solar generation			
Solar Gardens – Allendale, Cadillac, Kalamazoo, and Grand Rapids	2016-2021	5	7
Muskegon Solar Energy Center	2025	250	2
		255	9
Battery storage capacity			
Batteries – Grand Rapids, Cadillac, Kalamazoo, and Standish	4 Units, 2021-2022	1	—
Total owned generation		5,940	24,236
Purchased power[7]			
Coal generation – T.E.S. Filer City		63	352
Gas generation – MCV Facility[8]		1,240	7,206
Other gas generation		254	1,233
Wind generation		384	1,026
Solar generation		1,017	1,355
Battery storage		100	(8) [9]
Other renewable generation		192	1,005
		3,250	12,169
Net interchange power[10]		—	(502)
Total purchased and interchange power		3,250	11,667
Total supply		9,190	35,903
Less distribution and transmission loss			2,094
Total net bundled sales			33,809

[1] With the exception of wind and solar generation, the amount represents generation capacity during the summer months (planning year 2025 capacity as reported to MISO and limited by interconnection service limits). For wind and solar generation, the amount represents installed capacity.

[2] Consumers planned to retire these generating units in May 2025. However, the retirement of J.H. Campbell is subject to temporary extensions under emergency orders issued by the U.S. Secretary of Energy. Under those emergency orders, Consumers has continued to operate these units for the benefit of MISO's North and Central regions. Of the 7,320 GWh generated by these units during 2025, Consumers supplied 3,608 GWh of electricity to MISO in order to comply with the emergency orders. For a more detailed discussion of the emergency orders, see Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations—Outlook—Consumers Electric Utility Outlook and Uncertainties—J.H. Campbell Emergency Orders and Item 8. Financial Statements and Supplementary Data—Notes to the Consolidated Financial Statements—Note 3, Regulatory Matters.

[3] Represents Consumers' share of the electric supply of the J.H. Campbell 3 unit, net of the 6.69-percent ownership interest of the Michigan Public Power Agency and Wolverine Power, each a non-affiliated company.

[4] Represents Consumers' 51-percent share of the capacity of Ludington. DTE Electric holds the remaining 49-percent ownership interest.

[5] Represents Consumers' share of net pumped-storage generation. The pumped-storage facility consumes electricity to pump water during off-peak hours for storage in order to generate electricity later during peak-demand hours.

[6] In 2025, Consumers entered an agreement to sell the 13 hydroelectric dams that comprise the 35 generating units. For a more detailed discussion of this transaction, see Item 8. Financial Statements and Supplementary Data—Notes to the Consolidated Financial Statements—Note 20, Exit Activities and Asset Sales.

[7] Represents purchases under long-term PPAs, including capacity purchases.

[8] For information about Consumers' long-term PPA related to the MCV Facility, see Item 8. Financial Statements and Supplementary Data—Notes to the Consolidated Financial Statements—Note 4, Contingencies and Commitments—Contractual Commitments.

[9] Reflects net delivered energy from storage operations, after accounting for charging losses.

[10] Represents the net amount of generation offered to and purchased from the MISO energy market.

Presented in the following table are the sources of Consumers' electric supply for the last three years:

			GWh
Years Ended December 31	2025	2024	2023
Owned generation			
Gas	14,661	14,856	11,221
Coal	7,320	7,932	6,884
Renewable energy	2,509	2,521	1,993
Oil	106	96	2
Net pumped storage[1]	(360)	(458)	(349)
Total owned generation	24,236	24,947	19,751
Purchased power[2]			
Gas generation	8,439	9,662	7,244
Renewable energy generation	3,386	3,138	2,585
Battery storage[3]	(8)	—	—
Coal generation	352	230	318
Net interchange power[4]	(502)	(2,715)	4,532
Total purchased and interchange power	11,667	10,315	14,679
Total supply	35,903	35,262	34,430

1 Represents Consumers' share of net pumped-storage generation. During 2025, the pumped-storage facility consumed 1,351 GWh of electricity to pump water during off-peak hours for storage in order to generate 991 GWh of electricity later during peak-demand hours.

2 Represents purchases under long-term PPAs, including capacity purchases.

3 Reflects net delivered energy from storage operations, after accounting for charging losses.

4 Represents the net amount of generation offered to and purchased from the MISO energy market.

During 2025, 41 percent of Consumers' electric supply was generated by its natural gas-fueled generating units, which burned 105 Bcf of natural gas and produced a combined total of 14,661 GWh of electricity.

In order to obtain the gas it needs for electric generation fuel, Consumers' electric utility purchases gas from the market near the time of consumption, at prices that allow it to compete in the electric wholesale market. For the Covert Generating Station and Jackson and Zeeland plants, Consumers utilizes an agent that owns firm transportation rights to each plant to purchase gas from the market and transport the gas to the facilities. For units 3 & 4 of D.E. Karn, Consumers holds gas transportation contracts to transport to the plant gas that Consumers or an agent purchase from the market.

During 2025, Consumers acquired 32 percent of its electric supply through long-term PPAs and the MISO energy market. Consumers offers its generation into the MISO energy market on a day-ahead and real-time basis and bids for power in the market to serve the demand of its customers. Consumers supplements its generation capability with purchases from the MISO energy market.

At December 31, 2025, Consumers had future commitments to purchase capacity and energy under long-term PPAs with various generating plants. These contracts require monthly capacity payments based on the plants' availability or deliverability. The payments for 2026 through 2060 are estimated to total $17.0 billion and, for each of the next five years, range from $0.9 billion to $1.0 billion annually. These amounts may vary depending on plant availability and fuel costs. For further information about

Consumers’ future capacity and energy purchase obligations, see Item 7. Management’s Discussion and Analysis of Financial Condition and Results of Operations—Capital Resources and Liquidity—Other Material Cash Requirements and Item 8. Financial Statements and Supplementary Data—Notes to the Consolidated Financial Statements—Note 4, Contingencies and Commitments—Contractual Commitments.

During 2025, 20 percent of Consumers’ electric supply was generated by its coal-fueled generating units, which burned 4 million tons of coal and produced a combined total of 7,320 GWh of electricity. Consumers planned to exit coal generation in 2025 but the retirement of J.H. Campbell is subject to temporary extensions under emergency orders issued by the U.S. Secretary of Energy. Of the 7,320 GWh generated by these units during 2025, Consumers supplied 3,608 GWh of electricity to MISO in order to comply with the emergency orders. For a more detailed discussion of the emergency orders, see Item 7. Management’s Discussion and Analysis of Financial Condition and Results of Operations—Outlook—Consumers Electric Utility Outlook and Uncertainties—J.H. Campbell Emergency Orders and Item 8. Financial Statements and Supplementary Data—Notes to the Consolidated Financial Statements—Note 3, Regulatory Matters.

In order to obtain the coal it needs, Consumers has historically entered into physical coal supply contracts, leased a fleet of railcars, and secured transportation contracts with various companies to provide rail services for delivery of purchased coal to Consumers’ generating facilities. Following the emergency orders, Consumers was able to utilize relationships with existing suppliers in order to procure additional supply and maintain railcar leases and transportation contracts past the planned shutdown date of May 2025. At December 31, 2025, Consumers had future commitments to purchase and deliver coal for the remainder of the then-current emergency order, with options to extend these agreements if needed.

Electric Utility Competition: Consumers’ electric utility business is subject to actual and potential competition from many sources, in both the wholesale and retail markets, as well as in electric generation, electric delivery, and retail services.

Michigan law allows electric customers in Consumers’ service territory to buy electric generation service from alternative electric suppliers in an aggregate amount capped at 10 percent of Consumers’ sales, with certain exceptions. At December 31, 2025, electric deliveries under the ROA program were at the 10-percent limit. Fewer than 300 of Consumers’ electric customers purchased electric generation service under the ROA program. For additional information, see Item 7. Management’s Discussion and Analysis of Financial Condition and Results of Operations—Outlook—Consumers Electric Utility Outlook and Uncertainties.

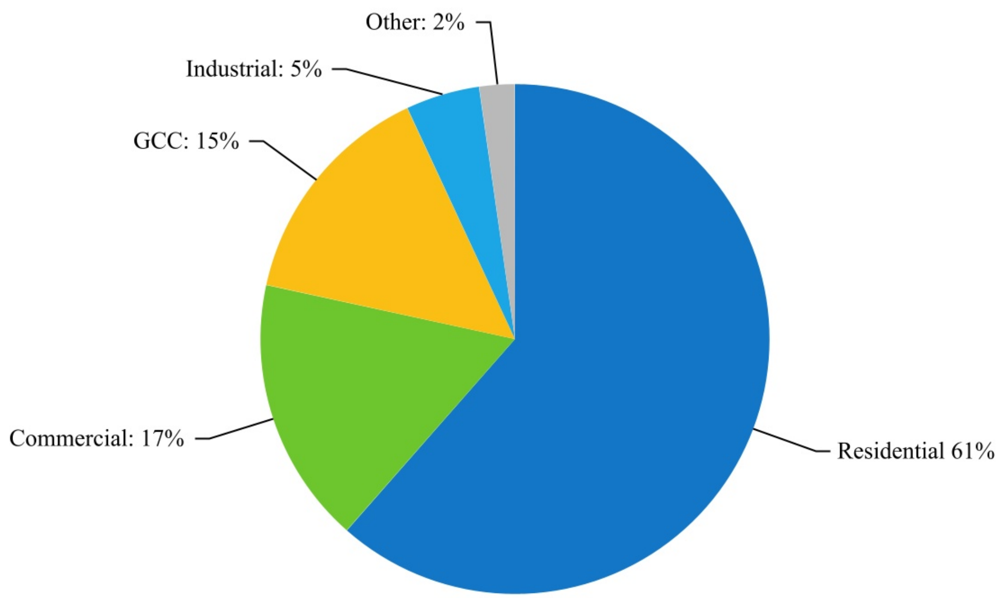
Consumers also faces competition or potential competition associated with data center expansion and industrial customer relocation outside of Consumers’ service territory for economic reasons; municipalities owning or operating competing electric delivery systems; and customer self-generation. Consumers addresses this competition in various ways, including:

- aggressively controlling operating, maintenance, power supply, and fuel costs and passing savings on to customers
- providing renewable energy options and energy waste reduction programs
- providing competitive rate-design options, particularly for large energy-intensive customers
- offering tariff-based incentives that support economic development
- monitoring activity in adjacent geographical areas

Consumers Gas Utility

Gas Utility Operations: Consumers' gas utility operations, which include the purchase, transmission, storage, distribution, and sale of natural gas, generated operating revenue of $2.5 billion in 2025, $2.1 billion in 2024, and $2.4 billion in 2023. Consumers' gas utility customer base consists of a mix of primarily residential, commercial, and diversified industrial customers in Michigan's Lower Peninsula.

Presented in the following illustration is Consumers' 2025 gas utility operating revenue of $2.5 billion by customer class:



Consumers' gas utility operations are not dependent on a single customer, or even a few customers, and the loss of any one or even a few of Consumers' largest customers is not reasonably likely to have a material adverse effect on Consumers' financial condition.

In 2025, deliveries of natural gas through Consumers' pipeline and distribution network, including off-system transportation deliveries, totaled 396 Bcf, which included GCC deliveries of 31 Bcf. In 2024, deliveries of natural gas through Consumers' pipeline and distribution network, including off-system transportation deliveries, totaled 362 Bcf, which included GCC deliveries of 27 Bcf. Consumers' gas utility operations are seasonal. The consumption of natural gas increases in the winter, due primarily to colder temperatures and the resulting use of natural gas as heating fuel. Consumers injects natural gas into storage during the summer months for use during the winter months. During 2025, 46 percent of the natural gas supplied to all customers during the winter months was supplied from storage.

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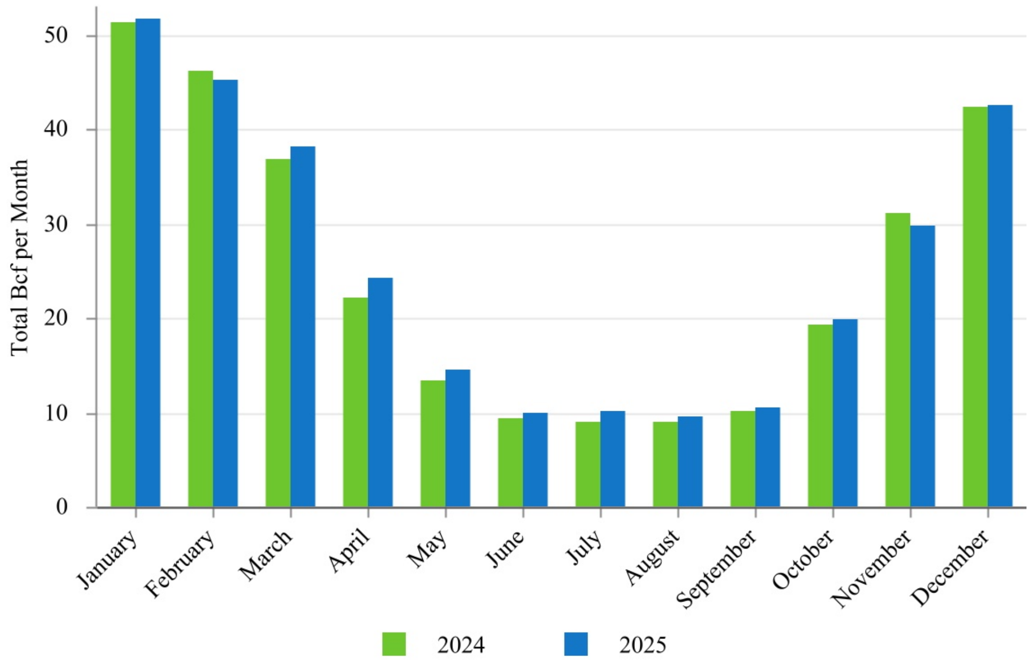
Presented in the following illustration are Consumers' monthly weather-normalized natural gas deliveries (deliveries adjusted to reflect normal weather conditions) to its customers, including GCC deliveries, during 2025 and 2024:



Gas Utility Properties: Consumers' gas transmission, storage, and distribution system consists of:

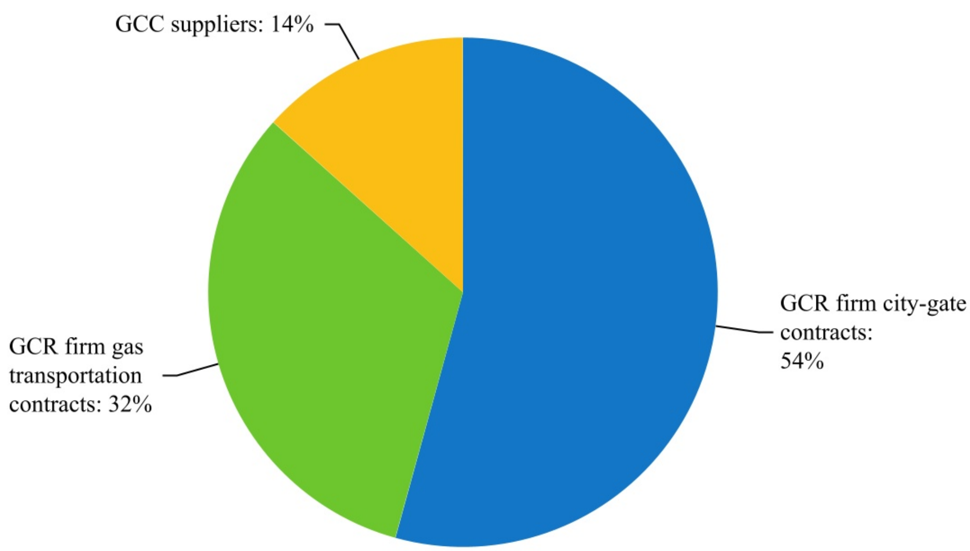
- 2,337 miles of transmission lines
- 14 gas storage fields with a total storage capacity of 300 Bcf and a working gas volume of 153 Bcf
- 28,433 miles of distribution mains
- 8 compressor stations with a total of 147,393 installed and available horsepower

Under its Methane Reduction Plan, Consumers has set a goal of net-zero methane emissions from its natural gas delivery system by 2030. Consumers plans to reduce methane emissions from its system by about 80 percent from 2012 baseline levels by accelerating the replacement of aging pipe, rehabilitating or retiring outdated infrastructure, and adopting new technologies and practices. The remaining emissions will likely be offset through clean fuel alternatives or nature-based carbon removal pathways.

Consumers has also set a goal to reduce customer greenhouse gas emissions by 25 percent by 2035. Consumers' Natural Gas Delivery Plan, a rolling ten-year investment plan to deliver safe, reliable, clean, and affordable natural gas to customers, outlines ways in which Consumers can make early progress toward these goals in a cost-effective manner, including energy waste reduction, carbon offsets, and renewable natural gas supply.

Consumers has already initiated work in these key areas by continuing to expand its energy waste reduction targets and by offering gas customers the ability to offset their carbon footprint associated with natural gas use by purchasing renewable natural gas and/or carbon credits associated with Michigan forest preservation. Consumers has renewable natural gas facilities under construction scheduled for commercial operation in 2026 and is monitoring regulatory developments and market conditions closely as part of its ongoing evaluation of the projects. For further information on Consumers' progress towards its net-zero methane emissions goal, see Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations—Executive Overview.

Gas Utility Supply: In 2025, Consumers purchased 86 percent of the gas it delivered to its full-service sales customers. The remaining 14 percent was purchased from authorized GCC suppliers and delivered by Consumers to customers in the GCC program. Presented in the following illustration are the supply arrangements for the gas Consumers delivered to GCC and GCR customers during 2025:



Firm city-gate and firm gas transportation contracts are those that define a fixed amount, price, and delivery time frame. Consumers' firm gas transportation contracts are with Panhandle Eastern Pipe Line Company and Trunkline Gas Company, LLC, each a non-affiliated company. Under these contracts, Consumers purchases and transports gas to Michigan for ultimate delivery to its customers. Consumers' firm gas transportation contracts expire on various dates through 2028 with planned contract volumes providing 34 percent of Consumers' total forecasted gas supply requirements for 2026. Consumers purchases the balance of its required gas supply under firm city-gate contracts and through authorized suppliers under the GCC program.

Gas Utility Competition: Competition exists in various aspects of Consumers' gas utility business. Competition comes from GCC and transportation programs; system bypass by new and existing customers; and from alternative fuels and energy sources, such as propane, oil, and electricity.

NorthStar Clean Energy—Non-utility Operations and Investments

NorthStar Clean Energy, through various subsidiaries and certain equity investments, is engaged in domestic independent power production, including the development and operation of renewable generation, and the marketing of independent power production. NorthStar Clean Energy's operating revenue was $408 million in 2025, $316 million in 2024, and $297 million in 2023.

Independent Power Production: Presented in the following table is information about the independent power plants in which CMS Energy had an ownership interest at December 31, 2025:

Location	Ownership Interest (%)	Primary Fuel Type	Gross Capacity [1] (MW)	2025 Net Generation (GWh)
Dearborn, Michigan	100	Natural gas	770	3,965
Jackson County, Arkansas	100	Solar	180	356
Gaylord, Michigan	100	Natural gas	134	22
Comstock, Michigan	100	Natural gas	76	136
Genesee County, Michigan[2]	100	Solar	42	1
Alpena, Michigan[3]	100	Solar	21	27
Saginaw, Michigan[3]	100	Solar	8	10
Paulding County, Ohio	100	Solar and Storage	3	—
Grayling, Michigan[3]	100	Solar	1	—
Coke County, Texas	51	Wind	525	1,697
Paulding County, Ohio[4]	50	Wind	100	299
Filer City, Michigan	50	Coal	73	351
New Bern, North Carolina	50	Wood waste	50	284
Flint, Michigan	50	Wood waste	40	117
Grayling, Michigan	50	Wood waste	38	182
Delta Township, Michigan[4]	50	Solar	24	38
Total			2,085	7,485

1 Represents the intended full-load sustained output of each plant. The amount of capacity relating to CMS Energy's ownership interest was 1,665 MW and net generation relating to CMS Energy's ownership interest was 6,018 GWh at December 31, 2025.

2 This project began operations in December 2025.

3 Represents a behind-the-meter system located on customer premises.

4 NorthStar Clean Energy sold a noncontrolling interest in this plant in 2025. For additional details see Item 8. Financial Statements and Supplementary Data—Notes to the Consolidated Financial Statements—Note 19, Variable Interest Entities.

The operating revenue from independent power production was $77 million in 2025, $69 million in 2024, and $64 million in 2023.

Energy Resource Management: CMS ERM purchases and sells energy commodities in support of NorthStar Clean Energy's generating facilities with a focus on optimizing the independent power production portfolio. In 2025, CMS ERM marketed 2 Bcf of natural gas and 7,625 GWh of electricity. Electricity marketed by CMS ERM was generated by independent power production of NorthStar Clean

Energy and by unrelated third parties. CMS ERM’s operating revenue was $331 million in 2025, $247 million in 2024, and $233 million in 2023.

NorthStar Clean Energy Competition: NorthStar Clean Energy competes with other energy developers, energy retailers, and independent power producers. The needs of this market are driven by current electric demand and available generation, as well as projections of future electric demand and available generation.

CMS Energy and Consumers Regulation

CMS Energy, Consumers, and their subsidiaries are subject to regulation by various federal, state, and local governmental agencies, including those described in the following sections. Rate proceedings and other regulatory actions may affect operations and financial results. If CMS Energy, Consumers, or their subsidiaries failed to comply with applicable laws and regulations, they could become subject to fines, penalties, or disallowed costs, or be required to implement additional compliance, cleanup, or remediation programs, the cost of which could be material. For more information on the potential impacts of government regulation and rate proceedings affecting CMS Energy, Consumers, and their subsidiaries, see Item 1A. Risk Factors, Item 7. Management’s Discussion and Analysis of Financial Condition and Results of Operations—Outlook, and Item 8. Financial Statements and Supplementary Data—Notes to the Consolidated Financial Statements—Note 3, Regulatory Matters.

FERC and NERC

CMS Energy and its affiliates and subsidiaries are subject to regulation by FERC in a number of areas. FERC regulates certain aspects of Consumers’ electric business, including, but not limited to, compliance with FERC accounting rules, wholesale electric and transmission rates, operation of licensed hydroelectric generating plants, corporate mergers and the sale and purchase of certain assets, issuance of securities, and conduct among affiliates. FERC also regulates the tariff rules and procedures administered by MISO and other independent system operators/regional transmission organizations, including rules governing wholesale electric markets and interconnection of new generating facilities to the transmission system. FERC, in connection with NERC and with regional reliability organizations, also regulates generation and transmission owners and operators, load-serving entities, and others with regard to reliability of the bulk power system.

FERC also regulates limited aspects of Consumers’ gas business, principally compliance with FERC capacity release rules, shipping rules, the prohibition of certain buy/sell transactions, and the price-reporting rule.

FERC also regulates holding company matters, interlocking directorates, and other issues affecting CMS Energy. In addition, similar to FERC’s regulation of Consumers’ electric and gas businesses, FERC has jurisdiction over several independent power plants, PURPA-qualifying facilities, and exempt wholesale generators in which NorthStar Clean Energy has ownership interests, as well as over NorthStar Clean Energy itself, CMS ERM, CMS Gas Transmission, and DIG.

MPSC

Consumers is subject to the jurisdiction of the MPSC, which regulates public utilities in Michigan with respect to retail utility rates, accounting, utility services, certain facilities, certain asset transfers, corporate mergers, and other matters.

The Michigan Attorney General, ABATE, the MPSC Staff, residential customer advocacy groups, environmental organizations, and certain other parties typically participate in MPSC proceedings concerning Consumers. These parties often challenge various aspects of those proceedings, including the prudence of Consumers' policies and practices, and seek cost disallowances and other relief. The parties also have appealed significant MPSC and FERC orders.

Other Regulation

The U.S. Secretary of Energy regulates imports and exports of natural gas and has delegated various aspects of this jurisdiction to FERC and the DOE's Office of Fossil Fuels. Additionally, the U.S. Secretary of Energy has the authority to issue emergency orders for power plants under section 202(c) of the Federal Power Act. This provision allows the U.S. Secretary of Energy to temporarily alter the operation of the electricity system during emergencies.

The U.S. Department of Transportation's Office of Pipeline Safety regulates the safety and security of gas pipelines through the Natural Gas Pipeline Safety Act of 1968 and subsequent laws.

The Transportation Security Administration, an agency of the U.S. Department of Homeland Security, regulates certain activities related to the safety and security of natural gas pipelines.

Energy Legislation

In 2023, Michigan enacted the 2023 Energy Law, which among other things:

- increased the renewable energy standard from 15 percent to 50 percent by 2030 and 60 percent by 2035; renewable energy generated anywhere within MISO can be applied to meeting this standard, with certain limitations
- established a clean energy standard of 80 percent by 2035 and 100 percent by 2040; low- or zero-carbon emitting resources, such as nuclear generation and natural gas generation coupled with carbon capture, qualify as clean energy sources under this standard
- authorized the MPSC to grant extensions of the clean energy or renewable energy standards deadlines if compliance is not practically feasible, would be excessively costly to customers, or would cause reliability issues
- increased the energy waste reduction requirement for electric utilities to achieve annual reductions in customers' electricity use from the present 1-percent reduction requirement to 1.5 percent beginning in 2026; beyond this requirement, the law set a goal of a 2-percent reduction and required that such goal be incorporated in an electric utility's integrated resource plan modeling scenarios
- increased the energy waste reduction requirement for gas utilities to achieve annual reductions in customers' gas use from the present 0.75-percent reduction requirement to 0.875 percent beginning in 2026
- enhanced existing incentives for energy efficiency programs and returns earned on new clean or renewable PPAs
- created a new energy storage standard, requiring electric utilities to file plans by 2029 to help achieve a statewide target of 2,500 MW
- expanded the statutory cap on distributed generation resources to 10 percent of the electric utility's five-year average peak load
- expanded the MPSC's scope of considerations in integrated resource plans to include affordability, greenhouse gas emissions, environmental justice considerations, the effects on human health, and other environmental concerns
- provided the MPSC siting authority over large renewable energy projects

Consumers' updates to its Renewable Energy Plan, which were approved by the MPSC in September 2025, and planned updates to its integrated resource plan in 2026 will serve as a blueprint to meeting the requirements of the 2023 Energy Law by focusing on increasing the generation of renewable energy, deploying energy storage, helping customers use less energy, and offering demand response programs to reduce demand during critical peak times.

CMS Energy and Consumers Environmental Strategy and Compliance

CMS Energy and Consumers are committed to protecting the environment; this commitment extends beyond compliance with applicable laws and regulations. Consumers' Electric Supply Plan, its long-term strategy for delivering safe, reliable, affordable, clean, and equitable energy to its customers, is outlined in its integrated resource plan and incorporates Consumers' Renewable Energy Plan. The Electric Supply Plan is Consumers' blueprint for compliance with Michigan's 2023 Energy Law and for advancing sustainability objectives. This plan positions Consumers to achieve 60-percent renewable energy by 2035 and 100-percent clean energy by 2040.

Under its Methane Reduction Plan, Consumers has set a goal of net-zero methane emissions from its natural gas delivery system by 2030. Consumers plans to reduce methane emissions from its system by about 80 percent from 2012 baseline levels by accelerating the replacement of aging pipe, rehabilitating or retiring outdated infrastructure, and adopting new technologies and practices. The remaining emissions will likely be offset through clean fuel alternatives or nature-based carbon removal pathways. For additional information on Consumers' Methane Reduction Plan, see Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations—Outlook—Consumers Gas Utility Outlook and Uncertainties—Gas Environmental Outlook.

Consumers has also set a goal to reduce customer greenhouse gas emissions by 25 percent by 2035. Consumers expects to meet this goal through carbon offset measures, renewable natural gas, energy efficiency and demand response programs, and the adoption of cost-effective emerging technologies once proven and commercially available.

CMS Energy's and Consumers' commitment to protecting the environment extends to advancing the principles of environmental justice in current and future operations. These principles center on protecting communities impacted by the companies' operations, especially those communities that are most vulnerable and may have suffered disparate impacts of environmental harm.

Advancing environmental justice comes in a variety of forms. For example, Consumers has conducted an environmental justice analysis to help understand the environmental impacts of its clean energy transformation. Similarly, Consumers is using an environmental justice screening tool provided by the State of Michigan in the planning of improvements to the electric and gas distribution system, including prioritizing investments in more vulnerable communities.

A core tenet of environmental justice is inviting the input of the stakeholders in the local communities where CMS Energy and Consumers operate and invest. The companies are committed to maintaining a transparent dialogue when developing projects, whether in new or existing areas of operation.

CMS Energy, Consumers, and their subsidiaries are subject to various federal, state, and local environmental regulations for solid waste management, air and water quality, and other matters. Consumers expects to recover costs to comply with environmental regulations in customer rates but cannot guarantee this result. For additional information concerning environmental matters, see Item 1A. Risk Factors, Item 7. Management's Discussion and Analysis of Financial Condition and Results of

Operations—Outlook, and Item 8. Financial Statements and Supplementary Data—Notes to the Consolidated Financial Statements—Note 4, Contingencies and Commitments.

CMS Energy has recorded a $48 million liability for its subsidiaries' obligations associated with Bay Harbor and Consumers has recorded a $59 million liability for its obligations at a number of former MGP sites. For additional information, see Item 1A. Risk Factors and Item 8. Financial Statements and Supplementary Data—Notes to the Consolidated Financial Statements—Note 4, Contingencies and Commitments.

Costs related to the construction, operation, corrective action, and closure of solid waste disposal facilities for coal ash are significant. Consumers' coal ash disposal areas are regulated under Michigan's solid waste rules and by the EPA's rules regulating CCRs. To address some of the requirements of these rules, Consumers has converted all of its fly ash handling systems to dry conveyance systems. In addition, Consumers' ash facilities have programs designed to protect the environment and are subject to quarterly EGLE inspections. Consumers' estimate of capital and cost of removal expenditures to comply with regulations relating to ash disposal is $241 million from 2026 through 2030. Consumers' future costs to comply with solid waste disposal regulations may vary depending on future legislation, litigation, executive orders, treaties, or rulemaking. These costs may further increase if additional emergency orders necessitate continued operation of the J.H. Campbell plant beyond current expectations. Consumers intends to request recovery of any incremental costs through its ongoing cases before FERC. For additional information, see Item 8. Financial Statements and Supplementary Data—Notes to the Consolidated Financial Statements—Note 3, Regulatory Matters.

For further information concerning estimated capital expenditures related to environmental matters, see Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations—Outlook—Consumers Electric Utility Outlook and Uncertainties—Electric Environmental Outlook.

Insurance

CMS Energy and its subsidiaries, including Consumers, maintain insurance coverage generally similar to comparable companies in the same lines of business. The insurance policies are subject to terms, conditions, limitations, and exclusions that might not fully compensate CMS Energy or Consumers for all losses. A portion of each loss is generally assumed by CMS Energy or Consumers in the form of deductibles and self-insured retentions that, in some cases, are substantial. As CMS Energy or Consumers renews its policies, it is possible that some of the present insurance coverage may not be renewed or obtainable on commercially reasonable terms due to restrictive insurance markets.

Human Capital

CMS Energy and Consumers employ a highly trained and skilled workforce comprised of union and non-union employees. Presented in the following table are the number of employees of CMS Energy and Consumers:

December 31	2025	2024	2023
CMS Energy, including Consumers			
Full-time and part-time employees	8,350	8,324	8,356
Consumers			
Full-time and part-time employees	8,095	8,090	8,144

At December 31, 2025, unions represented 44 percent of CMS Energy's employees and 45 percent of Consumers' employees. The UWUA represents Consumers' and NorthStar Clean Energy's operating, maintenance, construction employees and Consumers' customer contact center employees. The USW represents Consumers' Zeeland plant employees. Consumers' union agreements expire in 2030 and the majority of NorthStar Clean Energy's represented employees have an agreement that expires in 2029.

The safety of co-workers, customers, and the general public is a priority of CMS Energy and Consumers. Accordingly, CMS Energy and Consumers have worked to integrate a set of safety principles into their business operations and culture. These principles include complying with applicable safety, health, and security regulations and implementing programs and processes aimed at continually improving safety and security conditions. On an annual basis, CMS Energy and Consumers set various safety goals tied to the OSHA recordable incident rate and to high-risk injuries. The companies' OSHA recordable incident rate was 2.34 in 2025 and 1.71 in 2024. High-risk injuries encompass all recordable and non-recordable incidents with the potential for serious injury or fatality. In 2025, the companies recorded nine high-risk injuries, achieving their goal of less than 12 high-risk injuries. Beginning in 2026, the companies will utilize the serious injury incidence rate to measure and set safety goals. The target serious injury incidence rate for 2026 is 0.037, which, if achieved, would place Consumers within the second quartile of its EEI peer group.

Within the utility industry, there is strong competition for rare, high-demand talent, including those related to electric line work, renewable energy generation, technology, and data analytics. In order to address this competition and to be able to meet their human capital needs, CMS Energy and Consumers provide compensation and benefits that are competitive with industry peers. Furthermore, CMS Energy and Consumers have developed a comprehensive talent strategy, the People Strategy, to attract, develop, and retain highly skilled co-workers. The strategy focuses on three areas, which are summarized below. The first two areas listed below focus on creating an environment that attracts and retains top talent and ensuring that all co-workers can thrive and contribute to the companies' mission and purpose.

- **Cultivating a Purpose-driven Culture:** This goal aims to ensure all co-workers understand how their work contributes to CMS Energy's and Consumers' key strategic goals.
- **Creating a Breakthrough Employee Experience:** A breakthrough employee experience is one that instills pride and ownership in one's work. To measure progress toward a breakthrough employee experience, CMS Energy and Consumers assess engagement, empowerment, and

diversity, equity, and inclusion efforts using the companies' culture index. For the year ended December 31, 2025, the companies attained scores of:

- 75-percent positive sentiment for engagement, up 3 percentage points from 2024
- 65-percent positive sentiment for empowerment, no change from 2024
- 75-percent positive sentiment for diversity, equity, and inclusion, up 2 percentage points from 2024

CMS Energy and Consumers aim to continuously improve these scores every year.

- **Building Skill Sets at Scale:** With an overarching goal of ensuring co-workers have the right skills to succeed, CMS Energy and Consumers measure progress in this area through achievement of workforce planning and hiring milestones and through a first-time skill attainment index to evaluate the effectiveness of training. CMS Energy and Consumers develop skill sets in co-workers through a variety of means, including union apprenticeship programs and yearly trainings for newly required skills.

This talent strategy allows CMS Energy and Consumers to shape co-workers' experience and enable leaders to coach and develop co-workers, source talent, and anticipate and adjust to changing skill sets in the business environment.

Diversity, Equity, and Inclusion

As a part of their People Strategy, CMS Energy and Consumers employ a broad and holistic diversity, equity, and inclusion strategy focused on embracing differences and creating a sense of belonging for all co-workers. The strategy is aimed at integrating principles of equity and inclusion into every process and co-worker experience. To measure their success, CMS Energy and Consumers utilize select questions in the annual engagement survey to create a diversity, equity, and inclusion index. For the year ended December 31, 2025, the diversity, equity, and inclusion index score was 75 percent.

CMS Energy and Consumers are committed to building an inclusive workplace that embraces the diverse makeup of the communities that they serve. The following table presents the composition of CMS Energy's and Consumers' workforce:

December 31, 2025	CMS Energy, including Consumers	Consumers
Percent female employees	26 %	26 %
Percent racially or ethnically diverse employees	13	13
Percent employees with disabilities	5	5
Percent veteran employees	10	10

Co-workers are also empowered to engage in business employee resource groups and events that encourage candid conversations around diversity, equity, and inclusion. These activities enhance personal growth, build stronger connections among co-workers, and contribute to a more inclusive workplace. There are eight business employee resource groups available to all co-workers; these groups are:

- Women in Energy, working toward an inclusive place for all women in the fields they have chosen, from front line to management
- the Minority Advisory Panel, promoting a culture of diversity and inclusion among all racial and ethnic minorities through education, leadership, development, and networking
- the Veterans Advisory Panel, supporting former and active military personnel and assisting in recruiting and retaining veterans through career development
- Genergy, a multigenerational group designed to bridge the gap of learning, networking, and mentoring across the generations of the workforce
- the Pride Alliance of CMS Energy, promoting an inclusive environment that is safe, supportive, and respectful for lesbian, gay, bi-sexual, and transgender persons and allies
- Capable, aimed at removing barriers and creating pathways to meaningful work for co-workers of all abilities
- Interfaith, a space for co-workers of all backgrounds to gather and celebrate their unique beliefs, creating an environment of understanding and respect for all faiths, religions, and spiritual beliefs, including those with no faith affiliation
- People and Planet Partners, empowering co-workers to drive social benefits for customers and communities and advance environmental improvements, reduce the companies’ environmental footprint, and support the companies’ planet goals

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Information About CMS Energy's and Consumers' Executive Officers

Presented in the following table are the company positions held during the last five years for each of CMS Energy's and Consumers' executive officers as of February 10, 2026:

Name, Age, Position(s)	Period
Garrick J. Rochow (age 51)	
CMS Energy	
President, CEO, and Director	12/2020 – Present
Consumers	
President, CEO, and Director	12/2020 – Present
NorthStar Clean Energy	
Chairman of the Board, CEO, and Director	12/2020 – 7/2025
Rejji P. Hayes (age 51)	
CMS Energy	
Executive Vice President and CFO	5/2017 – Present
Consumers	
Executive Vice President and CFO	5/2017 – Present
NorthStar Clean Energy	
Chairman of the Board and Director	7/2025 – Present
Executive Vice President, CFO, and Director	5/2017 – 6/2024
EnerBank	
Chairman of the Board and Director	10/2018 – 10/2021
Tonya L. Berry (age 53)	
CMS Energy	
Executive Vice President and Chief Operating Officer	7/2025 – Present
Senior Vice President	2/2022 – 7/2025
Consumers	
Executive Vice President and Chief Operating Officer	7/2025 – Present
Senior Vice President	2/2022 – 7/2025
Vice President	11/2018 – 2/2022
Shaun M. Johnson (age 47)	
CMS Energy	
Executive Vice President and Chief Legal and Administrative Officer	7/2025 – Present
Senior Vice President and General Counsel	5/2019 – 7/2025
Consumers	
Executive Vice President and Chief Legal and Administrative Officer	7/2025 – Present
Senior Vice President and General Counsel	5/2019 – 7/2025
NorthStar Clean Energy	
Senior Vice President, General Counsel, and Director	4/2019 – 6/2024

Name, Age, Position(s)	Period
Brandon J. Hofmeister (age 49)	
CMS Energy	
Senior Vice President	7/2017 – Present
Consumers	
Senior Vice President	7/2017 – Present
NorthStar Clean Energy	
Senior Vice President	9/2017 – 6/2024
Lauren Snyder (age 44)	
CMS Energy	
Senior Vice President and Chief Customer and Growth Officer	7/2025 – Present
Consumers	
Senior Vice President and Chief Customer and Growth Officer	7/2025 – Present
Vice President	7/2017 – 7/2025
Scott B. McIntosh (age 50)	
CMS Energy	
Vice President, Controller, and CAO	9/2021 – Present
Vice President and Controller	6/2021 – 9/2021
Vice President	9/2015 – 6/2021
Consumers	
Vice President, Controller, and CAO	9/2021 – Present
Vice President and Controller	6/2021 – 9/2021
Vice President	9/2015 – 6/2021
NorthStar Clean Energy	
Vice President, CAO, and Director	6/2024 – Present
Vice President, Controller, and CAO	9/2021 – 6/2024
Vice President and Controller	6/2021 – 9/2021
Vice President	9/2015 – 6/2021

There are no family relationships among executive officers and directors of CMS Energy or Consumers. The list of directors and their biographies will be included in CMS Energy’s and Consumers’ definitive proxy statement for their 2026 Annual Meetings of Shareholders to be held May 8, 2026. The term of office of each of the executive officers extends to the first meeting of the Board after the next annual election of Directors of CMS Energy and Consumers (to be held on May 8, 2026).

Available Information

CMS Energy's internet address is www.cmsenergy.com. CMS Energy routinely posts important information on its website and considers the Investor Relations section, www.cmsenergy.com/investor-relations, a channel of distribution for material information. Information contained on CMS Energy's website is not incorporated herein. CMS Energy's and Consumers' annual reports on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K, and any amendments to those reports filed pursuant to Section 13(a) or 15(d) of the Exchange Act are accessible free of charge on CMS Energy's website. These reports are available soon after they are electronically filed with the SEC. Also on CMS Energy's website are CMS Energy's and Consumers':

- Corporate Governance Principles
- Articles of Incorporation
- Bylaws
- Charters and Codes of Conduct (including the Charters of the Audit Committee, Compensation and Human Resources Committee, Finance Committee, and Governance, Sustainability and Public Responsibility Committee, as well as the Employee, the Board, and Third Party Codes of Conduct)

CMS Energy will provide this information in print to any stockholder who requests it.

The SEC maintains an internet site that contains reports, proxy and information statements, and other information regarding issuers that file electronically with the SEC. The address is www.sec.gov.

Item 1A. Risk Factors

CMS Energy and Consumers are exposed to a variety of factors, often beyond their control, that are difficult to predict and that involve uncertainties that may materially adversely affect CMS Energy's or Consumers' business, liquidity, financial condition, or results of operations. Additional risks and uncertainties not presently known or that management believes to be immaterial may also adversely affect CMS Energy or Consumers. The risk factors described in the following sections, as well as the other information included in this report and in other documents filed with the SEC, should be considered carefully before making an investment in securities of CMS Energy or Consumers. Risk factors of Consumers are also risk factors of CMS Energy.

Investment/Financial Risks

CMS Energy depends on dividends from its subsidiaries to meet its debt service obligations.

Due to its holding company structure, CMS Energy depends on dividends from its subsidiaries to meet its debt service and other payment obligations. If sufficient dividends were not paid to CMS Energy by its subsidiaries, CMS Energy might not be able to generate the funds necessary to fulfill its payment obligations.

Consumers' ability to pay dividends or acquire its own stock from CMS Energy is limited by restrictions contained in Consumers' preferred stock provisions and potentially by other legal restrictions, such as certain terms in its articles of incorporation and FERC requirements.

CMS Energy has indebtedness that could limit its financial flexibility and its ability to meet its debt service obligations.

The level of CMS Energy’s present and future indebtedness could have several important effects on its future operations, including, among others, that:

- a significant portion of CMS Energy’s cash flow from operations could be dedicated to the payment of principal and interest on its indebtedness and would not be available for other purposes
- covenants contained in CMS Energy’s existing debt arrangements, which require it to meet certain financial tests, could affect its flexibility in planning for, and reacting to, changes in its business
- CMS Energy’s ability to obtain additional financing for working capital, capital expenditures, acquisitions, and general corporate and other purposes could become limited
- CMS Energy could be placed at a competitive disadvantage to its competitors that are less leveraged
- CMS Energy’s vulnerability to adverse economic and industry conditions could increase
- CMS Energy’s future credit ratings could fluctuate

CMS Energy’s ability to meet its debt service obligations and to reduce its total indebtedness will depend on its future performance, which will be subject to general economic conditions, industry cycles, changes in laws or regulatory decisions, and financial, business, and other factors affecting its operations, many of which are beyond its control. CMS Energy cannot make assurances that its businesses will continue to generate sufficient cash flow from operations to service its indebtedness, which could require CMS Energy to sell assets or obtain additional financing.

CMS Energy and Consumers have financing needs and could be unable to obtain bank financing or access the capital markets.

CMS Energy and Consumers rely on the capital markets, as well as on bank syndications, to meet their financial commitments and short-term liquidity needs not otherwise funded internally.

Disruptions in the capital and credit markets, or the inability to obtain required regulatory authorization for issuances of securities including debt, including as may be required from FERC, could adversely affect CMS Energy’s and Consumers’ access to liquidity needed for their businesses. Any liquidity disruption could require CMS Energy and Consumers to take measures to conserve cash including, but not limited to, deferring capital expenditures, changing commodity purchasing strategies to avoid collateral-posting requirements, and reducing or eliminating future share repurchases, dividend payments, or other discretionary uses of cash.

Entering into new financings is subject in part to capital market receptivity to utility industry securities in general and to CMS Energy’s and Consumers’ securities in particular. CMS Energy and Consumers continue to explore financing opportunities to supplement their respective financial strategies. These potential opportunities include refinancing and/or issuing new debt, issuing CMS Energy preferred stock and/or common equity, or entering into commercial paper, bank financing, and leasing arrangements. CMS Energy and Consumers cannot guarantee the capital markets’ acceptance of their securities. CMS Energy and Consumers may also, from time to time, repurchase (either in open market transactions or through privately negotiated transactions), redeem, or otherwise retire outstanding debt. Such activities, if any, will depend on prevailing market conditions, contractual restrictions, and other factors. The amounts involved may or may not be material.

Certain of CMS Energy's and Consumers' securities and those of their affiliates are rated by various credit rating agencies. A reduction or withdrawal of one or more of its credit ratings could have a material adverse impact on CMS Energy's or Consumers' ability to access capital on acceptable terms and maintain commodity lines of credit, could increase their cost of borrowing, and could cause CMS Energy or Consumers to reduce capital expenditures. If either or both were unable to maintain commodity lines of credit, CMS Energy or Consumers might have to post collateral or make prepayments to certain suppliers under existing contracts. Further, since Consumers provides dividends to CMS Energy, any adverse developments affecting Consumers that result in a lowering of its credit ratings could have an adverse effect on CMS Energy's credit ratings.

Market performance and other changes could decrease the value of employee benefit plan assets, which then could require substantial funding.

The performance of various markets affects the value of assets that are held in trust to satisfy future obligations under CMS Energy's and Consumers' pension and postretirement benefit plans. CMS Energy and Consumers have significant obligations under these plans and hold significant assets in these trusts. These assets are subject to market fluctuations and will yield uncertain returns, which could fall below CMS Energy's and Consumers' forecasted return rates. A decline in the market value of the assets or a change in the level of interest rates used to measure the required minimum funding levels could significantly increase the funding requirements of these obligations. Also, changes in demographics, including an increased number of retirements or changes in life expectancy assumptions, could significantly increase the funding requirements of the obligations related to the pension and postretirement benefit plans.

Industry/Regulatory Risks

Changes to ROA could have a material adverse effect on CMS Energy's and Consumers' businesses.

Michigan law allows electric customers in Consumers' service territory to buy electric generation service from alternative electric suppliers in an aggregate amount capped at 10 percent of Consumers' sales, with certain exceptions. The proportion of Consumers' electric deliveries under the ROA program and on the ROA waiting list is over 10 percent. Consumers' rates are regulated by the MPSC, while alternative electric suppliers charge market-based rates, putting competitive pressure on Consumers' electric supply. Groups are advocating for an ROA-like community solar program that allows third parties to sell directly to customers and offer them a regulated bill credit. If the amount of ROA sales increased, this new ROA-like community solar program were allowed, or electric generation service in Michigan were further deregulated, it could have a material adverse effect on CMS Energy and Consumers.

FERC issued an advance notice of proposed rulemaking in response to the Secretary of the DOE's direction to FERC to consider the advance notice of proposed rulemaking as a means to standardize and expedite interconnection procedures and agreements for large electric loads. If FERC asserts jurisdiction over the distribution components of large-load customers' interconnections to the transmission system, or allows large-load customers to directly purchase electricity from wholesale markets, it could have a material adverse effect on CMS Energy and Consumers.

The creation of utilities by municipalities in Consumers' service territory, or the impairment of Consumers' franchise rights to serve customers in municipalities, could have a material adverse effect on CMS Energy's and Consumers' businesses.

Michigan law allows Consumers' electric and natural gas utility businesses to serve customers pursuant to franchises granted by municipalities. Michigan law also allows municipalities to create, own, and operate utilities. If one or more municipalities in Consumers' service territory created a new or supplemental utility, or impaired the franchise under which Consumers serves customers in the municipality, it could have a material adverse effect on CMS Energy and Consumers.

Distributed energy resources could have a material adverse effect on CMS Energy's and Consumers' businesses.

Michigan law allows customers to use distributed energy resources for their electric energy needs. These distributed energy resources are connected to Consumers' electric grid. The 2023 Energy Law increases the cap on Consumers' distributed generation program to 10 percent of utilities' peak loads. It also specifies an inflow and outflow rate method that must be implemented by the MPSC. FERC policy allows many customer-owned behind-the-meter and grid-connected distributed energy resources to participate in and receive revenue from wholesale electricity markets, as governed by evolving wholesale market rules subject to FERC oversight. Increased customer use of distributed energy resources could result in a reduction of Consumers' electric sales. Third parties' operations of distributed energy resources could also potentially have a negative impact on the stability of the grid. An increase in customers' use of distributed energy resources, and the rate structure for distributed energy resources customers' use of Consumers' system and Consumers' purchases of their excess generation, could have a material adverse effect on CMS Energy and Consumers.

CMS Energy and Consumers are subject to rate regulation, which could have a material adverse effect on financial results.

CMS Energy and Consumers are subject to rate regulation. Consumers' electric and gas retail rates are set by the MPSC and cannot be changed without regulatory authorization. If rate regulators fail to provide adequate rate relief, it could have a material adverse effect on Consumers or Consumers' plans for making significant capital investments. Additionally, increasing rates could result in additional regulatory scrutiny, regulatory or legislative actions, and increased competitive or political pressures, all of which could have a material adverse effect on CMS Energy's and Consumers' liquidity, financial condition, and results of operations.

Orders of the MPSC could limit recovery of costs of providing service. These orders could also result in adverse regulatory treatment of other matters. For example, MPSC orders could prevent or curtail Consumers from shutting off non-paying customers, could prevent or limit the implementation of an electric or gas revenue mechanism, or could penalize Consumers for not meeting service and reliability standards. Regulators could face competitive or political pressures to avoid or limit rate increases for a number of reasons, including affordability concerns, economic downturn, reliability and economic justice concerns, or decreased customer base, among others.

FERC authorizes certain subsidiaries of CMS Energy, including Consumers, to sell wholesale electricity at market-based rates and to provide certain other wholesale electric services at rates and terms subject to FERC approval. Failure of these subsidiaries to maintain this FERC authority could have a material adverse effect on CMS Energy's and Consumers' liquidity, financial condition, and results of operations. Electric transmission and natural gas pipeline rates paid by Consumers and other CMS Energy subsidiaries are also set by FERC, as are the tariff terms governing the participation of Consumers and other CMS Energy subsidiaries in FERC-regulated wholesale electricity markets operated by regional transmission organizations and independent system operators such as MISO and PJM. At least one CMS Energy subsidiary participates in the wholesale electricity markets operated by ERCOT, over which FERC has limited control.

Consumers also faces regulatory uncertainty resulting from the U.S. Secretary of Energy's emergency orders issued under the Federal Power Act and associated DOE regulations, which direct continued operation of the J.H. Campbell, as well as similar prior or future executive actions, including the January 2025 and April 2025 executive orders related to energy supply and reliability. The Federal Power Act, DOE regulations, and U.S. Secretary of Energy emergency orders all provide for cost recovery associated with continued operations, but there is not currently a FERC-approved MISO Tariff for recovery of compliance costs associated with the continued operation of J.H. Campbell, and continued operation of J.H. Campbell is not contemplated in Consumers' current MPSC rates or rate filings at the MPSC. Consumers is pursuing cost recovery at FERC but cannot predict the outcome of those efforts or the impact of other executive actions.

The various risks associated with the MPSC and FERC regulation of CMS Energy's and Consumers' businesses, which include the risk of adverse decisions in any number of rate or regulatory proceedings before either agency, as well as judicial proceedings challenging any agency decisions, could have a material adverse effect on CMS Energy and Consumers. Changes to the tariffs or business practice manuals of certain wholesale market operators such as MISO, PJM, or ERCOT, or corresponding impacts such as interconnection delays for new electric generation or storage projects, could also have a material adverse effect on CMS Energy and Consumers.

Utility regulation, state or federal legislation, regulation, and compliance could have a material adverse effect on CMS Energy's and Consumers' businesses.

CMS Energy and certain of its subsidiaries, including Consumers, are subject to, or affected by, extensive utility regulation and state and federal legislation and regulation, including through application of policies and rules of numerous state and federal agencies and governmental entities. If it were determined that CMS Energy or Consumers failed to comply with applicable laws and regulations or with applicable tariff provisions, they could become subject to fines, penalties, refund or disgorgement orders, or disallowed costs, or be required to implement additional compliance, cleanup, or remediation programs, the cost of which could be material. CMS Energy and Consumers cannot predict the impact of new laws, rules, regulations, tariffs, principles, orders, or practices by federal or state agencies or wholesale electricity market operators, or challenges or changes to present laws, rules, regulations, tariffs, principles, orders, or practices and the interpretation of any adoption or change. Furthermore, any state or federal legislation, regulation, order, or other action concerning CMS Energy's or Consumers' operations could also have a material adverse effect.

FERC, through NERC and its delegated regional entities, oversees reliability of certain portions of the electric grid. CMS Energy and Consumers cannot predict the impact of the DOE or FERC orders or actions of NERC and its regional entities on electric system reliability. Additionally, natural gas pipeline infrastructure has recently been under scrutiny following disruptions related to extreme weather and cyber incidents. Additional regulation in this area could adversely affect Consumers' gas operations.

CMS Energy and Consumers have announced ambitious plans to reduce their impact on climate change and increase the reliability of their electric distribution system. Achieving these plans depends on numerous factors, many of which are outside of their control.

Consumers has announced a long-term strategy for delivering clean, reliable, resilient, and affordable energy, and other subsidiaries of CMS Energy have plans to develop and operate clean energy assets. The MPSC, FERC, other regulatory authorities, or other third parties may prohibit, delay, or impair some or all of CMS Energy's and Consumers' planned acquisitions or development of owned or purchased electric generation and storage capacity. Consumers' planned electric generation capacity, including renewable generation or storage projects, may be adversely impacted by interconnection delays at MISO or in the footprints of other regional transmission organizations, and/or by interconnection costs. CMS Energy and Consumers and its contractors may be unable to acquire, site, construct timely, and/or permit generation and storage capacity, including some or all of the generation and storage capacity proposed in Consumers' plan. CMS Energy and Consumers' ability to implement their plans may be affected by environmental regulations, global supply chain disruptions, import tariffs, and changes in the cost, availability, and supply of generation and storage capacity. While CMS Energy and Consumers continue to advocate for advances in commercially available technologies required to reduce or eliminate greenhouse gases on a cost-effective basis at scale, such advances are largely outside of CMS Energy's and Consumers' control. Advancements in technology related to items such as battery storage, carbon capture/storage, and electric vehicles may not become commercially available or economically feasible as projected. Customer programs such as energy efficiency and demand response may not realize the projected levels of customer participation.

Consumers has also announced its electric Reliability Roadmap. The Reliability Roadmap includes larger investments in grid hardening, distribution capacity, and automation to deliver better than median reliability to customers given increasingly severe weather and customer adoption of new technologies. The MPSC or other third parties may prohibit, delay, or impair the Reliability Roadmap and some or all of the associated capital investments. Consumers' ability to implement its plan may be affected by global supply chain disruptions and/or workforce availability.

Consumers has also announced its Natural Gas Delivery Plan, a rolling ten-year investment plan to deliver safe, reliable, clean, and affordable natural gas to customers. This plan includes accelerated infrastructure replacements, innovative leak detection technology, and process changes to reduce or eliminate methane emissions. The MPSC, FERC, U.S. Department of Transportation, other regulatory authorities, or other third parties may prohibit, delay, or impair the Natural Gas Delivery Plan and some or all of the associated capital investments. Consumers' ability to implement its plan may be affected by environmental regulations, global supply chain disruptions, import tariffs, and changes in the cost, availability, and supply of natural gas or the ability to deliver natural gas to customers. Advancements in technology related to items such as renewable natural gas may not become commercially available or economically feasible as projected in Consumers' plan.

CMS Energy and Consumers could suffer financial loss, reputational damage, litigation, or other negative repercussions if they are unable to achieve their ambitious plans.

Changes in taxation as well as the inherent difficulty in quantifying potential tax effects of business decisions could negatively impact CMS Energy and Consumers.

CMS Energy and Consumers are required to make judgments regarding the potential tax effects of various financial transactions and results of operations in order to estimate their obligations to taxing authorities. The tax obligations include income taxes, real estate taxes, sales and use taxes, employment-related taxes, and ongoing issues related to these tax matters. The judgments include determining reserves for potential adverse outcomes regarding tax positions that have been taken and may be subject to challenge by the IRS and/or other taxing authorities. Unfavorable settlements of any of the issues related to these reserves or other tax matters at CMS Energy or Consumers could have a material adverse effect. Additionally, changes in federal, state, or local tax rates or other changes in tax laws could have adverse impacts. In July 2025, President Trump signed the OBBBA into law. CMS Energy and Consumers evaluated the provisions of the OBBBA and concluded that the legislation is not expected to have a material impact on their respective financial statements. This conclusion is subject to change as additional guidance or interpretations become available.

CMS Energy and its subsidiaries, including Consumers, must comply with the Dodd-Frank Act and its related regulations.

The Dodd-Frank Act provides for regulation by the Commodity Futures Trading Commission of certain commodity-related contracts. Although CMS Energy, Consumers, and certain subsidiaries of NorthStar Clean Energy qualify for an end-user exception from mandatory clearing of commodity-related swaps, these regulations could affect the ability of these entities to participate in these markets and could add additional regulatory oversight over their contracting activities.

CMS Energy and Consumers could incur substantial costs to comply with environmental requirements.

CMS Energy and Consumers are subject to costly and stringent environmental regulations that may require additional significant capital expenditures for CCR disposal and storage, emission reductions, and PCB remediation. In addition, regulatory action on PFAS at the state and/or federal level could cause CMS Energy and Consumers to further test and remediate some sites if PFAS is present at certain levels. Present and reasonably anticipated state and federal environmental statutes and regulations will continue to have a material effect on CMS Energy and Consumers.

CMS Energy and Consumers have interests in fossil-fuel-fired power plants, other types of power plants, and natural gas systems that emit greenhouse gases. Federal, state, and local environmental laws, regulations and orders, as well as international accords and treaties, could require CMS Energy and Consumers to install additional equipment for emission controls, undertake heat-rate improvement projects, purchase carbon emissions allowances, curtail or extend operations, invest in generating capacity with fewer carbon dioxide emissions, or take other significant steps to manage or lower the emission of greenhouse gases. Similarly, Consumers could be restricted from constructing natural gas infrastructure due to potential environmental regulations, which could require more costly alternatives.

The following risks related to climate change, emissions, and environmental regulations could also have a material adverse impact on CMS Energy and Consumers:

- a change in policy/regulation, regulators' implementation of policy/regulation or litigation originated by third parties against CMS Energy or Consumers due to CMS Energy's or Consumers' greenhouse gas or other emissions or CCR disposal and storage
- impairment of CMS Energy's or Consumers' reputation due to their greenhouse gas or other emissions and public perception of their response to potential environmental regulations, rules, orders, and legislation
- weather that may affect customer demand, company operations, or company infrastructure, including catastrophic weather-related damage and extreme temperatures; natural disasters such as severe storms, floods, and droughts; fires; or smoke
- implementation of state or federal environmental justice requirements

Consumers expects to collect fully from its customers, through the ratemaking process, expenditures incurred to comply with environmental regulations, but cannot guarantee this outcome. There is not currently a FERC-approved MISO Tariff for recovery of compliance costs associated with the continued operation of J.H. Campbell, and continued operation of J.H. Campbell is not contemplated in Consumers' current MPSC rates or rate filings at the MPSC. Consumers is pursuing cost recovery at FERC but cannot predict the outcome of those efforts or the impact of other executive actions. If Consumers were unable to recover these expenditures from customers in rates, CMS Energy or Consumers could be required to seek significant additional financing to fund these expenditures.

For additional information regarding compliance with environmental regulations, see Item 1. Business—CMS Energy and Consumers Environmental Strategy and Compliance and Item 7. Management’s Discussion and Analysis of Financial Condition and Results of Operations—Outlook.

CMS Energy’s and Consumers’ businesses could be affected adversely by any delay in meeting environmental requirements.

A delay or failure by CMS Energy or Consumers to obtain or maintain any necessary environmental permits or approvals to satisfy any applicable environmental regulatory requirements or install emission or pollution control equipment could:

- prevent the construction of new facilities
- prevent the continued operation of and sale of energy from existing facilities
- modify the way in which a facility is operated
- prevent the suspension of operations at existing facilities
- prevent the modification of existing facilities
- result in significant additional costs, including fines or penalties

CMS Energy and Consumers expect to incur additional substantial costs related to environmental remediation of former sites.

Consumers expects to incur additional substantial costs related to the remediation of its former MGP sites and other response activity costs at a number of other former sites, including, but not limited to, sites of retired coal-fueled electric generating units and sites containing coal ash and related materials, under NREPA, RCRA, CERCLA and related state and federal regulations. Consumers believes these costs should be recoverable in rates but cannot guarantee that outcome.

Business/Operations Risks

There are risks associated with Consumers’ substantial capital investment program planned for the next five years.

Consumers’ planned investments include the construction or acquisition of electric generation, electric and gas infrastructure, conversions and expansions, environmental controls, electric grid automation technologies, and other electric and gas investments to upgrade delivery systems, as well as decommissioning of older facilities. The success of these capital investments depends on or could be affected by a variety of factors that include, but are not limited to:

- effective pre-acquisition evaluation of asset values, future operating costs, potential environmental and other liabilities, and other factors beyond Consumers’ control
- effective cost and schedule management of new capital projects
- availability of qualified construction personnel, both internal and contracted
- effective and timely contractor performance
- changes in commodity and other prices, applicable tariffs, and/or material and equipment availability
- governmental actions
- interconnection uncertainty, delays, and costs for electric generation projects

- operational performance
- changes in environmental, legislative, and regulatory requirements
- regulatory cost recovery
- inflation of labor rates and material and equipment prices
- supply chain disruptions and increased lead times
- barriers to accessing key materials for renewable projects (solar, battery, and other key equipment) created by geopolitical relations

It is possible that adverse events associated with these factors could have a material adverse effect on Consumers.

CMS Energy and Consumers could be affected adversely by legacy litigation and retained liabilities.

The agreements that CMS Energy and Consumers enter into for the sale of assets can include provisions whereby they are required to:

- retain specified preexisting liabilities, such as for taxes, pensions, or environmental conditions
- indemnify the buyers against specified risks, including the inaccuracy of representations and warranties that CMS Energy and Consumers make
- make payments to the buyers depending on the outcome of post-closing adjustments, litigation, audits, or other reviews, including claims resulting from attempts by foreign or domestic governments to assess taxes on past operations or transactions

Many of these contingent liabilities can remain open for extended periods of time after the sales are closed. Depending on the extent to which the buyers might ultimately seek to enforce their rights under these contractual provisions, and the resolution of any disputes concerning them, there could be a material adverse effect on CMS Energy's or Consumers' liquidity, financial condition, and results of operations.

Consumers is exposed to risks related to general economic conditions in its service territories.

Consumers' electric and gas utility businesses are affected by the economic conditions impacting the customers they serve. If the Michigan economy becomes sluggish or declines, Consumers could experience reduced demand for electricity or natural gas that could result in decreased earnings and cash flow. In addition, economic conditions in Consumers' service territory affect its collections of accounts receivable and levels of lost or stolen gas.

Consumers is exposed to changes in customer usage that could impact financial results.

Technology advances, government incentives and subsidies, and regulatory decisions could increase the cost effectiveness of customer-owned methods of producing electricity and managing energy use resulting in reduced load, cross subsidization, and increased costs.

Customers could also reduce their consumption of electricity and natural gas through energy waste reduction programs. Similarly, customers could also reduce their consumption of natural gas through alternative technologies or fuels or through electrification.

CMS Energy's and Consumers' energy sales and operations are affected by seasonal factors and varying weather conditions from year to year.

CMS Energy's and Consumers' utility operations are seasonal. The consumption of electric energy typically increases in the summer months, due primarily to the use of air conditioners and other cooling equipment, while peak demand for natural gas occurs in the winter due to colder temperatures and the resulting use of natural gas as heating fuel. Accordingly, CMS Energy's and Consumers' overall results may fluctuate substantially on a seasonal basis. Mild temperatures during the summer cooling season and winter heating season as well as the impact of extreme weather events on Consumers' system could have a material adverse effect.

Demand for electricity associated with data center expansion could have a material effect on CMS Energy and Consumers.

Consumers' utility operations are affected by new customers and load growth. Rapid expansion of data centers associated with increasing demand for cloud services, artificial intelligence, and other applications could lead to an unprecedented increase in demand for electric power in MISO and in Consumers' service territory. Data center electric demand could require a rapid and significant increase in generation capacity and grid infrastructure in the MISO footprint as well as in Consumers' service territory, which could have a material effect on CMS Energy and Consumers.

Alternatively, this rapid expansion of data centers and resulting increase in demand for electric power in MISO and in Consumers' service territory may not develop as anticipated. Efforts to attract data center developers could be unsuccessful as other utilities and regions compete for these projects, which may limit future load growth. In addition, local zoning, permitting, land-use constraints, and other external factors outside Consumers' control could impede data center development. If these challenges arise and cannot be effectively mitigated, the anticipated benefits of data center load growth may not materialize. Further, even when data center customers enter into contracts to purchase utility service, there is a risk they may not fulfill their contractual or tariff obligations.

CMS Energy and Consumers are subject to information security risks, risks of unauthorized access to their systems, and technology failures.

In the regular course of business, CMS Energy and Consumers handle a range of sensitive confidential security and customer information. In addition, CMS Energy and Consumers operate in a highly regulated industry that requires the continued operation of sophisticated information and control technology systems and network infrastructure. Despite implementation of security measures, technology systems, including disaster recovery and backup systems, are vulnerable to failure, cyber attacks, unauthorized access, and being disabled. These events could impact the reliability of electric generation and electric and gas delivery and also subject CMS Energy and Consumers to financial harm. Cyber attacks, which include the use of malware, ransomware, computer viruses, and other means for disruption or unauthorized access against companies, including CMS Energy and Consumers, are increasing in frequency, scope, and potential impact. While CMS Energy and Consumers have not been subject to cyber incidents that have had a material impact on their operations to date, their security measures in place may be insufficient to prevent a major cyber incident in the future. If technology systems, including disaster recovery and backup systems, were to fail or be breached, CMS Energy and Consumers might not be able to fulfill critical business functions, and sensitive confidential and proprietary data could be compromised. In addition, because CMS Energy's and Consumers' generation, transmission, and distribution systems are part of an interconnected system, a disruption caused by a cyber incident at another utility, electric generator, system operator, or commodity supplier could also adversely affect CMS Energy or Consumers.

A variety of technological tools and systems, including both company-owned IT and technological services provided by outside parties, support critical functions. The failure of these technologies, including backup systems, or the inability of CMS Energy and Consumers to have these technologies supported, updated, expanded, or integrated into other technologies, could hinder their business operations.

CMS Energy's and Consumers' businesses have liability risks.

Assets, equipment, and personnel of CMS Energy and Consumers, including electric and gas delivery systems, power plants, gas infrastructure including storage facilities, wind energy or solar equipment, energy products, energy storage assets, vehicle fleets and equipment, other assets, or employees and contractors, could be involved in incidents, failures, or accidents that result in injury, loss of life, or property loss and damage to customers, employees, or the public. Although CMS Energy and Consumers have insurance coverage for many potential incidents (subject to deductibles, limitations, and self-insurance amounts that could be material), depending upon the nature or severity of any incident, failure, or accident, CMS Energy or Consumers could suffer financial loss, reputational damage, and negative repercussions from regulatory agencies or other public authorities, even where there is no legal liability.

CMS Energy and Consumers are subject to risks that are beyond their control, including but not limited to natural disasters, civil unrest, terrorist attacks and related acts of war, cyber incidents, vandalism, and other catastrophic events.

Natural disasters, severe weather, extreme temperatures, wildfires, fires, smoke, flooding, wars, terrorist acts, civil unrest, vandalism, theft, cyber incidents, government shutdowns, pandemics, and other catastrophic events could result in severe damage to CMS Energy's and Consumers' assets beyond what could be recovered through insurance policies (which are subject to deductibles, limitations, and self-insurance amounts that could be material), could require CMS Energy and Consumers to incur significant upfront costs, and could severely disrupt operations, resulting in loss of service to customers. There is also a risk that regulators could, after the fact, conclude that Consumers' preparedness or response to such an event was inadequate and take adverse actions as a result.

Energy risk management strategies might not be effective in managing fuel and electricity pricing risks, which could result in unanticipated liabilities to CMS Energy and Consumers or increased volatility in their earnings.

CMS Energy and Consumers are exposed to changes in market prices for commodities including, but not limited to, natural gas, coal, electric capacity, electric energy, emission allowances, gasoline, diesel fuel, and RECs. CMS Energy and Consumers manage commodity price risk using established policies and procedures, and they may use various contracts to manage this risk, including swaps, options, futures, and forward contracts. No assurance can be made that these strategies will be successful in managing CMS Energy's and Consumers' risk or that they will not result in net liabilities to CMS Energy or Consumers as a result of future volatility.

A substantial portion of Consumers' operating expenses for its electric generating plants and vehicle fleet consists of the costs of obtaining commodities. The contracts associated with Consumers' fuel for electric generation and purchased power are executed in conjunction with the PSCR mechanism, which is designed to allow Consumers to recover prudently incurred costs associated with its positions in these commodities. If the MPSC determined that any of these contracts or related contracting policies were imprudent, recovery of these costs could be disallowed.

Natural gas prices in particular have been historically volatile. Consumers routinely enters into contracts for natural gas to mitigate exposure to the risks of demand, market effects of weather, and changes in commodity prices associated with the gas distribution business. These contracts are executed in conjunction with the GCR mechanism, which is designed to allow Consumers to recover prudently incurred costs associated with its natural gas positions. If the MPSC determined that any of these contracts or related contracting policies were imprudent, recovery of these costs could be disallowed.

CMS Energy and Consumers do not always hedge any or all of the exposure of their operations from commodity price volatility. Furthermore, the ability to hedge exposure to commodity price volatility depends on liquid commodity markets. As a result, to the extent the commodity markets are illiquid, CMS Energy and Consumers might not be able to execute their risk management strategies, which could result in larger unhedged positions than preferred at a given time. To the extent that unhedged positions exist, fluctuating commodity prices could have a negative effect on CMS Energy and Consumers. Changes in laws that limit CMS Energy's and Consumers' ability to hedge could also have a negative effect on CMS Energy and Consumers.

CMS Energy and Consumers might not be able to obtain an adequate supply of natural gas or coal, which could limit their ability to operate electric generation facilities or serve Consumers' natural gas customers.

CMS Energy and Consumers have contracts in place for the supply and transportation of the natural gas, coal, and other fuel sources they require for their electric generating capacity. Consumers also has interstate transportation and supply agreements in place to facilitate delivery of natural gas to its customers. Apart from the contractual and monetary remedies available to CMS Energy and Consumers in the event of a counterparty's failure to perform under any of these contracts, there can be no assurances that the counterparties to these contracts will fulfill their obligations to provide natural gas or coal to CMS Energy or Consumers. The counterparties under the agreements could experience financial or operational problems that inhibit their ability to fulfill their obligations to CMS Energy or Consumers. In addition, counterparties under these contracts might not be required to supply natural gas or coal to CMS Energy or Consumers under certain circumstances, such as in the event of a natural disaster or severe weather.

If Consumers were unable to obtain its supply requirements, it could be required to purchase natural gas or coal at higher prices, implement its natural gas curtailment program filed with the MPSC, or purchase replacement power at higher prices.

Unplanned outages or maintenance could be costly for CMS Energy or Consumers.

Unforeseen outages or maintenance of the electric and gas delivery systems, power plants, gas infrastructure including storage facilities and compression stations, wind energy or solar equipment, energy storage assets, and energy products owned in whole or in part by CMS Energy or Consumers may be required for many reasons. When unplanned outages occur, CMS Energy and Consumers will not only incur unexpected maintenance expenses, but may also have to make spot market purchases of electric and gas commodities that may exceed CMS Energy's or Consumers' expected cost of generation or gas supply, be forced to curtail services, or retire a given asset if the cost or timing of the maintenance is not reasonable and prudent. Unplanned generator outages could reduce the capacity credit CMS Energy or Consumers receives from MISO and could cause CMS Energy or Consumers to incur additional capacity costs in future years.

General Risk Factors

CMS Energy and Consumers are exposed to counterparty risk.

Adverse economic conditions or financial difficulties experienced by counterparties with whom CMS Energy and Consumers do business could impair the ability of these counterparties to pay for CMS Energy's and Consumers' services and/or fulfill their contractual obligations, including performance and payment of damages. CMS Energy and Consumers depend on these counterparties to remit payments and perform contracted services in a timely and adequate fashion. In addition, any delay or default in payment or performance, including inadequate performance, of contractual obligations (such as contractual obligations by third parties to purchase utility services, perform work, supply equipment, provide services, and meet related specifications or requirements), could have a material adverse effect on CMS Energy and Consumers.

Volatility and disruptions in capital and credit markets could have a negative impact on CMS Energy's and Consumers' lenders, vendors, contractors, suppliers, customers, and other counterparties, causing them to fail to meet their obligations.

CMS Energy and Consumers are exposed to significant reputational risks.

CMS Energy and Consumers could suffer negative impacts to their reputations as a result of operational incidents, accidents, actual or perceived violations of corporate policies or regulatory violations, inappropriate use of social media, or other events. Reputational damage could have a material adverse effect and could result in negative customer perception and increased regulatory oversight.

A work interruption or other union actions could adversely affect CMS Energy and Consumers.

At December 31, 2025, unions represent 45 percent of Consumers' employees and 22 percent of NorthStar Clean Energy's employees. Consumers' union agreements expire in 2030 and the majority of NorthStar Clean Energy's represented employees have an agreement that expires in 2029. If these employees were to engage in a strike, work stoppage, or other slowdown, CMS Energy or Consumers could experience a significant disruption in its operations and higher ongoing labor costs.

Failure to attract and retain an appropriately qualified workforce could adversely impact CMS Energy's and Consumers' results of operations.

In some areas, competition for skilled employees is high and if CMS Energy and Consumers were unable to match skill sets to future needs, they could encounter operating challenges and increased costs. These challenges could include a lack of resources, loss of knowledge, and delays in skill development. Additionally, higher costs could result from the use of contractors to replace employees, loss of productivity, and safety incidents. Failing to train replacement employees adequately and to transfer internal knowledge and expertise could adversely affect CMS Energy's and Consumers' ability to manage and operate their businesses.

Item 1B. Unresolved Staff Comments

None.

Item 1C. Cybersecurity

Enterprise Risk Management: CMS Energy and Consumers manage security risks, including cybersecurity risks, through a robust enterprise risk management program that includes people, processes, technology, and governance structures. The enterprise risk management program identifies risks that may significantly impact the business and informs the companies' risk-mitigation strategies. The enterprise risk management program is reviewed with the Board at least annually.

Cybersecurity Program: CMS Energy's and Consumers' security function, led by the Vice President of IT and Security and CIO, is accountable for cyber and physical security and is subject to various state, federal, and industry cybersecurity, physical security, and privacy regulations. Their cybersecurity program is responsible for assessing, identifying, and managing risks from cybersecurity threats using industry frameworks, as well as best practices developed by government and industry partners. All employees and contractors are required to complete annual trainings on a variety of security-related topics. Additionally, the companies continuously upgrade technological investments designed to prevent, detect, and respond to attacks. The companies' electric, natural gas, and corporate systems each follow standards, controls, and requirements designed to maintain compliance with applicable regulations and standards, such as MPSC, NERC critical infrastructure protection, and payment card industry regulations. Technology projects and third-party service providers are reviewed for adherence to cybersecurity requirements.

CMS Energy's and Consumers' cybersecurity program focuses on finding and remediating vulnerabilities in their systems. The companies use third-party firms for penetration testing, audits, and assessments, and conduct technical exercises to practice their response to simulated events as well as tabletop exercises to test that response using their incident command system, including leadership decisions. The companies also have a dedicated, proactive function focused fully on monitoring CMS Energy's and Consumers' systems and responding when cybersecurity attacks occur. This includes regular information sharing with industry partners, peer utilities, and state and federal partners. The companies' incident response plan outlines the individuals responsible, the methods employed, and the timeline for notifying state and federal governmental agencies. The companies retain a third-party cybersecurity firm to assist with potentially significant cybersecurity incidents and have invested in cybersecurity insurance to offset costs incurred from any such cybersecurity incidents. To manage cybersecurity risks associated with the companies' use of third-party service providers, the companies incorporate security requirements into contracts, when deemed applicable, and pursue third-party security certifications for vendors with a higher risk profile.

CMS Energy and Consumers have experienced no material cybersecurity incidents; however, future cybersecurity incidents could materially affect their business strategy, results of operations, or financial condition. For additional details regarding these and other uncertainties, see Item 1A. Risk Factors.

Management's Role: The Vice President of IT and Security and CIO has over 25 years of IT and security experience and, to enhance governance, reports to the Executive Vice President of Business Transformation and Chief Legal and Administrative Officer. The Vice President of IT and Security and CIO is responsible for informing the CEO and other members of senior management, as necessary, about cybersecurity incidents, covering prevention, detection, mitigation, and remediation efforts as they are detected by the cybersecurity team. Cybersecurity incidents are managed using the companies' standard process for critical events. In the event of such cybersecurity incidents, the Vice President of IT and Security and CIO communicates and collaborates with the officers of the companies and subject matter experts to address business continuity, contingency, and recovery plans. Senior management will notify the Board, including the Audit Committee, of any significant cybersecurity incidents.

Board Oversight: As part of the Board's risk oversight process, senior management meets with the Board or Audit Committee at least twice annually to provide updates on and discuss cybersecurity. Such updates include a review of the companies' cybersecurity strategy, a scan of the threat landscape, and recent performance. Additionally, cybersecurity risks are included in the Audit Committee's risk oversight functions, which focus on operating and financial activities that could impact the companies' financial and other disclosure reporting. The Audit Committee's oversight involves reviewing and approving policies on risk assessment, controls, and accounting risk exposure. The Audit Committee also reviews internal audit reports regarding cybersecurity processes, and receives updates that focus on CMS Energy's and Consumers' cybersecurity program, mitigation of cybersecurity risks, and assessments by third-party experts. Of note, two members of the Board have extensive industry experience in cybersecurity and are on CMS Energy's and Consumers' Audit Committee.

Item 2. Properties

Descriptions of CMS Energy's and Consumers' properties are found in the following sections of Item 1. Business, all of which are incorporated by reference in this Item 2:

- General—CMS Energy
- General—Consumers
- Business Segments—Consumers Electric Utility—Electric Utility Properties
- Business Segments—Consumers Electric Utility—Electric Utility Generation and Supply Mix
- Business Segments—Consumers Gas Utility—Gas Utility Properties
- Business Segments—NorthStar Clean Energy—Non-utility Operations and Investments—Independent Power Production

Item 3. Legal Proceedings

For information regarding CMS Energy's and Consumers' significant pending administrative and judicial proceedings involving regulatory, operating, transactional, environmental, and other matters, see Item 8. Financial Statements and Supplementary Data—Notes to the Consolidated Financial Statements—Note 3, Regulatory Matters and Note 4, Contingencies and Commitments.

CMS Energy, Consumers, and certain of their affiliates are also parties to routine lawsuits and administrative proceedings incidental to their businesses involving, for example, claims for personal injury and property damage, contractual matters, various taxes, and rates and licensing.

Item 4. Mine Safety Disclosures

Not applicable.

Part II

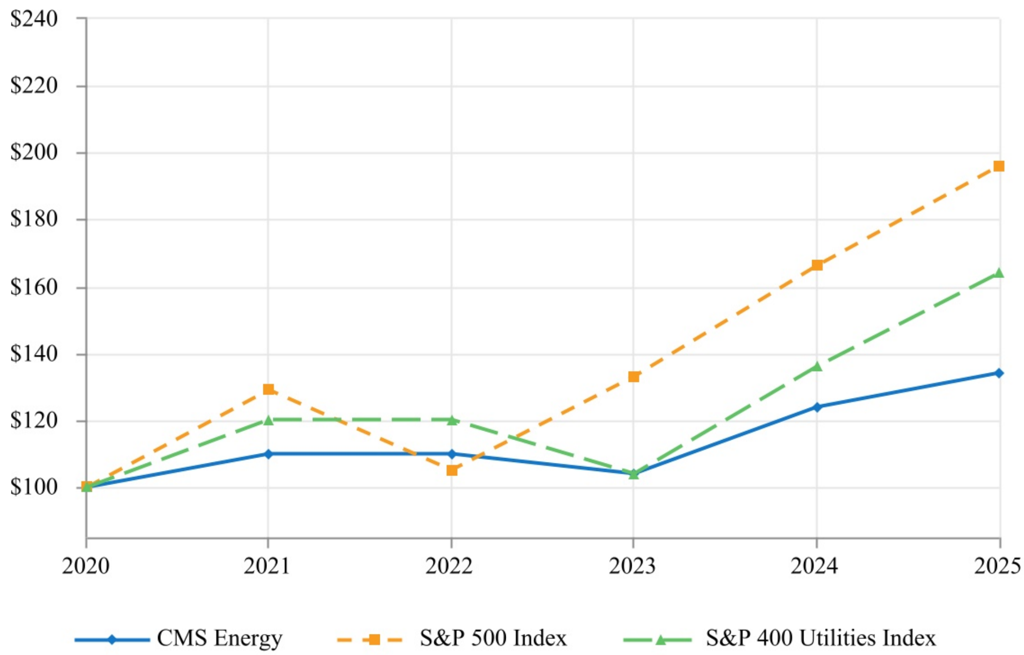
Item 5. Market For Registrant’s Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities

CMS Energy

CMS Energy’s common stock is traded on the New York Stock Exchange under the symbol CMS. At January 16, 2026, the number of registered holders of CMS Energy’s common stock totaled 22,938, based on the number of record holders.

For additional information regarding securities authorized for issuance under equity compensation plans, see Item 8. Financial Statements and Supplementary Data—Notes to the Consolidated Financial Statements—Note 12, Stock-based Compensation and Item 12. Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters. For additional information regarding dividends and dividend restrictions, see Item 8. Financial Statements and Supplementary Data—Notes to the Consolidated Financial Statements—Note 5, Financings and Capitalization.

Comparison of Five-year Cumulative Total Return



	Five-year Cumulative Total Return					
Company/Index	2020	2021	2022	2023	2024	2025
CMS Energy	$ 100	$ 110	$ 110	$ 104	$ 124	$ 134
S&P 500 Index	100	129	105	133	166	196
S&P 400 Utilities Index	100	120	120	104	136	164

These cumulative total returns assume reinvestments of dividends.

Consumers

Consumers' common stock is privately held by its parent, CMS Energy, and does not trade in the public market.

Issuer Repurchases of Equity Securities

CMS Energy repurchases common stock to satisfy the minimum statutory income tax withholding obligation for common shares that have vested under the PISP. The value of shares repurchased is based on the market price on the vesting date. Presented in the following table are CMS Energy's repurchases of common stock for the three months ended December 31, 2025:

Period	Total Number of Shares Purchased	Average Price Paid Per Share
October 1, 2025 to October 31, 2025	—	$ —
November 1, 2025 to November 30, 2025	132	73.99
December 1, 2025 to December 31, 2025	320	69.84
Total	452	$ 71.05

As of December 31, 2025, CMS Energy has no other publicly announced plans or programs that permit the repurchase of equity securities.

Unregistered Sales of Equity Securities

None.

Item 6. Reserved

Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations

This Management's Discussion and Analysis of Financial Condition and Results of Operations is a combined report of CMS Energy and Consumers.

Executive Overview

CMS Energy is an energy company operating primarily in Michigan. It is the parent holding company of several subsidiaries, including Consumers, an electric and gas utility, and NorthStar Clean Energy, primarily a domestic independent power producer and marketer. Consumers' electric utility operations include the generation, purchase, distribution, and sale of electricity, and Consumers' gas utility operations include the purchase, transmission, storage, distribution, and sale of natural gas. Consumers' customer base consists of a mix of primarily residential, commercial, and diversified industrial customers. NorthStar Clean Energy, through its subsidiaries and equity investments, is engaged in domestic independent power production, including the development and operation of renewable generation, and the marketing of independent power production.

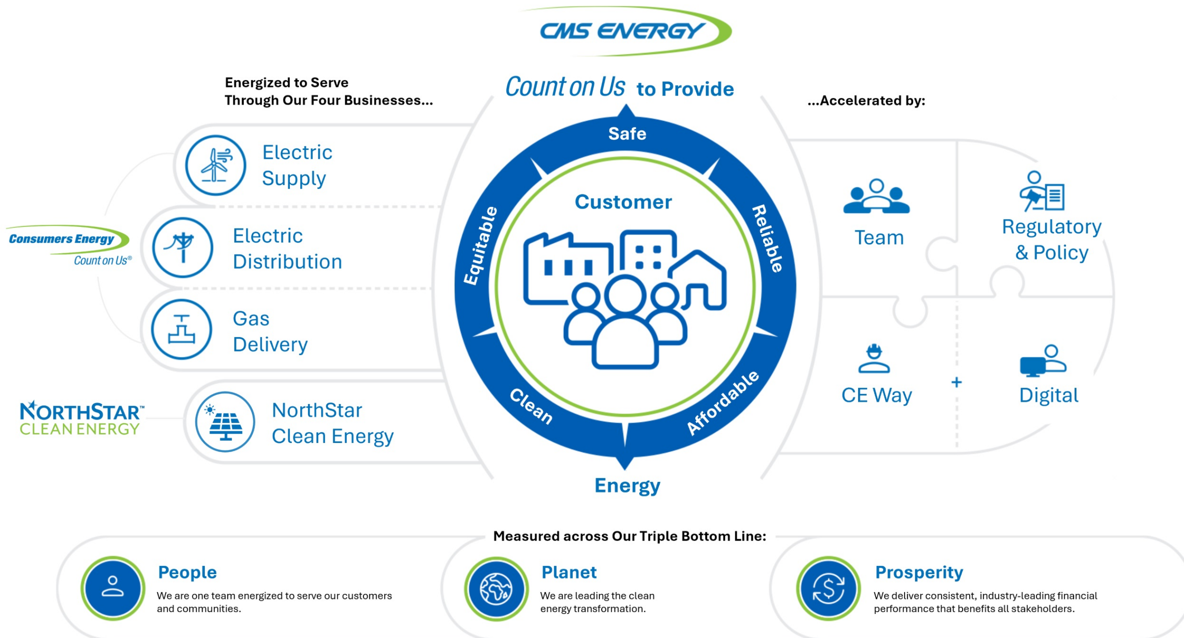
CMS Energy and Consumers manage their businesses by the nature of services each provides. CMS Energy operates principally in three business segments: electric utility; gas utility; and NorthStar Clean Energy, its non-utility operations and investments. Consumers operates principally in two business segments: electric utility and gas utility. CMS Energy's and Consumers' businesses are affected primarily by:

- regulation and regulatory matters
- state and federal legislation
- economic conditions
- load growth
- weather
- energy commodity prices
- interest rates
- their securities' credit ratings

The Triple Bottom Line

CMS Energy's and Consumers' purpose is to provide safe, reliable, affordable, clean, and equitable energy in service of their customers. In support of this purpose, CMS Energy and Consumers couple digital transformation with the "CE Way," a lean operating system designed to improve safety, quality, cost, delivery, and employee morale.

CMS Energy and Consumers measure their progress toward the purpose by considering their impact on the "triple bottom line" of people, planet, and prosperity; this consideration takes into account not only the economic value that CMS Energy and Consumers create for customers and investors, but also their responsibility to social and environmental goals. The triple bottom line balances the interests of employees, customers, suppliers, regulators, creditors, Michigan's residents, the investment community, and other stakeholders, and it reflects the broader societal impacts of CMS Energy's and Consumers' activities.



CMS Energy's Sustainability Report, which is available to the public, describes CMS Energy's and Consumers' progress toward world class performance measured in the areas of people, planet, and prosperity.

People: The people element of the triple bottom line represents CMS Energy's and Consumers' commitment to their employees, their customers, the residents of local communities in which they do business, and other stakeholders.

The safety of co-workers, customers, and the general public is a priority of CMS Energy and Consumers. Accordingly, CMS Energy and Consumers have worked to integrate a set of safety principles into their business operations and culture. These principles include complying with applicable safety, health, and security regulations and implementing programs and processes aimed at continually improving safety and security conditions.

CMS Energy and Consumers also place a high priority on customer value and on providing reliable, affordable, and equitable energy in service of their customers. Consumers' customer-driven investment program is aimed at improving safety and increasing electric and gas reliability.

In the electric rate case it filed with the MPSC in June 2025, Consumers updated its Reliability Roadmap, a five-year strategy to improve Consumers' electric distribution system and the reliability of the grid. The plan proposes spending through 2029 for projects designed to reduce the number and duration of power outages to customers through investment in infrastructure upgrades, vegetation management, and grid modernization. Consumers has requested rate recovery of the investments needed to achieve the Reliability Roadmap’s key objectives in its electric rate cases.

Central to Consumers’ commitment to its customers are the initiatives it has undertaken to keep electricity and natural gas affordable, including:

- replacement of coal-fueled generation and PPAs with a cost-efficient and reliable mix of renewable energy, less-costly dispatchable generation sources, and energy waste reduction and demand response programs
- targeted infrastructure investment to reduce maintenance costs and improve reliability and safety
- supply chain optimization
- economic development to increase sales and reduce overall rates
- information and control system efficiencies
- employee and retiree health care cost sharing
- tax planning
- cost-effective financing
- workforce productivity enhancements

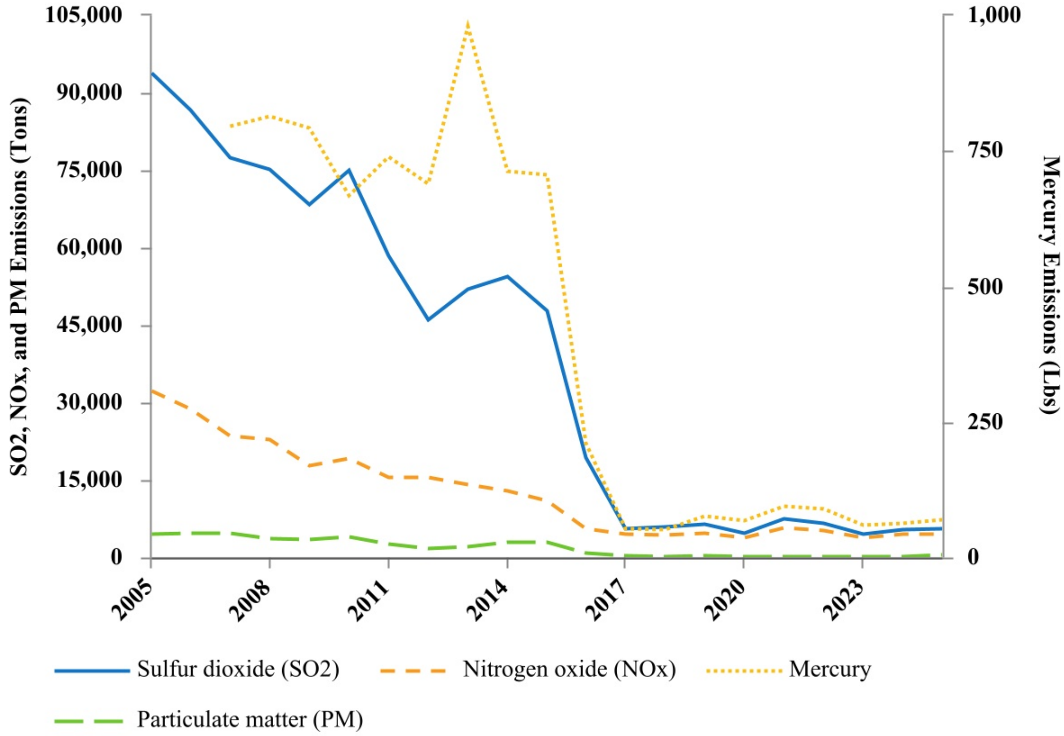
While inflationary pressures and tariffs could impact supply chain availability and pricing, CMS Energy and Consumers are taking steps to help mitigate the impact on their ability to provide safe, reliable, affordable, clean, and equitable energy in service of their customers.

Planet: The planet element of the triple bottom line represents CMS Energy’s and Consumers’ commitment to protect the environment. This commitment extends beyond compliance with various state and federal environmental, health, and safety laws and regulations. Management considers climate change and other environmental risks in strategy development, business planning, and enterprise risk management processes.

CMS Energy and Consumers continue to focus on opportunities to protect the environment and reduce their carbon footprint from owned generation. CMS Energy, including Consumers, has decreased its combined percentage of electric supply (self-generated and purchased) from coal by 24 percentage points since 2015. Additionally, as a result of actions already taken through 2025, preliminary data indicates Consumers has:

- reduced carbon dioxide emissions from owned generation by nearly 30 percent since 2005
- reduced methane emissions by more than 40 percent since 2012
- reduced the volume of water used to generate electricity by nearly 60 percent since 2012
- reduced landfill waste disposal by more than 2 million tons since 1992
- enhanced, restored, or protected more than 13,500 acres of land since 2017
- reduced sulfur dioxide and particulate matter emissions by more than 90 percent since 2005
- reduced NOx emissions by more than 85 percent since 2005
- reduced mercury emissions by more than 90 percent since 2007

Presented in the following illustration are Consumers' reductions in these emissions:



In 2023, Michigan enacted the 2023 Energy Law, which among other things:

- increased the renewable energy standard from 15 percent to 50 percent by 2030 and 60 percent by 2035; renewable energy generated anywhere within MISO can be applied to meeting this standard, with certain limitations
- established a clean energy standard of 80 percent by 2035 and 100 percent by 2040; low- or zero-carbon emitting resources, such as nuclear generation and natural gas generation coupled with carbon capture, qualify as clean energy sources under this standard
- enhanced existing incentives for energy efficiency programs and returns earned on new clean or renewable PPAs
- created a new energy storage standard, requiring electric utilities to file plans by 2029 to help achieve a statewide target of 2,500 MW
- expanded the statutory cap on distributed generation resources to 10 percent of the electric utility's five-year average peak load

Consumers' Electric Supply Plan, its long-term strategy for delivering safe, reliable, affordable, clean, and equitable energy to its customers, is outlined in its integrated resource plan and incorporates Consumers' Renewable Energy Plan. The Electric Supply Plan is Consumers' blueprint for compliance with Michigan's 2023 Energy Law and for advancing sustainability objectives.

To meet these objectives, Consumers is executing a multi-faceted strategy. This strategy involves taking steps to end the use of coal, including the retirement of the D.E. Karn coal-fueled generating units, totaling 515 MW of nameplate capacity, in 2023 and obtaining MPSC approval to retire J.H. Campbell, totaling 1,407 MW of nameplate capacity. The retirement of J.H. Campbell is subject to temporary extensions under emergency orders issued by the U.S. Secretary of Energy. For a more detailed discussion of the emergency orders, see Consumers Electric Utility Outlook and Uncertainties—J.H. Campbell Emergency Orders and Item 8. Financial Statements and Supplementary Data—Notes to the Consolidated Financial Statements—Note 3, Regulatory Matters.

To continue providing controllable sources of electricity to customers, Consumers purchased the Covert Generating Station, representing 1,200 MW of nameplate capacity, in 2023 and has solicited additional capacity from controllable sources of electricity to customers.

Consumers' updates to its Renewable Energy Plan include up to 9,000 MW of both purchased and owned solar energy resources and up to 4,000 MW of wind energy resources. Coupled with updates to its integrated resource plan, these actions position Consumers to achieve 60-percent renewable energy by 2035 and 100-percent clean energy by 2040, and will also contribute to Consumers' achievement of the emissions reductions goals discussed below.

Under its Methane Reduction Plan, Consumers has set a goal of net-zero methane emissions from its natural gas delivery system by 2030. Consumers plans to reduce methane emissions from its system by about 80 percent from 2012 baseline levels by accelerating the replacement of aging pipe, rehabilitating or retiring outdated infrastructure, and adopting new technologies and practices. The remaining emissions will likely be offset through clean fuel alternatives or nature-based carbon removal pathways. To date, Consumers has reduced methane emissions by more than 40 percent.

Consumers has also set a goal to reduce customer greenhouse gas emissions by 25 percent by 2035. Consumers expects to meet this goal through carbon offset measures, renewable natural gas, energy efficiency and demand response programs, and the adoption of cost-effective emerging technologies once proven and commercially available.

Additionally, to advance its environmental stewardship in Michigan and to minimize the impact of future regulations, Consumers set the following goals for the five-year period 2023 through 2027:

- to enhance, restore, or protect 6,500 acres of land through 2027; Consumers surpassed this goal during the three-year period 2023 through 2025 and enhanced, restored, or protected 6,700 acres of land
- to reduce water usage by 1.7 billion gallons through 2027; Consumers had reduced water usage by more than 1.9 billion gallons towards this goal
- to annually divert a minimum of 90 percent of waste from landfills (through waste reduction, recycling, and reuse); during 2025, Consumers' rate of waste diverted from landfills was 93 percent

CMS Energy and Consumers are monitoring numerous legislative, policy, executive, and regulatory initiatives, including those related to regulation and reporting of greenhouse gases, and related litigation. While CMS Energy and Consumers cannot predict the outcome of these matters, which could affect them materially, they intend to continue to move forward with a triple-bottom-line approach that focuses on people, planet, and prosperity.

Prosperity: The prosperity element of the triple bottom line represents CMS Energy's and Consumers' commitment to meeting their financial objectives and providing economic development opportunities and benefits in the communities in which they do business. CMS Energy's and Consumers' financial strength allows them to maintain solid investment-grade credit ratings and thereby reduce funding costs for the benefit of customers and investors, to attract and retain talent, and to reinvest in the communities they serve.

In 2025, CMS Energy's net income available to common stockholders was $1.1 billion, and diluted EPS were $3.53. This compares with net income available to common stockholders of $993 million and diluted EPS of $3.33 in 2024. In 2025, higher gas and electric sales, due primarily to favorable weather, and electric and gas rate increases were offset partially by increased depreciation and property taxes, reflecting higher capital spending, and higher interest charges. A more detailed discussion of the factors affecting CMS Energy's and Consumers' performance can be found in the Results of Operations section that follows this Executive Overview.

Over the next five years, Consumers expects weather-normalized electric deliveries to increase compared to 2025. This outlook reflects strong growth in electric demand, offset partially by the effects of energy waste reduction programs. Weather-normalized gas deliveries are expected to remain stable relative to 2025, reflecting modest growth in gas demand, offset by the effects of energy waste reduction programs.

Performance: Impacting the Triple Bottom Line

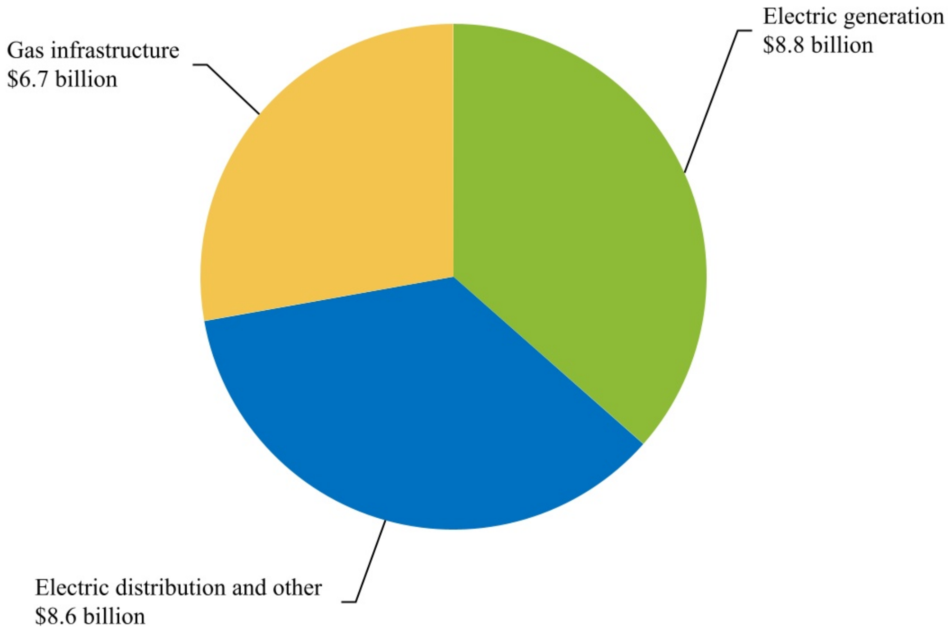
CMS Energy and Consumers remain committed to delivering safe, reliable, affordable, clean, and equitable energy in service of their customers and positively impacting the triple bottom line of people, planet, and prosperity. During 2025, CMS Energy and Consumers:

- connected over 140,000 customers with $60 million in energy-bill assistance and helped make over $100 million in statewide aid available for 2026, reinforcing Consumers' commitment to affordability
- began operations at Muskegon Solar Energy Center, a 1,900-acre project generating 250 MW of clean energy to power 40,000 homes and businesses, supporting Michigan's energy needs and advancing the company's long-term clean energy strategy
- reached an agreement with a new data center expected to add more than 1 GW of incremental load growth in our service territory, supporting long-term sales growth and delivering economic benefits for Michigan
- expanded the use of drone technology enabling faster, safer inspections of 400 miles of hard-to-reach power lines and infrastructure resulting in reduced average outage time per customer and improved storm recovery capabilities
- announced the launch of "Green Giving," a program enabling the general public to contribute to renewable energy while offering financial benefits to low-income customers, along with a new Residential Renewable Energy Program, which allows customers of all income levels to subscribe and match their energy usage with renewable energy sources, supporting clean energy initiatives
- moved forward with an aggressive plan to enhance grid reliability for nearly 2 million homes and businesses by clearing trees along 8,000 miles of power lines and creating a modern, stronger, and more resilient power grid through infrastructure upgrades and technology investments
- deployed eight state-of-the-art vehicles that survey the company's nearly 30,000-mile gas distribution system to find methane emissions, enhancing safety and reliability for Consumers' natural gas customers
- experienced success with the underground power line pilot program in early 2025, with pilot areas seeing 100-percent reduction in storm-related outages and improved customer satisfaction

CMS Energy and Consumers will continue to utilize the CE Way to enable them to achieve world class performance and positively impact the triple bottom line. Consumers' investment plan and the regulatory environment in which it operates also drive its ability to impact the triple bottom line.

Investment Plan: Over the next five years, Consumers expects to make significant expenditures on infrastructure upgrades, replacements, and clean generation. While it has a large number of potential investment opportunities that would add customer value, Consumers has prioritized its spending based on the criteria of enhancing public safety, increasing reliability, maintaining affordability for its customers, and advancing its environmental stewardship. Consumers' investment program, which is subject to approval through general rate case and other MPSC proceedings, is expected to result in annual rate-base growth of more than 8 percent. This rate-base growth, together with cost-control measures, should allow Consumers to maintain affordable customer prices.

Presented in the following illustration are Consumers' planned capital expenditures through 2030 of $24.1 billion:



Of this amount, Consumers plans to spend $8.8 billion on electric generation, which includes solar, wind, and natural gas-fueled generation, as well as energy storage. Consumers also expects to spend $15.3 billion over the next five years primarily to maintain and upgrade its electric distribution systems and gas infrastructure in order to enhance safety and reliability, improve customer satisfaction, reduce energy waste on those systems, and facilitate its clean energy transformation. Electric distribution and other projects comprise $8.6 billion primarily to strengthen circuits and substations, replace poles, and interconnect clean energy resources. The gas infrastructure projects comprise $6.7 billion to sustain deliverability, enhance pipeline integrity and safety, and reduce methane emissions.

Regulation: Regulatory matters are a key aspect of Consumers' business, particularly rate cases and regulatory proceedings before the MPSC, which permit recovery of new investments while helping to ensure that customer rates are fair and affordable. Important regulatory events and developments not already discussed are summarized below.

2024 Electric Rate Case: In March 2025, the MPSC issued an order authorizing an annual rate increase of $176 million, which is inclusive of a $22 million surcharge for the recovery of distribution investments made in 2023 that exceeded the rate amounts authorized in accordance with previous electric rate orders. The approved rate increase is based on a 9.90-percent authorized return on equity. The new rates became effective in April 2025

2025 Electric Rate Case: In June 2025, Consumers filed an application with the MPSC seeking a rate increase of $460 million, made up of two components. First, Consumers requested a $436 million annual rate increase, based on a 10.25-percent authorized return on equity for the projected 12-month period ending April 30, 2027. The filing requested authority to recover costs related to new infrastructure investment primarily in distribution system reliability. Second, Consumers requested approval of a $24 million surcharge for the recovery of distribution investments made during the 12 months ended February 28, 2025 that exceeded the rate amounts authorized in accordance with previous electric rate orders. In October 2025, Consumers revised its requested increase to $447 million, which includes the $24 million surcharge to recover deferred distribution investments. The MPSC must issue a final order in this case before or in April 2026.

2024 Gas Rate Case: In September 2025, the MPSC issued an order authorizing an annual rate increase of $157.5 million, based on a 9.80-percent authorized return on equity. The new rates became effective in November 2025.

2025 Gas Rate Case: In December 2025, Consumers filed an application with the MPSC seeking an annual rate increase of $240 million based on a 10.25-percent authorized return on equity for the projected 12-month period ending October 31, 2027. The MPSC must issue a final order in this case before or in October 2026.

Looking Forward

CMS Energy and Consumers will continue to consider the impact on the triple bottom line of people, planet, and prosperity in their daily operations as well as in their long-term strategic decisions. Consumers will continue to seek fair and timely regulatory treatment that will support its customer-driven investment plan, while pursuing cost-control measures that will allow it to maintain sustainable customer base rates. The CE Way is an important means of realizing CMS Energy's and Consumers' purpose of providing safe, reliable, affordable, clean, and equitable energy in service of their customers.

Results of Operations

CMS Energy Consolidated Results of Operations

In Millions, Except Per Share Amounts

Years Ended December 31	2025	2024	Change
Net Income Available to Common Stockholders	$ 1,061	$ 993	$ 68
Basic Earnings Per Average Common Share	$ 3.53	$ 3.34	$ 0.19
Diluted Earnings Per Average Common Share	$ 3.53	$ 3.33	$ 0.20

In Millions

Years Ended December 31	2025	2024	Change
Electric utility	$ 719	$ 681	$ 38
Gas utility	409	328	81
NorthStar Clean Energy	71	63	8
Corporate interest and other	(138)	(79)	(59)
Net Income Available to Common Stockholders	$ 1,061	$ 993	$ 68

For a summary of net income available to common stockholders for 2024 versus 2023, as well as detailed changes by reportable segment, see Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations—Results of Operations, in the Form 10-K for the fiscal year ended December 31, 2024, filed February 11, 2025.

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Presented in the following table is a summary of changes to net income available to common stockholders for 2025 versus 2024:

		In Millions
Year Ended December 31, 2024		$ 993
Reasons for the change		
Consumers electric utility and gas utility		
Electric sales	$ 49	
Gas sales	151	
Electric rate increase	210	
Gas rate increase, including gain amortization in lieu of rate relief	71	
Lower coal-fueled generation costs[1]	26	
Higher income tax expenses	(87)	
Higher depreciation and amortization	(63)	
Higher interest charges	(43)	
Higher property taxes, reflecting higher capital spending	(29)	
Higher IT expenses, including early-phase ERP implementation costs	(27)	
Higher service restoration costs, net of 2025 deferred storm expense[2]	(25)	
Higher vegetation management costs	(25)	
Higher other electric distribution costs	(13)	
Higher other electric supply costs	(21)	
Higher other maintenance and operating expenses	(30)	
Impairment of project development assets	(15)	
Absence of ASP revenue, net of expense, due to sale in 2024[3]	(5)	
Lower other income, net of expenses	(5)	
		$ 119
NorthStar Clean Energy		8
Corporate interest and other		(59)
Year Ended December 31, 2025		$ 1,061

1 See Item 8. Financial Statements and Supplementary Data—Notes to the Consolidated Financial Statements—Note 3, Regulatory Matters—Consumers Electric Utility—J.H. Campbell Emergency Order.

2 See Item 8. Financial Statements and Supplementary Data—Notes to the Consolidated Financial Statements—Note 3, Regulatory Matters—Regulatory Assets—Service Restoration Cost Deferral.

3 See Item 8. Financial Statements and Supplementary Data—Notes to the Consolidated Financial Statements—Note 3, Regulatory Matters—Regulatory Liabilities—ASP Gain.

Consumers Electric Utility Results of Operations

Presented in the following table are the detailed changes to the electric utility's net income available to common stockholders for 2025 versus 2024:

In Millions

Year Ended December 31, 2024		$ 681
Reasons for the change		
Electric deliveries[1] and rate increases		
Rate increase, including return on higher renewable capital spending	$ 210	
Higher revenue due primarily to higher sales volume	29	
Lower energy waste reduction program revenues	(8)	
Higher other revenues	20	
		$ 251
Maintenance and other operating expenses		
Lower coal-fueled generation costs[2]	26	
Lower energy waste reduction program costs	8	
Higher service restoration costs, net of 2025 deferred storm expense[3]	(25)	
Higher vegetation management costs	(25)	
Higher other supply costs	(21)	
Higher IT expenses, including early-phase ERP implementation costs	(19)	
Higher other distribution costs	(13)	
Higher other maintenance and operating expenses	(11)	
		(80)
Depreciation and amortization		
Increased plant in service, reflecting higher capital spending		(38)
General taxes		
Higher property taxes, reflecting higher capital spending		(16)
Other income, net of expenses		(2)
Interest charges		(29)
Income taxes		
Higher electric utility pre-tax earnings	(25)	
Absence of 2024 deferred tax liability reversals	(11)	
State deferred tax remeasurement[4]	(8)	
Higher other income taxes	(4)	
		(48)
Year Ended December 31, 2025		$ 719

1 Deliveries to end-use customers were 37.4 billion kWh in 2025 and 36.8 billion kWh in 2024.

2 See Item 8. Financial Statements and Supplementary Data—Notes to the Consolidated Financial Statements—Note 3, Regulatory Matters—Consumers Electric Utility—J.H. Campbell Emergency Order.

3 See Item 8. Financial Statements and Supplementary Data—Notes to the Consolidated Financial Statements—Note 3, Regulatory Matters—Regulatory Assets—Service Restoration Cost Deferral.

4 See Item 8. Financial Statements and Supplementary Data—Notes to the Consolidated Financial Statements—Note 13, Income Taxes.

Consumers Gas Utility Results of Operations

Presented in the following table are the detailed changes to the gas utility's net income available to common stockholders for 2025 versus 2024:

		In Millions
Year Ended December 31, 2024		$ 328
Reasons for the change		
Gas deliveries[1] and rate increases		
Rate increase	$ 60	
Higher revenue due primarily to the absence of 2024 unfavorable weather	155	
Higher energy waste reduction program revenues	16	
Absence of ASP business revenue[2]	(19)	
ASP gain customer bill credit[2]	(20)	
Lower other revenues	(3)	
		$ 189
Maintenance and other operating expenses		
Amortization of ASP gain[2]	30	
Absence of 2024 ASP business expense[2]	14	
Higher energy waste reduction program costs	(16)	
Impairment of project development assets	(15)	
Higher IT expenses, including early-phase ERP implementation costs	(8)	
Higher maintenance and other operating expenses	(19)	
		(14)
Depreciation and amortization		
Increased plant in service, reflecting higher capital spending		(25)
General taxes		
Higher property taxes, reflecting higher capital spending		(13)
Other income, net of expenses		(3)
Interest charges		(14)
Income taxes		
Higher gas utility pre-tax earnings	(31)	
Absence of 2024 deferred tax liability reversals	(5)	
State deferred tax remeasurement[3]	(4)	
Lower other income taxes	1	
		(39)
Year Ended December 31, 2025		$ 409

1 Deliveries to end-use customers were 311 Bcf in 2025 and 268 Bcf in 2024.

2 See Item 8. Financial Statements and Supplementary Data—Notes to the Consolidated Financial Statements—Note 3, Regulatory Matters—Regulatory Liabilities—ASP Gain.

3 See Item 8. Financial Statements and Supplementary Data—Notes to the Consolidated Financial Statements—Note 13, Income Taxes.

NorthStar Clean Energy Results of Operations

Presented in the following table are the detailed changes to NorthStar Clean Energy's net income available to common stockholders for 2025 versus 2024:

		In Millions
Year Ended December 31, 2024	$	63
Reason for the change		
Higher renewable earnings primarily driven by new project development	$	26
Lower other expenses		7
Higher tax expenses		(3)
Lower operating earnings, due primarily to planned major outage at DIG		(22)
Year Ended December 31, 2025	$	71

Corporate Interest and Other Results of Operations

Presented in the following table are the detailed changes to corporate interest and other results for 2025 versus 2024:

		In Millions
Year Ended December 31, 2024	$	(79)
Reasons for the change		
Higher interest charges	$	(61)
Lower gains on extinguishment of debt[1]		(38)
Higher interest earnings and other		21
Lower tax expense		19
Year Ended December 31, 2025	$	(138)

1 See Item 8. Financial Statements and Supplementary Data—Notes to the Consolidated Financial Statements—Note 5, Financings and Capitalization—CMS Energy's Purchase of Consumers' First Mortgage Bonds.

Cash Position, Investing, and Financing

At December 31, 2025, CMS Energy had $615 million of consolidated cash and cash equivalents, which included $106 million of restricted cash and cash equivalents. At December 31, 2025, Consumers had $111 million of consolidated cash and cash equivalents, which included $86 million of restricted cash and cash equivalents.

For specific components of net cash provided by operating activities, net cash used in investing activities, and net cash provided by financing activities for 2024 versus 2023, see Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations—Cash Position, Investing, and Financing, in the Form 10-K for the fiscal year ended December 31, 2024, filed February 11, 2025.

Operating Activities

Presented in the following table are specific components of net cash provided by operating activities for 2025 versus 2024:

		In Millions
CMS Energy, including Consumers		
Year Ended December 31, 2024	$	2,370
Reasons for the change		
Higher net income	$	55
Non-cash transactions[1]		133
Unfavorable impact of changes in core working capital,[2] due primarily to fluctuations in gas prices and higher undercollections of PSCR		(107)
Unfavorable impact of changes in other assets and liabilities, due primarily to lower tax-credit sale proceeds and higher service restoration[3] and renewable energy expenditures		(216)
Year Ended December 31, 2025	$	2,235
Consumers		
Year Ended December 31, 2024	$	2,446
Reasons for the change		
Higher net income	$	120
Non-cash transactions[1]		(26)
Unfavorable impact of changes in core working capital,[2] due primarily to fluctuations in gas prices and higher undercollections of PSCR		(102)
Unfavorable impact of changes in other assets and liabilities, due primarily to higher income tax payments to CMS Energy and service restoration[3] and renewable energy expenditures		(200)
Year Ended December 31, 2025	$	2,238

1 Non-cash transactions comprise depreciation and amortization, changes in deferred income taxes and investment tax credits, bad debt expense, and other non-cash operating activities and reconciling adjustments.

2 Core working capital comprises accounts receivable, accrued revenue, inventories, accounts payable, and accrued rate refunds.

3 See Item 8. Financial Statements and Supplementary Data—Notes to the Consolidated Financial Statements—Note 3, Regulatory Matters.

Investing Activities

Presented in the following table are specific components of net cash used in investing activities for 2025 versus 2024:

		In Millions
CMS Energy, including Consumers		
Year Ended December 31, 2024	$	(3,054)
Reasons for the change		
Higher capital expenditures	$	(806)
Absence of proceeds from sale of ASP business in 2024		(124)
Other investing activities, primarily higher cost to retire property		(54)
Year Ended December 31, 2025	$	(4,038)
Consumers		
Year Ended December 31, 2024	$	(2,872)
Reasons for the change		
Higher capital expenditures	$	(472)
Absence of proceeds from sale of ASP business in 2024		(124)
Other investing activities, primarily higher cost to retire property		(67)
Year Ended December 31, 2025	$	(3,535)

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Financing Activities

Presented in the following table are specific components of net cash provided by financing activities for 2025 versus 2024:

	In Millions
CMS Energy, including Consumers	
Year Ended December 31, 2024	$ 614
Reasons for the change	
Higher debt issuances	$ 1,647
Higher debt retirements	(198)
Higher repayments of notes payable	(37)
Higher issuances of common stock	239
Higher payments of dividends on common stock	(37)
Proceeds from sale of membership interests in VIEs	59
Lower contributions from noncontrolling interest	(1)
Higher distributions to noncontrolling interest	(2)
Other financing activities, primarily higher debt issuance costs	(44)
Year Ended December 31, 2025	$ 2,240
Consumers	
Year Ended December 31, 2024	$ 489
Reasons for the change	
Lower debt issuances	$ (174)
Lower debt retirements	274
Higher repayments of notes payable	(37)
Borrowings from CMS Energy	340
Higher stockholder contribution from CMS Energy	185
Absence of return of stockholder contribution to CMS Energy in 2024	320
Higher payments of dividends on common stock	(103)
Other financing activities	(5)
Year Ended December 31, 2025	$ 1,289

Capital Resources and Liquidity

CMS Energy and Consumers expect to have sufficient liquidity to fund their present and future commitments. CMS Energy uses dividends and tax-sharing payments from its subsidiaries and external financing and capital transactions to invest in its utility and non-utility businesses, retire debt, pay dividends, and fund its other obligations. The ability of CMS Energy's subsidiaries, including Consumers, to pay dividends to CMS Energy depends upon each subsidiary's revenues, earnings, cash needs, and other factors. In addition, Consumers' ability to pay dividends is restricted by certain terms included in its articles of incorporation and potentially by FERC requirements and provisions under the Federal Power Act and the Natural Gas Act. For additional details on Consumers' dividend restrictions, see Item 8. Financial Statements and Supplementary Data—Notes to the Consolidated Financial Statements—Note 5, Financings and Capitalization—Dividend Restrictions. During the year ended December 31, 2025, Consumers paid $898 million in dividends on its common stock to CMS Energy.

Consumers uses cash flows generated from operations, external financing transactions, and the monetization of tax credits, along with stockholder contributions from CMS Energy, to fund capital expenditures, retire debt, pay dividends, and fund its other obligations. Consumers also uses these sources of funding to contribute to its employee benefit plans.

Financing and Capital Resources: CMS Energy and Consumers rely on the capital markets to fund their robust capital plan. Barring any sustained market dislocations or disruptions, CMS Energy and Consumers expect to continue to have ready access to the financial and capital markets and will continue to explore possibilities to take advantage of market opportunities as they arise with respect to future funding needs. If access to these markets were to diminish or otherwise become restricted, CMS Energy and Consumers would implement contingency plans to address debt maturities, which could include reduced capital spending.

In 2023, CMS Energy entered into an equity offering program under which it may sell shares of its common stock having an aggregate sales price of up to $1 billion in privately negotiated transactions, in "at the market" offerings, or through forward sales transactions. During the year ended December 31, 2025, CMS Energy settled forward sale contracts issued under this program, resulting in net proceeds of $497 million. Following these settlements, CMS Energy has $8 million in outstanding forward contracts under the program, maturing November 30, 2026.

CMS Energy, NorthStar Clean Energy, and Consumers use revolving credit facilities for general working capital purposes and to issue letters of credit. At December 31, 2025, CMS Energy had $715 million of its revolving credit facility available, NorthStar Clean Energy had $5 million available under its revolving credit facility, and Consumers had $1.4 billion available under its revolving credit facilities.

An additional source of liquidity is Consumers' commercial paper program, which allows Consumers to issue, in one or more placements, up to $500 million in aggregate principal amount of commercial paper notes with maturities of up to 365 days at market interest rates. These issuances are supported by Consumers' revolving credit facilities. While the amount of outstanding commercial paper does not reduce the available capacity of the revolving credit facilities, Consumers does not intend to issue commercial paper in an amount exceeding the available capacity of the facilities. At December 31, 2025, there were no commercial paper notes outstanding under this program.

For additional details about these programs and facilities, see Item 8. Financial Statements and Supplementary Data—Notes to the Consolidated Financial Statements—Note 5, Financings and Capitalization.

Certain of CMS Energy's, NorthStar Clean Energy's, and Consumers' credit agreements contain covenants that require each entity to maintain certain financial ratios, as defined therein. At December 31, 2025, no default had occurred with respect to any of the financial covenants contained in these credit agreements. Each of the entities was in compliance with the covenants contained in their respective credit agreements as of December 31, 2025, as presented in the following table:

	Limit	Actual
CMS Energy, parent only		
Debt to capital[1]	≤ 0.70 to 1.0	0.56 to 1.0
NorthStar Clean Energy		
Debt to capital[2]	≤ 0.50 to 1.0	0.14 to 1.0
Debt service coverage[2]	≥ 2.00 to 1.0	5.03 to 1.0
Pledged equity interests to aggregate commitment[2,3]	≥ 2.00 to 1.0	2.06 to 1.0
Consumers		
Debt to capital[4]	≤ 0.65 to 1.0	0.51 to 1.0

1 Applies to CMS Energy's revolving credit agreement and letter of credit reimbursement agreement.

2 Applies to NorthStar Clean Energy's revolving credit agreement.

3 The aggregate book value of the pledged equity interests under the revolving credit agreement was at least two-times the aggregate commitment under the revolving credit agreement at December 31, 2025.

4 Applies to Consumers' revolving credit agreements and certain letter of credit reimbursement agreements.

Material Cash Requirements: Based on the present investment plan, during 2026, CMS Energy, including Consumers, projects capital expenditures of $4.4 billion and Consumers projects capital expenditures of $4.1 billion. CMS Energy's 2026 contractual commitments comprise $2.4 billion of purchase obligations and $1.8 billion of principal and interest payments on long-term debt. Consumers' 2026 contractual commitments comprise $2.1 billion of purchase obligations and $1.1 billion of principal and interest payments on long-term debt.

Components of CMS Energy's and Consumers' cash management plan include controlling operating expenses and capital expenditures and evaluating market conditions for financing and refinancing opportunities. CMS Energy's and Consumers' present level of cash and expected cash flows from operating activities, together with access to sources of liquidity, are anticipated to be sufficient to fund contractual obligations and other material cash requirements for 2026 and beyond.

Capital Expenditures: Over the next five years, CMS Energy and Consumers expect to make substantial capital investments. The companies may revise their forecast of capital expenditures periodically due to a number of factors, including environmental regulations, MPSC approval or disapproval, business opportunities, market volatility, economic trends, and the ability to access capital. Presented in the following table are CMS Energy’s and Consumers’ estimated capital expenditures, including lease commitments, for 2026 through 2030:

In Billions

	2026	2027	2028	2029	2030	Total
CMS Energy, including Consumers						
Consumers	$ 4.1	$ 5.4	$ 5.7	$ 5.0	$ 3.9	$ 24.1
NorthStar Clean Energy	0.3	0.4	0.5	0.4	0.1	1.7
Total CMS Energy	$ 4.4	$ 5.8	$ 6.2	$ 5.4	$ 4.0	$ 25.8
Consumers						
Electric utility operations	$ 3.0	$ 4.1	$ 4.4	$ 3.5	$ 2.4	$ 17.4
Gas utility operations	1.1	1.3	1.3	1.5	1.5	6.7
Total Consumers	$ 4.1	$ 5.4	$ 5.7	$ 5.0	$ 3.9	$ 24.1

Other Material Cash Requirements: Presented in the following table are CMS Energy’s and Consumers’ material cash obligations from known contractual and other legal obligations:

In Billions

	Payments Due	
December 31, 2025	Less Than One Year	Total
CMS Energy, including Consumers		
Long-term debt	$ 1.0	$ 18.9
Interest payments on long-term debt	0.8	15.1
Purchase obligations	2.4	20.6
AROs	0.1	2.7
Total obligations	$ 4.3	$ 57.3
Consumers		
Long-term debt	$ 0.6	$ 13.2
Interest payments on long-term debt	0.5	8.0
Purchase obligations	2.1	19.7
AROs	0.1	2.6
Total obligations	$ 3.3	$ 43.5

Purchase obligations arise from long-term contracts for the purchase of commodities and related services, primarily long-term PPAs, and construction and service agreements. For more information on CMS Energy’s and Consumers’ purchase obligations, see Item 8. Financial Statements and Supplementary Data—Notes to the Consolidated Financial Statements—Note 4, Contingencies and Commitments—Contractual Commitments.

CMS Energy, Consumers, and certain of their subsidiaries enter into various arrangements in the normal course of business to facilitate commercial transactions with third parties. These arrangements include indemnities, surety bonds, letters of credit, and financial and performance guarantees. For additional details on indemnity and guarantee arrangements, see Item 8. Financial Statements and Supplementary Data—Notes to the Consolidated Financial Statements—Note 4, Contingencies and Commitments—Guarantees. For additional details on letters of credit and CMS Energy’s forward sales contracts, see Item 8. Financial Statements and Supplementary Data—Notes to the Consolidated Financial Statements—Note 5, Financings and Capitalization.

Outlook

Several business trends and uncertainties may affect CMS Energy’s and Consumers’ financial condition and results of operations. These trends and uncertainties could have a material impact on CMS Energy’s and Consumers’ consolidated income, cash flows, or financial position.

During 2025, the federal government took numerous executive actions related to tariffs and trade, alleviating regulatory burdens, and environmental regulations and enforcement, among other areas of potential impact. Many of these actions require further implementation by federal agencies and departments, and some of these actions will likely be subject to further judicial review. CMS Energy and Consumers continue to monitor these executive actions and will continue taking steps to deliver consistently on the triple bottom line.

For additional details regarding these and other uncertainties, see Forward-looking Statements and Information; Item 1A. Risk Factors; and Item 8. Financial Statements and Supplementary Data—Notes to the Consolidated Financial Statements—Note 3, Regulatory Matters and Note 4, Contingencies and Commitments.

Consumers Electric Utility Outlook and Uncertainties

Energy Supply: Consumers’ Electric Supply Plan, its long-term strategy for delivering safe, reliable, affordable, clean, and equitable energy to its customers, is outlined in its integrated resource plan and incorporates Consumers’ Renewable Energy Plan. The Electric Supply Plan is Consumers’ blueprint for compliance with Michigan’s 2023 Energy Law and for advancing sustainability objectives.

Among other things, the 2023 Energy Law:

- increased the renewable energy standard from 15 percent to 50 percent by 2030 and 60 percent by 2035
- established a clean energy standard of 80 percent by 2035 and 100 percent by 2040; low- or zero-carbon emitting resources, such as nuclear generation and natural gas generation coupled with carbon capture, qualify as clean energy sources under this standard
- created a new energy storage standard, requiring electric utilities to file plans by 2029 to help achieve a statewide target of 2,500 MW; the MPSC Staff has indicated that Consumers’ share of this target is 817 MW

Consumers’ integrated resource planning process provides a clear path toward these goals. Updates to its integrated resource plan will be filed in 2026 to reinforce and expand that pathway, while recent updates to the Renewable Energy Plan—approved by the MPSC in September 2025—position Consumers to achieve 60-percent renewable energy by 2035 and 100-percent clean energy by 2040.

To meet these objectives, Consumers is executing a multi-faceted strategy:

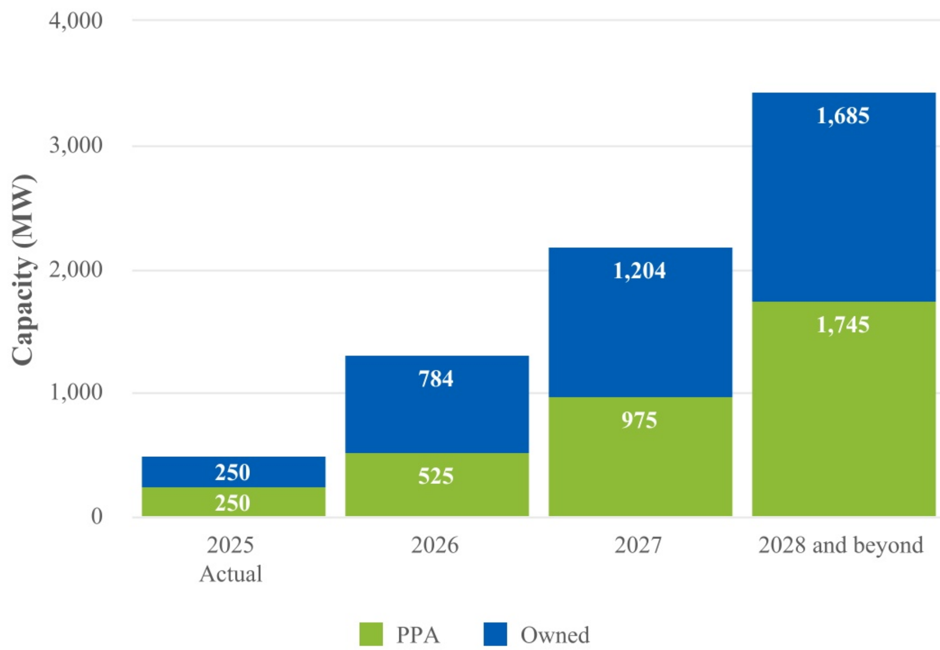
- Ending the use of coal—In 2023, Consumers retired the D.E. Karn coal-fueled generating units, totaling 515 MW of nameplate capacity, and as authorized by the MPSC, issued securitization bonds to finance the recovery of and return on those units. Additionally, Consumers obtained MPSC approval to retire J.H. Campbell in May 2025, totaling 1,407 MW of nameplate capacity, and to recover its remaining book value plus a 9.0-percent return on equity through regulatory asset treatment upon its retirement. As discussed further below, the retirement of J.H. Campbell is subject to temporary extensions under emergency orders issued by the U.S. Secretary of Energy.

- Resource adequacy and reliability—To maintain reliability during the transition, Consumers purchased the Covert Generating Station, representing 1,200 MW of nameplate capacity, in 2023. Additionally, in September 2025, Consumers entered into a new 10-year PPA with the MCV Partnership for the purchase of up to 1,240 MW of capacity and associated energy from the MCV Facility, effective June 1, 2030.

- Energy storage investments—Consumers has contracted to purchase 850 MW of capacity from battery storage facilities to be located in Michigan's Lower Peninsula and with expected commercial operation dates through 2028.

- Renewable expansion—Recent Renewable Energy Plan updates include up to 4,000 MW of wind energy resources and up to 9,000 MW of both purchased and owned solar energy resources, of which 1,060 MW will support Consumers' voluntary green pricing program.

Presented in the following illustration is the aggregate renewable capacity that Consumers expects to add to its portfolio through PPAs and owned generation under its integrated resource plan, voluntary green pricing program, and Renewable Energy Plan updates:



The company earns a return equal to its pre-tax weighted-average cost of capital on permanent capital structure for payments under new clean, renewable, or energy storage PPAs with non-affiliated entities.

Consumers will continue to competitively bid new capacity and energy resources, ensuring a balanced portfolio of intermittent renewables and dispatchable clean resources. Any resulting contracts are subject to MPSC approval. Through these integrated plans, Consumers is advancing Michigan's clean energy transition while maintaining system reliability, affordability, and regulatory compliance.

J.H. Campbell Emergency Orders: In May 2025, before the planned closure of J.H. Campbell, the U.S. Secretary of Energy issued an emergency order under section 202(c) of the Federal Power Act requiring J.H. Campbell to continue operating for 90 days, through August 20, 2025. Subsequently, the

U.S. Secretary of Energy issued two additional emergency orders for 90 days each, ultimately requiring continued operation of J.H. Campbell through February 17, 2026. These orders stated that continued operation of J.H. Campbell was required to meet an energy emergency across MISO's North and Central regions. Consistent with the Federal Power Act and DOE regulations, the orders authorize Consumers to obtain cost recovery at FERC.

As directed, Consumers has continued to make J.H. Campbell available in the MISO market and, in June 2025, filed a complaint at FERC seeking a modification of the MISO Tariff to establish a mechanism for recovery and allocation of the cost to comply with this order. In August 2025, FERC granted Consumers' complaint and ordered MISO to revise its tariff accordingly. MISO submitted a compliance filing with FERC in September 2025, and FERC approval of the compliance filing remains pending. For additional discussion of this FERC proceeding and Consumers' request for recovery, see Item 8. Financial Statements and Supplementary Data—Notes to the Consolidated Financial Statements—Note 3, Regulatory Matters.

Following the May 2025 emergency order, several third-party stakeholders, including the Michigan Attorney General, the Organization of MISO States, and a group of environmental and public interest groups, asked the U.S. Secretary of Energy to reconsider the May 2025 emergency order. In July 2025, after the U.S. Secretary of Energy took no action on those requests, several parties filed petitions for review of the May 2025 emergency order in federal court. The requests for rehearing were subsequently denied, and similar challenges to the August and November 2025 orders are underway. The U.S. Secretary of Energy may issue more orders to require the continued operation of J.H. Campbell. While the timing and content of future orders and the outcome of third-party legal challenges are not yet known, Consumers is committed to pursuing cost recovery as provided for under applicable laws, orders, and proceedings.

Electric Customer Deliveries and Revenue: Consumers' electric customer deliveries are seasonal and largely dependent on Michigan's economy. The consumption of electric energy typically increases in the summer months, due primarily to the use of air conditioners and other cooling equipment. In addition, Consumers' electric rates, which follow a seasonal rate design, are higher in the summer months than in the remaining months of the year. Each year in June, electric residential customers transition to a summer peak time-of-use rate that allows them to take advantage of lower-cost energy during off-peak times during the summer months. Thus, customers can reduce their electric bills by shifting their consumption from on-peak to off-peak times.

Over the next five years, Consumers expects weather-normalized electric deliveries to increase compared to 2025. This outlook reflects strong growth in electric demand, offset partially by the effects of energy waste reduction programs. Actual delivery levels will depend on:

- energy conservation measures and results of energy waste reduction programs
- weather fluctuations
- Michigan's economic conditions, including data center expansion; utilization, expansion, or contraction of large commercial and industrial facilities; economic development; population trends; electric vehicle adoption; and housing activity

Electric ROA: Michigan law allows electric customers in Consumers' service territory to buy electric generation service from alternative electric suppliers in an aggregate amount capped at 10 percent of Consumers' sales, with certain exceptions. At December 31, 2025, electric deliveries under the ROA program were at the 10-percent limit. Fewer than 300 of Consumers' electric customers purchased electric generation service under the ROA program.

In 2016, Michigan law established a path to ensure that forward capacity is secured for all electric customers in Michigan, including customers served by alternative electric suppliers under ROA. The law also authorized the MPSC to ensure that alternative electric suppliers have procured enough capacity to cover their anticipated capacity requirements for the four-year forward period. In 2017, the MPSC issued an order establishing a state reliability mechanism for Consumers. Under this mechanism, if an alternative electric supplier does not demonstrate that it has procured its capacity requirements for the four-year forward period, its customers will pay a set charge to the utility for capacity that is not provided by the alternative electric supplier.

During 2017, the MPSC issued orders finding that it has statutory authority to determine and implement a local clearing requirement, which requires all electric suppliers to demonstrate that a portion of the capacity used to serve customers is located in the MISO footprint in Michigan's Lower Peninsula. In 2020, the Michigan Supreme Court affirmed the MPSC's statutory authority to implement a local clearing requirement on individual electric providers.

In 2020, ABATE and another intervenor filed a complaint against the MPSC in the U.S. District Court for the Eastern District of Michigan challenging the constitutionality of a local clearing requirement. The complaint requested the federal court to issue a permanent injunction prohibiting the MPSC from implementing a local clearing requirement on individual electric providers. In 2023, the U.S. District Court for the Eastern District of Michigan dismissed the complaint. ABATE and the other intervenor filed a claim of appeal of the Eastern District Court's decision with the U.S. Court of Appeals for the Sixth Circuit.

In January 2025, the Sixth Circuit Court of Appeals issued an opinion finding that the MPSC's imposition of a local clearing requirement on individual electric suppliers would discriminate against interstate commerce. The Court of Appeals remanded to the District Court for a determination of whether the local clearing requirement discriminated against interstate commerce and whether the MPSC's regulation survives a strict scrutiny standard, which depends on a determination of whether the local clearing requirement is the only means of achieving the state's goal of securing reliable energy supply. In January 2025, Consumers filed a petition for rehearing and en banc review with the Sixth Circuit Court of Appeals, requesting the Court to reconsider and reverse the panel's opinion. In February 2025, the Sixth Circuit Court of Appeals issued an order denying Consumers' petition for rehearing and en banc review. The case has therefore been remanded to the District Court for the Eastern District of Michigan for consideration of whether the MPSC's local clearing requirement meets the strict scrutiny standard pursuant to the Court of Appeals' decision. The remanded proceeding has begun at the Eastern District Court; there is no deadline for decision.

Sale of Hydroelectric Facilities: In September 2025, Consumers signed an agreement to sell its 13 river hydroelectric dams, which are located throughout Michigan, to a non-affiliated company. Additionally, Consumers signed an agreement to purchase power generated by the facilities for 30 years, at a price that reflects the counterparty's acceptance of the risks and rewards of ownership of the facilities, including FERC licensing obligations. The agreements are contingent upon MPSC and FERC approval, for which Consumers filed in October 2025. Timing of the regulatory review process is uncertain and could extend 12 to 18 months or longer. In Consumers' most recent electric rate case, the MPSC approved deferred accounting treatment for costs of owning and operating the hydroelectric dams pending and until completion of the transaction. At December 31, 2025, the net book value of the hydroelectric facilities was immaterial.

To ensure necessary staffing at the hydroelectric facilities through the anticipated sale, Consumers has provided current employees at the facilities with a retention incentive program. Subsequently, to ensure continued safe operation of the facilities after the sale, the buyer will offer employment to the current hydroelectric employees for a period of at least a year. The retention incentive benefits are contingent upon MPSC and FERC approval of the sale transaction.

Electric Rate Matters: Rate matters are critical to Consumers' electric utility business. For additional details on rate matters, see Item 8. Financial Statements and Supplementary Data—Notes to the Consolidated Financial Statements—Note 3, Regulatory Matters and Note 4, Contingencies and Commitments.

MPSC Distribution System Audit: In 2022, the MPSC ordered the state's two largest electric utilities, including Consumers, to report on their compliance with regulations and past MPSC orders governing the utilities' response to outages and downed lines. Consumers responded to the MPSC's order as directed.

Additionally, as directed by the MPSC, the MPSC Staff engaged a third-party auditor to review all equipment and operations of the two utilities' distribution systems. In September 2024, the MPSC Staff released the third-party auditor's final report on its audit of Consumers' distribution system. The report included several recommendations to improve Consumers' distribution system and associated processes and procedures. Consumers filed a response to the audit report in November 2024. In June 2025, the MPSC issued an order adopting the audit's findings and recommendations. Consumers is committed to working with the MPSC to continue improving electric reliability and safety in Michigan.

Performance-based Financial Incentives/Disincentives Mechanism: In February 2025, the MPSC issued an order establishing a mechanism through which the state's largest electric utilities, including Consumers, could realize up to $10 million each in incentives or penalties annually for meeting or failing to meet reliability benchmarks, beginning in 2026. As directed, Consumers filed proposed company-specific baseline metrics for the performance mechanism in April 2025; the MPSC approved Consumers' proposed metrics in December 2025.

2025 Electric Rate Case: In June 2025, Consumers filed an application with the MPSC seeking a rate increase of $460 million, made up of two components. First, Consumers requested a $436 million annual rate increase, based on a 10.25-percent authorized return on equity for the projected 12-month period ending April 30, 2027. The filing requested authority to recover costs related to new infrastructure investment primarily in distribution system reliability. Second, Consumers requested approval of a $24 million surcharge for the recovery of distribution investments made during the 12 months ended February 28, 2025 that exceeded the rate amounts authorized in accordance with previous electric rate orders.

In October 2025, Consumers revised its requested increase to $447 million. Presented in the following table are the components of the revised requested increase in revenue:

		In Millions
Projected 12-Month Period Ending April 30		2027
Investment in rate base	$	192
Operating and maintenance costs		157
Cost of capital		67
Sales and other revenue		7
Subtotal	$	423
Surcharge		24
Total	$	447

The MPSC must issue a final order in this case before or in April 2026.

Large-load Tariff: In November 2025, the MPSC approved changes to Consumers' standard large-customer tariff to govern service for new large electricity users such as data centers. Consumers sought these changes to protect existing customers. The changes apply to customers with a minimum service threshold of 100 MW and require a minimum 15-year contract (beyond the construction period), an 80-percent minimum demand billing obligation, upfront fees, and strong collateral and exit-fee protections to ensure these large customers fully cover their own costs of service and do not shift risk or costs to existing customers. Each large-load contract must receive MPSC approval before taking effect. The MPSC also directed Consumers to present multiple cost-allocation and rate-design options before its next rate case to ensure that large-load customers pay their fair share of system costs going forward.

Depreciation Rate Case: In December 2025, Consumers filed a depreciation case related to its electric and common utility property. In this case, Consumers requested to increase depreciation expense, and its recovery of that expense of $34 million annually based on December 31, 2024 balances.

Retention Incentive Program: The retirement of J.H. Campbell is subject to temporary extensions under emergency orders issued by the U.S. Secretary of Energy. As a result, Consumers has implemented retention measures to ensure appropriate staffing levels and expects to incur up to $4 million during each 90-day emergency order period. Consumers will seek recovery of these retention costs from FERC, consistent with rate recovery sought for other costs of complying with the emergency orders. For additional details on this program, see Item 8. Financial Statements and Supplementary Data—Notes to the Consolidated Financial Statements—Note 20, Exit Activities and Asset Sales. For additional details on the emergency orders, see Item 8. Financial Statements and Supplementary Data—Notes to the Consolidated Financial Statements—Note 3, Regulatory Matters.

Electric Environmental Outlook: Consumers' electric operations are subject to various federal, state, and local environmental laws and regulations. Consumers estimates that it will incur capital expenditures of $245 million from 2026 through 2030 to continue to comply with RCRA, the Clean Air Act, and numerous other environmental regulations. Consumers expects to recover these costs in customer rates, but cannot guarantee this result. Multiple environmental laws and regulations are subject to litigation. Consumers' primary environmental compliance focus includes, but is not limited to, the following matters.

Air Quality: Multiple air quality regulations apply, or may apply, to Consumers' electric utility.

MATS, emission standards for electric generating units published by the EPA based on Section 112 of the Clean Air Act, continue to apply to Consumers. In June 2025, the EPA issued a proposed rule to repeal changes made to the MATS rule in 2024. The company has complied, and continues to comply, with the MATS regulation and both the 2024 and proposed 2025 versions of MATS have minimal impacts on Consumers' electric generating units. Consumers does not expect MATS to materially impact its environmental strategy.

CSAPR requires Michigan and many other states to improve air quality by reducing power plant emissions that, according to EPA modeling, contribute to ground-level ozone in other downwind states. Consumers complies with this regulation and expects it to have minimal financial and operational impact in the near and/or long term.

In 2015, the EPA lowered the NAAQS for ozone and made it more difficult to construct or modify power plants and other emission sources in areas of the country that do not meet the ozone standard. As of 2023, three counties in western Michigan have been designated as not meeting the ozone standard. Based on recent data, the EPA reclassified these counties from "moderate" to "serious" nonattainment. Additionally, a December 2025 court decision vacated the EPA's 2023 redesignation of a seven-county area in southeast Michigan from moderate ozone nonattainment to attainment. None of Consumers' fossil-fuel-fired generating units are located in these areas. Consumers will continue to monitor the impact of the recent court decision on the seven-county area in southeast Michigan, including resulting agency actions, but does not anticipate it will have any impact on Consumers' generating assets.

In March 2024, the EPA published a lower fine particulate matter NAAQS, which could result in newly designated nonattainment areas in Michigan starting in 2026. In 2025, EGLE proposed nonattainment areas for Kalamazoo and Wayne counties, with a decision by the EPA expected in 2026. Consumers does not have any fossil-fuel-fired generating assets in these counties and therefore does not expect this rule to have significant impacts on its existing generating assets or its clean energy strategy. Consumers will continue to monitor NAAQS rulemakings and litigation to evaluate potential impacts to its generating assets.

In January 2026, the EPA published a final rule amending new source performance standards for new, modified, and reconstructed stationary combustion turbines to lower emission limits for NOx. This final rule requires new large simple-cycle turbine units with higher capacity factors to install control equipment for NOx emissions. Consumers is evaluating this rule to determine its impact.

Consumers continues to evaluate these rules in conjunction with other EPA and EGLE rulemakings, litigation, executive orders, treaties, and congressional actions. This evaluation could result in:

- a change in Consumers' fuel mix
- changes in the types of generating units Consumers may purchase or build in the future
- changes in how certain units are operated, including the installation of additional emission control equipment
- the retirement, mothballing, extended operation, or repowering with an alternative fuel of some of Consumers' generating units
- changes in Consumers' environmental compliance costs
- the purchase or sale of emission allowances

Greenhouse Gases: There have been numerous legislative, executive, and regulatory initiatives at the state, regional, national, and international levels that involve the potential regulation and reporting of greenhouse gases. Consumers continues to monitor and comment on these initiatives, as appropriate.

In September 2025, the EPA proposed a rule to reconsider the Greenhouse Gas Reporting Program by eliminating the reporting obligations from numerous emission sources, including Consumers' electric generation sites and distribution equipment. Reporting of carbon dioxide to the EPA, however, will continue for sources subject to the Clean Air Act Acid Rain Program, which includes Consumers' fossil-fuel-fired electric generation. This change could result in inconsistent approaches in voluntary greenhouse gas accounting for industrial sources.

In April 2024, the EPA finalized its rule under Section 111 of the Clean Air Act to address greenhouse gas emissions from new combustion turbine electric generating units and existing coal-, gas-, and oil-fueled steam electric generating units. These rules do not address existing combustion turbine electric generating units. In June 2025, the EPA issued a proposed rule containing two different pathways to rescind these requirements. Consumers does not expect these proposed changes will have a significant impact on its existing gas- and oil-fueled steam electric generating assets. Consumers will continue to follow the EPA rules that address greenhouse gas emissions and will continue to evaluate potential impacts to its operations.

Increased frequency or intensity of severe or extreme weather events, including those due to climate change, could materially impact Consumers' facilities, energy sales, and results of operations. Consumers is unable to predict these events; however, Consumers evaluates the potential physical impacts of climate change on its operations, including increased frequency or intensity of storm activity; increased precipitation; increased temperature; and changes in lake and river levels. Consumers released a report addressing the physical risks of climate change on its infrastructure in 2022. Consumers is taking steps to mitigate these risks as appropriate.

While Consumers cannot predict the outcome of changes in U.S. policy or of other legislative, executive, or regulatory initiatives involving the potential regulation or reporting of greenhouse gases, it intends to move forward with its compliance with Michigan's clean energy requirements, its own sustainability goals, and its emphasis on reliable and resilient electric supply. Litigation, international treaties, executive orders, federal laws and regulations (including regulations by the EPA), and state laws and regulations, if enacted or ratified, could ultimately impact Consumers. Consumers may be required to:

- replace equipment
- install additional emission control equipment
- purchase emission allowances or credits (including potential greenhouse gas offset credits)
- curtail operations or modify existing facility retirement schedules
- arrange for alternative sources of supply
- purchase or build facilities that generate fewer emissions
- mothball, sell, or retire facilities that generate certain emissions
- pursue energy efficiency or demand response measures more swiftly
- take other steps to manage, sequester, or lower the emission of greenhouse gases

Although associated capital or operating costs relating to greenhouse gas regulation or legislation could be material and cost recovery cannot be assured, Consumers expects to recover these costs in rates consistent with the recovery of other reasonable costs of complying with environmental laws and regulations.

CCRs: In 2015, the EPA published a rule regulating CCRs under RCRA. This rule adopts minimum standards for the disposal of non-hazardous CCRs in CCR landfills and surface impoundments and criteria for the beneficial use of CCRs. The rule also sets out conditions under which some CCR units would be forced to cease receiving CCRs and related process water and to initiate closure. Due to continued litigation, many aspects of the rule have been remanded to the EPA, resulting in more proposed and final rules.

In May 2024, the EPA finalized a rule regulating legacy CCR surface impoundments and CCR management units in response to litigation that exempted inactive impoundments at inactive facilities from the 2015 CCR rule. The new rule adopts minimum standards for impoundments at electric generating facilities that became inactive before the 2015 CCR rule's effective date. During 2024, owners and operators were required to assess whether an inactive facility contains a legacy surface impoundment and then, for identified locations, proceed with the compliance schedule.

Additionally, the EPA established groundwater monitoring, corrective action, closure, and post-closure care requirements for CCR surface impoundments and landfills closed prior to the effective date of the 2015 CCR rule, but that do not meet the closure technical and performance standards of the May 2024 rule. These include inactive CCR landfills that were previously exempted from regulation but that are now considered CCR management units. Owners are required to conduct an evaluation at active facilities or any inactive facilities with at least one legacy impoundment to identify CCR management units and determine an appropriate course of action (closure, groundwater treatment, etc.) for each identified unit according to established compliance milestone schedules. In February 2026, the EPA issued a final rule extending the compliance milestone schedule for CCR management units. This extension does not have a material impact on Consumers' compliance strategy.

Separately, Congress passed legislation in 2016 allowing participating states to develop permitting programs for CCRs under RCRA Subtitle D. The EPA was granted authority to review these permitting programs to determine if permits issued under the proposed program would be as protective as the federal rule. Once approved, permits issued from an authorized state would serve as the basis for compliance, replacing the requirement to self-certify each aspect of the 2015 CCR rule.

Consumers, with agreement from EGLE, completed the work necessary to initiate closure by excavating CCRs or placing a final cover over each of its relevant CCR units prior to the closure initiation deadline set forth in the 2015 CCR rule. Consumers has historically been authorized to recover in electric rates costs related to coal ash disposal sites that supported power generation. Consumers completed an assessment of inactive facilities as required by the 2024 CCR rule, and did not identify any legacy impoundments. Consumers is continuing evaluations related to CCR management units and 2024 CCR rule impacts on the state permit program.

Water: Multiple water-related regulations apply, or may apply, to Consumers.

The EPA regulates cooling water intake systems of existing electric generating plants under Section 316(b) of the Clean Water Act. The rules seek to reduce alleged harmful impacts on aquatic organisms, such as fish. In 2018, Consumers submitted to EGLE studies and recommended plans to comply with Section 316(b) for its coal-fueled units but has not yet received final approval.

The EPA also regulates the discharge of wastewater through its effluent limitation guidelines for steam electric generating plants. Consumers has submitted the appropriate notices of planned participation in compliance with this rule. Consumers has also submitted timely NPDES permit applications and will be working with EGLE to incorporate applicable provisions during the permit renewal process.

Many of Consumers' facilities maintain NPDES permits, which are vital to the facilities' operations. Consumers applies for renewal of these permits every five years. Failure of EGLE to renew any NPDES permit, a successful appeal against a permit, a change in the interpretation or scope of NPDES permitting, or onerous terms contained in a permit could have a significant detrimental effect on the operations of a facility.

Protected Wildlife: Multiple regulations apply, or may apply, to Consumers relating to protected species and habitats.

Statutes like the federal Endangered Species Act, the Migratory Bird Treaty Act, and the Bald and Golden Eagle Protection Act of 1940 and changes to permitting may impact operations at Consumers' facilities. In February 2024, the U.S. Fish and Wildlife Service published a final rule providing for bald eagle general permits for qualifying wind farms and electric distribution systems. Consumers has received, or is pursuing, bald eagle general permits for all its wind farms. While any resulting permitting and monitoring fees and/or restrictions on operations could impact Consumers' existing and future operations, Consumers does not expect any material changes to its environmental strategy or Electric Supply Plan as a result of this rule.

Additionally, Consumers regularly monitors proposed changes to the listing status of several species within its operational area. A change in species listed under the Endangered Species Act, or under Michigan's equivalent law, may impact Consumers' costs to mitigate its impact on protected species and habitats at certain existing facilities as well as siting choices for new facilities.

Other Matters: Other electric environmental matters could have a material impact on Consumers' outlook. For additional details on other electric environmental matters, see Item 8. Financial Statements and Supplementary Data—Notes to the Consolidated Financial Statements—Note 4, Contingencies and Commitments—Consumers Electric Utility Contingencies—Electric Environmental Matters.

Consumers Gas Utility Outlook and Uncertainties

Gas Deliveries: Consumers' gas customer deliveries are seasonal. The peak demand for natural gas occurs in the winter due to colder temperatures and the resulting use of natural gas as heating fuel.

Over the next five years, Consumers expects weather-normalized gas deliveries to remain stable relative to 2025. This outlook reflects modest growth in gas demand, offset by the effects of energy waste reduction programs. Actual delivery levels will depend on:

- weather fluctuations
- use by power producers
- availability and development of renewable energy sources
- gas price changes
- Michigan's economic conditions, including population trends and housing activity
- the price or demand of competing energy sources or fuels
- energy efficiency and conservation impacts

Gas Rate Matters: Rate matters are critical to Consumers' gas utility business. For additional details on rate matters, see Item 8. Financial Statements and Supplementary Data—Notes to the Consolidated Financial Statements—Note 3, Regulatory Matters and Note 4, Contingencies and Commitments.

2025 Gas Rate Case: In December 2025, Consumers filed an application with the MPSC seeking an annual rate increase of $240 million based on a 10.25-percent authorized return on equity for the projected 12-month period ending October 31, 2027.

Presented in the following table are the components of the requested increase in revenue:

	In Millions
Projected 12-Month Period Ending October 31	2027
Investment in rate base	$ 108
Operating and maintenance costs	65
Cost of capital	66
Sales/gross margin	1
Total	$ 240

The MPSC must issue a final order in this case before or in October 2026.

Gas Pipeline and Storage Integrity and Safety: Consumers' gas operations are governed by federal and state pipeline safety rules, and there are robust processes and procedures in place to maintain compliance with these regulations. The U.S. Department of Transportation's Pipeline and Hazardous Materials Safety Administration has published various rules that revise federal safety standards for gas transmission pipelines and underground storage facilities. Consumers has implemented measures to achieve compliance with the revised rules. There are also proposed rules expanding requirements for gas safety, although these rules are subject to reconsideration by the current administration. Under the proposed rules, Consumers will incur increased capital and increased operating and maintenance costs to install and remediate pipelines and to expand inspections, maintenance, and monitoring of existing pipelines and storage facilities.

Although associated capital or operating and maintenance costs relating to these regulations could be material and cost recovery cannot be assured, Consumers expects to recover such costs in rates consistent with the recovery of other reasonable costs of complying with laws and regulations.

Gas Environmental Outlook: Consumers expects to incur response activity costs at a number of sites, including 23 former MGP sites. For additional details, see Item 8. Financial Statements and Supplementary Data—Notes to the Consolidated Financial Statements—Note 4, Contingencies and Commitments—Consumers Gas Utility Contingencies.

Consumers' gas operations are subject to various federal, state, and local environmental laws and regulations. Multiple environmental laws and regulations are subject to litigation. Consumers' primary environmental compliance focus includes, but is not limited to, the following matters.

Air Quality: Multiple air quality regulations apply, or may apply, to Consumers' gas utility.

In 2015, the EPA lowered the NAAQS for ozone and made it more difficult to construct or modify natural gas compressor stations and other emission sources in areas of the country that do not meet the ozone standard. As of 2023, three counties in western Michigan have been designated as not meeting the ozone standard. Based on recent data, the EPA reclassified these counties from "moderate" to "serious" nonattainment, which has more stringent requirements. One of Consumers' compressor stations is in a serious ozone nonattainment area. Consequently, Consumers has initiated plans to retrofit equipment at this compressor station to lower NOx emissions.

Additionally, a December 2025 court decision vacated the EPA's 2023 redesignation of the seven-county area in southeast Michigan from moderate ozone nonattainment to attainment. Four of Consumers' compressor stations are located in these counties, with one station having assets that may be impacted by the redesignation change. Consumers will continue to monitor the recent court decision's impact on the seven-county area in southeast Michigan, including resulting agency actions, and the potential impacts to compressor station assets.

Consumers will continue to monitor NAAQS rulemakings and litigation, and evaluate potential impacts to its compressor stations and other applicable natural gas storage and delivery assets.

In March 2024, the EPA published a lower fine particulate matter NAAQS, which could result in newly designated nonattainment areas in Michigan starting in 2026. In 2025, EGLE proposed nonattainment areas for Kalamazoo and Wayne counties, with a decision by the EPA expected in 2026. Consumers has one compressor station located in Wayne County and will continue to monitor NAAQS rulemakings and litigation to evaluate potential impacts to the natural gas compressor station assets.

Greenhouse Gases: Some interest exists at the various levels of government in regulating greenhouse gases or their sources. Future regulations, if adopted, may involve requirements to reduce methane emissions from Consumers' gas utility operations and carbon dioxide emissions from customer use of natural gas. Consumers will continue to monitor such potential rules for impacts.

In September 2025, the EPA proposed a rule to reconsider the Greenhouse Gas Reporting Program by removing the natural gas distribution segment from the reporting obligations under the petroleum and natural gas source category, and proposed to delay the reporting obligations until 2034 for the remaining sources in this category. If this proposal is finalized as proposed, it could result in inconsistent approaches in voluntary greenhouse gas accounting for industrial sources.

Consumers is making voluntary efforts to reduce its gas utility's methane emissions. Under its Methane Reduction Plan, Consumers has set a goal of net-zero methane emissions from its natural gas delivery system by 2030. Consumers plans to reduce methane emissions from its system by about 80 percent from 2012 baseline levels by accelerating the replacement of aging pipe, rehabilitating or retiring outdated infrastructure, and adopting new technologies and practices. The remaining emissions will likely be offset through clean fuel alternatives or nature-based carbon removal pathways. To date, Consumers has reduced methane emissions by more than 40 percent.

Consumers has also set a goal to reduce customer greenhouse gas emissions by 25 percent by 2035. Consumers' Natural Gas Delivery Plan, a rolling ten-year investment plan to deliver safe, reliable, clean, and affordable natural gas to customers, outlines ways in which Consumers can make early progress toward these goals in a cost-effective manner, including energy waste reduction, carbon offsets, and renewable natural gas supply.

Consumers has already initiated work in these key areas by continuing to expand its energy waste reduction targets and by offering gas customers the ability to offset their carbon footprint associated with natural gas use by purchasing renewable natural gas and/or carbon credits associated with Michigan forest preservation. Consumers has renewable natural gas facilities under construction scheduled for commercial operation in 2026 and is monitoring regulatory developments and market conditions closely as part of its ongoing evaluation of the projects. As part of this evaluation, two early-phase renewable natural gas development projects have been paused indefinitely, and Consumers recognized an impairment charge of $15 million related to these projects in 2025. Consumers is evaluating and monitoring newer technologies to determine their role in achieving Consumers' interim and long-term net-zero goals, including biofuels, geothermal, synthetic methane, carbon capture sequestration systems, and other innovative technologies.

NorthStar Clean Energy Outlook and Uncertainties

CMS Energy's primary focus with respect to its NorthStar Clean Energy businesses is to maximize the value of generating assets representing 1,665 MW of capacity, and to pursue opportunities for the development of renewable generation projects, including leveraging strategic partnerships and available tax incentives.

In December 2025, NorthStar Clean Energy sold a Class A membership interest in BG Solar Holdings to a tax equity investor. BG Solar Holdings is the holding company of a 200-MW solar generation project being constructed in Branch County, Michigan. All of the project's nameplate capacity has been committed under a 15-year renewable energy purchase agreement. The tax equity investor contributed $15 million and recognized a deemed contribution of $35 million associated with BG Solar Holdings' sale of investment tax credits related to a portion of the project placed into service for tax purposes in 2025. The tax equity investor will contribute additional amounts upon commercial operation of the project in 2026.

NorthStar Clean Energy retained a Class B membership interest in BG Solar Holdings. Earnings, tax attributes, and cash flows generated by BG Solar Holdings will be allocated among and distributed to the membership classes in accordance with the ratios specified in the associated limited liability company operating agreement; these ratios change over time and are not representative of the ownership interest percentages of each membership class. For additional details, see Item 8. Financial Statements and Supplementary Data—Notes to the Consolidated Financial Statements—Note 19, Variable Interest Entities.

Trends, uncertainties, and other matters related to NorthStar Clean Energy that could have a material impact on CMS Energy's consolidated income, cash flows, or financial position include:

- investment in and financial benefits received from renewable energy and energy storage projects, including changes to tax and trade policy
- delays or difficulties in financing, constructing, and developing projects, including those arising from the performance of contractors, suppliers, or other counterparties
- changes in energy, capacity, and other commodity prices
- severe weather events and climate change associated with increasing levels of greenhouse gases
- changes in various environmental laws, regulations, principles, or practices, or in their interpretation
- indemnity obligations assumed in connection with ownership interests in facilities that involve tax equity financing
- representations, warranties, and indemnities provided in connection with sales of assets
- delays or difficulties in obtaining environmental permits

For additional details regarding NorthStar Clean Energy's uncertainties, see Item 8. Financial Statements and Supplementary Data—Notes to the Consolidated Financial Statements—Note 4, Contingencies and Commitments—Guarantees.

NorthStar Clean Energy Environmental Outlook: NorthStar Clean Energy's operations are subject to various federal, state, and local environmental laws and regulations. Multiple environmental laws and regulations are subject to litigation. NorthStar Clean Energy's primary environmental compliance focus includes, but is not limited to, the following matters.

CSAPR requires Michigan and many other states to improve air quality by reducing power plant emissions that, according to EPA modeling, contribute to ground-level ozone in other downwind states. NorthStar Clean Energy complies with this regulation and expects it to have minimal financial and operational impact in the near and/or long term.

In March 2024, the EPA published a lower fine particulate matter NAAQS, which could result in newly designated nonattainment areas in Michigan starting in 2026. In 2025, EGLE proposed nonattainment areas for Kalamazoo and Wayne counties, with a decision by the EPA expected in 2026. NorthStar Clean Energy has two fossil-fuel-fired generating units in these counties and therefore will continue to monitor NAAQS rulemaking and litigation to evaluate potential impacts to its generating assets.

In January 2026, the EPA published a final rule amending new source performance standards for new, modified, and reconstructed stationary combustion turbines to lower emission limits for NOx. This final rule requires new large simple-cycle turbine units with higher capacity factors to install control equipment for NOx emissions. NorthStar Clean Energy will monitor this rulemaking.

A December 2025 court decision vacated the EPA's 2023 redesignation of the seven-county area in southeast Michigan from moderate ozone nonattainment to attainment. NorthStar Clean Energy has one electric generating station located within this area. NorthStar Clean Energy will continue to monitor the recent court decision's impact on the seven-county area in southeast Michigan, including resulting agency actions, and the potential impacts to compressor station assets.

For additional details regarding the ozone NAAQS, see Consumers Electric Utility Outlook and Uncertainties—Electric Environmental Outlook.

In September 2025, the EPA proposed a rule to reconsider the Greenhouse Gas Reporting Program by eliminating the reporting obligations from numerous emission sources. Reporting of carbon dioxide to the

EPA, however, will continue for sources subject to the Clean Air Act Acid Rain Program. This change could result in inconsistent approaches in voluntary greenhouse gas accounting for industrial sources.

In April 2024, the EPA finalized its rule under Section 111 of the Clean Air Act to address greenhouse gas emissions from new combustion turbine electric generating units and existing coal-, gas-, and oil-fueled steam electric generating units. These rules do not address existing combustion turbine electric generating units. In June 2025, the EPA issued a proposed rule containing two different pathways to rescind these requirements. Neither pathway impacts NorthStar Clean Energy's existing facilities. NorthStar Clean Energy will continue to follow the EPA rules that address greenhouse gas emissions and will continue to evaluate potential impacts to its operations.

Many of NorthStar Clean Energy's facilities maintain NPDES permits, which are vital to the facilities' operations. NorthStar Clean Energy applies for renewal of these permits every five years. Failure of EGLE to renew any NPDES permit, a successful appeal against a permit, a change in the interpretation or scope of NPDES permitting, or onerous terms contained in a permit could have a significant detrimental effect on the operations of a facility.

Other Outlook and Uncertainties

Tax Legislation: CMS Energy and Consumers are subject to changing tax laws. In July 2025, President Trump signed into law the OBBBA. The legislation allows for the immediate expensing of domestic research and development costs and includes changes to clean energy tax credits enacted by the Inflation Reduction Act of 2022. While the OBBBA restores, and makes permanent, the 100-percent bonus depreciation deduction, it also retains a provision that allows utilities to take a full deduction of interest expense in lieu of 100-percent bonus depreciation. CMS Energy and Consumers evaluated the provisions of the OBBBA and concluded that the legislation is not expected to have a material impact on their respective financial statements. This conclusion is subject to change as additional guidance or interpretations become available.

Litigation: CMS Energy, Consumers, and certain of their subsidiaries are named as parties in various litigation matters, as well as in administrative proceedings before various courts and governmental agencies, arising in the ordinary course of business. For additional details regarding certain legal matters, see Item 8. Financial Statements and Supplementary Data—Notes to the Consolidated Financial Statements—Note 3, Regulatory Matters and Note 4, Contingencies and Commitments.

Critical Accounting Estimates

The following information is important to understand CMS Energy's and Consumers' results of operations and financial condition. For additional accounting policies, see Item 8. Financial Statements and Supplementary Data—Notes to the Consolidated Financial Statements—Note 1, Significant Accounting Policies.

In the preparation of CMS Energy's and Consumers' consolidated financial statements, estimates and assumptions are used that may affect reported amounts and disclosures. CMS Energy and Consumers use accounting estimates for asset valuations, unbilled revenue, depreciation, amortization, financial and derivative instruments, employee benefits, stock-based compensation, the effects of regulation, indemnities, contingencies, and AROs. Actual results may differ from estimated results due to changes in the regulatory environment, regulatory decisions, lawsuits, competition, and other factors. CMS Energy and Consumers consider all relevant factors in making these assessments.

Accounting for the Effects of Industry Regulation: Because Consumers has regulated operations, it uses regulatory accounting to recognize the effects of the regulators' decisions on its financial statements. Consumers continually assesses whether future recovery of its regulatory assets is probable by considering communications and experience with its regulators and changes in the regulatory environment. If Consumers determined that recovery of a regulatory asset were not probable, Consumers would be required to write off the asset and immediately recognize the expense in earnings. For additional information, see Item 8. Financial Statements and Supplementary Data—Notes to the Consolidated Financial Statements—Note 3, Regulatory Matters.

Contingencies: CMS Energy and Consumers make judgments regarding the future outcome of various matters that give rise to contingent liabilities. For such matters, they record liabilities when they are considered probable and reasonably estimable, based on all available information. In particular, CMS Energy and Consumers are participating in various environmental remediation projects for which they have recorded liabilities. The recorded amounts represent estimates that may take into account such considerations as the number of sites, the anticipated scope, cost, and timing of remediation work, the available technology, applicable regulations, and the requirements of governmental authorities. For remediation projects in which the timing of estimated expenditures is considered reliably determinable, CMS Energy and Consumers record the liability at its net present value, using a discount rate equal to the interest rate on monetary assets that are essentially risk-free and have maturities comparable to that of the environmental liability. The amount recorded for any contingency may differ from actual costs incurred when the contingency is resolved. For additional details, see Item 8. Financial Statements and Supplementary Data—Notes to the Consolidated Financial Statements—Note 4, Contingencies and Commitments.

Income Taxes: The amount of income taxes paid by CMS Energy is subject to ongoing audits by federal, state, and foreign tax authorities, which can result in proposed assessments. An estimate of the potential outcome of any uncertain tax issue is highly judgmental. CMS Energy believes adequate reserves have been provided for these exposures; however, future results may include favorable or unfavorable adjustments to the estimated tax liabilities in the period the assessments are made or resolved or when statutes of limitation on potential assessments expire. Additionally, CMS Energy's judgment as to the ability to recover its deferred tax assets may change. CMS Energy believes the valuation allowances related to its deferred tax assets are adequate, but future results may include favorable or unfavorable adjustments. As a result, CMS Energy's effective tax rate may fluctuate significantly over time. For additional details, see Item 8. Financial Statements and Supplementary Data—Notes to the Consolidated Financial Statements—Note 13, Income Taxes.

Pension and OPEB: CMS Energy and Consumers provide retirement pension benefits to certain employees under non-contributory DB Pension Plans, and they provide postretirement health and life benefits to qualifying retired employees under an OPEB Plan.

CMS Energy and Consumers record liabilities for pension and OPEB on their consolidated balance sheets at the present value of the future obligations, net of any plan assets. The calculation of the liabilities and associated expenses requires the expertise of actuaries, and requires many assumptions, including:

- life expectancies
- discount rates
- expected long-term rate of return on plan assets
- rate of compensation increases
- expected health care costs

A change in these assumptions could change significantly CMS Energy's and Consumers' recorded liabilities and associated expenses.

Presented in the following table are estimates of credits and cash contributions through 2028 for the DB Pension Plans and OPEB Plan. Actual future costs, credits, and contributions will depend on future investment performance, discount rates, and various factors related to the participants of the DB Pension Plans and OPEB Plan. CMS Energy and Consumers will, at a minimum, contribute to the plans as needed to comply with federal funding requirements.

In Millions

	DB Pension Plans		OPEB Plan	
	Credit	Contribution	Credit	Contribution
CMS Energy, including Consumers				
2026	$ (86)	$ —	$ (109)	$ —
2027	(87)	—	(99)	—
2028	(100)	—	(92)	—
Consumers[1]				
2026	$ (81)	$ —	$ (101)	$ —
2027	(81)	—	(91)	—
2028	(94)	—	(84)	—

1 Consumers' pension and OPEB costs are recoverable through its general ratemaking process.

Lowering the expected long-term rate of return on the assets of the DB Pension Plans by 25 basis points would increase estimated pension cost for 2026 by $8 million for both CMS Energy and Consumers. Lowering the PBO discount rates by 25 basis points would decrease estimated pension cost for 2026 by $1 million for both CMS Energy and Consumers. Pension and OPEB costs above or below the amounts used to set existing rates will be deferred as a regulatory asset or liability in accordance with Consumers' postretirement benefits expense deferral mechanism; for more information, see Item 8. Financial Statements and Supplementary Data—Notes to the Consolidated Financial Statements—Note 3, Regulatory Matters.

Pension and OPEB plan assets are accounted for and disclosed at fair value. Fair value measurements incorporate assumptions that market participants would use in pricing an asset or liability, including assumptions about risk. Development of these assumptions may require judgment.

For additional details on postretirement benefits, including the fair value measurements for the assets of the DB Pension Plans and OPEB Plan, see Item 8. Financial Statements and Supplementary Data—Notes to the Consolidated Financial Statements—Note 11, Retirement Benefits.

Unbilled Revenues: Consumers' customers are billed monthly in cycles having billing dates that do not generally coincide with the end of a calendar month. This results in customers having received electricity or natural gas that they have not been billed for as of the month-end. Consumers estimates its unbilled revenues by applying an average billed rate to total unbilled deliveries for each customer class. Consumers records unbilled revenues as accounts receivable and accrued revenue on its consolidated balance sheet. For additional information on unbilled revenues, see Item 8. Financial Statements and Supplementary Data—Notes to the Consolidated Financial Statements—Note 15, Revenue.

New Accounting Standards

For details regarding new accounting standards issued but not yet effective, See Item 8. Financial Statements and Supplementary Data—Notes to the Consolidated Financial Statements—Note 2, New Accounting Standards.

Item 7A. Quantitative and Qualitative Disclosures About Market Risk

CMS Energy and Consumers are exposed to market risks including, but not limited to, changes in interest rates, commodity prices, and investment security prices. They may enter into various risk management contracts to mitigate exposure to these risks, including swaps, options, futures, and forward contracts. CMS Energy and Consumers enter into these contracts using established policies and procedures, under the direction of an executive oversight committee consisting of certain officers and a risk committee consisting of those and other officers and business managers.

The following risk sensitivity illustrates the potential loss in fair value, cash flows, or future earnings from financial instruments, assuming a hypothetical adverse change in market rates or prices of 10 percent. Potential losses could exceed the amounts shown in the sensitivity analyses if changes in market rates or prices were to exceed 10 percent.

Long-term Debt: CMS Energy and Consumers are exposed to interest-rate risk resulting from issuing fixed-rate and variable-rate debt instruments. CMS Energy and Consumers use a combination of these instruments, and may also enter into interest-rate swap agreements, in order to manage this risk and to achieve a reasonable cost of capital.

Presented in the following table is a sensitivity analysis of interest-rate risk on CMS Energy’s and Consumers’ debt instruments (assuming an adverse change in market interest rates of 10 percent):

In Millions

December 31	2025	2024
Fixed-rate financing—potential loss in fair value		
CMS Energy, including Consumers	$ 792	$ 717
Consumers	535	543

The fair value losses in the above table could be realized only if CMS Energy and Consumers transferred all of their fixed-rate financing to other creditors. The annual earnings exposure related to variable-rate financing was immaterial for both CMS Energy and Consumers at December 31, 2025 and 2024, assuming an adverse change in market interest rates of 10 percent. For additional details on financial instruments see Item 8. Financial Statements and Supplementary Data—Notes to the Consolidated Financial Statements—Note 7, Financial Instruments.

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Item 8. Financial Statements and Supplementary Data

Index to Financial Statements

CMS Energy Corporation
Consolidated Statements of Income

In Millions, Except Per Share Amounts

Years Ended December 31	2025	2024	2023
Operating Revenue	$ 8,539	$ 7,515	$ 7,462
Operating Expenses			
Fuel for electric generation	657	624	561
Purchased and interchange power	1,706	1,333	1,375
Purchased power – related parties	94	71	75
Cost of gas sold	809	640	902
Maintenance and other operating expenses	1,727	1,638	1,687
Depreciation and amortization	1,306	1,240	1,180
General taxes	513	482	447
Total operating expenses	6,812	6,028	6,227
Operating Income	1,727	1,487	1,235
Other Income (Expense)			
Non-operating retirement benefits, net	186	169	180
Other income	151	207	195
Other expense	(27)	(32)	(13)
Total other income	310	344	362
Interest Charges			
Interest on long-term debt	798	700	616
Interest expense – related parties	11	12	12
Other interest expense	(9)	14	18
Allowance for borrowed funds used during construction	(11)	(18)	(3)
Total interest charges	789	708	643
Income Before Income Taxes	1,248	1,123	954
Income Tax Expense	246	176	147
Income From Continuing Operations	1,002	947	807
Income From Discontinued Operations, Net of Tax of $— for all periods	—	—	1
Net Income	1,002	947	808
Loss Attributable to Noncontrolling Interests	(69)	(56)	(79)
Net Income Attributable to CMS Energy	1,071	1,003	887
Preferred Stock Dividends	10	10	10
Net Income Available to Common Stockholders	$ 1,061	$ 993	$ 877
Basic Earnings Per Average Common Share	$ 3.53	$ 3.34	$ 3.01
Diluted Earnings Per Average Common Share	$ 3.53	$ 3.33	$ 3.01

The accompanying notes are an integral part of these statements.

CMS Energy Corporation
Consolidated Statements of Comprehensive Income

In Millions

Years Ended December 31		2025		2024		2023
Net Income	$	1,002	$	947	$	808
Retirement Benefits Liability						
Net gain arising during the period, net of tax of $2, $1, and $2		4		2		5
Prior service credit adjustment, net of tax of $— for all periods		—		1		—
Amortization of net actuarial loss, net of tax of $— for all periods		2		2		2
Amortization of prior service credit, net of tax of $— for all periods		(1)		—		(1)
Other Comprehensive Income		5		5		6
Comprehensive Income		1,007		952		814
Comprehensive Loss Attributable to Noncontrolling Interests		(69)		(56)		(79)
Comprehensive Income Attributable to CMS Energy	$	1,076	$	1,008	$	893

The accompanying notes are an integral part of these statements.

CMS Energy Corporation
Consolidated Statements of Cash Flows

In Millions

Years Ended December 31	2025	2024	2023
Cash Flows from Operating Activities			
Net income	$ 1,002	$ 947	$ 808
Adjustments to reconcile net income to net cash provided by operating activities			
Depreciation and amortization	1,306	1,240	1,180
Deferred income taxes and investment tax credits	202	142	157
Bad debt expense	40	33	34
Postretirement benefits contributions	(16)	(13)	(12)
Other non-cash operating activities and reconciling adjustments	(238)	(241)	(274)
Changes in assets and liabilities			
Accounts receivable and accrued revenue	(251)	(155)	241
Inventories	(28)	164	185
Accounts payable and accrued rate refunds	196	15	(136)
Other current assets and liabilities	78	42	(21)
Other non-current assets and liabilities	(56)	196	147
Net cash provided by operating activities	2,235	2,370	2,309
Cash Flows from Investing Activities			
Capital expenditures (excludes assets placed under finance lease)	(3,824)	(3,018)	(2,407)
Covert Generating Station acquisition	—	—	(812)
Proceeds from sale of ASP business	—	124	—
Cost to retire property and other investing activities	(214)	(160)	(167)
Net cash used in investing activities	(4,038)	(3,054)	(3,386)
Cash Flows from Financing Activities			
Proceeds from issuance of debt	3,609	1,962	3,551
Retirement of debt	(1,150)	(952)	(2,132)
Increase (decrease) in notes payable	(65)	(28)	73
Issuance of common stock	525	286	192
Payment of dividends on common and preferred stock	(663)	(626)	(579)
Proceeds from the sale of membership interests in VIEs	44	—	—
Proceeds from the sale of membership interest in VIE to tax equity investor	15	—	86
Contributions from noncontrolling interests	4	5	6
Distributions to noncontrolling interests	(14)	(12)	(12)
Other financing costs	(65)	(21)	(42)
Net cash provided by financing activities	2,240	614	1,143
Net Increase (Decrease) in Cash and Cash Equivalents, Including Restricted Amounts	437	(70)	66
Cash and Cash Equivalents, Including Restricted Amounts, Beginning of Period	178	248	182
Cash and Cash Equivalents, Including Restricted Amounts, End of Period	$ 615	$ 178	$ 248

Years Ended December 31						*In Millions* 2023
		2025		2024		
Other Cash Flow Activities and Non-cash Investing and Financing Activities						
Cash transactions						
Interest paid (net of amounts capitalized)	$	741	$	677	$	607
Income taxes paid (proceeds from sale of renewable energy tax credits), net		(20)		(69)		15
Non-cash transactions						
Capital expenditures not paid	$	662	$	517	$	265
Deemed contribution from sale of membership interest		35		—		—

The accompanying notes are an integral part of these statements.

CMS Energy Corporation
Consolidated Balance Sheets

ASSETS

In Millions

December 31	2025	2024
Current Assets		
Cash and cash equivalents	$ 509	$ 103
Restricted cash and cash equivalents	106	75
Accounts receivable and accrued revenue, less allowance of $27 in 2025 and $23 in 2024	1,306	1,049
Accounts receivable – related parties	17	14
Inventories at average cost		
Gas in underground storage	427	435
Materials and supplies	329	299
Generating plant fuel stock	35	35
Deferred property taxes	479	448
Regulatory assets	104	229
Prepayments and other current assets	160	103
Total current assets	3,472	2,790
Plant, Property, and Equipment		
Plant, property, and equipment, gross	37,763	34,932
Less accumulated depreciation and amortization	10,135	9,569
Plant, property, and equipment, net	27,628	25,363
Construction work in progress	3,052	2,098
Total plant, property, and equipment	30,680	27,461
Other Non-current Assets		
Regulatory assets	3,355	3,569
Accounts receivable	18	20
Investments	61	69
Postretirement benefits	1,957	1,627
Other	398	384
Total other non-current assets	5,789	5,669
Total Assets	$ 39,941	$ 35,920

LIABILITIES AND EQUITY

In Millions

December 31	2025	2024
Current Liabilities		
Current portion of long-term debt and finance leases	$ 956	$ 1,195
Notes payable	—	65
Accounts payable	1,395	1,085
Accounts payable – related parties	9	8
Accrued rate refunds	28	38
Accrued interest	182	156
Accrued taxes	708	654
Regulatory liabilities	85	111
Other current liabilities	185	209
Total current liabilities	3,548	3,521
Non-current Liabilities		
Long-term debt	17,807	15,194
Non-current portion of finance leases	135	112
Regulatory liabilities	4,091	4,067
Postretirement benefits	95	96
AROs	792	728
Deferred investment tax credit	118	122
Deferred income taxes	3,252	2,925
Other non-current liabilities	392	407
Total non-current liabilities	26,682	23,651
Commitments and Contingencies (Notes 3 and 4)		
Equity		
Common stockholders' equity		
Common stock, authorized 350.0 shares in both periods; outstanding 306.4 shares in 2025 and 298.8 shares in 2024	3	3
Other paid-in capital	6,510	6,009
Accumulated other comprehensive loss	(36)	(41)
Retained earnings	2,443	2,035
Total common stockholders' equity	8,920	8,006
Cumulative redeemable perpetual preferred stock, Series C, authorized 9.2 depositary shares; outstanding 9.2 depositary shares in both periods	224	224
Total stockholders' equity	9,144	8,230
Noncontrolling interests	567	518
Total equity	9,711	8,748
Total Liabilities and Equity	$ 39,941	$ 35,920

The accompanying notes are an integral part of these statements.

CMS Energy Corporation
Consolidated Statements of Changes in Equity

In Millions, Except Number of Shares in Thousands and Per Share Amounts

	Number of Shares					
Years Ended December 31	2025	2024	2023	2025	2024	2023
Total Equity at Beginning of Period				$ 8,748	$ 8,125	$ 7,595
Common Stock						
At beginning and end of period				3	3	3
Other Paid-in Capital						
At beginning of period	298,790	294,440	291,268	6,009	5,705	5,490
Common stock issued	7,839	4,673	3,355	548	315	222
Common stock repurchased	(181)	(181)	(119)	(13)	(11)	(7)
Common stock reacquired	(39)	(142)	(64)	—	—	—
Adjustment for sale of membership interests in VIEs				(34)	—	—
At end of period	306,409	298,790	294,440	6,510	6,009	5,705
Accumulated Other Comprehensive Loss						
Retirement benefits liability						
At beginning of period				(41)	(46)	(52)
Net gain arising during the period				4	2	5
Prior service credit adjustment				—	1	—
Amortization of net actuarial loss				2	2	2
Amortization of prior service credit				(1)	—	(1)
At end of period				(36)	(41)	(46)
Retained Earnings						
At beginning of period				2,035	1,658	1,350
Net income attributable to CMS Energy				1,071	1,003	887
Dividends declared on common stock				(653)	(616)	(569)
Dividends declared on preferred stock				(10)	(10)	(10)
At end of period				2,443	2,035	1,658
Cumulative Redeemable Perpetual Preferred Stock, Series C						
At beginning and end of period				224	224	224
Noncontrolling Interests						
At beginning of period				518	581	580
Sale of membership interests in VIEs				78	—	—
Sale of membership interest in VIE to tax equity investor				50	—	86
Contributions from noncontrolling interests				4	5	6
Distributions to noncontrolling interests				(14)	(12)	(12)
Loss attributable to noncontrolling interests				(69)	(56)	(79)
At end of period				567	518	581
Total Equity at End of Period				$ 9,711	$ 8,748	$ 8,125
Dividends declared per common share				$ 2.170	$ 2.060	$ 1.950
Dividends declared per preferred stock Series C depositary share				$ 1.050	$ 1.050	$ 1.050

The accompanying notes are an integral part of these statements.

Consumers Energy Company
Consolidated Statements of Income

In Millions

Years Ended December 31	2025	2024	2023
Operating Revenue	$ 8,132	$ 7,200	$ 7,166
Operating Expenses			
Fuel for electric generation	535	511	435
Purchased and interchange power	1,564	1,285	1,331
Purchased power – related parties	94	71	75
Cost of gas sold	803	637	897
Maintenance and other operating expenses	1,614	1,520	1,586
Depreciation and amortization	1,254	1,191	1,137
General taxes	499	470	437
Total operating expenses	6,363	5,685	5,898
Operating Income	1,769	1,515	1,268
Other Income (Expense)			
Non-operating retirement benefits, net	175	157	171
Other income	55	85	49
Other expense	(22)	(30)	(12)
Total other income	208	212	208
Interest Charges			
Interest on long-term debt	521	488	415
Interest expense – related parties	41	31	20
Other interest expense	8	12	16
Allowance for borrowed funds used during construction	(10)	(13)	(3)
Total interest charges	560	518	448
Income Before Income Taxes	1,417	1,209	1,028
Income Tax Expense	288	200	161
Net Income	1,129	1,009	867
Preferred Stock Dividends	2	2	2
Net Income Available to Common Stockholder	$ 1,127	$ 1,007	$ 865

The accompanying notes are an integral part of these statements.

Consumers Energy Company
Consolidated Statements of Comprehensive Income

In Millions

Years Ended December 31	2025	2024	2023
Net Income	$ 1,129	$ 1,009	$ 867
Retirement Benefits Liability			
Net gain (loss) arising during the period, net of tax of $(1), $1, and $—	(2)	3	(1)
Amortization of net actuarial loss, net of tax of $— for all periods	—	1	1
Other Comprehensive Income (Loss)	(2)	4	—
Comprehensive Income	$ 1,127	$ 1,013	$ 867

The accompanying notes are an integral part of these statements.

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Consumers Energy Company
Consolidated Statements of Cash Flows

In Millions

Years Ended December 31	2025	2024	2023
Cash Flows from Operating Activities			
Net income	$ 1,129	$ 1,009	$ 867
Adjustments to reconcile net income to net cash provided by operating activities			
Depreciation and amortization	1,254	1,191	1,137
Deferred income taxes and investment tax credits	48	115	156
Bad debt expense	40	33	34
Postretirement benefits contributions	(10)	(9)	(9)
Other non-cash operating activities and reconciling adjustments	(165)	(137)	(123)
Changes in assets and liabilities			
Accounts and notes receivable and accrued revenue	(235)	(153)	219
Inventories	(24)	164	186
Accounts payable and accrued rate refunds	187	19	(127)
Other current assets and liabilities	104	75	(35)
Other non-current assets and liabilities	(90)	139	125
Net cash provided by operating activities	2,238	2,446	2,430
Cash Flows from Investing Activities			
Capital expenditures (excludes assets placed under finance lease)	(3,314)	(2,842)	(2,248)
Covert Generating Station acquisition	—	—	(812)
Proceeds from sale of ASP business	—	124	—
Cost to retire property and other investing activities	(221)	(154)	(141)
Net cash used in investing activities	(3,535)	(2,872)	(3,201)
Cash Flows from Financing Activities			
Proceeds from issuance of debt	1,123	1,297	2,666
Retirement of debt	(115)	(389)	(1,654)
Increase (decrease) in notes payable	(65)	(28)	73
Increase (decrease) in notes payable – related parties	340	—	(75)
Stockholder contribution	920	735	475
Return of stockholder contribution	—	(320)	—
Payment of dividends on common and preferred stock	(900)	(797)	(697)
Other financing costs	(14)	(9)	(21)
Net cash provided by financing activities	1,289	489	767
Net Increase (Decrease) in Cash and Cash Equivalents, Including Restricted Amounts	(8)	63	(4)
Cash and Cash Equivalents, Including Restricted Amounts, Beginning of Period	119	56	60
Cash and Cash Equivalents, Including Restricted Amounts, End of Period	$ 111	$ 119	$ 56

In Millions

Years Ended December 31	2025	2024	2023
Other Cash Flow Activities and Non-cash Investing and Financing Activities			
Cash transactions			
Interest paid (net of amounts capitalized)	$ 526	$ 484	$ 417
Income taxes paid (proceeds from sale of renewable energy tax credits), net	161	(19)	31
Non-cash transactions			
Capital expenditures not paid	$ 533	$ 395	$ 264

The accompanying notes are an integral part of these statements.

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Consumers Energy Company
Consolidated Balance Sheets

ASSETS

In Millions

December 31	2025	2024
Current Assets		
Cash and cash equivalents	$ 25	$ 44
Restricted cash and cash equivalents	86	75
Accounts receivable and accrued revenue, less allowance of $27 in 2025 and $23 in 2024	1,210	1,019
Accounts and notes receivable – related parties	15	17
Inventories at average cost		
Gas in underground storage	427	435
Materials and supplies	316	291
Generating plant fuel stock	31	30
Deferred property taxes	479	448
Regulatory assets	104	229
Prepayments and other current assets	132	86
Total current assets	2,825	2,674
Plant, Property, and Equipment		
Plant, property, and equipment, gross	36,120	33,434
Less accumulated depreciation and amortization	9,842	9,310
Plant, property, and equipment, net	26,278	24,124
Construction work in progress	2,354	1,766
Total plant, property, and equipment	28,632	25,890
Other Non-current Assets		
Regulatory assets	3,355	3,569
Accounts receivable	24	26
Accounts and notes receivable – related parties	88	92
Postretirement benefits	1,821	1,514
Other	346	323
Total other non-current assets	5,634	5,524
Total Assets	$ 37,091	$ 34,088

LIABILITIES AND EQUITY

		In Millions
December 31	2025	2024
Current Liabilities		
Current portion of long-term debt and finance leases	$ 579	$ 456
Notes payable	—	65
Notes payable – related parties	340	—
Accounts payable	1,229	917
Accounts payable – related parties	14	12
Accrued rate refunds	28	38
Accrued interest	149	130
Accrued taxes	747	678
Regulatory liabilities	85	111
Other current liabilities	163	185
Total current liabilities	3,334	2,592
Non-current Liabilities		
Long-term debt	11,524	10,818
Long-term debt – related parties	1,005	823
Non-current portion of finance leases	81	69
Regulatory liabilities	4,091	4,067
Postretirement benefits	70	70
AROs	753	694
Deferred investment tax credit	118	122
Deferred income taxes	3,201	3,053
Other non-current liabilities	336	349
Total non-current liabilities	21,179	20,065
Commitments and Contingencies (Notes 3 and 4)		
Equity		
Common stockholder's equity		
Common stock, authorized 125.0 shares; outstanding 84.1 shares in both periods	841	841
Other paid-in capital	9,094	8,174
Accumulated other comprehensive loss	(13)	(11)
Retained earnings	2,619	2,390
Total common stockholder's equity	12,541	11,394
Cumulative preferred stock, $4.50 series, authorized 7.5 shares; outstanding 0.4 shares in both periods	37	37
Total equity	12,578	11,431
Total Liabilities and Equity	$ 37,091	$ 34,088

The accompanying notes are an integral part of these statements.

Consumers Energy Company
Consolidated Statements of Changes in Equity

In Millions

Years Ended December 31	2025	2024	2023
Total Equity at Beginning of Period	$ 11,431	$ 10,800	$ 10,155
Common Stock			
At beginning and end of period	841	841	841
Other Paid-in Capital			
At beginning of period	8,174	7,759	7,284
Stockholder contribution	920	735	475
Return of stockholder contribution	—	(320)	—
At end of period	9,094	8,174	7,759
Accumulated Other Comprehensive Loss			
Retirement benefits liability			
At beginning of period	(11)	(15)	(15)
Net gain (loss) arising during the period	(2)	3	(1)
Amortization of net actuarial loss	—	1	1
At end of period	(13)	(11)	(15)
Retained Earnings			
At beginning of period	2,390	2,178	2,008
Net income	1,129	1,009	867
Dividends declared on common stock	(898)	(795)	(695)
Dividends declared on preferred stock	(2)	(2)	(2)
At end of period	2,619	2,390	2,178
Cumulative Preferred Stock			
At beginning and end of period	37	37	37
Total Equity at End of Period	$ 12,578	$ 11,431	$ 10,800

The accompanying notes are an integral part of these statements.

CMS Energy Corporation
Consumers Energy Company
Notes to the Consolidated Financial Statements

1: Significant Accounting Policies

Principles of Consolidation: CMS Energy and Consumers prepare their consolidated financial statements in conformity with GAAP. CMS Energy's consolidated financial statements comprise CMS Energy, Consumers, NorthStar Clean Energy, and all other entities in which CMS Energy has a controlling financial interest or is the primary beneficiary. Consumers' consolidated financial statements comprise Consumers and all other entities in which it has a controlling financial interest. CMS Energy uses the equity method of accounting for investments in companies and partnerships that are not consolidated, where they have significant influence over operations and financial policies but are not the primary beneficiary. CMS Energy and Consumers eliminate intercompany transactions and balances.

Use of Estimates: CMS Energy and Consumers are required to make estimates using assumptions that may affect reported amounts and disclosures. Actual results could differ from those estimates.

Cash and Cash Equivalents and Restricted Cash and Cash Equivalents: Cash and cash equivalents include short-term, highly liquid investments with original maturities of three months or less. Restricted cash and cash equivalents are held primarily for the repayment of securitization bonds and funds held in escrow. These amounts are classified as current assets since they relate to payments that could or will occur within one year.

Contingencies: CMS Energy and Consumers record estimated loss contingencies on their consolidated financial statements when it is probable that a loss has been incurred and when the amount of loss can be reasonably estimated. For environmental remediation projects in which the timing of estimated expenditures is considered reliably determinable, CMS Energy and Consumers record the liability at its net present value, using a discount rate equal to the interest rate on monetary assets that are essentially risk-free and have maturities comparable to that of the environmental liability. Unless regulatory accounting applies, CMS Energy and Consumers expense legal fees as incurred; fees incurred but not yet billed are accrued based on estimates of work performed.

Debt Issuance Costs, Discounts, Premiums, and Refinancing Costs: Upon the issuance of long-term debt, CMS Energy and Consumers defer issuance costs, discounts, and premiums and amortize those amounts over the terms of the associated debt. Debt issuance costs are presented as a direct deduction from the carrying amount of long-term debt on the balance sheet. Upon the refinancing of long-term debt, Consumers, as a regulated entity, defers any remaining unamortized issuance costs, discounts, and premiums associated with the refinanced debt and amortizes those amounts over the term of the newly issued debt. For the non-regulated portions of CMS Energy's business, any remaining unamortized issuance costs, discounts, and premiums associated with extinguished debt are charged to earnings.

Derivative Instruments: In order to support ongoing operations, CMS Energy and Consumers may enter into contracts for the future purchase and sale of various commodities, such as electricity, natural gas, and coal. These forward contracts are generally long-term in nature and result in physical delivery of the commodity at a contracted price. Most of these contracts are not subject to derivative accounting for one or more of the following reasons:

- they do not have a notional amount (that is, a number of units specified in a derivative instrument, such as MWh of electricity or Bcf of natural gas)
- they qualify for the normal purchases and sales exception
- they cannot be net settled due in part to the absence of an active market for the commodity

Consumers also uses FTRs to manage price risk related to electricity transmission congestion. An FTR is a financial instrument that entitles its holder to receive compensation or requires its holder to remit payment for congestion-related transmission charges. Consumers accounts for FTRs as derivatives and changes in the fair value of FTRs are deferred as regulatory assets or liabilities. For details regarding CMS Energy's and Consumers' derivative instruments recorded at fair value, see Note 6, Fair Value Measurements.

Electricity Market Transactions: Wholesale electricity market operators require the submission of hourly day-ahead and real-time bids and offers for energy at locations across each region. CMS Energy and Consumers account for such transactions on a net hourly basis in each of the real-time and day-ahead markets, netted across all locations in the energy market. CMS Energy and Consumers record net hourly purchases in purchased and interchange power and net hourly sales in operating revenue on their consolidated statements of income. They record net billing adjustments upon receipt of settlement statements, record accruals for future net purchases and sales adjustments based on historical experience, and reconcile accruals to actual expenses and sales upon receipt of settlement statements.

EPS: CMS Energy calculates basic and diluted EPS using the weighted-average number of shares of common stock and dilutive potential common stock outstanding during the period. Potential common stock, for purposes of determining diluted EPS, includes the effects of nonvested stock awards, forward equity sales, and convertible securities. CMS Energy computes the effect on potential common stock using the treasury stock method. Potentially dilutive common shares issuable upon conversion of the convertible senior notes are determined using the if-converted method for calculating diluted EPS. Diluted EPS excludes the impact of antidilutive securities, which are those securities resulting in an increase in EPS or a decrease in loss per share. For EPS computations, see Note 14, Earnings Per Share—CMS Energy.

Impairment of Long-lived Assets and Equity Method Investments: CMS Energy and Consumers perform tests of impairment if certain triggering events occur that indicate the carrying amount of an asset may not be recoverable or that there has been a decline in value that may be other than temporary.

CMS Energy and Consumers evaluate long-lived assets held in use for impairment by calculating the undiscounted future cash flows expected to result from the use of the asset and its eventual disposition. If the undiscounted future cash flows are less than the carrying amount, CMS Energy and Consumers recognize an impairment loss equal to the amount by which the carrying amount exceeds the fair value. CMS Energy and Consumers estimate the fair value of the asset using quoted market prices, market prices of similar assets, or discounted future cash flow analyses.

CMS Energy also assesses equity method investments for impairment whenever there has been a decline in value that is other than temporary. This assessment requires CMS Energy to determine the fair value of the equity method investment. CMS Energy determines fair value using valuation methodologies, including discounted cash flows, and assesses the ability of the investee to sustain an earnings capacity that justifies the carrying amount of the investment. CMS Energy records an impairment if the fair value is less than the carrying amount and the decline in value is considered to be other than temporary.

Investment Tax Credits: CMS Energy and its subsidiaries use the flow-through method of accounting for investment tax credits. Under the flow-through method, the credit is recognized as a reduction to income tax expense when the related plant, property, and equipment is placed into service. For its regulated utility assets, Consumers amortizes its investment tax credits over the life of the related property in accordance with regulatory treatment.

Inventory: CMS Energy and Consumers use the weighted-average cost method for valuing working gas, recoverable base gas in underground storage facilities, and materials and supplies inventory. CMS Energy and Consumers also use this method for valuing coal inventory, and they classify these amounts as generating plant fuel stock on their consolidated balance sheets.

CMS Energy and Consumers account for RECs and other environmental credits as inventory and use the weighted-average cost method to remove amounts from inventory. RECs and other environmental credits are used to satisfy compliance obligations related to the generation of power and in support of sustainability commitments. CMS Energy and Consumers classify these amounts within other assets on their consolidated balance sheets.

CMS Energy and Consumers evaluate inventory for impairment as required to ensure that its carrying value does not exceed the lower of cost or net realizable value.

Property Taxes: Property taxes are based on the taxable value of CMS Energy's and Consumers' real and personal property assessed by local taxing authorities. CMS Energy and Consumers record property tax expense over the fiscal year of the taxing authority for which the taxes are levied. The deferred property tax balance represents the amount of CMS Energy's and Consumers' accrued property tax that will be recognized over future governmental fiscal periods.

Other: For additional accounting policies, see:

- Note 3, Regulatory Matters
- Note 8, Plant, Property, and Equipment
- Note 9, Leases
- Note 10, Asset Retirement Obligations
- Note 11, Retirement Benefits
- Note 12, Stock-based Compensation
- Note 13, Income Taxes
- Note 14, Earnings Per Share—CMS Energy
- Note 15, Revenue
- Note 19, Variable Interest Entities

2: New Accounting Standards

Implementation of New Accounting Standards

ASU 2023-09, Incomes Taxes (Topic 740): Improvements to Income Tax Disclosures: This standard, which was effective on January 1, 2025 for CMS Energy and Consumers, requires expanded annual disclosures of the income taxes, including a more detailed reconciliation of the effective tax rate and disaggregated information on federal and state income taxes. The standard also requires disclosure of significant reconciling items and qualitative information about state and local jurisdictions contributing to income tax expense. The adoption of the new standard did not impact CMS Energy's or Consumers' liquidity, financial condition, or results of operations. The expanded disclosures required by this standard are included in Note 13, Income Taxes.

New Accounting Standards Not Yet Effective

ASU 2024-03, Income Statement—Reporting Comprehensive Income—Expense Disaggregation Disclosures (Subtopic 220-40): Disaggregation of Income Statement Expenses: This standard requires public companies to provide disaggregated information about certain expense categories presented on the income statement. The guidance calls for annual and interim disclosures that separate specified components, such as employee compensation, depreciation, and amortization, within relevant expense line items in the notes to the financial statements. The standard is effective for annual reporting periods beginning after December 15, 2026, and interim periods beginning after December 15, 2027, with early adoption permitted. CMS Energy and Consumers will adopt the guidance upon the effective date. The standard will not have an impact on CMS Energy's or Consumers' consolidated net income, cash flows, or financial position.

ASU 2025-06, Intangibles—Goodwill and Other—Internal-Use Software (Subtopic 350-40): Targeted Improvements to the Accounting for Internal-Use Software: This standard updates guidance for capitalizing costs related to internal-use software development. The amendments remove references to the previous "project stage" model and clarify the threshold for when capitalization should begin, focusing on whether completion of the project is probable. The amendments are effective for annual and interim reporting periods beginning after December 15, 2027. The guidance may be applied on a prospective, retrospective, or modified transition basis. Early adoption is permitted. CMS Energy and Consumers are currently evaluating the new standard.

3: Regulatory Matters

Regulatory matters are critical to Consumers. The Michigan Attorney General, ABATE, the MPSC Staff, residential customer advocacy groups, environmental organizations, and certain other parties typically participate in MPSC proceedings concerning Consumers, such as Consumers' rate cases and PSCR and GCR processes. Intervenors also participate in certain FERC matters, including FERC's regulation of certain wholesale rates that affect Consumers' power supply costs. These parties often challenge various aspects of those proceedings, including the prudence of Consumers' policies and practices, and seek cost disallowances and other relief. The parties also have appealed significant MPSC and FERC orders. Depending upon the specific issues, the outcomes of rate cases and proceedings, including judicial proceedings challenging MPSC and FERC orders or other actions, could negatively affect CMS Energy's and Consumers' liquidity, financial condition, and results of operations. Consumers cannot predict the outcome of these proceedings.

Regulatory Assets and Liabilities

Consumers is subject to the actions of the MPSC and FERC and therefore prepares its consolidated financial statements in accordance with the provisions of regulatory accounting. A utility must apply regulatory accounting when its rates are designed to recover specific costs of providing regulated services. Under regulatory accounting, Consumers records regulatory assets or liabilities for certain transactions that would have been treated as expense or revenue by non-regulated businesses.

Presented in the following table are the regulatory assets and liabilities on Consumers' consolidated balance sheets:

In Millions

December 31	2025	2024
Regulatory assets		
Current		
Energy waste reduction plan incentive[1]	$ 66	$ 60
Retention incentive program[2]	10	18
2022 PSCR underrecovery[3]	—	126
Other	28	25
Total current regulatory assets	$ 104	$ 229
Non-current		
Costs of coal-fueled electric generating units to be retired[3]	$ 1,179	$ 1,266
Postretirement benefits[2]	589	747
Securitized costs[3]	549	666
ARO[4]	379	366
Decommissioning costs[2]	197	158
Unamortized loss on reacquired debt[3]	89	92
MGP sites[3]	82	90
Energy waste reduction plan incentive[1]	64	64
Ludington overhaul contract dispute[2]	60	31
Service restoration cost deferral[4]	52	—
Energy waste reduction plan[3]	26	31
Postretirement benefits expense deferral mechanism[2]	22	21
Renewable Energy Plan[3]	7	—
Retention incentive program[2]	6	12
Other	54	25
Total non-current regulatory assets	$ 3,355	$ 3,569
Total regulatory assets	$ 3,459	$ 3,798
Regulatory liabilities		
Current		
Income taxes, net	$ 47	$ 53
ASP gain	28	47
Other	10	11
Total current regulatory liabilities	$ 85	$ 111
Non-current		
Cost of removal	$ 2,727	$ 2,665
Income taxes, net	1,118	1,163
Energy waste reduction plan	68	41
Green giving program	41	—
Postretirement benefits expense deferral mechanism	40	37
Renewable energy grant	38	40
ASP gain	19	46
Renewable Energy Plan	—	51
Other	40	24
Total non-current regulatory liabilities	$ 4,091	$ 4,067
Total regulatory liabilities	$ 4,176	$ 4,178

[1] These regulatory assets have arisen from an alternative-revenue program and are not associated with incurred costs or capital investments. Therefore, the MPSC has provided for recovery without a return.

[2] This regulatory asset is included in rate base, thereby providing a return.

[3] The MPSC has provided a specific return on these regulatory assets.

[4] These regulatory assets represent incurred costs for which the MPSC has provided recovery without a return on investment.

Regulatory Assets

Energy Waste Reduction Plan Incentive: The energy waste reduction incentive mechanism provides a financial incentive if the energy savings of Consumers' customers exceed annual targets established by the MPSC. Consumers accounts for this program as an alternative-revenue program that meets the criteria for recognizing revenue related to the incentive as soon as energy savings exceed the annual targets established by the MPSC.

In January 2026, the MPSC approved a settlement agreement authorizing Consumers to collect $64 million during 2026 as an incentive for exceeding its statutory savings targets in 2024. Consumers recognized incentive revenue under this program of $64 million in 2024.

Consumers also exceeded its statutory savings targets in 2025, achieved certain other goals, and will request the MPSC's approval to collect $64 million in the energy waste reduction reconciliation to be filed in May 2026. Consumers recognized incentive revenue under this program of $64 million in 2025.

Retention Incentive Program: To ensure necessary staffing at the D.E. Karn and J.H. Campbell coal-fueled generating units through their retirement, Consumers established retention incentive programs. The MPSC has approved deferred accounting treatment for the retention and severance costs incurred under these programs and has allowed for recovery over three years. These MPSC-approved retention plans concluded in November 2025. For additional details regarding retention incentive programs, see Note 20, Exit Activities and Asset Sales.

2022 PSCR Underrecovery: As a result of rising fuel prices during 2022, Consumers' power supply costs for 2022 were significantly higher than those projected in its 2022 PSCR plan. At the end of 2022, Consumers had recorded $401 million of under-recovered power supply costs. In 2023, the MPSC authorized Consumers to recover the 2022 underrecovery amount over three years, providing immediate relief to electric customers.

Costs of Coal-fueled Electric Generating Units to be Retired: In 2022, the MPSC approved Consumers' plans to retire the J.H. Campbell coal-fueled generating units in 2025. The MPSC authorized regulatory asset treatment for Consumers to recover the remaining book value of the units upon their retirement, as well as a 9.0-percent return on equity, through 2040, the units' original retirement date. Accordingly, in 2022, Consumers removed from total plant, property, and equipment an amount of $1.3 billion, representing the projected remaining book value of the electric generating units upon their retirement, and recorded it as a non-current regulatory asset on its consolidated balance sheets.

As discussed further below, the retirement of J.H. Campbell is subject to temporary extensions under emergency orders issued by the U.S. Secretary of Energy. Such orders authorize Consumers to obtain cost recovery at FERC; thus, Consumers has deferred the costs of complying with these orders as a regulatory asset.

Postretirement Benefits: As part of the ratemaking process, the MPSC allows Consumers to recover the costs of postretirement benefits. Accordingly, Consumers defers the net impact of actuarial losses and gains, prior service costs and credits, and settlements associated with postretirement benefits as a regulatory asset or liability. The asset or liability will decrease as the deferred items are amortized and recognized as components of net periodic benefit cost. For details about the amortization periods, see Note 11, Retirement Benefits.

Securitized Costs: The MPSC has issued securitization financing orders authorizing Consumers to issue securitization bonds in order to finance the recovery of the remaining book value of three smaller natural gas-fueled electric generating units that Consumers retired in 2015, seven smaller coal-fueled electric generating units that Consumers retired in 2016, and the D.E. Karn coal-fueled electric generating units that Consumers retired in 2023. Consumers has removed from plant, property, and equipment and recorded as a regulatory asset the book value of these units. Consumers is amortizing the regulatory asset over the life of the related securitization bonds, which it issued through subsidiaries in 2014 and 2023. For additional details regarding the securitization bonds, see Note 5, Financings and Capitalization—Securitization Bonds.

ARO: The recovery of the underlying asset investments and related removal and monitoring costs of recorded AROs is approved by the MPSC in depreciation rate cases. Consumers records a regulatory asset and a regulatory liability for timing differences between the recognition of AROs for financial reporting purposes and the recovery of these costs from customers. The recovery period approximates the useful life of the assets to be removed.

Decommissioning Costs: In Consumers' electric depreciation and general rate cases, the MPSC has authorized Consumers to remove from depreciation rates the costs of decommissioning the D.E. Karn coal-fueled electric generating units, and instead defer those costs as a regulatory asset to be recovered through 2031. Additionally, ash disposal costs related to Consumers' retired coal-fueled generating units may be deferred as a regulatory asset and collected over a ten-year period. In its 2022 order approving Consumers' integrated resource plan, the MPSC authorized similar treatment for the decommissioning and ash disposal costs associated with the J.H. Campbell coal-fueled generating units that were planned for retirement in 2025.

Unamortized Loss on Reacquired Debt: Under regulatory accounting, any unamortized discount, premium, or expense related to debt redeemed with the proceeds of new debt is deferred and amortized over the life of the new debt.

MGP Sites: Consumers is incurring environmental remediation and other response activity costs at 23 former MGP facilities. The MPSC allows Consumers to recover from its natural gas customers over a ten-year period the costs incurred to remediate the MGP sites. For additional information, see Note 4, Contingencies and Commitments—Consumers Gas Utility Contingencies.

Ludington Overhaul Contract Dispute: The MPSC has authorized Consumers to defer as a regulatory asset costs associated with correcting incomplete, nonconforming, and defective work performed by TAES during a major overhaul and upgrade of Ludington. Consumers will defer such costs while post-verdict proceedings and any appeals in the litigation with TAES and Toshiba continue; such costs will be offset, in part or in whole, by future litigation proceeds received from TAES or Toshiba. Consumers has also deferred replacement power costs due to outages resulting from correcting this work. Consumers will have the opportunity to seek appropriate recovery and ratemaking treatment for amounts recorded as a regulatory asset following resolution of the litigation. During 2025, cash expenditures associated with the Ludington overhaul contract dispute were $30 million. For additional details on the contract dispute, see Note 4, Contingencies and Commitments—Consumers Electric Utility Contingencies.

Service Restoration Cost Deferral: As a result of catastrophic storms in Consumers' electric service territory, Consumers incurred significant service restoration costs during March and April 2025. In April 2025, Consumers filed with the MPSC an ex parte application requesting approval to defer, as a regulatory asset, operating and maintenance expenses associated with the storms. In June 2025, the MPSC approved the application, authorizing the deferral of these expenses for accounting purposes. Recovery of this regulatory asset will be requested in a future case.

Energy Waste Reduction Plan: Michigan law requires electric and gas utilities to implement programs that reduce energy consumption through energy efficiency and demand-side energy conservation. Utilities may recover the cost of achieving specified reductions in customers' electricity and gas use through surcharges. The amount of spending incurred in excess of surcharges collected is recorded as a regulatory asset and amortized as surcharges are collected from customers over the plan period. The amount of surcharges collected in excess of spending incurred is recorded as a regulatory liability and amortized as costs are incurred.

Postretirement Benefits Expense Deferral Mechanism: In Consumers' general rate cases, the MPSC approved a mechanism allowing Consumers to defer for future recovery or refund pension and OPEB expenses above or below the amounts used to set existing rates. Amounts deferred will be collected from or refunded to customers over ten years.

Renewable Energy Plan: Under Michigan law, renewable energy standards specify how much electricity must come from renewable sources and which technologies, such as wind, solar, and certain biomass, qualify. Utilities may recover compliance costs, including renewable power purchases (and related financial mechanisms), depreciation, property taxes, interest, and other operating and maintenance expenses for company-owned renewable assets, along with a return on those assets. The MPSC allows Consumers to transfer and collect a portion of these costs through its PSCR process. Incremental costs may be collected through surcharges. If spending exceeds amounts collected, the difference is recorded as a regulatory asset and amortized as recovered from customers; this excludes amounts related to return on equity. If collections exceed spending, the excess is recorded as a regulatory liability and amortized as future costs are incurred for operating renewable facilities and purchasing RECs under renewable energy agreements.

Regulatory Liabilities

Income Taxes, Net: Consumers records regulatory assets and liabilities to reflect the difference between deferred income taxes recognized for financial reporting purposes and amounts previously reflected in Consumers' rates. This net balance will decrease over the remaining life of the related temporary differences and flow through income tax expense. The majority of the net regulatory liability recorded related to income taxes is associated with plant assets that are subject to normalization, which is governed by the Internal Revenue Code, and will be returned to customers over the remaining book life of the related plant assets. For additional details on deferred income taxes, see Note 13, Income Taxes.

ASP Gain: In April 2024, Consumers sold its unregulated ASP business to a non-affiliated company, resulting in a $110 million gain. In July 2024, the MPSC approved the utilization of $27.5 million, or one-fourth, of the gain on the sale as an offset to the revenue deficiency in lieu of additional rate relief during the 12-month period beginning October 1, 2024, with the remaining three-fourths of the gain, or $82.5 million, to be credited to customers as a bill credit over a three-year period beginning October 1, 2024.

Cost of Removal: The MPSC allows Consumers to collect amounts from customers to fund future asset removal activities. This regulatory liability is reduced as costs are incurred to remove the assets at the end of their useful lives.

Green Giving Program: In conjunction with Consumers' voluntary green pricing program, the MPSC has directed Consumers to use surplus program funds to support renewable-energy participation by low-income customers.

Renewable Energy Grant: In 2013, Consumers received a $69 million renewable energy grant for Lake Winds® Energy Park, which began operations in 2012. This grant reduces Consumers' cost of complying with Michigan's renewable portfolio standard and, accordingly, reduces the overall renewable energy surcharge to be collected from customers. The regulatory liability recorded for the grant will be amortized over the life of Lake Winds® Energy Park. Consumers presents the amortization as a reduction to maintenance and other operating expenses on its consolidated statements of income.

Consumers Electric Utility

2024 Electric Rate Case: In May 2024, Consumers filed an application with the MPSC seeking a rate increase of $325 million, made up of two components. First, Consumers requested a $303 million annual rate increase, based on a 10.25-percent authorized return on equity for the projected 12-month period ending February 28, 2026. The filing requested authority to recover costs related to new infrastructure investment primarily in distribution system reliability and cleaner energy resources. Second, Consumers requested approval of a $22 million surcharge for the recovery of distribution investments made in 2023 that exceeded the rates authorized in accordance with previous electric rate orders.

In October 2024, Consumers revised its requested increase to $277 million, primarily to reflect the removal of projected capital investments associated with certain solar facilities that Consumers incorporated into its amended Renewable Energy Plan.

In March 2025, the MPSC issued an order authorizing an annual rate increase of $176 million, which is inclusive of a $22 million surcharge for the recovery of distribution investments made in 2023 that exceeded the rate amounts authorized in accordance with previous electric rate orders. The approved rate increase is based on a 9.90-percent authorized return on equity. The new rates became effective in April 2025

J.H. Campbell Emergency Order: In May 2025, before the planned closure of J.H. Campbell, the U.S. Secretary of Energy issued an emergency order under section 202(c) of the Federal Power Act requiring J.H. Campbell to continue operating for 90 days, through August 20, 2025. Subsequently, the U.S. Secretary of Energy issued two additional emergency orders for 90 days each, ultimately requiring continued operation of J.H. Campbell through February 17, 2026. These orders stated that continued operation of J.H. Campbell was required to meet an energy emergency across MISO's North and Central regions. Consistent with the Federal Power Act and DOE regulations, the orders authorize Consumers to obtain cost recovery at FERC.

As directed, Consumers has continued to make J.H. Campbell available in the MISO market and, in June 2025, filed a complaint at FERC seeking a modification of the MISO Tariff that would enable Consumers to recover the costs of complying with the emergency orders. Consumers' complaint sought a mechanism in the MISO Tariff that would allow allocation of those compliance costs across the MISO North and Central regions, consistent with the nature of the energy emergency declared in the U.S. Secretary of Energy orders. In August 2025, FERC granted Consumers' complaint and ordered MISO to revise its tariff accordingly. MISO submitted a compliance filing with FERC in September 2025, and FERC approval of the compliance filing remains pending.

In January 2026, Consumers filed a request at FERC seeking recovery of the net financial impact of complying with the May 2025 emergency order, which was $42 million after applying MISO revenues of $78 million. This filing encompasses recovery sought by the joint owners of J.H. Campbell.

For the second emergency order period through December 31, 2025, the net financial impact of compliance was $93 million after applying MISO revenues of $77 million. Consumers will seek recovery of these compliance costs at a later date, consistent with rate recovery sought for the May 2025 emergency order. The ultimate financial impact remains subject to the outcome of the FERC proceeding and any future guidance or interpretation.

Consumers Gas Utility

2024 Gas Rate Case: In December 2024, Consumers filed an application with the MPSC seeking an annual rate increase of $248 million based on a 10.25-percent authorized return on equity for the projected 12-month period ending October 31, 2026. In July 2025, Consumers revised its requested increase to $217 million. In September 2025, the MPSC issued an order authorizing an annual rate increase of $157.5 million, based on a 9.80-percent authorized return on equity. The new rates became effective in November 2025.

PSCR and GCR

The PSCR and GCR ratemaking processes are designed to allow Consumers to recover all of its power supply and purchased natural gas costs if incurred under reasonable and prudent policies and practices. The MPSC reviews these costs, policies, and practices in annual plan and reconciliation proceedings. Consumers adjusts its PSCR and GCR billing charges monthly, subject to ceiling factor limitations, in order to minimize the underrecovery or overrecovery amount in the annual reconciliations. Underrecoveries represent power supply and purchased natural gas costs that will be recovered from customers; overrecoveries represent previously collected revenues that will be refunded to customers.

Presented in the following table are the liabilities for PSCR and GCR underrecoveries and overrecoveries reflected on Consumers' consolidated balance sheets:

In Millions

December 31	2025	2024
Assets		
PSCR underrecoveries	$ 38	$ —
Accounts receivable and accrued revenue	$ 38	$ —
Liabilities		
PSCR overrecoveries	$ —	$ 13
GCR overrecoveries	28	25
Accrued rate refunds	$ 28	$ 38

4: Contingencies and Commitments

CMS Energy and Consumers are involved in various matters that give rise to contingent liabilities. Depending on the specific issues, the resolution of these contingencies could negatively affect CMS Energy's and Consumers' liquidity, financial condition, and results of operations. In their disclosures of these matters, CMS Energy and Consumers provide an estimate of the possible loss or range of loss when such an estimate can be made. Disclosures stating that CMS Energy or Consumers cannot predict the outcome of a matter indicate that they are unable to estimate a possible loss or range of loss for the matter.

CMS Energy Contingencies

CMS Land retained environmental remediation obligations for the collection and treatment of leachate at Bay Harbor after selling its interests in the development in 2002. Leachate is produced when water enters into cement kiln dust piles left over from former cement plant operations at the site. In 2012, CMS Land and EGLE finalized an agreement establishing the final remedies and the future water quality criteria at the site. CMS Land completed all construction necessary to implement the remedies required by the agreement and will continue to maintain and operate a system to discharge treated leachate into Little Traverse Bay under an NPDES permit, which was valid through 2025. CMS Land submitted a renewal request in March 2025, and will continue to operate under the existing permit until a renewal is issued.

At December 31, 2025, CMS Energy had a recorded liability of $48 million for its remaining obligations for environmental remediation. CMS Energy calculated this liability based on discounted projected costs, using a discount rate of 4.34 percent and an inflation rate of 1 percent on annual operating and maintenance costs. The undiscounted amount of the remaining obligation is $62 million. CMS Energy expects to pay the following amounts for long-term leachate disposal and operating and maintenance costs in each of the next five years:

In Millions

	2026	2027	2028	2029	2030
Long-term leachate disposal and operating and maintenance costs	$ 4	$ 4	$ 4	$ 4	$ 4

CMS Energy's estimate of response activity costs and the timing of expenditures could change if there are changes in circumstances or assumptions used in calculating the liability. Although a liability for its present estimate of remaining response activity costs has been recorded, CMS Energy cannot predict the ultimate financial impact or outcome of this matter.

Consumers Electric Utility Contingencies

Electric Environmental Matters: Consumers' operations are subject to environmental laws and regulations. Historically, Consumers has generally been able to recover, in customer rates, the costs to operate its facilities in compliance with these laws and regulations.

Cleanup and Solid Waste: Consumers expects to incur remediation and other response activity costs at a number of sites under NREPA. Consumers believes that these costs should be recoverable in rates, but cannot guarantee that outcome. Consumers estimates its liability for NREPA sites for which it can estimate a range of loss to be between $2 million and $3 million. At December 31, 2025, Consumers had a recorded liability of $2 million, the minimum amount in the range of its estimated probable NREPA liability, as no amount in the range was considered a better estimate than any other amount.

Consumers is a potentially responsible party at a number of contaminated sites administered under CERCLA. CERCLA liability is joint and several. In 2010, Consumers received official notification from the EPA that identified Consumers as a potentially responsible party for cleanup of PCBs at the Kalamazoo River CERCLA site. The notification claimed that the EPA had reason to believe that Consumers disposed of PCBs and arranged for the disposal and treatment of PCB-containing materials at portions of the site. In 2011, Consumers received a follow-up letter from the EPA requesting that Consumers agree to participate in a removal action plan along with several other companies for an area of lower Portage Creek, which is connected to the Kalamazoo River. All parties asked to participate in the removal action plan, including Consumers, declined to accept liability. Until further information is received from the EPA, Consumers is unable to estimate a range of potential liability for cleanup of the river.

Based on its experience, Consumers estimates its share of the total liability for known CERCLA sites to be between $3 million and $8 million. Various factors, including the number and creditworthiness of potentially responsible parties involved with each site, affect Consumers' share of the total liability. At December 31, 2025, Consumers had a recorded liability of $3 million for its share of the total liability at these sites, the minimum amount in the range of its estimated probable CERCLA liability, as no amount in the range was considered a better estimate than any other amount.

The timing of payments related to Consumers' remediation and other response activities at its CERCLA and NREPA sites is uncertain. Consumers periodically reviews these cost estimates. A change in the underlying assumptions, such as an increase in the number of sites, different remediation techniques, the nature and extent of contamination, and legal and regulatory requirements, could affect its estimates of NREPA and CERCLA liability.

Ludington Overhaul Contract Dispute: Consumers and DTE Electric, co-owners of Ludington, entered into a 2010 engineering, procurement, and construction agreement with Toshiba International, under which Toshiba International contracted to perform a major overhaul and upgrade of Ludington. Toshiba International later assigned the contract and all of its obligations to TAES. TAES' work under the contract was incomplete, defective, and non-conforming. Consumers and DTE Electric repeatedly documented TAES' failure to perform under the contract and demanded that TAES provide a comprehensive plan to resolve those matters, including adherence to its warranty commitments and other contractual obligations. Consumers and DTE Electric engaged in extensive efforts to resolve these issues with TAES, including a formal demand to TAES' parent, Toshiba, under a parent guaranty it provided. TAES did not provide a comprehensive plan or otherwise meet its performance obligations. As a result of TAES' defaults, Consumers and DTE Electric terminated the contract.

In order to enforce their rights under the contract and parent guaranty, and to pursue appropriate damages, Consumers and DTE Electric filed a complaint against TAES and Toshiba in the U.S. District Court for the Eastern District of Michigan in 2022. TAES and Toshiba filed a motion to dismiss the complaint, along with an answer and counterclaims seeking approximately $15 million in damages related to payments allegedly owed under the parties' contract. The court denied the motion to dismiss filed by TAES and Toshiba.

The case against TAES went to trial before a jury and, in December 2025, the jury rendered a verdict in Consumers' and DTE Electric's favor. The jury found that TAES breached the parties' contract and awarded damages of $383 million. The parties separately stipulated to $11 million in additional liquidated damages for late performance by TAES. These amounts are subject to pre- and post-judgment interest. In addition, the jury rejected TAES' counterclaim, determining that Consumers and DTE Electric did not breach the contract. The parent guaranty provided by Toshiba allows Consumers and DTE Electric to recover legal costs in addition to damages. The parties are still engaged in post-verdict proceedings at the District Court and the jury verdict may be appealed; these processes could take two years or more to conclude with finality. The jury verdict was a favorable outcome for Consumers but an unfavorable outcome in these additional proceedings could have a material adverse effect on CMS Energy's and Consumers' financial condition, results of operations, or liquidity. Consumers and DTE Electric must still also resolve their claim against Toshiba under the parent guaranty, which is still pending but which was bifurcated by the Court from the claims against TAES.

Previously, Toshiba announced that TBJH became the majority shareholder and new parent company of Toshiba through a common stock purchase. TBJH is a subsidiary of a Japanese private equity firm. Consumers and DTE Electric do not believe that this affects their rights under the parent guaranty provided by Toshiba.

With MPSC approval, Consumers and DTE Electric were authorized to defer as a regulatory asset the costs associated with repairing or replacing the defective work performed by TAES while the litigation with TAES and Toshiba remains pending. Consumers currently estimates that its share of repair, replacement, and other damages resulting from TAES' defective work is approximately $350 million, which is expected to be offset in part or entirely by future litigation proceeds received from TAES or Toshiba. Consumers and DTE Electric will have the opportunity to seek appropriate recovery and ratemaking treatment for amounts recorded as a regulatory asset following resolution of the litigation, including any amounts not recovered from TAES or Toshiba. Consumers cannot predict the financial impact or outcome of such proceedings.

Consumers Gas Utility Contingencies

Consumers expects to incur remediation and other response activity costs at a number of sites under NREPA. These sites include 23 former MGP facilities. Consumers operated the facilities on these sites for some part of their operating lives. For some of these sites, Consumers has no present ownership interest or may own only a portion of the original site.

At December 31, 2025, Consumers had a recorded liability of $59 million for its remaining obligations for these sites. Consumers expects to pay the following amounts for remediation and other response activity costs in each of the next five years:

In Millions

	2026	2027	2028	2029	2030
Remediation and other response activity costs	$ 3	$ 8	$ 25	$ 11	$ 3

Consumers periodically reviews these cost estimates. Any significant change in the underlying assumptions, such as an increase in the number of sites, changes in remediation techniques, or legal and regulatory requirements, could affect Consumers' estimates of annual response activity costs and the MGP liability.

Pursuant to orders issued by the MPSC, Consumers defers its MGP-related remediation costs and recovers them from its customers over a ten-year period. At December 31, 2025, Consumers had a regulatory asset of $82 million related to the MGP sites.

Guarantees

Presented in the following table are CMS Energy's and Consumers' guarantees at December 31, 2025:

In Millions

Guarantee Description	Issue Date	Expiration Date	Maximum Obligation	Carrying Amount
CMS Energy, including Consumers				
Indemnity obligations from sale of membership interests in VIEs[1]	various	various	$ 230	$ —
Indemnity obligations from stock and asset sale agreements[2]	various	indefinite	152	—
Guarantee[3]	2011	indefinite	30	—
Consumers				
Guarantee[3]	2011	indefinite	$ 30	$ —

1 These obligations arose from the sale of membership interests in Aviator Wind, BG Solar Holdings, Newport Solar Holdings, and NWO Holdco to tax equity investors. NorthStar Clean Energy provided certain indemnity obligations that protect the tax equity investors against losses incurred as a result of breaches of representations and warranties under the associated limited liability company agreements. These obligations are generally capped at an amount equal to the tax equity investor's capital contributions plus a specified return, less any distributions and tax benefits it receives, in connection with its membership interest. For any indemnity obligations related to Aviator Wind, NorthStar Clean Energy would recover 49 percent of any amounts paid to the tax equity investor from the other owner of Aviator Wind Equity Holdings. Additionally, Aviator Wind holds insurance coverage that would partially protect against losses incurred as a result of certain failures to qualify for production tax credits. For further details on NorthStar Clean Energy's ownership interest in these entities, see Note 19, Variable Interest Entities.

2 These obligations arose from stock and asset sale agreements under which CMS Energy or a subsidiary of CMS Energy indemnified the purchaser for losses resulting from various matters, including claims related to taxes. The maximum obligation amount is mostly related to an Equatorial Guinea tax claim.

3 This obligation comprises a guarantee provided by Consumers to the DOE in connection with a settlement agreement regarding damages resulting from the department's failure to accept spent nuclear fuel from nuclear power plants formerly owned by Consumers.

Additionally, in the normal course of business, CMS Energy, Consumers, and certain other subsidiaries of CMS Energy have entered into various agreements containing tax and other indemnity provisions for which they are unable to estimate the maximum potential obligation. CMS Energy and Consumers consider the likelihood that they would be required to perform or incur substantial losses related to these indemnities and those disclosed in the table to be remote.

Other Contingencies

In addition to the matters disclosed in this Note and Note 3, Regulatory Matters, there are certain other lawsuits and administrative proceedings before various courts and governmental agencies, as well as unasserted claims that may result in such proceedings, arising in the ordinary course of business to which CMS Energy, Consumers, and certain other subsidiaries of CMS Energy are parties. These other lawsuits, proceedings, and unasserted claims may involve personal injury, property damage, contracts, environmental matters, federal and state taxes, rates, licensing, employment, and other matters. Certain of these matters, while potentially substantial, are covered by insurance and the insurer or insurers are involved in the relevant proceedings. Further, CMS Energy and Consumers occasionally self-report certain regulatory non-compliance matters that may or may not eventually result in administrative proceedings. CMS Energy and Consumers believe that the outcome of any one of these proceedings and potential claims will not have a material negative effect on their consolidated results of operations, financial condition, or liquidity.

Contractual Commitments

Purchase Obligations: Purchase obligations arise from long-term contracts for the purchase of commodities and related services, primarily long-term PPAs, and construction and service agreements. Related-party PPAs are between Consumers and certain affiliates of NorthStar Clean Energy. Presented in the following table are CMS Energy's and Consumers' contractual purchase obligations at December 31, 2025 for each of the periods shown:

In Millions

	Payments Due						
	Total	2026	2027	2028	2029	2030	Beyond 2030
CMS Energy, including Consumers							
Total PPAs	$ 16,983	$ 873	$ 904	$ 930	$ 942	$ 1,011	$ 12,323
Other	3,582	1,511	762	468	391	303	147
Total purchase obligations	20,565	2,384	1,666	1,398	1,333	1,314	12,470
Consumers							
PPAs							
MCV PPA	$ 5,539	$ 339	$ 312	$ 316	$ 308	$ 395	$ 3,869
Related-party PPAs	62	32	30	—	—	—	—
Other PPAs	11,382	502	562	614	634	616	8,454
Total PPAs	$ 16,983	$ 873	$ 904	$ 930	$ 942	$ 1,011	$ 12,323
Other	2,700	1,185	599	363	266	232	55
Total purchase obligations	19,683	2,058	1,503	1,293	1,208	1,243	12,378

MCV PPA: Consumers has a PPA with the MCV Partnership giving Consumers the right to purchase up to 1,240 MW of capacity and energy produced by the MCV Facility through May 2030. The MCV PPA provides for:

- a capacity charge of $10.14 per MWh of available capacity through March 2025 and $5.00 per MWh of available capacity from March 2025 through the termination date of the PPA
- a fixed energy charge of $6.30 per MWh for on-peak hours and $6.00 for off-peak hours
- a variable energy charge based on the MCV Partnership's cost of production for energy delivered to Consumers
- a $5 million annual contribution by the MCV Partnership to a renewable resources program through March 2025

Capacity and energy charges under the MCV PPA were $360 million in 2025, $358 million in 2024, and $340 million in 2023.

In September 2025, Consumers entered into a new ten-year PPA with the MCV Partnership for the purchase of up to 1,240 MW of capacity and associated energy from the MCV Facility, effective June 1, 2030. Under the terms of the new agreement, Consumers will pay a monthly capacity charge of $5.00 per MWh of available capacity. Energy payments include a fixed component designed to recover non-fuel operating costs and a variable component based on the MCV Partnership's cost of production for energy delivered to Consumers. The agreement, which is subject to MPSC approval, supports Consumers' ongoing resource adequacy and energy supply planning efforts.

Other PPAs: Consumers has PPAs expiring through 2060 with various counterparties. The majority of the PPAs have capacity and energy charges for delivered energy. Capacity and energy charges under these PPAs were $603 million in 2025, $565 million in 2024, and $498 million in 2023. In addition, CMS Energy and Consumers account for several of their PPAs as leases. See Note 9, Leases for more information about CMS Energy's and Consumers' lease obligations.

5: Financings and Capitalization

Presented in the following table is CMS Energy's long-term debt at December 31:

In Millions, Except Interest Rate and Maturity

	Interest Rate (%)	Maturity	2025	2024
CMS Energy, including Consumers				
CMS Energy, parent only				
Senior notes	3.600	2025	$ —	$ 250
	3.000	2026	300	300
	2.950	2027	275	275
	3.450	2027	350	350
	4.700	2043	250	250
	4.875	2044	300	300
			$ 1,475	$ 1,725
Convertible senior notes[1]	3.375 [2]	2028	$ 800	$ 800
	3.125 [3]	2031	1,000	—
			$ 1,800	$ 800
Junior subordinated notes[4]	4.750 [5]	2050	$ 500	$ 500
	3.750 [6]	2050	400	400
	6.500 [7]	2055	1,000	—
	5.625	2078	200	200
	5.875	2078	280	280
	5.875	2079	630	630
			$ 3,010	$ 2,010
Term loan facilities	variable	2025	$ —	$ 90
	variable	2025	—	400
			$ —	$ 490
Total CMS Energy, parent only			$ 6,285	$ 5,025
CMS Energy subsidiaries				
Consumers			$ 12,196	$ 11,370
NorthStar Clean Energy				
Revolving credit facility	variable [8]	2028	235	150
Construction financing agreement[9]	variable	Five years after conversion date	223	—
Total principal amount outstanding			$ 18,939	$ 16,545
Current amounts			(950)	(1,192)
Unamortized discounts			(28)	(29)
Unamortized issuance costs			(154)	(130)
Total CMS Energy long-term debt			$ 17,807	$ 15,194

1 Holders of the convertible senior notes may convert their notes at their option in accordance with the conditions outlined in the related indentures. CMS Energy will settle conversions of the notes in accordance with the terms outlined in the related indentures. The conversion rate will be subject to adjustment for

anti-dilutive events and fundamental change and redemption provisions as described in the related indentures. There are no sinking fund requirements for the notes.

[2] At December 31, 2025, the conversion price for the notes was $73.61 per share of common stock. Unamortized debt costs associated with this issuance were $6 million at December 31, 2025 and $9 million at December 31, 2024.

[3] At December 31, 2025, the conversion price for the notes was $90.61 per share of common stock. Unamortized debt costs associated with this issuance were $12 million at December 31, 2025.

[4] These unsecured obligations rank subordinate and junior in right of payment to all of CMS Energy's existing and future senior indebtedness.

[5] On June 1, 2030, and every five years thereafter, the notes will reset to an interest rate equal to the five-year treasury rate plus 4.116 percent.

[6] On December 1, 2030, and every five years thereafter, the notes will reset to an interest rate equal to the five-year treasury rate plus 2.900 percent.

[7] On June 1, 2035, and every five years thereafter, the notes will reset to an interest rate equal to the five-year treasury rate plus 1.961 percent.

[8] Loans under this facility have an interest rate of one-month Term SOFR plus 1.750 percent less an adjustment of 0.050 percent for green credit advances. At December 31, 2025, the weighted-average interest rate for the loans issued under this facility was 5.436 percent.

[9] Loans under this facility have an interest rate of one-month Term SOFR plus 2.250 percent. At December 31, 2025, the weighted-average interest rate for the loans issued under this facility was 6.476 percent. At completion of project construction, scheduled for the first half of 2026, a portion of this financing will convert into a term loan that will mature five years after the conversion date.

Presented in the following table is Consumers' long-term debt at December 31:

In Millions, Except Interest Rate and Maturity

	Interest Rate (%)	Maturity	2025	2024
Consumers				
First mortgage bonds	5.240	2026	$ 115	$ 115
	3.680	2027	100	100
	3.390	2027	35	35
	4.650	2028	425	425
	3.800	2028	300	300
	4.900	2029	500	500
	5.070	2029	50	50
	4.600	2029	600	600
	4.700	2030	700	700
	4.500	2031	500	—
	5.170	2032	95	95
	3.600	2032	350	350
	3.180	2032	100	100
	4.625	2033	700	700
	5.050	2035	625	—
	5.800	2035	175	175
	5.380	2037	140	140
	3.520	2037	335	335
	4.010	2038	215	215
	6.170	2040	50	50
	4.970	2040	50	50
	4.310	2042	263	263
	3.950	2043	425	425
	4.100	2045	250	250
	3.250	2046	450	450
	3.950	2047	350	350
	4.050	2048	550	550
	4.350	2049	550	550
	3.750	2050	300	300
	3.100	2050	550	550
	3.500	2051	575	575
	2.650	2052	300	300
	4.200	2052	450	450
	3.860	2052	50	50
	4.280	2057	185	185
	2.500	2060	525	525
	4.350	2064	250	250
	variable [1]	2069	76	76
	variable [1]	2070	134	134
	variable [1]	2070	127	127
			$ 12,520	$ 11,395

In Millions, Except Interest Rate and Maturity

	Interest Rate (%)	Maturity		2025		2024
Tax-exempt revenue bonds	0.875 [2]	2035	$	35	$	35
	3.350 [3]	2049		75		75
			$	110	$	110
2014 Securitization bonds	3.528 [4]	2029 [5]	$	81	$	112
2023 Securitization bonds	5.281 [6]	2028-2031 [5]		504		588
			$	585	$	700
Total principal amount outstanding			$	13,215	$	12,205
Current amounts				(573)		(452)
Long-term debt – related parties[7] principal amount outstanding		2043-2060		(1,019)		(835)
Unamortized discounts				(26)		(27)
Unamortized issuance costs				(73)		(73)
Total long-term debt			$	11,524	$	10,818

1 The variable-rate bonds bear interest quarterly at a rate of three-month SOFR minus 0.038 percent, subject to a zero-percent floor. At December 31, 2025, the interest rates were 3.685 percent for bonds due September 2069, 3.851 percent for bonds due May 2070, and 3.897 percent for bonds due October 2070. The interest rate for the variable-rate bonds at December 31, 2024 were 4.320 percent, 4.483 percent, and 4.551 percent, respectively. The holders of these variable-rate bonds may put them to Consumers for redemption on certain dates prior to their stated maturity, including dates within one year of December 31, 2025.

2 The interest rate on these tax-exempt revenue bonds will reset on October 8, 2026.

3 The interest rate on these tax-exempt revenue bonds will reset on October 1, 2027.

4 The weighted-average interest rate for Consumers' securitization bonds issued through its subsidiary, Consumers 2014 Securitization Funding, was 3.528 percent at December 31, 2025 and 2024.

5 Principal and interest payments are made semiannually.

6 The weighted-average interest rate for Consumers' securitization bonds issued through its subsidiary, Consumers 2023 Securitization Funding, was 5.281 percent at December 31, 2025 and 5.322 percent at December 31, 2024.

7 Long-term debt – related parties reflects Consumers' outstanding debt held by its parent as a result of CMS Energy's repurchase of Consumers' first mortgage bonds. Unamortized discounts associated with the repurchase of Consumers' first mortgage bonds were $5 million at December 31, 2025 and 2024. Unamortized issuance costs were $9 million at December 31, 2025 and $7 million at December 31, 2024.

Financings: Presented in the following table is a summary of major long-term debt issuances during 2025:

	Principal (In Millions)	Interest Rate (%)	Issuance Date	Maturity Date
CMS Energy, parent only				
Junior subordinated notes	$ 1,000	6.500	February 2025	June 2055
Term loan credit agreement	110	variable	February 2025	December 2025
Convertible senior notes	1,000	3.125	November 2025	May 2031
Total CMS Energy, parent only	$ 2,110			
NorthStar Clean Energy				
Construction financing agreement	$ 223	variable	February 2025	Five years after conversion date
Total NorthStar Clean Energy	$ 223			
Consumers				
First mortgage bonds	$ 500	4.500	May 2025	January 2031
First mortgage bonds	625	5.050	May 2025	May 2035
Total Consumers	$ 1,125			
Total CMS Energy	$ 3,458			

Retirements: Presented in the following table is a summary of major long-term debt retirements during 2025:

	Principal (In Millions)	Interest Rate (%)	Retirement Date	Maturity Date
CMS Energy, parent only				
Term loan credit agreement	$ 400	variable	February 2025	September 2025
Term loan credit agreement	200	variable	February 2025	December 2025
Senior notes	250	3.600	November 2025	November 2025
Total CMS Energy, parent only	$ 850			
Total CMS Energy	$ 850			

CMS Energy's Purchase of Consumers' First Mortgage Bonds: CMS Energy purchased Consumers' first mortgage bonds with a principal balance of $184 million during 2025 in exchange for cash of $109 million. On a consolidated basis, CMS Energy's repurchase of Consumers' first mortgage bonds was accounted for as a debt extinguishment and resulted in a pre-tax gain of $72 million during 2025, which was recorded in other income on CMS Energy's consolidated statements of income. Interest expense related to the repurchased bonds was $28 million for the year ended December 31, 2025, which was recorded in interest expense – related parties on Consumers' consolidated statements of income.

In 2024, CMS Energy purchased Consumers' first mortgage bonds with a principal balance of $404 million in exchange for cash of $289 million. On a consolidated basis, CMS Energy's repurchase of Consumers' first mortgage bonds resulted in a pre-tax gain of $110 million for the year ended December 31, 2024. Interest expense related to the repurchased bonds was $19 million for the year ended December 31, 2024.

In 2023, CMS Energy purchased Consumers' first mortgage bonds with a principal balance of $431 million in exchange for cash of $293 million. On a consolidated basis, CMS Energy's repurchase of Consumers' first mortgage bonds resulted in a pre-tax gain of $131 million for the year ended

December 31, 2023. Interest expense related to the repurchased bonds was $5 million for the year ended December 31, 2023.

Regulatory Authorization for Financings: Consumers is required to maintain FERC authorization for financings. Any long-term issuances during the authorization period are exempt from FERC's competitive bidding and negotiated placement requirements. Its short-term authorization ends on May 2, 2026. In January 2026, Consumers filed an application with FERC for authority to issue long-term and short-term debt securities between May 1, 2026 and April 30, 2028.

First Mortgage Bonds: Consumers secures its first mortgage bonds by a mortgage and lien on substantially all of its property. Consumers' ability to issue first mortgage bonds is restricted by certain provisions in the First Mortgage Bond Indenture and the need for regulatory approvals under federal law. Restrictive issuance provisions in the First Mortgage Bond Indenture include achieving a two-times interest coverage ratio and having sufficient unfunded net property additions.

Securitization Bonds: Certain regulatory assets held by Consumers' subsidiaries, Consumers 2014 Securitization Funding and Consumers 2023 Securitization Funding, collateralize Consumers' securitization bonds. Consumers 2014 Securitization Funding and Consumers 2023 Securitization Funding are distinct subsidiaries. The bondholders of each entity have no recourse to the other's assets or the assets of Consumers. Consumers collects securitization surcharges to cover the principal and interest on the bonds as well as certain other qualified costs. The surcharges collected by Consumers on behalf of each entity are remitted to that subsidiary's account and are not available to creditors of Consumers or creditors of Consumers' affiliates other than the subsidiary that issued the bonds.

Debt Maturities: At December 31, 2025, the aggregate annual maturities for long-term debt for the next five years, based on stated maturities or earlier put dates, were:

In Millions

	2026	2027	2028	2029	2030
CMS Energy, including Consumers					
Long-term debt					
CMS Energy, parent only	$ 300	$ 625	$ 800	$ —	$ —
NorthStar Clean Energy	77	—	235	—	—
Consumers	573	263	843	1,256	812
Total CMS Energy	$ 950	$ 888	$ 1,878	$ 1,256	$ 812
Consumers					
Long-term debt	$ 573	$ 263	$ 843	$ 1,256	$ 812

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Credit Facilities: The following credit facilities with banks were available at December 31, 2025:

In Millions

Expiration Date	Amount of Facility	Amount Borrowed	Letters of Credit Outstanding	Amount Available
CMS Energy, parent only				
Unsecured revolving credit facility, expiring November 2030[1]	$ 750	$ —	$ 35	$ 715
Unsecured letter of credit facility, expiring September 2026	50	—	50	—
NorthStar Clean Energy				
Secured revolving credit facility, expiring May 2028[2]	$ 250	$ 235	$ 10	$ 5
Secured letter of credit facility, expiring September 2028[3]	37	—	37	—
Secured letter of credit facility[4]	19	—	12	7
Consumers				
Secured revolving credit facility, expiring November 2030[5,6]	$ 1,100	$ —	$ 6	$ 1,094
Secured revolving credit facility, expiring November 2028[5,6]	300	—	—	300
Secured letter of credit facility, expiring May 2027[5]	100	—	100	—
Unsecured letter of credit facility, expiring March 2028	50	—	43	7
Unsecured letter of credit facility[7]	100	—	97	3
Unsecured letter of credit facility[7]	100	—	100	—

1 There were no borrowings under this facility during the year ended December 31, 2025.

2 Obligations under this facility are secured by certain pledged equity interests in subsidiaries of NorthStar Clean Energy; under the terms of this facility, the interests may not be sold by NorthStar Clean Energy unless there is an agreed-upon substitution for the pledged equity interests. At December 31, 2025, the net book value of the pledged equity interests was $514 million. Also under the terms of this facility, NorthStar Clean Energy may be restricted from remitting cash dividends to CMS Energy in the event of default.

3 This letter of credit facility is available to a subsidiary of Aviator Wind Equity Holdings and is secured by assets of Aviator Wind. For more information regarding Aviator Wind Equity Holdings and Aviator Wind, see Note 19, Variable Interest Entities.

4 The letter of credit facility is available to certain subsidiaries of NorthStar Clean Energy. The letter of credit facility is secured under a construction-to-term financing agreement and will expire five years after the term conversion date.

5 Obligations under these facilities are secured by first mortgage bonds of Consumers.

6 There were no borrowings under these facilities during the year ended December 31, 2025.

7 Uncommitted letter of credit facility with automatic renewal provisions and therefore no expiration.

Short-term Borrowings: Under Consumers' commercial paper program, Consumers may issue, in one or more placements, investment-grade commercial paper notes with maturities of up to 365 days at market interest rates. These issuances are supported by Consumers' revolving credit facilities and may have an aggregate principal amount outstanding of up to $500 million. While the amount of outstanding commercial paper does not reduce the available capacity of the revolving credit facilities, Consumers does not intend to issue commercial paper in an amount exceeding the available capacity of the facilities. At December 31, 2025, there were no commercial paper notes outstanding under this program.

In December 2025, Consumers renewed a short-term credit agreement with CMS Energy, permitting Consumers to borrow up to $500 million at an interest rate of the prior month's average one-month Term SOFR minus 0.100 percent. At December 31, 2025, outstanding borrowings under the agreement were $340 million bearing interest at 3.859 percent, recorded as current notes payable – related parties on Consumers' consolidated balance sheets.

NorthStar Clean Energy's Supplier Financing Program: Under a supplier financing program, NorthStar Clean Energy agrees to pay a bank that is acting as its payment agent the stated amount of confirmed invoices from participating suppliers on the original maturity dates of the invoices. The bank is required to pay the supplier invoices that have been confirmed as valid under the program in full within 135 days of the invoice date. NorthStar Clean Energy does not provide collateral or a guarantee to the bank in support of its payment obligations under the agreement, nor does it pay a fee for the service. NorthStar Clean Energy or the bank may terminate the supplier financing program agreement upon 30 days prior written notice to the other party. Obligations under this program are accounted for in accounts payable on CMS Energy's consolidated balance sheets.

Presented in the following table is the activity under NorthStar Clean Energy's supplier financing program during the year ended December 31, 2025

In Millions

Year Ended December 31	2025	2024
Balance of payables under suppler financing program at beginning of period	$ 22	$ —
Payables confirmed	158	22
Payments and other adjustments	(102)	—
Balance of payables under suppler financing program at end of period	$ 78	$ 22

Dividend Restrictions: At December 31, 2025, payment of dividends by CMS Energy on its common stock was limited to $8.9 billion under provisions of the Michigan Business Corporation Act of 1972.

Under the provisions of its articles of incorporation, at December 31, 2025, Consumers had $2.5 billion of unrestricted retained earnings available to pay dividends on its common stock to CMS Energy. Provisions of the Federal Power Act and the Natural Gas Act appear to restrict dividends payable by Consumers to the amount of Consumers' retained earnings. Several decisions from FERC suggest that, under a variety of circumstances, dividends from Consumers on its common stock would not be limited to amounts in Consumers' retained earnings. Any decision by Consumers to pay dividends on its common stock in excess of retained earnings would be based on specific facts and circumstances and would be subject to a formal regulatory filing process.

During the year ended December 31, 2025, Consumers paid $898 million in dividends on its common stock to CMS Energy.

Capitalization: The authorized capital stock of CMS Energy consists of:

- 350 million shares of CMS Energy Common Stock, par value $0.01 per share
- 10 million shares of CMS Energy Preferred Stock, par value $0.01 per share

Issuance of Common Stock: In 2023, CMS Energy entered into an equity offering program under which it may sell shares of its common stock having an aggregate sales price of up to $1 billion in privately negotiated transactions, in "at the market" offerings, or through forward sales transactions.

Under the forward sales transactions, CMS Energy may either settle physically by issuing shares of its common stock at the then-applicable forward sale price specified by the agreement or settle net by delivering or receiving cash or shares. CMS Energy may settle the contracts at any time through their maturity dates, and presently intends to physically settle the contracts by delivering shares of its common stock.

As of December 31, 2024, CMS Energy had 0.4 million shares contracted under forward sale agreements at a weighted average initial forward price of $69.43 per share. During the year ended December 31, 2025, CMS Energy entered into forward sale agreements for approximately 6.7 million shares at a weighted average initial forward price of $71.08 per share. During the same period, CMS Energy settled forward sale contracts under this program by issuing approximately 7.0 million shares at a weighted average price of $71.16 per share, resulting in net proceeds of $497 million. Following these transactions, outstanding forward contracts under the program have an aggregate sales price of $8 million, maturing November 30, 2026.

The initial forward price in the forward equity sale contracts includes a deduction for commissions and will be adjusted on a daily basis over the term based on an interest rate factor and decreased on certain dates by certain predetermined amounts to reflect expected dividend payments. No amounts are recorded on CMS Energy's consolidated balance sheets until settlements of the forward equity sale contracts occur. If CMS Energy had elected to net share settle or net cash settle the contracts as of December 31, 2025, it would not have been required to deliver shares or pay cash.

Preferred Stock: CMS Energy's Series C preferred stock is traded on the New York Stock Exchange under the symbol CMS PRC. Depositary shares represent a 1/1000th interest in a share of its Series C preferred stock. The Series C preferred stock has no maturity or mandatory redemption date and is not redeemable at the option of the holders. CMS Energy may, at its option, redeem the Series C preferred stock, in whole or in part, at any time on or after July 15, 2026. The Series C preferred stock ranks senior to CMS Energy's common stock with respect to dividend rights and distribution rights upon liquidation. Presented in the following table are details of CMS Energy's Series C preferred stock at December 31, 2025 and 2024:

	Depositary Share Par Value	Depositary Share Optional Redemption Price	Number of Depositary Shares Authorized	Number of Depositary Shares Outstanding
Cumulative, redeemable perpetual	$ 25	$ 25	9,200,000	9,200,000

Preferred Stock of Subsidiary: Consumers' preferred stock is traded on the New York Stock Exchange under the symbol CMS-PB. Presented in the following table are details of Consumers' preferred stock at December 31, 2025 and 2024:

	Par Value	Optional Redemption Price	Number of Shares Authorized	Number of Shares Outstanding
Cumulative, with no mandatory redemption	$ 100	$ 110	7,500,000	373,148

6: Fair Value Measurements

Accounting standards define fair value as the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants. When measuring fair value, CMS Energy and Consumers are required to incorporate all assumptions that market participants would use in pricing an asset or liability, including assumptions about risk. A fair value hierarchy prioritizes inputs used to measure fair value according to their observability in the market. The three levels of the fair value hierarchy are as follows:

- Level 1 inputs are unadjusted quoted prices in active markets for identical assets or liabilities.
- Level 2 inputs are observable, market-based inputs, other than Level 1 prices. Level 2 inputs may include quoted prices for similar assets or liabilities in active markets, quoted prices in inactive markets, and inputs derived from or corroborated by observable market data.
- Level 3 inputs are unobservable inputs that reflect CMS Energy's or Consumers' own assumptions about how market participants would value their assets and liabilities.

CMS Energy and Consumers classify fair value measurements within the fair value hierarchy based on the lowest level of input that is significant to the fair value measurement in its entirety.

Assets and Liabilities Measured at Fair Value on a Recurring Basis

Presented in the following table are CMS Energy's and Consumers' assets and liabilities recorded at fair value on a recurring basis:

In Millions

	CMS Energy, including Consumers		Consumers	
December 31	2025	2024	2025	2024
Assets[1]				
Cash equivalents	$ 154	$ 27	$ —	$ —
Restricted cash equivalents	106	75	86	75
Nonqualified deferred compensation plan assets	36	34	27	25
Derivative instruments	2	2	2	2
Total assets	$ 298	$ 138	$ 115	$ 102
Liabilities[1]				
Nonqualified deferred compensation plan liabilities	$ 36	$ 34	$ 27	$ 25
Derivative instruments	3	—	—	—
Total liabilities	$ 39	$ 34	$ 27	$ 25

1 All assets and liabilities were classified as Level 1 with the exception of derivative contracts, which were classified as Level 2 and 3.

Cash Equivalents: Cash equivalents and restricted cash equivalents consist of money market funds with daily liquidity.

Nonqualified Deferred Compensation Plan Assets and Liabilities: The nonqualified deferred compensation plan assets consist of mutual funds, which are bought and sold only at the discretion of plan participants. The assets are valued using the daily quoted net asset values. CMS Energy and Consumers value their nonqualified deferred compensation plan liabilities based on the fair values of the plan assets, as they reflect the amount owed to the plan participants in accordance with their investment elections. CMS Energy and Consumers report the assets in other non-current assets and the liabilities in other non-current liabilities on their consolidated balance sheets.

Derivative Instruments: CMS Energy and Consumers value their derivative instruments using either a market approach that incorporates information from market transactions, or an income approach that discounts future expected cash flows to a present value amount. CMS Energy's and Consumers' derivatives are classified as Level 2 and 3.

The derivatives classified as Level 2 are interest rate swaps at NorthStar Clean Energy, which are valued using market-based inputs.

In February 2025, a subsidiary of NorthStar Clean Energy entered into floating-to-fixed interest rate swaps to reduce the impact of interest rate fluctuations associated with interest payments on certain future long-term variable-rate debt. The interest rate swaps economically hedge the future variability of interest payments on debt with a notional amount of $109 million. Gains or losses on these swaps are reported in other expense on CMS Energy's consolidated statements of income. The amount recorded in other expense was $3 million for the year ended December 31, 2025. The fair value of these swaps recorded in other non-current liabilities on CMS Energy's consolidated balance sheets totaled $3 million at December 31, 2025.

The majority of derivatives classified as Level 3 are FTRs held by Consumers. Due to the lack of quoted pricing information, Consumers determines the fair value of its FTRs based on Consumers' average historical settlements. Consumers reports derivatives associated with FTRs in other current assets on its consolidated balance sheets.There was no material activity within the Level 3 category of derivatives during the periods presented.

7: Financial Instruments

Presented in the following table are the carrying amounts and fair values, by level within the fair value hierarchy, of CMS Energy's and Consumers' financial instruments that are not recorded at fair value. The table excludes cash, cash equivalents, short-term financial instruments, and trade accounts receivable and payable whose carrying amounts approximate their fair values. For information about assets and liabilities recorded at fair value and for additional details regarding the fair value hierarchy, see Note 6, Fair Value Measurements.

In Millions

	December 31, 2025					December 31, 2024				
		Fair Value					Fair Value			
			Level					Level		
	Carrying Amount	Total	1	2	3	Carrying Amount	Total	1	2	3
CMS Energy, including Consumers										
Assets										
Long-term receivables[1]	$ 7	$ 6	$ —	$ —	$ 6	$ 9	$ 8	$ —	$ —	$ 8
Liabilities										
Long-term debt[2]	18,757	17,645	2,042	13,663	1,940	16,386	14,876	1,018	11,952	1,906
Long-term payables[3]	7	7	—	—	7	9	9	—	—	9
Consumers										
Assets										
Long-term receivables[1]	$ 7	$ 6	$ —	$ —	$ 6	$ 9	$ 8	$ —	$ —	$ 8
Notes receivable – related party[4]	90	90	—	—	90	94	94	—	—	94
Liabilities										
Long-term debt[5]	12,097	11,031	—	9,091	1,940	11,270	9,940	—	8,034	1,906
Long-term debt – related party[6]	1,005	657	—	657	—	823	549	—	549	—
Long-term payables	2	2	—	—	2	4	4	—	—	4

[1] Includes current portion of long-term accounts receivable and notes receivable of $3 million at December 31, 2025 and $4 million at December 31, 2024.

[2] Includes current portion of long-term debt of $950 million at December 31, 2025 and $1.2 billion at December 31, 2024.

[3] Includes current portion of long-term payables of $2 million at December 31, 2025 and 2024.

[4] Includes current portion of notes receivable – related party of $7 million at December 31, 2025 and 2024. For more information on notes receivable – related party, see Note 18, Related-party Transactions—Consumers

[5] Includes current portion of long-term debt of $573 million at December 31, 2025 and $452 million at December 31, 2024.

[6] For more information on CMS Energy's repurchases of Consumers' first mortgage bonds, see Note 5, Financings and Capitalization—CMS Energy's Purchase of Consumers' First Mortgage Bonds.

Notes receivable – related party represents Consumers' portion of the DB SERP demand note payable issued by CMS Energy to the DB SERP rabbi trust. The demand note bears interest at an annual rate of 4.10 percent and has a maturity date of 2028.

8: Plant, Property, and Equipment

Presented in the following table are details of CMS Energy's and Consumers' plant, property, and equipment:

In Millions, Except as Noted

December 31	Estimated Depreciable Life in Years	2025	2024
CMS Energy, including Consumers			
Plant, property, and equipment, gross			
Consumers	3 – 125	$ 36,120	$ 33,434
NorthStar Clean Energy			
Independent power production[1]	3 – 40	1,585	1,452
Assets under finance leases[2]		55	45
Other	3 – 5	3	1
Plant, property, and equipment, gross		$ 37,763	$ 34,932
Construction work in progress		3,052	2,098
Accumulated depreciation and amortization		(10,135)	(9,569)
Total plant, property, and equipment[3]		$ 30,680	$ 27,461
Consumers			
Plant, property, and equipment, gross			
Electric			
Generation[4]	15 – 125	$ 7,171	$ 6,576
Distribution	15 – 75	13,360	12,135
Other	5 – 55	1,209	1,307
Assets under finance leases[2]		131	119
Gas			
Distribution	20 – 85	8,553	7,942
Transmission	17 – 75	3,236	3,081
Underground storage facilities[5]	29 – 75	1,535	1,405
Other	5 – 55	886	828
Assets under finance leases[2]		8	12
Other non-utility property	3 – 51	31	29
Plant, property, and equipment, gross		$ 36,120	$ 33,434
Construction work in progress[6]		2,354	1,766
Accumulated depreciation and amortization		(9,842)	(9,310)
Total plant, property, and equipment[3]		$ 28,632	$ 25,890

1 A portion of independent power production assets are leased to others under operating leases. For information regarding CMS Energy's operating leases of owned assets, see Note 9, Leases.

2 For information regarding the amortization terms of CMS Energy's and Consumers' assets under finance leases, see Note 9, Leases.

3 Consumers' plant additions were $3.1 billion for the year ended December 31, 2025 and $2.1 billion for the year ended December 31, 2024. Consumers' plant retirements were $387 million for the year ended December 31, 2025 and $390 million for the year ended December 31, 2024.

4 Includes 13 hydroelectric dams that Consumers has agreed to sell, contingent upon MPSC and FERC approval. For more information, see Note 20, Exit Activities and Asset Sales.

5 Underground storage includes base natural gas of $24 million at December 31, 2025 and $26 million for the year ended December 31, 2024. Base natural gas is not subject to depreciation.

6 For the year ended December 31, 2025, Consumers fully impaired certain development assets totaling $20 million. Of this amount, $15 million relates to two early-phase renewable natural gas development projects that have been paused indefinitely. The remaining impairment charge was deferred as a regulatory asset and will be recovered through the Renewable Energy Plan.

Intangible Assets: Included in net plant, property, and equipment are intangible assets. Presented in the following table are details about Consumers' intangible assets:

In Millions, Except as Noted

		December 31, 2025		December 31, 2024	
Description	Amortization Life in Years	Gross Cost[1]	Accumulated Amortization	Gross Cost[1]	Accumulated Amortization
Consumers					
Software development	3 – 15	$ 649	$ 492	$ 679	$ 481
Rights of way	50 – 85	274	72	253	68
Franchises and consents	5 – 50	16	12	16	11
Leasehold improvements	various[2]	15	9	13	7
Other intangibles	various	33	17	28	16
Total		$ 987	$ 602	$ 989	$ 583

1 Consumers' intangible asset additions were $62 million for the year ended December 31, 2025 and $90 million for the year ended December 31, 2024. Consumers' intangible asset retirements were $64 million for the year ended December 31, 2025 and $153 million for the year ended December 31, 2024.

2 Leasehold improvements are amortized over the life of the lease, which may change whenever the lease is renewed or extended.

Capitalization: CMS Energy and Consumers record plant, property, and equipment at original cost when placed into service. The cost includes labor, material, applicable taxes, overhead such as pension and other benefits, and AFUDC, if applicable. Consumers' plant, property, and equipment is generally recoverable through its general ratemaking process.

With the exception of utility property for which the remaining book value has been securitized, mothballed utility property stays in rate base and continues to be depreciated at the same rate as before the mothball period. When utility property is retired or otherwise disposed of in the ordinary course of business, Consumers records the original cost to accumulated depreciation, along with associated cost of removal, net of salvage. CMS Energy and Consumers recognize gains or losses on the retirement or disposal of non-regulated assets in income. Consumers records cost of removal collected from customers, but not spent, as a regulatory liability.

Software: CMS Energy and Consumers capitalize the costs to purchase and develop internal-use computer software. These costs are expensed evenly over the estimated useful life of the internal-use computer software. If computer software is integral to computer hardware, then its cost is capitalized and depreciated with the hardware.

AFUDC: Consumers capitalizes AFUDC on regulated major construction projects. AFUDC represents the estimated cost of debt and authorized return-on-equity funds used to finance construction additions. Consumers records the offsetting credit as a reduction of interest for the amount representing the borrowed funds component and as other income for the equity funds component on the consolidated statements of income. When construction is completed and the property is placed in service, Consumers depreciates and recovers the capitalized AFUDC from customers over the life of the related asset. Presented in the following table are Consumers' average AFUDC capitalization rates:

Years Ended December 31	2025	2024	2023
Electric	6.9%	6.9%	6.5%
Gas	5.9	5.8	5.8

Assets Under Finance Leases: Presented in the following table are further details about changes in CMS Energy's and Consumers' assets under finance leases:

In Millions

Years Ended December 31	2025	2024
CMS Energy, including Consumers		
Balance at beginning of period	$ 176	$ 136
Additions	53	55
Net retirements and other adjustments	(36)	(15)
Balance at end of period	$ 193	$ 176
Consumers		
Balance at beginning of period	$ 131	$ 112
Additions	22	34
Net retirements and other adjustments	(15)	(15)
Balance at end of period	$ 138	$ 131

Assets under finance leases are presented as gross amounts. CMS Energy's, including Consumers', accumulated amortization of assets under finance leases was $53 million at December 31, 2025 and $57 million at December 31, 2024. Consumers' accumulated amortization of assets under finance leases was $48 million at December 31, 2025 and $55 million at December 31, 2024.

Depreciation and Amortization: Presented in the following table are further details about CMS Energy's and Consumers' accumulated depreciation and amortization:

In Millions

Years Ended December 31	2025	2024
CMS Energy, including Consumers		
Utility plant assets	$ 9,838	$ 9,307
Non-utility plant assets	297	262
Consumers		
Utility plant assets	$ 9,838	$ 9,307
Non-utility plant assets	4	3

Consumers depreciates utility property on an asset-group basis, in which it applies a single MPSC-approved depreciation rate to the gross investment in a particular class of property within the electric and gas segments. Consumers performs depreciation studies periodically to determine appropriate group lives. Presented in the following table are the composite depreciation rates for Consumers' segment properties:

Years Ended December 31	2025	2024	2023
Electric utility property	3.6%	3.6%	3.8%
Gas utility property	2.5	2.5	2.8
Other property	7.0	7.1	7.8

CMS Energy and Consumers record property repairs and minor property replacement as maintenance expense. CMS Energy and Consumers record planned major maintenance activities as operating expense unless the cost represents the acquisition of additional long-lived assets or the replacement of an existing long-lived asset.

Presented in the following table are the components of CMS Energy's and Consumers' depreciation and amortization expense:

In Millions

Years Ended December 31	2025	2024	2023
CMS Energy, including Consumers			
Depreciation expense – plant, property, and equipment	$ 1,099	$ 1,041	$ 1,050
Amortization expense			
Software	75	81	92
Other intangible assets	7	5	5
Other regulatory assets	8	2	—
Securitized regulatory assets	117	111	33
Total depreciation and amortization expense	$ 1,306	$ 1,240	$ 1,180
Consumers			
Depreciation expense – plant, property, and equipment	$ 1,047	$ 992	$ 1,007
Amortization expense			
Software	75	81	92
Other intangible assets	7	5	5
Other regulatory assets	8	2	—
Securitized regulatory assets	117	111	33
Total depreciation and amortization expense	$ 1,254	$ 1,191	$ 1,137

Presented in the following table is Consumers' estimated amortization expense on intangible assets for each of the next five years:

In Millions

	2026	2027	2028	2029	2030
Consumers					
Intangible asset amortization expense	$ 77	$ 66	$ 55	$ 50	$ 49

Jointly Owned Regulated Utility Facilities

Presented in the following table are Consumers' investments in jointly owned regulated utility facilities at December 31, 2025:

In Millions, Except Ownership Share

	J.H. Campbell Unit 3	Ludington	Other
Ownership share	93.3%	51.0%	various
Utility plant in service	$ 1,726	$ 620	$ 481
Accumulated provision for depreciation	(916)	(253)	(97)
Plant under construction	—	37	17
Net investment	$ 810	$ 404	$ 401

Consumers includes its share of the direct expenses of the jointly owned plants in operating expenses. Consumers shares operation, maintenance, and other expenses of these jointly owned utility facilities in proportion to each participant's undivided ownership interest. Consumers is required to provide only its share of financing for the jointly owned utility facilities.

Consumers plans to retire J.H. Campbell and, in 2022, removed an amount representing the projected remaining book value of the electric generating units upon their retirement from total plant, property, and equipment and recorded it as a regulatory asset on its consolidated balance sheets. The retirement of J.H. Campbell is subject to temporary extensions under emergency orders issued by the U.S. Secretary of Energy. For additional details, see Note 3, Regulatory Matters.

Consumers and DTE Electric engaged in litigation with TAES and Toshiba related to TAES' incomplete, defective, and nonconforming work during a major overhaul and upgrade of Ludington. For additional details on this dispute, see Note 4, Contingencies and Commitments—Ludington Overhaul Contract Dispute.

9: Leases

Lessee

CMS Energy and Consumers lease various assets from third parties, including coal-carrying railcars, real estate, service vehicles, and gas pipeline capacity. In addition, CMS Energy and Consumers account for several of their PPAs as leases.

CMS Energy and Consumers do not record right-of-use assets or lease liabilities on their consolidated balance sheets for rentals with lease terms of 12 months or less, most of which are for the lease of real estate and service vehicles. Lease expense for these rentals is recognized on a straight-line basis over the lease term.

CMS Energy and Consumers include future payments for all renewal options, fair market value extensions, and buyout provisions reasonably certain of exercise in their measurement of lease right-of-use assets and lease liabilities. In addition, certain leases for service vehicles contain end-of-lease adjustment clauses based on proceeds received from the sale or disposition of the vehicles. CMS Energy and Consumers also include executory costs in the measurement of their right-of-use assets and lease liabilities, except for maintenance costs related to their coal-carrying railcar leases.

Most of Consumers' PPAs contain provisions at the end of the initial contract terms to renew the agreements annually under mutually agreed-upon terms at the time of renewal. Energy and capacity payments that vary depending on quantities delivered are recognized as variable lease costs when incurred. Consumers accounts for a PPA with one of CMS Energy's equity method subsidiaries as a finance lease.

Presented in the following table is information about CMS Energy's and Consumers' lease right-of-use assets and lease liabilities:

In Millions, Except as Noted

	CMS Energy, including Consumers		Consumers	
December 31	2025	2024	2025	2024
Operating leases				
Right-of-use assets[1]	$ 22	$ 24	$ 18	$ 20
Lease liabilities				
Current lease liabilities[2]	3	3	3	3
Non-current lease liabilities[3]	19	21	15	17
Finance leases				
Right-of-use assets	140	119	90	76
Lease liabilities[4]				
Current lease liabilities	6	4	6	4
Non-current lease liabilities	135	112	81	69
Weighted-average remaining lease term (in years)				
Operating leases	20	20	20	19
Finance leases	24	26	19	22
Weighted-average discount rate				
Operating leases	5.3%	5.3%	5.4%	5.4%
Finance leases[5]	5.9%	5.8%	4.9%	4.8%

1 CMS Energy's and Consumers' operating right-of-use lease assets are reported as other non-current assets on their consolidated balance sheets.

2 The current portion of CMS Energy's and Consumers' operating lease liabilities are reported as other current liabilities on their consolidated balance sheets.

3 The non-current portion of CMS Energy's and Consumers' operating lease liabilities are reported as other non-current liabilities on their consolidated balance sheets.

4 Includes related-party lease liabilities of $22 million, of which $1 million was current, at December 31, 2025 and 2024.

5 This rate excludes the impact of Consumers' pipeline agreements and long-term PPAs accounted for as finance leases. The required capacity payments under these agreements, when compared to the underlying fair value of the leased assets, result in effective interest rates that exceed market rates for leases with similar terms.

CMS Energy and Consumers report operating, variable, and short-term lease costs as operating expenses on their consolidated statements of income, except for certain amounts that may be capitalized to other assets. Presented in the following table is a summary of CMS Energy's and Consumers' total lease costs:

In Millions

Years Ended December 31	2025	2024
CMS Energy, including Consumers		
Operating lease costs	$ 4	$ 6
Finance lease costs		
Amortization of right-of-use assets	8	6
Interest on lease liabilities	18	16
Variable lease costs	115	107
Short-term lease costs	25	13
Total lease costs	$ 170	$ 148
Consumers		
Operating lease costs	$ 4	$ 5
Finance lease costs		
Amortization of right-of-use assets	6	5
Interest on lease liabilities	14	13
Variable lease costs	115	107
Short-term lease costs	24	12
Total lease costs	$ 163	$ 142

Presented in the following table is supplemental cash flow information related to CMS Energy's and Consumers' lease liabilities:

In Millions

Years Ended December 31	2025	2024
CMS Energy, including Consumers		
Cash paid for amounts included in the measurement of lease liabilities		
Cash used in operating activities for operating leases	$ 4	$ 6
Cash used in operating activities for finance leases	17	15
Cash used in financing activities for finance leases	5	6
Lease liabilities arising from obtaining right-of-use assets		
Operating leases	1	3
Finance leases	22	55
Consumers		
Cash paid for amounts included in the measurement of lease liabilities		
Cash used in operating activities for operating leases	$ 4	$ 5
Cash used in operating activities for finance leases	14	13
Cash used in financing activities for finance leases	6	5
Lease liabilities arising from obtaining right-of-use assets		
Operating leases	1	1
Finance leases	22	34

Presented in the following table are the minimum rental commitments under CMS Energy's and Consumers' non-cancelable leases:

In Millions

December 31, 2025	Operating Leases	Finance Leases: Pipelines and PPAs	Finance Leases: Land and Other	Total
CMS Energy, including Consumers				
2026	$ 4	$ 17	$ 6	$ 23
2027	2	17	6	23
2028	2	17	5	22
2029	2	17	6	23
2030	1	17	6	23
2031 and thereafter	27	2	200	202
Total minimum lease payments	$ 38	$ 87	$ 229	$ 316
Less discount	16	42	133	175
Present value of minimum lease payments	$ 22	$ 45	$ 96	$ 141
Consumers				
2026	$ 4	$ 17	$ 3	$ 20
2027	2	17	3	20
2028	1	17	2	19
2029	1	17	2	19
2030	1	17	2	19
2031 and thereafter	22	2	72	74
Total minimum lease payments	$ 31	$ 87	$ 84	$ 171
Less discount	13	42	42	84
Present value of minimum lease payments	$ 18	$ 45	$ 42	$ 87

Lessor

CMS Energy and Consumers are the lessor under power sales and natural gas delivery agreements that are accounted for as leases.

CMS Energy has power sales agreements that are accounted for as operating leases. In addition to fixed payments, these agreements have variable payments based on energy delivered. For the year ended December 31, 2025, lease revenue from these power sales agreements was $149 million, which included variable lease payments of $105 million. For the year ended December 31, 2024, lease revenue from these power sales agreements was $105 million, which included variable lease payments of $61 million. These non-cancelable operating leases expire in 2026; remaining minimum rental payments amount to $18 million.

Consumers has a natural gas transportation agreement with a subsidiary of CMS Energy that extends through 2038, related to a pipeline owned by Consumers. This agreement is accounted for as a direct finance lease and will automatically extend annually unless terminated by either party. The effects of the lease are eliminated on CMS Energy's consolidated financial statements.

Minimum rental payments to be received under Consumers' direct financing lease are $1 million for each of the next five years and $6 million for the years thereafter. The lease receivable was $5 million as of December 31, 2025, which does not include unearned income of $5 million.

10: Asset Retirement Obligations

CMS Energy and Consumers record the fair value of the cost to remove assets at the end of their useful lives, if there is a legal obligation to remove them. If a reasonable estimate of fair value cannot be made in the period in which the ARO is incurred, such as for assets with indeterminate lives, the liability is recognized when a reasonable estimate of fair value can be made. CMS Energy and Consumers have not recorded liabilities associated with the closure of their hydroelectric facilities and certain gas wells that have an indeterminate life or for assets that have immaterial cumulative disposal costs, such as substation batteries.

CMS Energy and Consumers calculate the fair value of ARO liabilities using an expected present-value technique that reflects assumptions about costs and inflation, and uses a credit-adjusted risk-free rate to discount the expected cash flows. CMS Energy's ARO liabilities are primarily at Consumers.

Presented below are the categories of assets that CMS Energy and Consumers have legal obligations to remove at the end of their useful lives and for which they have an ARO liability recorded:

ARO Description	Long-lived Assets
Closure of coal ash disposal areas	Generating plants coal ash areas
Gas distribution cut, purge, and cap	Gas distribution mains and services
Asbestos abatement	Electric and gas utility plant
Closure of renewable generation assets	Wind and solar generation facilities
Capping and partial filling of water intake line	Generating plant water intake line
Gas wells plug and abandon	Gas transmission and storage

In May 2024, the EPA finalized a rule regulating CCR impoundments at electric generating facilities that became inactive prior to the effective date of a rule published in 2015 regulating CCRs under RCRA. Additionally, the EPA established groundwater monitoring, corrective action, closure, and post-closure care requirements for CCR surface impoundments and landfills closed prior to the effective date of the 2015 CCR rule, but that do not meet the closure technical and performance standards of the May 2024 rule. These include inactive CCR landfills that were previously exempted from regulation but that are now considered CCR management units.

In response to the new rule, Consumers has been performing its review of legacy impoundments and of other aspects of the 2024 rule in accordance with the timelines prescribed by the rule, including the requirement to determine and report the presence of any CCR management units to the EPA by February 2027. Consumers has been recording incremental AROs for legacy impoundments and CCR management units when a reasonable estimate of the fair value of the associated costs can be made, and the ultimate amount of any resulting ARO could be material. In February 2026, the EPA issued a final rule extending the compliance milestone schedule for CCR management units. This extension does not have a material impact on Consumers' compliance strategy. Consumers has historically been authorized to recover in electric rates costs related to coal ash disposal sites.

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Presented in the following tables are the changes in CMS Energy's and Consumers' ARO liabilities:

In Millions

Company and ARO Description	ARO Liability 12/31/2024	Incurred	Settled	Accretion	Cash Flow Revisions	ARO Liability 12/31/2025
CMS Energy, including Consumers						
Consumers	$ 694	$ 27	$ (73)	$ 32	$ 73	$ 753
Renewable generation assets	34	4	—	1	—	39
Total CMS Energy	$ 728	$ 31	$ (73)	$ 33	$ 73	$ 792
Consumers						
Coal ash disposal areas	$ 230	$ —	$ (37)	$ 10	$ 60 [1]	$ 263
Gas distribution cut, purge, and cap	295	10	(13)	15	—	307
Asbestos abatement	37	—	(2)	2	—	37
Renewable generation assets	105	17	—	3	—	125
Generating plant water intake line	—	—	—	1	18 [2]	19
Gas wells plug and abandon	27	—	(21)	1	(5)	2
Total Consumers	$ 694	$ 27	$ (73)	$ 32	$ 73	$ 753

[1] The increase in the AROs associated with coal ash disposal areas was primarily the result of incremental remedies required by EGLE for certain ash disposal ponds and incremental AROs recorded in response to reviews of legacy CCR impoundments.

[2] The increase in AROs associated with water intake lines, which were previously immaterial, was primarily the result of changes in the expected scope of required capping following the finalization of decommissioning plans with the local jurisdiction.

In Millions

Company and ARO Description	ARO Liability 12/31/2023	Incurred	Settled	Accretion	Cash Flow Revisions	ARO Liability 12/31/2024
CMS Energy, including Consumers						
Consumers	$ 739	$ 1	$ (69)	$ 33	$ (10)	$ 694
Renewable generation assets	32	—	—	2	—	34
Total CMS Energy	$ 771	$ 1	$ (69)	$ 35	$ (10)	$ 728
Consumers						
Coal ash disposal areas	$ 268	$ 1	$ (51)	$ 12	$ —	$ 230
Gas distribution cut, purge, and cap	290	—	(9)	15	(1)	295
Asbestos abatement	51	—	(7)	2	(9)	37
Renewable generation assets	102	—	—	3	—	105
Gas wells plug and abandon	28	—	(2)	1	—	27
Total Consumers	$ 739	$ 1	$ (69)	$ 33	$ (10)	$ 694

11: Retirement Benefits

Benefit Plans: CMS Energy and Consumers provide pension, OPEB, and other retirement benefits to eligible employees under a number of different plans. These plans include:

- non-contributory, qualified DB Pension Plans (closed to new non-union participants as of July 1, 2003 and closed to new union participants as of September 1, 2005)
- a non-contributory, qualified DCCP for employees hired on or after July 1, 2003
- benefits to certain management employees under a non-contributory, nonqualified DB SERP (closed to new participants as of March 31, 2006)
- a non-contributory, nonqualified DC SERP for certain management employees hired or promoted on or after April 1, 2006
- a contributory, qualified defined contribution 401(k) plan
- health care and life insurance benefits under an OPEB Plan

DB Pension Plans: Participants in the pension plans include present and former employees of CMS Energy and Consumers, including certain present and former affiliates and subsidiaries. Pension plan trust assets are not distinguishable by company. Effective December 31, 2017, CMS Energy's and Consumers' then-existing pension plan was amended to include only retired and former employees already covered; this amended plan is referred to as DB Pension Plan B. Also effective December 31, 2017, active employees were moved to a newly created pension plan, referred to as DB Pension Plan A, whose benefits mirror those provided under DB Pension Plan B. Maintaining separate plans for the two groups allows CMS Energy and Consumers to employ a more targeted investment strategy and provides additional opportunities to mitigate risk and volatility.

DCCP: CMS Energy and Consumers provide an employer contribution to the DCCP 401(k) plan for employees hired on or after July 1, 2003. The contribution ranges from 5 percent to 10 percent of base pay, depending on years of service and employee class. Employees are not required to contribute in order to receive the plan's employer contribution. DCCP expense for CMS Energy, including Consumers, was $57 million for the year ended December 31, 2025, $53 million for the year ended December 31, 2024, and $51 million for the year ended December 31, 2023. DCCP expense for Consumers was $55 million for the year ended December 31, 2025, $52 million for the year ended December 31, 2024, and $50 million for the year ended December 31, 2023.

DB SERP: The DB SERP is a nonqualified plan as defined by the Internal Revenue Code. DB SERP benefits are paid from a rabbi trust. The trust assets are not considered plan assets under ASC 715. DB SERP rabbi trust earnings are taxable. Presented in the following table are the fair values of trust assets and ABO for CMS Energy's and Consumers' DB SERP:

In Millions

Years Ended December 31	2025	2024
CMS Energy, including Consumers		
Trust assets	$ 122	$ 127
ABO	104	105
Consumers		
Trust assets	$ 92	$ 95
ABO	76	76

Neither CMS Energy nor Consumers made any contributions to the DB SERP in 2025 or 2024.

DC SERP: On April 1, 2006, CMS Energy and Consumers implemented a DC SERP and froze further new participation in the DB SERP. The DC SERP provides participants benefits ranging from 5 percent to 15 percent of total compensation. The DC SERP requires a minimum of five years of participation before vesting. CMS Energy's and Consumers' contributions to the plan, if any, are placed in a grantor trust. For CMS Energy and Consumers, trust assets were $18 million at December 31, 2025 and $17 million at December 31, 2024. DC SERP assets are included in other non-current assets on CMS Energy's and Consumers' consolidated balance sheets. CMS Energy's and Consumers' DC SERP expense was $1 million for the years ended December 31, 2025, 2024, and 2023.

401(k) Plan: The 401(k) plan employer match equals 4 to 6 percent of employee eligible contributions based on an employee's wages and class. The total 401(k) plan cost for CMS Energy, including Consumers, was $46 million for the year ended December 31, 2025, and $41 million for the years ended December 31, 2024 and 2023. The total 401(k) plan cost for Consumers was $44 million for the year ended December 31, 2025, $39 million for the year ended December 31, 2024, and $40 million for the year ended December 31, 2023.

Health-related OPEB Plan: Participants in the health-related OPEB Plan include regular full-time employees covered by the employee health care plan on the day before retirement from either CMS Energy or Consumers at age 55 or older with at least ten full years of applicable continuous service and hired before January 1, 2007 for non-union participants and hired before September 1, 2010 for union participants. Regular full-time employees who qualify for disability retirement under the DB Pension Plans or are disabled and covered by the DCCP and who have 15 years of applicable continuous service may also participate in the health-related OPEB Plan if hired before January 1, 2007 for non-union participants and hired before September 1, 2010 for union participants. Retiree health care costs were based on the assumption that costs would increase 8.00 percent in 2026 and 8.50 percent in 2025 for those under 65 and would increase 9.75 percent in 2026 and 10.25 percent in 2025 for those over 65. The rate of increase was assumed to decline to 4.75 percent by 2034 and thereafter for all retirees.

Assumptions: Presented in the following table are the weighted-average assumptions used in CMS Energy's, including Consumers', retirement benefit plans to determine benefit obligations and net periodic benefit cost:

December 31	2025	2024	2023
Weighted average for benefit obligations[1]			
Discount rate[2]			
DB Pension Plan A	5.58%	5.73%	5.05%
DB Pension Plan B	5.28	5.59	4.95
DB SERP	5.22	5.56	4.94
OPEB Plan	5.50	5.69	5.02
Rate of compensation increase			
DB Pension Plan A	3.70	3.70	3.60
Weighted average for net periodic benefit cost[1]			
Service cost discount rate[2,3]			
DB Pension Plan A	5.77%	5.08%	5.27%
DB SERP[4]	—	—	5.18
OPEB Plan	5.85	5.12	5.31
Interest cost discount rate[2,3]			
DB Pension Plan A	5.43	4.93	5.12
DB Pension Plan B	5.30	4.87	5.06
DB SERP	5.29	4.87	5.06
OPEB Plan	5.39	4.91	5.10
Expected long-term rate of return on plan assets[5]			
DB Pension Plans	7.30	7.50	7.20
OPEB Plan	7.15	7.50	7.20
Rate of compensation increase			
DB Pension Plan A	3.70	3.60	3.60
DB SERP[4]	—	—	5.50

1 The mortality assumption for benefit obligations and net periodic benefit cost was based on the Pri-2012 Mortality Table, with improvement scale MP-2021.

2 The discount rate reflects the rate at which benefits could be effectively settled and is equal to the equivalent single rate resulting from a yield-curve analysis. This analysis incorporated the projected benefit payments specific to CMS Energy's and Consumers' DB Pension Plans and OPEB Plan and the yields on high-quality corporate bonds rated Aa or better.

3 CMS Energy and Consumers have elected to use a full-yield-curve approach in the estimation of service cost and interest cost; this approach applies individual spot rates along the yield curve to future projected benefit payments based on the time of payment.

4 The last active participant in the DB SERP retired in 2023. Thus, the determination of the associated net periodic benefit cost no longer assumes a service cost discount rate nor a rate of compensation increase.

5 CMS Energy and Consumers determined the long-term rate of return using historical market returns, the present and expected future economic environment, the capital market principles of risk and return, and the expert opinions of individuals and firms with financial market knowledge. CMS Energy and Consumers considered the asset allocation of the portfolio in forecasting the future expected total return of the portfolio. The goal was to determine a long-term rate of return that could be incorporated into the planning

of future cash flow requirements in conjunction with the change in the liability. Annually, CMS Energy and Consumers review for reasonableness and appropriateness the forecasted returns for various classes of assets used to construct an expected return model. CMS Energy's and Consumers' expected long-term rate of return on the assets of the DB Pension Plans was 7.30 percent in 2025. The actual return on the assets of the DB Pension Plans was 12.7 percent in 2025, 3.6 percent in 2024, and 12.6 percent in 2023.

Costs: Presented in the following table are the costs (credits) and other changes in plan assets and benefit obligations incurred in CMS Energy's and Consumers' retirement benefit plans:

In Millions

	DB Pension Plans and DB SERP			OPEB Plan		
Years Ended December 31	2025	2024	2023	2025	2024	2023
CMS Energy, including Consumers						
Net periodic credit						
Service cost	$ 25	$ 28	$ 29	$ 8	$ 11	$ 12
Interest cost	114	109	112	43	43	44
Expected return on plan assets	(229)	(234)	(220)	(111)	(115)	(103)
Amortization of:						
Net loss	11	12	12	3	4	12
Prior service cost (credit)	4	4	4	(34)	(31)	(41)
Settlement loss	11	11	11	—	—	—
Net periodic credit	$ (64)	$ (70)	$ (52)	$ (91)	$ (88)	$ (76)
Consumers						
Net periodic credit						
Service cost	$ 24	$ 27	$ 28	$ 8	$ 11	$ 11
Interest cost	106	102	105	42	41	42
Expected return on plan assets	(215)	(221)	(208)	(104)	(107)	(95)
Amortization of:						
Net loss	10	11	11	3	4	12
Prior service cost (credit)	4	4	4	(33)	(30)	(40)
Settlement loss	11	11	11	—	—	—
Net periodic credit	$ (60)	$ (66)	$ (49)	$ (84)	$ (81)	$ (70)

In Consumers' electric and gas rate cases, the MPSC approved a mechanism allowing Consumers to defer for future recovery or refund pension and OPEB expenses above or below the amounts used to set existing rates. Amounts deferred will be collected from or refunded to customers over ten years. At December 31, 2025, CMS Energy, including Consumers, had deferred $3 million of pension costs and $6 million of OPEB credits under this mechanism related to 2025 expense. At December 31, 2024, CMS Energy, including Consumers, had deferred $15 million of pension credits and $11 million of OPEB credits under this mechanism related to 2024 expense. At December 31, 2023, CMS Energy, including Consumers, had deferred $11 million of pension credits and $23 million of OPEB costs under this mechanism related to 2023 expense.

CMS Energy and Consumers amortize net gains and losses in excess of 10 percent of the greater of the PBO or the MRV over the average remaining service period for DB Pension Plan A and the OPEB Plan and over the average remaining life expectancy of participants for DB Pension Plan B. For DB Pension Plan A, the estimated period of amortization of gains and losses was seven years for the year ended December 31, 2025, and eight years for the years ended December 31, 2024 and 2023. For DB Pension Plan B, the estimated period of amortization of gains and losses was 17 years for the years ended

December 31, 2025, 2024, and 2023. For the OPEB Plan, the estimated amortization period was nine years for the years ended December 31, 2025, 2024, and 2023.

Prior service cost (credit) amortization is established in the year in which the prior service cost (credit) first occurred, and is based on the same amortization period for all future years until the prior service cost (credit) is fully amortized. CMS Energy and Consumers had new prior service costs for OPEB in 2024. The estimated period of amortization of these new prior service costs is seven years.

CMS Energy and Consumers determine the MRV for the assets of the DB Pension Plans as the fair value of plan assets on the measurement date, adjusted by the gains or losses that will not be admitted into the MRV until future years. CMS Energy and Consumers reflect each year’s gain or loss in the MRV in equal amounts over a five-year period beginning on the date the original amount was determined. CMS Energy and Consumers determine the MRV for OPEB Plan assets as the fair value of assets on the measurement date.

Reconciliations: Presented in the following table are reconciliations of the funded status of CMS Energy's and Consumers' retirement benefit plans with their retirement benefit plans' liabilities:

In Millions

	DB Pension Plans		DB SERP		OPEB Plan	
Years Ended December 31	2025	2024	2025	2024	2025	2024
CMS Energy, including Consumers						
Benefit obligation at beginning of period	$ 2,094	$ 2,195	$ 105	$ 114	$ 831	$ 900
Service cost	25	28	—	—	8	11
Interest cost	109	104	5	5	43	43
Plan amendments	—	—	—	—	—	(25)
Actuarial loss (gain)	53 [1]	(91) [1]	4	(4)	2 [1]	(40) [1]
Benefits paid	(158)	(142)	(10)	(10)	(54)	(58)
Benefit obligation at end of period	$ 2,123	$ 2,094	$ 104	$ 105	$ 830	$ 831
Plan assets at fair value at beginning of period	$ 2,964	$ 3,004	$ —	$ —	$ 1,588	$ 1,559
Actual return on plan assets	371	102	—	—	197	86
Company contribution	—	—	10	10	—	—
Actual benefits paid	(158)	(142)	(10)	(10)	(52)	(57)
Plan assets at fair value at end of period	$ 3,177	$ 2,964	$ —	$ —	$ 1,733	$ 1,588
Funded status	$ 1,054 [2]	$ 870 [2]	$ (104)	$ (105)	$ 903	$ 757
Consumers						
Benefit obligation at beginning of period			$ 76	$ 83	$ 801	$ 867
Service cost			—	—	8	11
Interest cost			4	4	42	41
Plan amendments			—	—	—	(24)
Actuarial loss (gain)			3	(4)	1 [1]	(38) [1]
Benefits paid			(7)	(7)	(51)	(56)
Benefit obligation at end of period			$ 76	$ 76	$ 801	$ 801
Plan assets at fair value at beginning of period			$ —	$ —	$ 1,479	$ 1,453
Actual return on plan assets			—	—	184	80
Company contribution			7	7	—	—
Actual benefits paid			(7)	(7)	(50)	(54)
Plan assets at fair value at end of period			$ —	$ —	$ 1,613	$ 1,479
Funded status			$ (76)	$ (76)	$ 812	$ 678

1 The actuarial losses for 2025 for the DB Pension Plans and OPEB Plans were primarily the result of lower discount rates. The actuarial gains for 2024 for the DB Pension Plans and OPEB Plan were primarily the result of higher discount rates.

2 The total funded status of the DB Pension Plans attributable to Consumers, based on an allocation of expenses, was $1.0 billion at December 31, 2025 and $836 million at December 31, 2024.

Presented in the following table is the classification of CMS Energy's and Consumers' retirement benefit plans' assets and liabilities:

In Millions

December 31	2025	2024
CMS Energy, including Consumers		
Non-current assets		
DB Pension Plans	$ 1,054	$ 870
OPEB Plan	903	757
Current liabilities		
DB SERP	10	10
Non-current liabilities		
DB SERP	94	95
Consumers		
Non-current assets		
DB Pension Plans	$ 1,009	$ 836
OPEB Plan	812	678
Current liabilities		
DB SERP	7	7
Non-current liabilities		
DB SERP	69	69

The ABO for the DB Pension Plans was $1.9 billion at December 31, 2025 and $1.9 billion at December 31, 2024. At December 31, 2025 and 2024, the PBO and ABO did not exceed plan assets for any of the defined benefit pension plans.

Items Not Yet Recognized as a Component of Net Periodic Benefit Cost: Presented in the following table are the amounts recognized in regulatory assets and AOCI that have not been recognized as components of net periodic benefit cost. For additional details on regulatory assets see Note 3, Regulatory Matters.

In Millions

	DB Pension Plans and DB SERP		OPEB Plan	
December 31	2025	2024	2025	2024
CMS Energy, including Consumers				
Regulatory assets				
Net loss	$ 548	$ 653	$ 93	$ 176
Prior service cost (credit)	9	12	(61)	(94)
Regulatory assets	$ 557	$ 665	$ 32	$ 82
AOCI				
Net loss (gain)	57	60	(7)	(3)
Prior service credit	—	—	(2)	(2)
Total amounts recognized in regulatory assets and AOCI	$ 614	$ 725	$ 23	$ 77
Consumers				
Regulatory assets				
Net loss	$ 548	$ 653	$ 93	$ 176
Prior service cost (credit)	9	12	(61)	(94)
Regulatory assets	$ 557	$ 665	$ 32	$ 82
AOCI				
Net loss	18	15	—	—
Total amounts recognized in regulatory assets and AOCI	$ 575	$ 680	$ 32	$ 82

Plan Assets: Presented in the following tables are the fair values of the assets of CMS Energy's, including Consumers', DB Pension Plans and OPEB Plan, by asset category and by level within the fair value hierarchy. For additional details regarding the fair value hierarchy, see Note 6, Fair Value Measurements.

In Millions

	DB Pension Plans					
	December 31, 2025			December 31, 2024		
	Total	Level 1	Level 2	Total	Level 1	Level 2
Cash and short-term investments	$ 162	$ 162	$ —	$ 148	$ 148	$ —
Mutual funds	—	—	—	—	—	—
	$ 162	$ 162	$ —	$ 148	$ 148	$ —
Pooled funds	3,015			2,816		
Total	$ 3,177			$ 2,964		

In Millions

	OPEB Plan					
	December 31, 2025			December 31, 2024		
	Total	Level 1	Level 2	Total	Level 1	Level 2
Cash and short-term investments	$ 72	$ 72	$ —	$ 35	$ 35	$ —
U.S. government and agencies securities	15	—	15	13	—	13
Corporate debt	69	—	69	68	—	68
State and municipal bonds	4	—	4	2	—	2
Foreign bonds	16	—	16	15	—	15
Common stocks	215	215	—	170	170	—
Mutual funds	75	75	—	53	53	—
	$ 466	$ 362	$ 104	$ 356	$ 258	$ 98
Pooled funds	1,267			1,232		
Total	$ 1,733			$ 1,588		

Cash and Short-term Investments: Cash and short-term investments consist of money market funds with daily liquidity.

U.S. Government and Agencies Securities: U.S. government and agencies securities consist of U.S. Treasury notes and other debt securities backed by the U.S. government and related agencies. These securities are valued based on quoted market prices.

Corporate Debt: Corporate debt investments consist of investment grade bonds of U.S. issuers from diverse industries. These securities are valued based on quoted market prices, when available, or yields available on comparable securities of issuers with similar credit ratings.

State and Municipal Bonds: State and municipal bonds are valued using a matrix-pricing model that incorporates Level 2 market-based information. The fair value of the bonds is derived from various observable inputs, including benchmark yields, reported securities trades, broker/dealer quotes, bond ratings, and general information on market movements for investment grade state and municipal securities normally considered by market participants when pricing such debt securities.

Foreign Bonds: Foreign corporate and government debt securities are valued based on quoted market prices, when available, or on yields available on comparable securities of issuers with similar credit ratings.

Common Stocks: Common stocks in the OPEB Plan consist of equity securities that are actively managed and tracked to the S&P 500 Index and MSCI All Country World ex-US. These securities are valued at their quoted closing prices.

Mutual Funds: Mutual funds represent shares in registered investment companies that are priced based on the daily quoted net asset values that are publicly available and are the basis for transactions to buy or sell shares in the funds.

Pooled Funds: Pooled funds include both common and collective trust funds as well as special funds that contain only employee benefit plan assets from two or more unrelated benefit plans. These funds primarily consist of U.S. and foreign equity securities, but also include U.S. and foreign fixed-income securities and multi-asset investments. Since these investments are valued at their net asset value as a practical expedient, they are not classified in the fair value hierarchy.

Asset Allocations: Presented in the following table are the investment components of the assets of CMS Energy's DB Pension Plans and OPEB Plan as of December 31, 2025:

	DB Pension Plans	OPEB Plan
Fixed-income securities	39.2%	37.6%
Equity securities	38.7	42.4
Real asset investments	9.3	8.8
Return-seeking fixed income	7.1	5.6
Liquid alternative investments	4.3	3.7
Cash and cash equivalents	1.4	1.9
	100.0%	100.0%

CMS Energy's target 2025 asset allocation for the assets of the DB Pension Plans was 40-percent fixed income, 38-percent equity, 11-percent real assets, 7-percent return-seeking fixed income, and 4-percent liquid alternatives.

CMS Energy established union and non-union VEBA trusts to fund future retiree health and life insurance benefits known as OPEB. These trusts are funded through the ratemaking process for Consumers and through direct contributions from the non-utility subsidiaries. CMS Energy's target 2025 asset allocation for OPEB trusts was 40-percent fixed income, 38-percent equity, 11-percent real assets, 7-percent return-seeking fixed income, and 4-percent liquid alternatives.

The goal of these target allocations was to maximize the long-term return on plan assets, while maintaining a prudent level of risk. The level of acceptable risk is a function of the liabilities of the plans. Equity investments are diversified mostly across the S&P 500 Index, with lesser allocations to the S&P MidCap and SmallCap Indexes and Foreign Equity Funds. Fixed-income investments are diversified across investment grade instruments of government and corporate issuers, as well as high-yield and global bond funds. Return-seeking fixed-income investments are diversified exposure to high-yield bonds, emerging market debt, and bank loans. Real asset investments are diversified across core real estate and real estate investment trusts. Liquid alternatives are investments in private funds comprised of different and independent hedge funds with various investment strategies. CMS Energy uses annual liability measurements, quarterly portfolio reviews, and periodic asset/liability studies to evaluate the need for adjustments to the portfolio allocations.

Contributions: Contributions comprise required amounts and discretionary contributions. Neither CMS Energy nor Consumers made any contributions in 2025 or 2024, or plans to contribute to the DB Pension Plans or OPEB Plan in 2026. Actual future contributions will depend on future investment performance, discount rates, and various factors related to the participants of the DB Pension Plans and OPEB Plan. CMS Energy and Consumers will, at a minimum, contribute to the plans as needed to comply with federal funding requirements.

Benefit Payments: Presented in the following table are the expected benefit payments for each of the next five years and the five-year period thereafter:

In Millions

	DB Pension Plans	DB SERP	OPEB Plan
CMS Energy, including Consumers			
2026	$ 164	$ 10	$ 59
2027	165	10	61
2028	164	10	62
2029	164	9	62
2030	164	9	62
2031-2035	801	41	305
Consumers			
2026	$ 154	$ 7	$ 57
2027	155	7	58
2028	154	7	59
2029	155	6	59
2030	154	6	60
2031-2035	756	29	292

Collective Bargaining Agreements: At December 31, 2025, unions represented 44 percent of CMS Energy’s employees and 45 percent of Consumers’ employees. The UWUA represents Consumers’ and NorthStar Clean Energy’s operating, maintenance, construction employees and Consumers’ customer contact center employees. The USW represents Consumers’ Zeeland plant employees. Consumers’ union agreements expire in 2030 and the majority of NorthStar Clean Energy’s represented employees have an agreement that expires in 2029.

12: Stock-based Compensation

CMS Energy and Consumers provide a PISP to officers, employees, and non-employee directors based on their contributions to the successful management of the company. The PISP has a ten-year term, expiring in May 2030.

In 2025, all awards were in the form of restricted stock or restricted stock units. The PISP also allows for unrestricted common stock, stock options, stock appreciation rights, phantom shares, performance units, and incentive options, none of which was granted in 2025, 2024, or 2023.

Shares awarded or subject to stock options, phantom shares, or performance units may not exceed 6.5 million shares from June 2020 through May 2030. CMS Energy and Consumers may issue awards of up to 3,965,601 shares of common stock under the PISP as of December 31, 2025. Shares for which payment or exercise is in cash, as well as shares that expire, terminate, or are canceled or forfeited, may be awarded or granted again under the PISP.

All awards under the PISP vest fully upon death. Upon a change of control of CMS Energy or termination under an officer separation agreement, the awards will vest in accordance with specific officer agreements. If stated in the award, for restricted stock recipients who terminate employment due to retirement or disability, a pro-rata portion of the award will vest upon termination, with any market-based award also contingent upon the outcome of the market condition and any performance-based award contingent upon the outcome of the performance condition. The pro-rata portion is equal to the portion of the service period served between the award grant date and the employee's termination date. The remaining portion of the awards will be forfeited. All awards for directors vest fully upon retirement. Restricted shares may be forfeited if employment terminates for any other reason or if the minimum service requirements are not met, as described in the award document.

Restricted Stock Awards: Restricted stock awards for employees under the PISP are in the form of performance-based, market-based, and time-lapse restricted stock. Award recipients receive shares of CMS Energy common stock that have dividend and voting rights. The dividends on time-lapse restricted stock are paid in cash or in CMS Energy common stock. The dividends on performance-based and market-based restricted stock are paid in restricted shares equal to the value of the dividends. These additional restricted shares are subject to the same vesting conditions as the underlying restricted stock shares.

Performance-based restricted stock vesting is contingent on meeting at least a 36-month service requirement and a performance condition. The performance condition is based on an adjusted measure of CMS Energy's EPS growth relative to a peer group over a three-year period. The awards granted in 2025, 2024, and 2023 require a 38-month service period. Market-based restricted stock vesting is generally contingent on meeting a three-year service requirement and a market condition. The market condition is based on a comparison of CMS Energy's total shareholder return with the median total shareholder return of a peer group over the same three-year period. Depending on the outcome of the performance condition or the market condition, a recipient may earn a total award ranging from zero to 200 percent of the initial grant. Time-lapse restricted stock generally vests after a service period of three years.

Restricted Stock Units: In 2025, 2024, and 2023, CMS Energy and Consumers granted restricted stock units to certain non-employee directors who elected to defer their restricted stock awards. The restricted stock units generally vest after a service period of one year or, if earlier, at the next annual meeting. The restricted stock units will be distributed to the recipients as shares in accordance with the directors' deferral agreements. Restricted stock units do not have voting rights, but do have dividend rights. In lieu of cash dividend payments, the dividends on restricted stock units are paid in additional units equal to the value of the dividends. These additional restricted stock units are subject to the same vesting and distribution conditions as the underlying restricted stock units. No restricted stock units were forfeited during 2025.

Presented in the following tables is the activity for restricted stock and restricted stock units under the PISP:

	CMS Energy, including Consumers		Consumers	
Year Ended December 31, 2025	Number of Shares	Weighted-average Grant Date Fair Value Per Share	Number of Shares	Weighted-average Grant Date Fair Value Per Share
Nonvested at beginning of period	1,162,787	$ 59.34	1,081,573	$ 59.35
Granted				
Restricted stock	523,663	50.19	480,258	49.86
Restricted stock units	18,491	56.80	17,713	56.80
Vested				
Restricted stock	(450,699)	46.30	(424,830)	46.33
Restricted stock units	(27,035)	51.79	(25,994)	51.82
Forfeited – restricted stock	(38,364)	60.19	(36,119)	60.01
Nonvested at end of period	1,188,843	$ 60.36	1,092,601	$ 60.36

Year Ended December 31, 2025	CMS Energy, including Consumers	Consumers
Granted		
Time-lapse awards	118,842	109,242
Market-based awards	139,248	126,302
Performance-based awards	147,982	134,540
Restricted stock units	14,406	13,800
Dividends on market-based awards	13,484	12,472
Dividends on performance-based awards	14,458	13,389
Dividends on restricted stock units	4,085	3,913
Additional market-based shares based on achievement of condition	5,982	5,624
Additional performance-based shares based on achievement of condition	83,667	78,689
Total granted	542,154	497,971

CMS Energy and Consumers charge the fair value of the restricted stock awards to expense over the required service period and charge the fair value of the restricted stock units to expense immediately. For performance-based awards, CMS Energy and Consumers estimate the number of shares expected to vest at the end of the performance period based on the probable achievement of the performance objective. Performance-based and market-based restricted stock awards have graded vesting features for retirement-eligible employees, and CMS Energy and Consumers recognize expense for those awards on a graded vesting schedule over the required service period. Expense for performance-based and market-based restricted stock awards for non-retirement-eligible employees and time-lapse awards is recognized on a straight-line basis over the required service period.

The fair value of performance-based and time-lapse restricted stock and restricted stock units is based on the price of CMS Energy's common stock on the grant date. The fair value of market-based restricted stock awards is calculated on the grant date using a Monte Carlo simulation. CMS Energy and Consumers base expected volatilities on the historical volatility of the price of CMS Energy common stock. The risk-free rate for valuation of the market-based restricted stock awards was based on the three-year U.S. Treasury yield at the award grant date.

Presented in the following table are the most significant assumptions used to estimate the fair value of the market-based restricted stock awards:

Years Ended December 31	2025	2024	2023
Expected volatility	20.7%	20.2%	30.3%
Expected dividend yield	3.1	3.5	2.9
Risk-free rate	4.2	4.1	3.9

Presented in the following table is the weighted-average grant-date fair value of all awards under the PISP:

			In Millions
Years Ended December 31	2025	2024	2023
CMS Energy, including Consumers			
Weighted-average grant-date fair value per share			
Restricted stock granted	$ 50.19	$ 44.76	$ 52.62
Restricted stock units granted	56.80	52.43	50.32
Consumers			
Weighted-average grant-date fair value per share			
Restricted stock granted	$ 49.86	$ 44.49	$ 52.42
Restricted stock units granted	56.80	52.46	50.34

Presented in the following table are amounts related to restricted stock awards and restricted stock units:

			In Millions
Years Ended December 31	2025	2024	2023
CMS Energy, including Consumers			
Fair value of shares that vested during the year	$ 33	$ 28	$ 20
Compensation expense recognized	25	27	28
Income tax benefit recognized	2	3	3
Consumers			
Fair value of shares that vested during the year	$ 32	$ 27	$ 19
Compensation expense recognized	23	25	26
Income tax benefit recognized	2	3	2

At December 31, 2025, $28 million of total unrecognized compensation cost was related to restricted stock for CMS Energy, including Consumers, and $26 million of total unrecognized compensation cost was related to restricted stock for Consumers. CMS Energy and Consumers expect to recognize this cost over a weighted-average period of two years.

13: Income Taxes

CMS Energy and its subsidiaries file a consolidated U.S. federal income tax return as well as a Michigan Corporate Income Tax return for the unitary business group and various other state unitary group combined income tax returns. Income taxes are allocated based on each company's separate taxable income in accordance with the CMS Energy tax sharing agreement.

Presented in the following table is the difference between actual income tax expense on continuing operations and income tax expense computed by applying the statutory U.S. federal income tax rate:

In Millions, Except Tax Rate

	Amount	Percent	Amount	Percent	Amount	Percent
Years Ended December 31	2025		2024		2023	
CMS Energy, including Consumers						
Income from continuing operations before income taxes	$ 1,248		$ 1,123		$ 954	
Income tax expense at statutory rate	262	21.0 %	236	21.0 %	200	21.0 %
Increase (decrease) in income taxes from:						
State and local income taxes, net of federal income tax effect[1]	77	6.2	58	5.1	40	4.2
Tax credits						
Renewable energy tax credits	(68)	(5.4)	(71)	(6.4)	(55)	(5.8)
Other	(6)	(0.5)	(6)	(0.5)	(7)	(0.7)
Nontaxable or nondeductible items	3	0.2	4	0.4	3	0.3
Changes in unrecognized tax benefits	9	0.7	2	0.2	(11)	(1.2)
Other adjustments						
TCJA excess deferred taxes	(42)	(3.4)	(43)	(3.8)	(40)	(4.2)
Deferred tax adjustment[2]	—	—	(16)	(1.4)	—	—
Taxes attributable to noncontrolling interests	15	1.2	12	1.1	17	1.8
Other, net	(4)	(0.3)	—	—	—	—
Income tax expense	$ 246		$ 176		$ 147	
Effective tax rate		19.7 %		15.7 %		15.4 %

In Millions, Except Tax Rate

	Amount	Percent	Amount	Percent	Amount	Percent
Years Ended December 31	2025		2024		2023	
Consumers						
Income from continuing operations before income taxes	$ 1,417		$ 1,209		$ 1,028	
Income tax expense at statutory rate	298	21.0 %	254	21.0 %	216	21.0 %
Increase (decrease) in income taxes from:						
State and local income taxes, net of federal income tax effect[1]	80	5.7	60	5.0	47	4.6
Tax credits						
Renewable energy tax credits	(46)	(3.2)	(51)	(4.2)	(43)	(4.2)
Other	(6)	(0.4)	(6)	(0.5)	(7)	(0.7)
Nontaxable or nondeductible items	3	0.2	3	0.2	3	0.3
Changes in unrecognized tax benefits	9	0.6	1	0.1	(12)	(1.2)
Other adjustments						
TCJA excess deferred taxes	(42)	(3.0)	(43)	(3.6)	(40)	(3.9)
Deferred tax adjustment[2]	—	—	(16)	(1.3)	—	—
Other, net	(8)	(0.6)	(2)	(0.2)	(3)	(0.2)
Income tax expense	$ 288		$ 200		$ 161	
Effective tax rate		20.3 %		16.5 %		15.7 %

1 In June 2025, state deferred tax balances were increased by $12 million to reflect a change in Illinois tax policy that establishes nexus for Consumers. The policy change is effective for tax years beginning January 1, 2026. During 2023, CMS Energy initiated a plan to divest immaterial business activities in a non-Michigan jurisdiction and will no longer have a taxable presence within that jurisdiction. As a result of these actions, CMS Energy reversed a $13 million non-Michigan reserve, all of which was recognized at Consumers.

2 During 2024, Consumers recognized a $16 million tax benefit resulting from the expiration of the statute of limitations associated with audit points for the 2018 and 2019 tax years.

State Income Tax Claim: In February 2025, CMS Energy received an adverse ruling from the Michigan Tax Tribunal in regards to the methodology of state apportionment for Consumers' electricity sales to MISO. In March 2025, CMS Energy filed an appeal with the Michigan Court of Appeals and a hearing was held in February 2026. CMS Energy and Consumers have evaluated and concluded their uncertain tax positions associated with this matter to be sufficient as of December 31, 2025. While CMS Energy and Consumers expect the appeal to prevail, if it were to fail, the companies would be required to revise the estimated value of their state deferred tax liabilities, which could result in a material impact to their results of operations.

Tax Legislation: CMS Energy and Consumers are subject to changing tax laws. In July 2025, President Trump signed into law the OBBBA. The legislation allows for the immediate expensing of domestic research and development costs and includes changes to clean energy tax credits enacted by the Inflation Reduction Act of 2022. While the OBBBA restores, and makes permanent, the 100-percent bonus depreciation deduction, it also retains a provision that allows utilities to take a full deduction of interest expense in lieu of 100-percent bonus depreciation. CMS Energy and Consumers evaluated the provisions of the OBBBA and concluded that the legislation is not expected to have a material impact on their respective financial statements. This conclusion is subject to change as additional guidance or interpretations become available.

Renewable Energy Tax Credits: Under the Inflation Reduction Act of 2022, renewable energy tax credits produced after 2022 are eligible to be transferred to third parties. These sales are accounted for under ASC 740 with the discount from the sale of the tax credits included as a component of income tax expense. Renewable energy tax credits that have been generated and sold are presented as accounts receivable on CMS Energy's and Consumers' consolidated balance sheets until proceeds from the sale are received. Proceeds from the sale of tax credits are presented as operating activities on their consolidated statements of cash flows, consistent with the presentation of cash taxes paid.

During 2025, CMS Energy sold renewable energy tax credits generated in 2025 and received proceeds of $36 million, all of which was recognized at Consumers. CMS Energy also received proceeds of $13 million during 2025 from the 2024 sale of renewable energy tax credits, all of which was recognized at Consumers. CMS Energy will receive an additional $32 million in 2026 from the renewable energy tax credits generated and sold in 2025, of which $10 million will be recognized at Consumers.

Presented in the following table are the significant components of income tax expense on continuing operations:

In Millions

Years Ended December 31	2025	2024	2023
CMS Energy, including Consumers			
Current income taxes			
Federal	$ 34	$ 34	$ 5
State and local	9	—	1
	$ 43	$ 34	$ 6
Deferred income taxes			
Federal	107	70	107
State and local	100	76	38
	$ 207	$ 146	$ 145
Deferred income tax credit	(4)	(4)	(4)
Tax expense	$ 246	$ 176	$ 147
Consumers			
Current income taxes			
Federal	$ 207	$ 78	$ 3
State and local	33	7	2
	$ 240	$ 85	$ 5
Deferred income taxes			
Federal	(27)	51	117
State and local	79	68	43
	$ 52	$ 119	$ 160
Deferred income tax credit	(4)	(4)	(4)
Tax expense	$ 288	$ 200	$ 161

Presented in the following table are income taxes paid:

In Millions

Years Ended December 31	2025	2024	2023
CMS Energy, including Consumers			
Federal	$ 28	$ 27	$ 15
State	1	1	—
Total	$ 29	$ 28	$ 15
Consumers			
Federal	$ 189	$ 57	$ 23
State	21	—	8
Total	$ 210	$ 57	$ 31

CMS Energy and Consumers are domiciled in the U.S. and are not subject to taxes in any foreign jurisdiction. State income taxes paid (net of refunds) are primarily attributable to the state of Michigan.

Presented in the following table are the principal components of deferred income tax assets (liabilities) recognized:

In Millions

December 31	2025	2024
CMS Energy, including Consumers		
Deferred income tax assets		
Net regulatory tax liability	$ 294	$ 307
Tax loss and credit carryforwards	139	258
Reserves and accruals	16	27
Total deferred income tax assets	$ 449	$ 592
Valuation allowance	(2)	(1)
Total deferred income tax assets, net of valuation allowance	$ 447	$ 591
Deferred income tax liabilities		
Plant, property, and equipment	$ (2,833)	$ (2,682)
Employee benefits	(558)	(507)
Gas inventory	(24)	(38)
Securitized costs	(137)	(167)
Other	(147)	(122)
Total deferred income tax liabilities	$ (3,699)	$ (3,516)
Total net deferred income tax liabilities	$ (3,252)	$ (2,925)
Consumers		
Deferred income tax assets		
Net regulatory tax liability	$ 294	$ 307
Tax loss and credit carryforwards	18	37
Reserves and accruals	13	24
Total deferred income tax assets	$ 325	$ 368
Deferred income tax liabilities		
Plant, property, and equipment	$ (2,808)	$ (2,658)
Employee benefits	(534)	(489)
Gas inventory	(24)	(38)
Securitized costs	(137)	(167)
Other	(23)	(69)
Total deferred income tax liabilities	$ (3,526)	$ (3,421)
Total net deferred income tax liabilities	$ (3,201)	$ (3,053)

Deferred tax assets and liabilities are recognized for the estimated future tax effect of temporary differences between the tax basis of assets or liabilities and the reported amounts on CMS Energy’s and Consumers’ consolidated financial statements.

Presented in the following table are the tax loss and credit carryforwards at December 31, 2025:

In Millions

	Tax Attribute	Expiration
CMS Energy, including Consumers		
Michigan net operating loss carryforwards	$ 15	2030 – 2033
Arkansas net operating loss carryforwards	2	2033 - 2035
Local net operating loss carryforwards	2	2025 – 2040
General business credits[1]	120	2038 – 2045
Total tax attributes	$ 139	
Consumers		
Michigan net operating loss carryforwards	$ 10	2030 – 2033
General business credits[1]	8	2038 – 2045
Total tax attributes	$ 18	

1 General business credits comprise research and development tax credits and renewable energy tax credits that are not expected to be transferred to third parties.

CMS Energy has provided a valuation allowance of $2 million for state and local tax loss carryforwards. CMS Energy and Consumers expect to utilize fully their tax loss and credit carryforwards for which no valuation allowance has been provided. It is reasonably possible that further adjustments will be made to the valuation allowances within one year.

Presented in the following table is a reconciliation of the beginning and ending amount of uncertain tax benefits:

In Millions

Years Ended December 31	2025	2024	2023
CMS Energy, including Consumers			
Balance at beginning of period	$ 24	$ 26	$ 28
Additions for current-year tax positions	2	1	1
Additions for prior-year tax positions	7	2	—
Reductions for lapse of statute of limitations	(4)	(5)	(3)
Balance at end of period	$ 29	$ 24	$ 26
Consumers			
Balance at beginning of period	$ 32	$ 36	$ 36
Additions for current-year tax positions	1	6	1
Additions for prior-year tax positions	7	1	2
Reductions for lapse of statute of limitations	(4)	(11)	(3)
Balance at end of period	$ 36	$ 32	$ 36

If recognized, all of these uncertain tax benefits would affect CMS Energy's and Consumers' annual effective tax rates in future years. One uncertain tax benefit relates to the methodology of state apportionment for Consumers' electricity sales to MISO. CMS Energy has filed an appeal on an adverse ruling received from the Michigan Tax Tribunal on this methodology and a hearing was held in February 2026.

CMS Energy and Consumers recognize accrued interest and penalties, where applicable, as part of income tax expense. CMS Energy, including Consumers, recognized immaterial interest and penalties for each of the years ended December 31, 2025, 2024, and 2023.

The amount of income taxes paid is subject to ongoing audits by federal, state, local, and foreign tax authorities, which can result in proposed assessments. CMS Energy's federal income tax returns for 2022 and subsequent years remain subject to examination by the IRS. CMS Energy's Michigan Corporate Income Tax returns for 2013 through 2016 and 2021 and subsequent years remain subject to examination by the State of Michigan. CMS Energy's and Consumers' estimate of the potential outcome for any uncertain tax issue is highly judgmental. CMS Energy and Consumers believe that their accrued tax liabilities at December 31, 2025 were adequate for all years.

14: Earnings Per Share—CMS Energy

Presented in the following table are CMS Energy's basic and diluted EPS computations based on income from continuing operations:

In Millions, Except Per Share Amounts

Years Ended December 31	2025	2024	2023
Income available to common stockholders			
Income from continuing operations	$ 1,002	$ 947	$ 807
Less loss attributable to noncontrolling interests	(69)	(56)	(79)
Less preferred stock dividends	10	10	10
Income from continuing operations available to common stockholders – basic and diluted	$ 1,061	$ 993	$ 876
Average common shares outstanding			
Weighted-average shares – basic	300.4	297.6	291.2
Add dilutive nonvested stock awards	0.5	0.7	0.5
Add dilutive forward equity sale contracts	0.1	—	—
Weighted-average shares – diluted	301.0	298.3	291.7
Income from continuing operations per average common share available to common stockholders			
Basic	$ 3.53	$ 3.34	$ 3.01
Diluted	3.53	3.33	3.01

Nonvested Stock Awards

CMS Energy's nonvested stock awards are composed of participating and non-participating securities. The participating securities accrue cash dividends when common stockholders receive dividends. Since the recipient is not required to return the dividends to CMS Energy if the recipient forfeits the award, the nonvested stock awards are considered participating securities. As such, the participating nonvested stock awards were included in the computation of basic EPS. The non-participating securities accrue stock dividends that vest concurrently with the stock award. If the recipient forfeits the award, the stock dividends accrued on the non-participating securities are also forfeited. Accordingly, the non-participating awards and stock dividends were included in the computation of diluted EPS, but not in the computation of basic EPS.

Forward Equity Sale Contracts

CMS Energy has entered into forward equity sale contracts. These forward equity sale contracts are non-participating securities. While the forward sale price in the forward equity sale contract is decreased on certain dates by certain predetermined amounts to reflect expected dividend payments, these price adjustments were set upon inception of the agreement and the forward contract does not give the owner the right to participate in undistributed earnings. Accordingly, the forward equity sale contracts were included in the computation of diluted EPS, but not in the computation of basic EPS.

The potentially dilutive impact from these forward equity sale contracts is reflected in diluted EPS using the treasury stock method. There will be a dilutive effect on EPS when the average market price of common stock shares is above the applicable adjusted forward sale price. Additionally, any physical settlement or net share settlement of the agreements would dilute EPS. For further details on the forward equity sale contracts, see Note 5, Financings and Capitalization.

Convertible Securities

CMS Energy has issued convertible senior notes. Potentially dilutive common shares issuable upon conversion of the convertible senior notes are determined using the if-converted method for calculating diluted EPS. Upon conversion, the convertible senior notes are required to be paid in cash with only amounts exceeding the principal permitted to be settled in shares. Accordingly, the convertible senior notes were included in the computation of diluted EPS, but not in the computation of basic EPS. The impact to diluted EPS was de minimis.

15: Revenue

Presented in the following tables are the components of operating revenue:

In Millions

Year Ended December 31, 2025	Electric Utility	Gas Utility	NorthStar Clean Energy[1]	Consolidated
CMS Energy, including Consumers				
Consumers utility revenue	$ 5,578	$ 2,468	$ —	$ 8,046
Other	—	—	259	259
Revenue recognized from contracts with customers	$ 5,578	$ 2,468	$ 259	$ 8,305
Leasing income	—	—	149	149
Financing income	10	6	—	16
Consumers alternative-revenue programs	50	19	—	69
Total operating revenue – CMS Energy	$ 5,638	$ 2,493	$ 408	$ 8,539
Consumers				
Consumers utility revenue				
Residential	$ 2,661	$ 1,701		$ 4,362
Commercial	1,888	538		2,426
Industrial	762	62		824
Other	267	167		434
Revenue recognized from contracts with customers	$ 5,578	$ 2,468		$ 8,046
Financing income	10	6		16
Alternative-revenue programs	50	19		69
Other non-segment revenue	—	—		1
Total operating revenue – Consumers	$ 5,638	$ 2,493		$ 8,132

1 Amounts represent NorthStar Clean Energy’s operating revenue from independent power production and its sales of energy commodities.

In Millions

Year Ended December 31, 2024	Electric Utility	Gas Utility	NorthStar Clean Energy[1]	Consolidated
CMS Energy, including Consumers				
Consumers utility revenue	$ 4,995	$ 2,114	$ —	$ 7,109
Other	—	—	211	211
Revenue recognized from contracts with customers	$ 4,995	$ 2,114	$ 211	$ 7,320
Leasing income	—	—	105	105
Financing income	10	5	—	15
Consumers alternative-revenue programs	56	19	—	75
Total operating revenue – CMS Energy	$ 5,061	$ 2,138	$ 316	$ 7,515
Consumers				
Consumers utility revenue				
Residential	$ 2,318	$ 1,429		$ 3,747
Commercial	1,674	440		2,114
Industrial	670	50		720
Other	333	195		528
Revenue recognized from contracts with customers	$ 4,995	$ 2,114		$ 7,109
Financing income	10	5		15
Alternative-revenue programs	56	19		75
Other non-segment revenue	—	—		1
Total operating revenue – Consumers	$ 5,061	$ 2,138		$ 7,200

1 Amounts represent NorthStar Clean Energy’s operating revenue from independent power production and its sales of energy commodities.

In Millions

Year Ended December 31, 2023	Electric Utility	Gas Utility	NorthStar Clean Energy[1]	Consolidated
CMS Energy, including Consumers				
Consumers utility revenue	$ 4,686	$ 2,394	$ —	$ 7,080
Other	—	—	181	181
Revenue recognized from contracts with customers	$ 4,686	$ 2,394	$ 181	$ 7,261
Leasing income	—	—	116	116
Financing income	10	6	—	16
Consumers alternative-revenue programs	49	20	—	69
Total operating revenue – CMS Energy	$ 4,745	$ 2,420	$ 297	$ 7,462
Consumers				
Consumers utility revenue				
Residential	$ 2,236	$ 1,619		$ 3,855
Commercial	1,550	489		2,039
Industrial	660	60		720
Other	240	226		466
Revenue recognized from contracts with customers	$ 4,686	$ 2,394		$ 7,080
Financing income	10	6		16
Alternative-revenue programs	49	20		69
Other non-segment revenue	—	—		1
Total operating revenue – Consumers	$ 4,745	$ 2,420		$ 7,166

1 Amounts represent NorthStar Clean Energy’s operating revenue from independent power production and its sales of energy commodities.

Electric and Gas Utilities

Consumers Utility Revenue: Consumers recognizes revenue primarily from the sale of electric and gas utility services at tariff-based rates regulated by the MPSC. Consumers’ customer base consists of a mix of residential, commercial, and diversified industrial customers. Consumers’ tariff-based sales performance obligations are described below.

- Consumers has performance obligations for the service of standing ready to deliver electricity or natural gas to customers, and it satisfies these performance obligations over time. Consumers recognizes revenue at a fixed rate as it provides these services. These arrangements generally do not have fixed terms and remain in effect as long as the customer consumes the utility service. The rates are set by the MPSC through the rate-making process and represent the stand-alone selling price of Consumers’ service to stand ready to deliver.

- Consumers has performance obligations for the service of delivering the commodity of electricity or natural gas to customers, and it satisfies these performance obligations upon delivery. Consumers recognizes revenue at a price per unit of electricity or natural gas delivered, based on the tariffs established by the MPSC. These arrangements generally do not have fixed terms and remain in effect as long as the customer consumes the utility service. The rates are set by the MPSC through the rate-making process and represent the stand-alone selling price of a bundled product comprising the commodity, electricity or natural gas, and the service of delivering such commodity.

In some instances, Consumers has specific fixed-term contracts with large commercial and industrial customers to provide electricity or gas at certain tariff rates or to provide gas transportation services at contracted rates. The amount of electricity and gas to be delivered under these contracts and the associated future revenue to be received are generally dependent on the customers' needs. Accordingly, Consumers recognizes revenues at the tariff or contracted rate as electricity or gas is delivered to the customer. Consumers also has other miscellaneous contracts with customers related to pole and other property rentals and utility contract work. Generally, these contracts are short term or evergreen in nature.

Accounts Receivable and Unbilled Revenues: Accounts receivable comprise trade receivables and unbilled receivables. CMS Energy and Consumers record their accounts receivable at cost less an allowance for uncollectible accounts. The allowance is increased for uncollectible accounts expense and decreased for account write-offs net of recoveries. CMS Energy and Consumers establish the allowance based on historical losses, management's assessment of existing economic conditions, customer payment trends, and reasonable and supported forecast information. CMS Energy and Consumers assess late payment fees on trade receivables based on contractual past-due terms established with customers. Accounts are written off when deemed uncollectible, which is generally when they become six months past due.

CMS Energy and Consumers recorded uncollectible accounts expense of $40 million for the year ended December 31, 2025, $33 million for the year ended December 31, 2024, and $34 million for the year ended December 31, 2023.

Consumers' customers are billed monthly in cycles having billing dates that do not generally coincide with the end of a calendar month. This results in customers having received electricity or natural gas that they have not been billed for as of the month-end. Consumers estimates its unbilled revenues by applying an average billed rate to total unbilled deliveries for each customer class. Unbilled revenues, which are recorded as accounts receivable and accrued revenue on CMS Energy's and Consumers' consolidated balance sheets, were $659 million at December 31, 2025 and $584 million at December 31, 2024.

Alternative-revenue Programs: Consumers accounts for its energy waste reduction incentive mechanism, financial compensation mechanism, and demand response incentive mechanism as alternative-revenue programs.

Consumers recognizes revenue related to the energy waste reduction incentive as soon as energy savings exceed the annual targets established by the MPSC. Revenue related to the financial compensation mechanism is recognized as payments are made on MPSC-approved PPAs. Under a demand response incentive mechanism, Consumers earns a financial incentive when it meets demand response targets set by the MPSC. Consumers recognizes revenue related to this program once demand response incentive objectives are complete, the incentive amount is calculable, and the incentive revenue will be collected within a 24-month period. For additional information on these mechanisms, see Note 3, Regulatory Matters.

Consumers does not reclassify revenue from its alternative-revenue program to revenue from contracts with customers at the time the amounts are collected from customers.

16: Other Income and Other Expense

Presented in the following table are the components of other income and other expense at CMS Energy and Consumers:

In Millions

Years Ended December 31	2025	2024	2023
CMS Energy, including Consumers			
Other income			
Gain on extinguishment of debt[1]	$ 72	$ 110	$ 131
Interest income	37	50	37
Interest income – related parties	1	—	—
Allowance for equity funds used during construction	23	29	7
Income from equity method investees	5	7	7
All other	13	11	13
Total other income – CMS Energy	$ 151	$ 207	$ 195
Consumers			
Other income			
Interest income	$ 22	$ 42	$ 25
Interest income – related parties	4	5	5
Allowance for equity funds used during construction	23	29	7
All other	6	9	12
Total other income – Consumers	$ 55	$ 85	$ 49
CMS Energy, including Consumers			
Other expense			
Donations	$ (10)	$ (18)	$ (1)
Civic and political expenditures	(7)	(5)	(5)
All other	(10)	(9)	(7)
Total other expense – CMS Energy	$ (27)	$ (32)	$ (13)
Consumers			
Other expense			
Donations	$ (10)	$ (18)	$ (1)
Civic and political expenditures	(5)	(5)	(5)
All other	(7)	(7)	(6)
Total other expense – Consumers	$ (22)	$ (30)	$ (12)

1 For information regarding the gain on extinguishment of debt, see Note 5, Financings and Capitalization—CMS Energy’s Purchase of Consumers’ First Mortgage Bonds.

17: Reportable Segments

Reportable segments consist of business units defined by the products and services they offer. CMS Energy's and Consumers' chief operating decision-maker is the CEO. The chief operating decision-maker evaluates segment performance and profitability using net income available to CMS Energy's common stockholders. This metric provides a clear, consistent basis for analyzing the financial results of each segment and supports decision-making regarding the allocation of resources.

Resource allocation to CMS Energy's and Consumers' segments begins with the annual budgeting process, which establishes initial funding and resource levels for each segment. The budget incorporates key financial and operational inputs, including anticipated revenues, expenses, and capital requirements, aligning with CMS Energy's and Consumers' strategic objectives and regulatory obligations. The chief operating decision-maker reviews budget-to-actual variances on a monthly basis and makes interim decisions to reallocate resources among segments as needed, ensuring a timely and effective response to changing conditions. For the electric utility and gas utility segments, the chief operating decision-maker uses this assessment to determine whether the segments are achieving their regulatory authorized return on equity.

Accounting policies for CMS Energy's and Consumers' segments are as described in Note 1, Significant Accounting Policies. The consolidated financial statements reflect the assets, liabilities, revenues, and expenses of the individual segments when appropriate. Accounts are allocated among the segments when common accounts are attributable to more than one segment. The allocations are based on certain measures of business activities, such as revenue, labor dollars, customers, other operating and maintenance expense, construction expense, leased property, taxes, or functional surveys. For example, customer receivables are allocated based on revenue, and pension provisions are allocated based on labor dollars.

Inter-segment sales and transfers are accounted for at current market prices and are eliminated in consolidated net income available to common stockholders by segment. Inter-segment sales and transfers were immaterial for all periods presented.

CMS Energy

The segments reported for CMS Energy are:

- electric utility, consisting of regulated activities associated with the generation, purchase, distribution, and sale of electricity in Michigan
- gas utility, consisting of regulated activities associated with the purchase, transmission, storage, distribution, and sale of natural gas in Michigan
- NorthStar Clean Energy, consisting of various subsidiaries engaging in domestic independent power production, including the development and operation of renewable generation, and the marketing of independent power production

CMS Energy presents corporate interest and other expenses, discontinued operations, and Consumers' other consolidated entities within other reconciling items.

Consumers

The segments reported for Consumers are:

- electric utility, consisting of regulated activities associated with the generation, purchase, distribution, and sale of electricity in Michigan
- gas utility, consisting of regulated activities associated with the purchase, transmission, storage, distribution, and sale of natural gas in Michigan

Consumers' other consolidated entities are presented within other reconciling items.

Presented in the following tables is financial information by segment:

In Millions

Year Ended December 31, 2025	Electric Utility	Gas Utility	NorthStar Clean Energy	Segments Total	Other Reconciling Items	Consolidated
CMS Energy, including Consumers						
Operating revenue	$ 5,638	$ 2,493	$ 408	$ 8,539	$ —	$ 8,539
Operating expenses						
Power supply cost[1]	2,193	—	264	2,457	—	2,457
Cost of gas sold	—	803	6	809	—	809
Maintenance and other operating expenses	1,146	468	100	1,714	13	1,727
Depreciation and amortization	903	350	52	1,305	1	1,306
General taxes	297	201	14	512	1	513
Total operating expenses	4,539	1,822	436	6,797	15	6,812
Operating Income (Loss)	1,099	671	(28)	1,742	(15)	1,727
Other income[2]	124	83	17	224	86	310
Interest charges	353	206	(7)	552	237	789
Income (Loss) Before Income Taxes	870	548	(4)	1,414	(166)	1,248
Income tax expense (benefit)	150	138	(4)	284	(38)	246
Income (Loss) From Continuing Operations	720	410	—	1,130	(128)	1,002
Other segment items[3]	(1)	(1)	71	69	(10)	59
Net Income (Loss) Available to Common Stockholders	$ 719	$ 409	$ 71	$ 1,199	$ (138)	$ 1,061
Property, plant, and equipment, gross	$ 21,871 [4]	$ 14,218 [4]	$ 1,649	$ 37,738	$ 25	$ 37,763
Investments in equity method investees	—	—	61	61	—	61
Total assets	22,760 [4]	14,188 [4]	2,496	39,444	497	39,941
Capital expenditures[5]	2,408 [6]	1,064 [6]	498	3,970	—	3,970

1 Power supply costs comprise fuel for electric generation, purchased and interchange power, and purchased power – related parties.

2 Includes income from equity method investees of $5 million attributable to NorthStar Clean Energy. See Note 16, Other Income and Other Expense

3 Other segment items comprise loss attributable to noncontrolling interests and preferred stock dividends.

4 Amounts include a portion of Consumers’ other common assets attributable to both the electric and gas utility businesses.

5 Amounts include assets placed under finance lease.

6 Amounts include a portion of Consumers’ capital expenditures for plant and equipment attributable to both the electric and gas utility businesses.

In Millions

Year Ended December 31, 2025	Electric Utility	Gas Utility	Segments Total	Other Reconciling Items	Consolidated
Consumers					
Operating revenue	$ 5,638	$ 2,493	$ 8,131	$ 1	$ 8,132
Operating expenses					
Power supply cost[1]	2,193	—	2,193	—	2,193
Cost of gas sold	—	803	803	—	803
Maintenance and other operating expenses	1,146	468	1,614	—	1,614
Depreciation and amortization	903	350	1,253	1	1,254
General taxes	297	201	498	1	499
Total operating expenses	4,539	1,822	6,361	2	6,363
Operating Income (Loss)	1,099	671	1,770	(1)	1,769
Other income	124	83	207	1	208
Interest charges	353	206	559	1	560
Income (Loss) Before Income Taxes	870	548	1,418	(1)	1,417
Income tax expense	150	138	288	—	288
Net Income (Loss)	720	410	1,130	(1)	1,129
Other segment items[2]	(1)	(1)	(2)	—	(2)
Net Income (Loss) Available to Common Stockholder	$ 719	$ 409	$ 1,128	$ (1)	$ 1,127
Property, plant, and equipment, gross	$ 21,871 [3]	$ 14,218 [3]	$ 36,089	$ 31	$ 36,120
Total assets	22,814 [3]	14,229 [3]	37,043	48	37,091
Capital expenditures[4]	2,408 [5]	1,064 [5]	3,472	—	3,472

1 Power supply costs comprise fuel for electric generation, purchased and interchange power, and purchased power – related parties.

2 Other segment items comprise preferred stock dividends.

3 Amounts include a portion of Consumers’ other common assets attributable to both the electric and gas utility businesses.

4 Amounts include assets placed under finance lease.

5 Amounts include a portion of Consumers’ capital expenditures for plant and equipment attributable to both the electric and gas utility businesses.

In Millions

Year Ended December 31, 2024	Electric Utility	Gas Utility	NorthStar Clean Energy	Segments Total	Other Reconciling Items	Consolidated
CMS Energy, including Consumers						
Operating revenue	$ 5,061	$ 2,138	$ 316	$ 7,515	$ —	$ 7,515
Operating expenses						
Power supply cost[1]	1,867	—	161	2,028	—	2,028
Cost of gas sold	—	637	3	640	—	640
Maintenance and other operating expenses	1,066	454	101	1,621	17	1,638
Depreciation and amortization	865	325	49	1,239	1	1,240
General taxes	281	188	12	481	1	482
Total operating expenses	4,079	1,604	326	6,009	19	6,028
Operating Income (Loss)	982	534	(10)	1,506	(19)	1,487
Other income[2]	126	86	14	226	118	344
Interest charges	324	192	4	520	188	708
Income (Loss) Before Income Taxes	784	428	—	1,212	(89)	1,123
Income tax expense (benefit)	102	99	(5)	196	(20)	176
Income (Loss) From Continuing Operations	682	329	5	1,016	(69)	947
Other segment items[3]	(1)	(1)	58	56	(10)	46
Net Income (Loss) Available to Common Stockholders	$ 681	$ 328	$ 63	$ 1,072	$ (79)	$ 993
Property, plant, and equipment, gross	$ 20,137 [4]	$ 13,268 [4]	$ 1,506	$ 34,911	$ 21	$ 34,932
Investments in equity method investees	—	—	64	64	—	64
Total assets	20,710 [4]	13,247 [4]	1,893	35,850	70	35,920
Capital expenditures[5]	1,871 [6]	1,141 [6]	288	$ 3,300	1	3,301

1 Power supply costs comprise fuel for electric generation, purchased and interchange power, and purchased power – related parties.

2 Includes income from equity method investees of $7 million attributable to NorthStar Clean Energy. See Note 16, Other Income and Other Expense.

3 Other segment items comprise loss attributable to noncontrolling interests and preferred stock dividends.

4 Amounts include a portion of Consumers’ other common assets attributable to both the electric and gas utility businesses.

5 Amounts include assets placed under finance lease.

6 Amounts include a portion of Consumers’ capital expenditures for plant and equipment attributable to both the electric and gas utility businesses.

In Millions

Year Ended December 31, 2024	Electric Utility	Gas Utility	Segments Total	Other Reconciling Items	Consolidated
Consumers					
Operating revenue	$ 5,061	$ 2,138	$ 7,199	$ 1	$ 7,200
Operating expenses					
Power supply cost[1]	1,867	—	1,867	—	1,867
Cost of gas sold	—	637	637	—	637
Maintenance and other operating expenses	1,066	454	1,520	—	1,520
Depreciation and amortization	865	325	1,190	1	1,191
General taxes	281	188	469	1	470
Total operating expenses	4,079	1,604	5,683	2	5,685
Operating Income (Loss)	982	534	1,516	(1)	1,515
Other income	126	86	212	—	212
Interest charges	324	192	516	2	518
Income (Loss) Before Income Taxes	784	428	1,212	(3)	1,209
Income tax expense (benefit)	102	99	201	(1)	200
Net Income (Loss)	682	329	1,011	(2)	1,009
Other segment items[2]	(1)	(1)	(2)	—	(2)
Net Income (Loss) Available to Common Stockholder	$ 681	$ 328	$ 1,009	$ (2)	$ 1,007
Property, plant, and equipment, gross	$ 20,137 [3]	$ 13,268 [3]	$ 33,405	$ 29	$ 33,434
Total assets	20,767 [3]	13,289 [3]	34,056	32	34,088
Capital expenditures[4]	1,871 [5]	1,141 [5]	3,012	—	3,012

1 Power supply costs comprise fuel for electric generation, purchased and interchange power, and purchased power – related parties.

2 Other segment items comprise preferred stock dividends.

3 Amounts include a portion of Consumers' other common assets attributable to both the electric and gas utility businesses.

4 Amounts include assets placed under finance lease.

5 Amounts include a portion of Consumers' capital expenditures for plant and equipment attributable to both the electric and gas utility businesses.

In Millions

Year Ended December 31, 2023	Electric Utility	Gas Utility	NorthStar Clean Energy	Segments Total	Other Reconciling Items	Consolidated
CMS Energy, including Consumers						
Operating revenue	$ 4,745	$ 2,420	$ 297	$ 7,462	$ —	$ 7,462
Operating expenses						
Power supply cost[1]	1,841	—	170	2,011	—	2,011
Cost of gas sold	—	897	5	902	—	902
Maintenance and other operating expenses	1,075	511	88	1,674	13	1,687
Depreciation and amortization	797	338	43	1,178	2	1,180
General taxes	260	176	10	446	1	447
Total operating expenses	3,973	1,922	316	6,211	16	6,227
Operating Income (Loss)	772	498	(19)	1,251	(16)	1,235
Other income[2]	131	77	12	220	142	362
Interest charges	285	161	2	448	195	643
Income (Loss) Before Income Taxes	618	414	(9)	1,023	(69)	954
Income tax expense (benefit)	67	98	4	169	(22)	147
Income (Loss) From Continuing Operations	551	316	(13)	854	(47)	807
Other segment items[3]	(1)	(1)	80	78	(8)	70
Net Income (Loss) Available to Common Stockholders	$ 550	$ 315	$ 67	$ 932	$ (55)	$ 877

1 Power supply costs comprise fuel for electric generation, purchased and interchange power, and purchased power – related parties.

2 Includes income from equity method investees of $7 million attributable to NorthStar Clean Energy. See Note 16, Other Income and Other Expense.

3 Other segment items comprise income from discontinued operations, net of tax, loss attributable to noncontrolling interests, and preferred stock dividends.

In Millions

Year Ended December 31, 2023	Electric Utility	Gas Utility	Segments Total	Other Reconciling Items	Consolidated
Consumers					
Operating revenue	$ 4,745	$ 2,420	$ 7,165	$ 1	$ 7,166
Operating expenses					
Power supply cost[1]	1,841	—	1,841	—	1,841
Cost of gas sold	—	897	897	—	897
Maintenance and other operating expenses	1,075	511	1,586	—	1,586
Depreciation and amortization	797	338	1,135	2	1,137
General taxes	260	176	436	1	437
Total operating expenses	3,973	1,922	5,895	3	5,898
Operating Income (Loss)	772	498	1,270	(2)	1,268
Other income	131	77	208	—	208
Interest charges	285	161	446	2	448
Income (Loss) Before Income Taxes	618	414	1,032	(4)	1,028
Income tax expense (benefit)	67	98	165	(4)	161
Net Income	551	316	867	—	867
Other segment items[2]	(1)	(1)	(2)	—	(2)
Net Income Available to Common Stockholder	$ 550	$ 315	$ 865	$ —	$ 865

1 Power supply costs comprise fuel for electric generation, purchased and interchange power, and purchased power – related parties.

2 Other segment items comprise preferred stock dividends.

18: Related-party Transactions—Consumers

Consumers enters into a number of transactions with related parties in the normal course of business. These transactions include but are not limited to:

- purchases of electricity from affiliates of NorthStar Clean Energy
- payments to and from CMS Energy related to parent company overhead costs
- payments of principal and interest when due to CMS Energy related to borrowings under certain credit agreements and CMS Energy's repurchase of Consumers' first mortgage bonds

Transactions involving power supply purchases from certain affiliates of NorthStar Clean Energy are based on state law and competitive bidding. The payment of parent company overhead costs is based on the use of accepted industry allocation methodologies. These payments are for costs that occur in the normal course of business. Purchases of power and capacity from affiliates of NorthStar Clean Energy totaled $94 million in 2025, $71 million in 2024, and $75 million in 2023.

Amounts payable to related parties for purchased power and other services were $19 million at December 31, 2025 and $20 million at December 31, 2024. Accounts receivable from related parties were $13 million at December 31, 2025 and $15 million at December 31, 2024.

CMS Energy has a demand note payable to the DB SERP rabbi trust. The demand note bears interest at an annual rate of 4.10 percent and has a maturity date of 2028. The portion of the demand note attributable to Consumers was recorded as a note receivable – related party on Consumers' consolidated balance sheets at December 31, 2025 and 2024. For more information about Consumers' note receivable – related party, see Note 7, Financial Instruments.

Consumers has a natural gas transportation agreement with a subsidiary of CMS Energy that extends through 2038, related to a pipeline owned by Consumers. For additional details about the agreement, see Note 9, Leases.

CMS Energy has repurchased certain of Consumers' first mortgage bonds. Interest payable to related parties was $9 million at December 31, 2025 and $7 million at December 31, 2024. For more information about these repurchases, see Note 5, Financings and Capitalization—CMS Energy's Purchase of Consumers' First Mortgage Bonds.

In December 2025, Consumers renewed a short-term credit agreement with CMS Energy, permitting Consumers to borrow up to $500 million. For additional details about the agreement, see Note 5, Financings and Capitalization—Short-term Borrowings.

19: Variable Interest Entities

Consolidated VIEs: In March 2025, NorthStar Clean Energy sold a 50-percent interest in NWO Wind Equity Holdings for net proceeds of $36 million. NWO Wind Equity Holdings holds the Class B membership interest in NWO Holdco, the holding company of a 100-MW wind project located in Paulding County, Ohio. Additionally in March 2025, NorthStar Clean Energy sold a 50-percent interest in Delta Solar Equity Holdings for net proceeds of $8 million. Delta Solar Equity Holdings is the holding company of a 24-MW solar project located in Delta Township, Michigan.

In December 2025, NorthStar Clean Energy sold a Class A membership interest in BG Solar Holdings to a tax equity investor. BG Solar Holdings is the holding company of a 200-MW solar generation project being constructed in Branch County, Michigan. All of the project's nameplate capacity has been committed under a 15-year renewable energy purchase agreement. The tax equity investor contributed $15 million and recognized a deemed contribution of $35 million associated with BG Solar Holdings' sale of investment tax credits related to a portion of the project placed into service for tax purposes in 2025. The tax equity investor will contribute additional amounts upon commercial operation of the project in 2026.

NorthStar Clean Energy consolidates these and other entities that it does not wholly own, but for which it manages and controls the entities' operating activities. NorthStar Clean Energy is the primary beneficiary of these entities because it has the power to direct the activities that most significantly impact the economic performance of the companies, as well as the obligation to absorb losses or the right to receive benefits from the companies. Presented in the following table is information about the VIEs NorthStar Clean Energy consolidates:

Consolidated VIE	NorthStar Clean Energy's ownership interest	Description of VIE
Aviator Wind Equity Holdings	51-percent ownership interest[1]	Holds a Class B membership interest in Aviator Wind
Aviator Wind	Class B membership interest[2]	Holding company of a 525-MW wind generation project in Coke County, Texas
BG Solar Holdings	Class B membership interest[2]	Holding company of a 200-MW solar generation project in Branch County, Michigan
Delta Solar Equity Holdings	50-percent ownership interest[1]	Holding company of a 24-MW solar generation project in Delta Township, Michigan
Newport Solar Holdings	Class B membership interest[2]	Holding company of a 180-MW solar generation project in Jackson County, Arkansas
NWO Wind Equity Holdings	50-percent ownership interest[1]	Holds a Class B membership interest in NWO Holdco
NWO Holdco	Class B membership interest[2]	Holding company of a 100-MW wind generation project in Paulding County, Ohio

1 The remaining ownership interest is presented as noncontrolling interest on CMS Energy's consolidated balance sheets.

2 The Class A membership interest in the entity is held by a tax equity investor and is presented as noncontrolling interest on CMS Energy's consolidated balance sheets. Under the associated limited liability company agreement, the tax equity investor is guaranteed preferred returns from the entity.

Earnings, tax attributes, and cash flows generated by the entities in which NorthStar Clean Energy holds a Class B membership are allocated among and distributed to the membership classes in accordance with the ratios specified in the associated limited liability company agreements; these ratios change over time and are not representative of the ownership interest percentages of each membership class. Since these entities' income and cash flows are not distributed among their investors based on ownership interest percentages, NorthStar Clean Energy allocates the entities' income (loss) among the investors by applying the hypothetical liquidation at book value method. This method calculates each investor's earnings based on a hypothetical liquidation of the entities at the net book value of underlying assets as of the balance sheet date. The liquidation tax gain (loss) is allocated to each investor's capital account, resulting in income (loss) equal to the period change in the investor's capital account balance.

Presented in the following table are the carrying values of the VIEs' assets and liabilities included on CMS Energy's consolidated balance sheets:

In Millions

December 31	2025	2024
Current		
Cash and cash equivalents	$ 20	$ 18
Restricted cash	19	—
Accounts receivable	42	4
Prepayments and other current assets	5	3
Non-current		
Plant, property, and equipment, net	1,037	1,024
Construction work in progress	357	—
Other non-current assets	5	3
Total assets[1]	$ 1,485	$ 1,052
Current		
Current portion of long-term debt and finance leases	$ 65	$ —
Accounts payable	29	8
Non-current		
Long-term debt	118	—
Non-current portion of finance leases	39	23
AROs	38	33
Other non-current liabilities	3	—
Total liabilities	$ 292	$ 64

[1] Assets may be used only to meet VIEs' obligations and commitments.

NorthStar Clean Energy is obligated under certain indemnities that protect the tax equity investors against losses incurred as a result of breaches of representations and warranties under the associated limited liability company agreements. For additional details on these indemnity obligations, see Note 4, Contingencies and Commitments—Guarantees.

Consumers' wholly-owned subsidiaries, Consumers 2014 Securitization Funding and Consumers 2023 Securitization Funding, are VIEs designed to collateralize Consumers' securitization bonds. These entities are considered VIEs primarily because their equity capitalization is insufficient to support their operations. Consumers is the primary beneficiary of and consolidates these VIEs, as it has the power to direct the activities that most significantly impact the economic performance of the companies, as well as the obligation to absorb losses or the right to receive benefits from the companies. The VIEs' primary assets and liabilities comprise non-current regulatory assets and long-term debt. For more information on these assets and liabilities, see Note 3, Regulatory Matters—Securitized Costs and Note 5, Financings and Capitalization—Securitization Bonds

Non-consolidated VIEs: NorthStar Clean Energy has variable interests in T.E.S. Filer City, Grayling, Genesee, and Craven. While NorthStar Clean Energy owns 50 percent of each partnership, it is not the primary beneficiary of any of these partnerships because decision making is shared among unrelated parties, and no one party has the ability to direct the activities that most significantly impact the entities' economic performance, such as operations and maintenance, plant dispatch, and fuel strategy. The partners must agree on all major decisions for each of the partnerships.

Presented in the following table is information about these partnerships, which are accounted for using the equity method:

Name	Nature of the Entity	Nature of NorthStar Clean Energy's Involvement
T.E.S. Filer City	Coal-fueled power generator	Long-term PPA between partnership and Consumers Employee assignment agreement
Grayling	Wood waste-fueled power generator	Long-term PPA between partnership and Consumers Reduced dispatch agreement with Consumers[1] Operating and management contract
Genesee	Wood waste-fueled power generator	Long-term PPA between partnership and Consumers Reduced dispatch agreement with Consumers[1] Operating and management contract
Craven	Wood waste-fueled power generator	Operating and management contract

1 Reduced dispatch agreements allow the facilities to be dispatched based on the market price of power compared with the cost of production of the plants. This results in fuel cost savings that each partnership shares with Consumers' customers.

The creditors of these partnerships do not have recourse to the general credit of CMS Energy, NorthStar Clean Energy, or Consumers. NorthStar Clean Energy's maximum risk exposure to these partnerships is generally limited to its investment in the partnerships, which is included in investments on CMS Energy's consolidated balance sheets in the amount of $54 million at December 31, 2025 and $64 million at December 31, 2024.

20: Exit Activities and Asset Sales

J.H. Campbell Retirement: Under its integrated resource plan, Consumers had planned to retire J.H. Campbell in 2025. In order to ensure necessary staffing at J.H. Campbell through the planned retirement, Consumers implemented a retention incentive program. Consumers made final payments under this retention plan in November 2025. The aggregate cost of this program was $48 million, which has been deferred as a regulatory asset. The MPSC has approved recovery of these retention costs over three years.

The retirement of J.H. Campbell is subject to temporary extensions under emergency orders issued by the U.S. Secretary of Energy. As a result, Consumers has implemented retention measures to ensure appropriate staffing levels and expects to incur up to $4 million during each 90-day emergency order period. Consumers will seek recovery of these retention costs from FERC, consistent with rate recovery sought for other costs of complying with the emergency orders. For additional information on the emergency orders associated with J.H. Campbell, see Note 3, Regulatory Matters.

Presented in the following table is a reconciliation of the retention benefit liability recorded in other current liabilities on Consumers' consolidated balance sheets:

In Millions

Year Ended December 31	2025	2024
Retention benefit liability at beginning of period	$ 14	$ 16
Costs deferred as a regulatory asset	7	8
Costs paid or settled	(19)	(10)
Retention benefit liability at the end of the period	$ 2	$ 14

Sale of Hydroelectric Facilities: In September 2025, Consumers signed an agreement to sell its 13 river hydroelectric dams, which are located throughout Michigan, to a non-affiliated company. Additionally, Consumers signed an agreement to purchase power generated by the facilities for 30 years, at a price that reflects the counterparty's acceptance of the risks and rewards of ownership of the facilities, including FERC licensing obligations. The agreements are contingent upon MPSC and FERC approval, for which Consumers filed in October 2025. Timing of the regulatory review process is uncertain and could extend 12 to 18 months or longer. In Consumers' most recent electric rate case, the MPSC approved deferred accounting treatment for costs of owning and operating the hydroelectric dams pending and until completion of the transaction. At December 31, 2025, the net book value of the hydroelectric facilities was immaterial.

To ensure necessary staffing at the hydroelectric facilities through the anticipated sale, Consumers has provided current employees at the facilities with a retention incentive program. Subsequently, to ensure continued safe operation of the facilities after the sale, the buyer will offer employment to the current hydroelectric employees for a period of at least a year. The retention incentive benefits are contingent upon MPSC and FERC approval of the sale transaction.

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Report of Independent Registered Public Accounting Firm

To the Board of Directors and Stockholders of CMS Energy Corporation

Opinions on the Financial Statements and Internal Control over Financial Reporting

We have audited the accompanying consolidated balance sheets of CMS Energy Corporation and its subsidiaries (the "Company") as of December 31, 2025 and 2024, and the related consolidated statements of income, of comprehensive income, of changes in equity and of cash flows for each of the three years in the period ended December 31, 2025, including the related notes and financial statement schedules listed in the index appearing under Item 15 (collectively referred to as the "consolidated financial statements"). We also have audited the Company's internal control over financial reporting as of December 31, 2025, based on criteria established in *Internal Control - Integrated Framework* (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO).

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of the Company as of December 31, 2025 and 2024, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2025 in conformity with accounting principles generally accepted in the United States of America. Also in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2025, based on criteria established in *Internal Control - Integrated Framework* (2013) issued by the COSO.

Basis for Opinions

The Company's management is responsible for these consolidated financial statements, for maintaining effective internal control over financial reporting, and for its assessment of the effectiveness of internal control over financial reporting, included in Management's Annual Report on Internal Control Over Financial Reporting appearing under Item 9A. Our responsibility is to express opinions on the Company's consolidated financial statements and on the Company's internal control over financial reporting based on our audits. We are a public accounting firm registered with the Public Company Accounting Oversight Board (United States) (PCAOB) and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audits in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audits to obtain reasonable assurance about whether the consolidated financial statements are free of material misstatement, whether due to error or fraud, and whether effective internal control over financial reporting was maintained in all material respects.

Our audits of the consolidated financial statements included performing procedures to assess the risks of material misstatement of the consolidated financial statements, whether due to error or fraud, and performing procedures that respond to those risks. Such procedures included examining, on a test basis, evidence regarding the amounts and disclosures in the consolidated financial statements. Our audits also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements. Our audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audits also included performing such other procedures as we considered necessary in the circumstances. We believe that our audits provide a reasonable basis for our opinions.

Definition and Limitations of Internal Control over Financial Reporting

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (i) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (ii) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (iii) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

Critical Audit Matters

The critical audit matter communicated below is a matter arising from the current period audit of the consolidated financial statements that was communicated or required to be communicated to the audit committee and that (i) relates to accounts or disclosures that are material to the consolidated financial statements and (ii) involved our especially challenging, subjective, or complex judgments. The communication of critical audit matters does not alter in any way our opinion on the consolidated financial statements, taken as a whole, and we are not, by communicating the critical audit matter below, providing a separate opinion on the critical audit matter or on the accounts or disclosures to which it relates.

Accounting for the Effects of New Regulatory Matters

As described in Note 3 to the consolidated financial statements, the Company is a utility and must apply regulatory accounting when its rates are designed to recover specific costs of providing regulated services. Under regulatory accounting, the Company records regulatory assets or liabilities for certain transactions that would have been treated as expense or revenue by a non-regulated business. As of December 31, 2025 the Company has recognized a total of $3,459 million of regulatory assets, $4,176 million of regulatory liabilities, $38 million of accrued revenues, and $28 million of accrued rate refunds. As described by management, there are multiple participants to rate case proceedings who often challenge various aspects of those proceedings, including the prudence of the Company's policies and practices. These participants often seek cost disallowances and other relief and have appealed significant decisions reached by the regulators. The recovery of regulatory assets and the settlement of regulatory liabilities are contingent upon the outcomes of rate cases and regulatory proceedings. The principal considerations for our determination that performing procedures relating to accounting for the effects of new regulatory matters is a critical audit matter are (i) the high degree of auditor judgment and subjectivity applied to evaluate management's assessment of the potential outcomes and related accounting impacts associated with pending rate case proceedings; (ii) in some cases, the significant audit effort necessary to assess contrary evidence from various parties involved in rate case proceedings; and (iii) the significant audit effort necessary to evaluate audit evidence related to the recovery of regulatory assets and the settlement of regulatory liabilities. Addressing the matter involved performing procedures and evaluating audit evidence in connection with forming our overall opinion on the consolidated financial statements. These procedures included testing the effectiveness of controls relating to management's assessment of regulatory proceedings, including the probability of recovering incurred costs and the related accounting and disclosure impacts. These procedures also included, among others, (i) evaluating the Company's correspondence with regulators; (ii) evaluating the reasonableness of management's assessment regarding whether recovery of regulatory assets and settlement of regulatory liabilities is probable; (iii) evaluating the sufficiency of the disclosures in the consolidated financial statements; and (iv) testing, on a sample basis, the regulatory assets and liabilities, including those subject to pending rate cases and regulatory proceedings, based on (a) provisions and formulas outlined in rate orders; (b) other regulatory correspondence; and (c) application of relevant regulatory precedents.

/s/ PricewaterhouseCoopers LLP

Detroit, Michigan
February 10, 2026

We have served as the Company's auditor since 2007.

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Report of Independent Registered Public Accounting Firm

To the Board of Directors and Stockholders of Consumers Energy Company

Opinions on the Financial Statements and Internal Control over Financial Reporting

We have audited the accompanying consolidated balance sheets of Consumers Energy Company and its subsidiaries (the "Company") as of December 31, 2025 and 2024, and the related consolidated statements of income, of comprehensive income, of changes in equity and of cash flows for each of the three years in the period ended December 31, 2025, including the related notes and financial statement schedule listed in the index appearing under Item 15 (collectively referred to as the "consolidated financial statements"). We also have audited the Company's internal control over financial reporting as of December 31, 2025, based on criteria established in *Internal Control - Integrated Framework* (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO).

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of the Company as of December 31, 2025 and 2024, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2025 in conformity with accounting principles generally accepted in the United States of America. Also in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2025, based on criteria established in *Internal Control - Integrated Framework* (2013) issued by the COSO.

Basis for Opinions

The Company's management is responsible for these consolidated financial statements, for maintaining effective internal control over financial reporting, and for its assessment of the effectiveness of internal control over financial reporting, included in Management's Annual Report on Internal Control Over Financial Reporting appearing under Item 9A. Our responsibility is to express opinions on the Company's consolidated financial statements and on the Company's internal control over financial reporting based on our audits. We are a public accounting firm registered with the Public Company Accounting Oversight Board (United States) (PCAOB) and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audits in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audits to obtain reasonable assurance about whether the consolidated financial statements are free of material misstatement, whether due to error or fraud, and whether effective internal control over financial reporting was maintained in all material respects.

Our audits of the consolidated financial statements included performing procedures to assess the risks of material misstatement of the consolidated financial statements, whether due to error or fraud, and performing procedures that respond to those risks. Such procedures included examining, on a test basis, evidence regarding the amounts and disclosures in the consolidated financial statements. Our audits also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements. Our audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audits also included performing such other procedures as we considered necessary in the circumstances. We believe that our audits provide a reasonable basis for our opinions.

Definition and Limitations of Internal Control over Financial Reporting

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (i) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (ii) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (iii) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

Critical Audit Matters

The critical audit matter communicated below is a matter arising from the current period audit of the consolidated financial statements that was communicated or required to be communicated to the audit committee and that (i) relates to accounts or disclosures that are material to the consolidated financial statements and (ii) involved our especially challenging, subjective, or complex judgments. The communication of critical audit matters does not alter in any way our opinion on the consolidated financial statements, taken as a whole, and we are not, by communicating the critical audit matter below, providing a separate opinion on the critical audit matter or on the accounts or disclosures to which it relates.

Accounting for the Effects of New Regulatory Matters

As described in Note 3 to the consolidated financial statements, the Company is a utility and must apply regulatory accounting when its rates are designed to recover specific costs of providing regulated services. Under regulatory accounting, the Company records regulatory assets or liabilities for certain transactions that would have been treated as expense or revenue by a non-regulated business. As of December 31, 2025 the Company has recognized a total of $3,459 million of regulatory assets, $4,176 million of regulatory liabilities, $38 million of accrued revenues, and $28 million of accrued rate refunds. As described by management, there are multiple participants to rate case proceedings who often challenge various aspects of those proceedings, including the prudence of the Company's policies and practices. These participants often seek cost disallowances and other relief and have appealed significant decisions reached by the regulators. The recovery of regulatory assets and the settlement of regulatory liabilities are contingent upon the outcomes of rate cases and regulatory proceedings. The principal considerations for our determination that performing procedures relating to accounting for the effects of new regulatory matters is a critical audit matter are (i) the high degree of auditor judgment and subjectivity applied to evaluate management's assessment of the potential outcomes and related accounting impacts associated with pending rate case proceedings; (ii) in some cases, the significant audit effort necessary to assess contrary evidence from various parties involved in rate case proceedings; and (iii) the significant audit effort necessary to evaluate audit evidence related to the recovery of regulatory assets and the settlement of regulatory liabilities. Addressing the matter involved performing procedures and evaluating audit evidence in connection with forming our overall opinion on the consolidated financial statements. These procedures included testing the effectiveness of controls relating to management’s assessment of regulatory proceedings, including the probability of recovering incurred costs and the related accounting and disclosure impacts. These procedures also included, among others, (i) evaluating the Company’s correspondence with regulators; (ii) evaluating the reasonableness of management’s assessment regarding whether recovery of regulatory assets and settlement of regulatory liabilities is probable; (iii) evaluating the sufficiency of the disclosures in the consolidated financial statements; and (iv) testing, on a sample basis, the regulatory assets and liabilities, including those subject to pending rate cases and regulatory proceedings, based on (a) provisions and formulas outlined in rate orders; (b) other regulatory correspondence; and (c) application of relevant regulatory precedents.

/s/ PricewaterhouseCoopers LLP

Detroit, Michigan
February 10, 2026

We have served as the Company’s auditor since 2007.

Item 9. Changes in and Disagreements with Accountants on Accounting and Financial Disclosure

None.

Item 9A. Controls and Procedures

CMS Energy

Conclusion Regarding the Effectiveness of Disclosure Controls and Procedures: Under the supervision and with the participation of management, including its CEO and CFO, CMS Energy conducted an evaluation of its disclosure controls and procedures (as such term is defined in Rules 13a-15(e) and 15d-15(e) under the Exchange Act). Based on such evaluation, CMS Energy's CEO and CFO have concluded that its disclosure controls and procedures were effective as of December 31, 2025.

Management's Annual Report on Internal Control Over Financial Reporting: CMS Energy's management is responsible for establishing and maintaining adequate internal control over financial reporting, as defined in Exchange Act Rules 13a-15(f) and 15d-15(f). CMS Energy's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with GAAP and includes policies and procedures that:

- pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of CMS Energy
- provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with GAAP, and that receipts and expenditures of CMS Energy are being made only in accordance with authorizations of management and directors of CMS Energy
- provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of CMS Energy's assets that could have a material effect on its financial statements

Management, including its CEO and CFO, does not expect that its internal controls will prevent or detect all errors and all fraud. A control system, no matter how well designed and operated, can provide only reasonable, not absolute, assurance that the objectives of the control system are met. Further, the design of a control system must reflect the fact that there are resource constraints, and the benefits of controls must be considered relative to their costs. In addition, any evaluation of the effectiveness of controls is subject to risks that those internal controls may become inadequate in future periods because of changes in business conditions, or that the degree of compliance with the policies or procedures deteriorates.

Under the supervision and with the participation of management, including its CEO and CFO, CMS Energy conducted an evaluation of the effectiveness of its internal control over financial reporting as of December 31, 2025. In making this evaluation, management used the criteria set forth in the framework in Internal Control—Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on such evaluation, CMS Energy's management concluded that its internal control over financial reporting was effective as of December 31, 2025. The effectiveness of CMS Energy's internal control over financial reporting as of December 31, 2025 has been audited by PricewaterhouseCoopers LLP, an independent registered public accounting firm, as stated in their report which appears under Item 8. Financial Statements and Supplementary Data.

Changes in Internal Control Over Financial Reporting: There have not been any changes in CMS Energy’s internal control over financial reporting during the last fiscal quarter that have materially affected, or are reasonably likely to affect materially, its internal control over financial reporting.

Consumers

Conclusion Regarding the Effectiveness of Disclosure Controls and Procedures: Under the supervision and with the participation of management, including its CEO and CFO, Consumers conducted an evaluation of its disclosure controls and procedures (as such term is defined in Rules 13a-15(e) and 15d-15(e) under the Exchange Act). Based on such evaluation, Consumers’ CEO and CFO have concluded that its disclosure controls and procedures were effective as of December 31, 2025.

Management’s Annual Report on Internal Control Over Financial Reporting: Consumers’ management is responsible for establishing and maintaining adequate internal control over financial reporting, as defined in Exchange Act Rules 13a-15(f) and 15d-15(f). Consumers’ internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with GAAP and includes policies and procedures that:

- pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of Consumers
- provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with GAAP, and that receipts and expenditures of Consumers are being made only in accordance with authorizations of management and directors of Consumers
- provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of Consumers’ assets that could have a material effect on its financial statements

Management, including its CEO and CFO, does not expect that its internal controls will prevent or detect all errors and all fraud. A control system, no matter how well designed and operated, can provide only reasonable, not absolute, assurance that the objectives of the control system are met. Further, the design of a control system must reflect the fact that there are resource constraints, and the benefits of controls must be considered relative to their costs. In addition, any evaluation of the effectiveness of controls is subject to risks that those internal controls may become inadequate in future periods because of changes in business conditions, or that the degree of compliance with the policies or procedures deteriorates.

Under the supervision and with the participation of management, including its CEO and CFO, Consumers conducted an evaluation of the effectiveness of its internal control over financial reporting as of December 31, 2025. In making this evaluation, management used the criteria set forth in the framework in Internal Control—Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on such evaluation, Consumers’ management concluded that its internal control over financial reporting was effective as of December 31, 2025. The effectiveness of Consumers’ internal control over financial reporting as of December 31, 2025 has been audited by PricewaterhouseCoopers LLP, an independent registered public accounting firm, as stated in their report which appears under Item 8. Financial Statements and Supplementary Data.

Changes in Internal Control Over Financial Reporting: There have not been any changes in Consumers' internal control over financial reporting during the last fiscal quarter that have materially affected, or are reasonably likely to affect materially, its internal control over financial reporting.

Item 9B. Other Information

None.

Item 9C. Disclosure Regarding Foreign Jurisdictions that Prevent Inspections

Not applicable.

Part III

Item 10. Directors, Executive Officers and Corporate Governance

CMS Energy

CMS Energy has adopted an insider trading compliance policy and program applicable to directors, executive officers and employees, as well as CMS Energy itself. CMS Energy believes this policy is reasonably designed to promote compliance with insider trading laws, rules and regulations, and the New York Stock Exchange listing standards. A copy of the insider trading policy is filed as Exhibit 19.1 to this Form 10-K. Additional information that is required in Item 10 of this Form 10-K regarding executive officers is included in the Item 1. Business—Information About CMS Energy's and Consumers' Executive Officers section, which is incorporated by reference herein.

Information that is required in Item 10 of this Form 10-K regarding directors, executive officers, and corporate governance is incorporated by reference from CMS Energy's and Consumers' definitive proxy statement for their 2026 Annual Meetings of Shareholders to be held May 8, 2026. The proxy statement will be filed with the SEC, pursuant to Regulation 14A under the Exchange Act, within 120 days after the end of the fiscal year covered by this Form 10-K, all of which information is hereby incorporated by reference in, and made part of, this Form 10-K.

Code of Ethics

CMS Energy has adopted an employee code of ethics, entitled "CMS Energy Code of Conduct and Guide to Ethical Business Behavior" (Employee Code) that applies to its CEO, CFO, and CAO, as well as all other officers and employees of CMS Energy and its affiliates. The Employee Code is administered by the Chief Compliance Officer of CMS Energy, who reports directly to the Audit Committee. CMS Energy has also adopted a director code of ethics entitled "Board of Directors Code of Conduct and Guide to Ethical Business Behavior" (Director Code) that applies to its directors. The Director Code is administered by the Audit Committee. Any alleged violation of the Director Code by a director will be investigated by disinterested members of the Audit Committee, or if none, by disinterested members of the entire Board. The Employee Code and Director Code and any waivers of, or amendments or exceptions to, a provision of the Employee Code that applies to CMS Energy's CEO, CFO, CAO or persons performing similar functions and any waivers of, or amendments or exceptions to, a provision of CMS Energy's Director Code will be disclosed on CMS Energy's website at www.cmsenergy.com/corporate-governance/compliance-and-ethics.

Consumers

Consumers has adopted an insider trading compliance policy and program applicable to directors, executive officers and employees, as well as Consumers itself. Consumers believes this policy is reasonably designed to promote compliance with insider trading laws, rules and regulations, and the New York Stock Exchange listing standards. A copy of the insider trading policy is filed as Exhibit 19.1 to this Form 10-K. Additional information that is required in Item 10 of this Form 10-K regarding executive officers is included in the Item 1. Business—Information About CMS Energy's and Consumers' Executive Officers section, which is incorporated by reference herein.

Information that is required in Item 10 of this Form 10-K regarding directors, executive officers, and corporate governance is incorporated by reference from CMS Energy's and Consumers' definitive proxy statement for their 2026 Annual Meetings of Shareholders to be held May 8, 2026. The proxy statement will be filed with the SEC, pursuant to Regulation 14A under the Exchange Act, within 120 days after the end of the fiscal year covered by this Form 10-K, all of which information is hereby incorporated by reference in, and made part of, this Form 10-K.

Code of Ethics

Consumers has adopted an employee code of ethics, entitled "CMS Energy Code of Conduct and Guide to Ethical Business Behavior" (Employee Code) that applies to its CEO, CFO, and CAO, as well as all other officers and employees of Consumers and its affiliates. The Employee Code is administered by the Chief Compliance Officer of Consumers, who reports directly to the Audit Committee. Consumers has also adopted a director code of ethics entitled "Board of Directors Code of Conduct and Guide to Ethical Business Behavior" (Director Code) that applies to its directors. The Director Code is administered by the Audit Committee. Any alleged violation of the Director Code by a director will be investigated by disinterested members of the Audit Committee, or if none, by disinterested members of the entire Board. The Employee Code and Director Code and any waivers of, or amendments or exceptions to, a provision of the Employee Code that applies to Consumers' CEO, CFO, CAO or persons performing similar functions and any waivers of, or amendments or exceptions to, a provision of Consumers' Director Code will be disclosed on Consumers' website at www.cmsenergy.com/corporate-governance/compliance-and-ethics.

Item 11. Executive Compensation

See the note below.

Item 12. Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters

Securities Authorized for Issuance Under Equity Compensation Plans

Presented in the following table is information regarding CMS Energy's equity compensation plans as of December 31, 2025:

Plan Category	(a) Number of securities to be issued upon exercise of outstanding options, warrants, and rights	(b) Weighted-average exercise price of outstanding options, warrants, and rights	(c) Number of securities remaining available for future issuance under equity compensation plans (excluding securities reflected in column (a))
Equity compensation plan approved by shareholders	—	$ —	3,965,601

Also see the note below.

Item 13. Certain Relationships and Related Transactions, and Director Independence

See the note below.

Item 14. Principal Accountant Fees and Services

See the note below.

NOTE: Information that is required by Part III—Items 11, 12, 13, and 14 of this Form 10-K is incorporated by reference from CMS Energy's and Consumers' definitive proxy statement for their 2026 Annual Meetings of Shareholders to be held May 8, 2026. The proxy statement will be filed with the SEC, pursuant to Regulation 14A under the Exchange Act, within 120 days after the end of the fiscal year covered by this Form 10-K, all of which information is hereby incorporated by reference in, and made part of, this Form 10-K.

Part IV

Item 15. Exhibits and Financial Statement Schedules

The following financial statements are filed as part of this report under Item 8. Financial Statements and Supplementary Data:

- Consolidated Statements of Income of CMS Energy for the years ended December 31, 2025, 2024, and 2023
- Consolidated Statements of Comprehensive Income of CMS Energy for the years ended December 31, 2025, 2024, and 2023
- Consolidated Statements of Cash Flows of CMS Energy for the years ended December 31, 2025, 2024, and 2023
- Consolidated Balance Sheets of CMS Energy at December 31, 2025 and 2024
- Consolidated Statements of Changes in Equity of CMS Energy for the years ended December 31, 2025, 2024, and 2023
- Consolidated Statements of Income of Consumers for the years ended December 31, 2025, 2024, and 2023
- Consolidated Statements of Comprehensive Income of Consumers for the years ended December 31, 2025, 2024, and 2023
- Consolidated Statements of Cash Flows of Consumers for the years ended December 31, 2025, 2024, and 2023
- Consolidated Balance Sheets of Consumers at December 31, 2025 and 2024
- Consolidated Statements of Changes in Equity of Consumers for the years ended December 31, 2025, 2024, and 2023
- Notes to the Consolidated Financial Statements
- Report of Independent Registered Public Accounting Firm for CMS Energy
- Report of Independent Registered Public Accounting Firm for Consumers

The following financial statement schedules are included below:

- Schedule I — Condensed Financial Information of Registrant, CMS Energy—Parent Company at December 31, 2025 and 2024 and for the years ended December 31, 2025, 2024, and 2023
- Schedule II — Valuation and Qualifying Accounts and Reserves of CMS Energy for the years ended December 31, 2025, 2024, and 2023
- Schedule II — Valuation and Qualifying Accounts and Reserves of Consumers for the years ended December 31, 2025, 2024, and 2023

Schedule I — Condensed Financial Information of Registrant

CMS Energy—Parent Company

Condensed Statements of Income

In Millions

Years Ended December 31	2025	2024	2023
Operating Expenses			
Other operating expenses	$ 9	$ 10	$ 10
Total operating expenses	9	10	10
Operating Loss	(9)	(10)	(10)
Other Income (Expense)			
Equity earnings of subsidiaries	1,189	1,061	929
Nonoperating retirement benefits, net	(1)	(1)	(1)
Other income	69	45	31
Other expense	(2)	—	—
Total other income	1,255	1,105	959
Interest Charges			
Interest on long-term debt	266	205	201
Intercompany interest expense and other	10	10	10
Total interest charges	276	215	211
Income Before Income Taxes	970	880	738
Income Tax Benefit	(39)	(19)	(20)
Net Income Attributable to CMS Energy	1,009	899	758
Preferred Stock Dividends	10	10	10
Net Income Available to Common Stockholders	$ 999	$ 889	$ 748

The accompanying notes are an integral part of these statements.

Schedule I — Condensed Financial Information of Registrant (Continued)

CMS Energy—Parent Company
Condensed Statements of Cash Flows

In Millions

Years Ended December 31	2025	2024	2023
Cash Flows from Operating Activities			
Net cash provided by operating activities	$ 817	$ 774	$ 595
Cash Flows from Investing Activities			
Capital expenditures	(1)	(1)	—
Investment in subsidiaries	(1,062)	(535)	(630)
Investment in debt securities – intercompany	(109)	(288)	(293)
Decrease (increase) in notes receivable – intercompany	(309)	21	55
Proceeds from DB SERP investments	3	—	—
Net cash used in investing activities	(1,478)	(803)	(868)
Cash Flows from Financing Activities			
Proceeds from issuance of debt	2,110	490	800
Issuance of common stock	525	286	192
Retirement of long-term debt	(850)	(250)	—
Payment of dividends on common and preferred stock	(663)	(626)	(579)
Debt issuance costs and financing fees	(39)	(10)	(20)
Change in notes payable – intercompany	3	(6)	(7)
Net cash provided by (used in) financing activities	1,086	(116)	386
Net Increase (Decrease) in Cash and Cash Equivalents, Including Restricted Amounts	425	(145)	113
Cash and Cash Equivalents, Including Restricted Amounts, Beginning of Period	4	149	36
Cash and Cash Equivalents, Including Restricted Amounts, End of Period	$ 429	$ 4	$ 149

The accompanying notes are an integral part of these statements.

Schedule I — Condensed Financial Information of Registrant (Continued)

CMS Energy—Parent Company

Condensed Balance Sheets

ASSETS

In Millions

December 31	2025	2024
Current Assets		
Cash and cash equivalents	$ 429	$ 4
Notes and accrued interest receivable – intercompany	350	40
Accounts receivable – intercompany and related parties	8	8
Prepayments and other current assets	1	1
Total current assets	788	53
Other Non-current Assets		
Property, plant, and equipment	1	1
Deferred income taxes	105	150
Investments in subsidiaries	13,724	12,400
Investment in debt securities – intercompany	710	591
Other investments	8	9
Other	23	21
Total other non-current assets	14,571	13,172
Total Assets	$ 15,359	$ 13,225

LIABILITIES AND EQUITY

In Millions

December 31	2025	2024
Current Liabilities		
Current portion of long-term debt	$ 300	$ 740
Accounts and notes payable – intercompany	89	74
Accrued interest, including intercompany	43	34
Accrued taxes	41	16
Other current liabilities	8	6
Total current liabilities	481	870
Non-current Liabilities		
Long-term debt	5,906	4,226
Notes payable – intercompany	96	100
Postretirement benefits	13	14
Other non-current liabilities	14	17
Total non-current liabilities	6,029	4,357
Equity		
Common stock	3	3
Other stockholders’ equity	8,622	7,771
Total common stockholders’ equity	8,625	7,774
Preferred stock	224	224
Total equity	8,849	7,998
Total Liabilities and Equity	$ 15,359	$ 13,225

The accompanying notes are an integral part of these statements.

Schedule I — Condensed Financial Information of Registrant (Continued)

CMS Energy—Parent Company

Notes to the Condensed Financial Statements

1: Basis of Presentation

CMS Energy's condensed financial statements have been prepared on a parent-only basis. In accordance with Rule 12-04 of Regulation S-X, these parent-only financial statements do not include all of the information and notes required by GAAP for annual financial statements, and therefore these parent-only financial statements and other information included should be read in conjunction with CMS Energy's audited consolidated financial statements contained within Item 8. Financial Statements and Supplementary Data.

2: Guarantees

CMS Energy has issued guarantees with a maximum potential obligation of $1.3 billion on behalf of some of its wholly owned subsidiaries and related parties. CMS Energy's maximum potential obligation consists primarily of potential payments:

- to third parties under certain commodity purchase and sales agreements entered into by CMS ERM and other subsidiaries of NorthStar Clean Energy
- to tax equity investors that hold membership interests in certain VIEs held by NorthStar Clean Energy
- to EGLE on behalf of CMS Land and CMS Capital, for environmental remediation obligations at Bay Harbor
- to the DOE on behalf of Consumers, in connection with Consumers' 2011 settlement agreement with the DOE regarding damages resulting from the department's failure to accept spent nuclear fuel from nuclear power plants formerly owned by Consumers

The expiration dates of these guarantees vary, depending upon contractual provisions or upon the statute of limitations under the relevant governing law.

Schedule II — Valuation and Qualifying Accounts and Reserves

CMS Energy Corporation

Years Ended December 31, 2025, 2024, and 2023

In Millions

Description	Balance at Beginning of Period	Charged to Expense	Charged to Other Accounts	Deductions	Balance at End of Period
Allowance for uncollectible accounts[1]					
2025	$ 23	$ 40	$ —	$ 36	$ 27
2024	21	33	—	31	23
2023	27	34	—	40	21
Deferred tax valuation allowance					
2025	$ 1	$ 1	$ —	$ —	$ 2
2024	2	—	—	1	1
2023	2	—	—	—	2

1 Deductions represent write-offs of uncollectible accounts, net of recoveries.

Consumers Energy Company

Years Ended December 31, 2025, 2024, and 2023

In Millions

Description	Balance at Beginning of Period	Charged to Expense	Charged to Other Accounts	Deductions	Balance at End of Period
Allowance for uncollectible accounts[1]					
2025	$ 23	$ 40	$ —	$ 36	$ 27
2024	21	33	—	31	23
2023	27	34	—	40	21

1 Deductions represent write-offs of uncollectible accounts, net of recoveries.

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Exhibit Index

The agreements included as exhibits to this Form 10-K filing are included solely to provide information regarding the terms of the agreements and are not intended to provide any other factual or disclosure information about CMS Energy, Consumers, or other parties to the agreements. The agreements may contain representations and warranties made by each of the parties to each of the agreements that were made exclusively for the benefit of the parties involved in each of the agreements and should not be treated as statements of fact. The representations and warranties were made as a way to allocate risk if one or more of those statements prove to be incorrect. The statements were qualified by disclosures of the parties to each of the agreements that may not be reflected in each of the agreements. The agreements may apply standards of materiality that are different than standards applied to other investors. Additionally, the statements were made as of the date of the agreements or as specified in the agreements and have not been updated. The representations and warranties may not describe the actual state of affairs of the parties to each agreement.

Additional information about CMS Energy and Consumers may be found in this filing, at www.cmsenergy.com, at www.consumersenergy.com, and through the SEC's website at www.sec.gov.

	Previously Filed			
Exhibits	With File Number	As Exhibit Number		Description
3.1[1]	1-9513	3.1	—	Restated Articles of Incorporation of CMS Energy, effective June 1, 2004, as amended from time to time (Form 10-Q for the quarterly period ended June 30, 2024)
3.2[1]	1-9513	3.2	—	CMS Energy Bylaws, amended and restated effective February 8, 2016 (Form 8-K filed February 8, 2016)
3.3	1-5611	3(c)	—	Restated Articles of Incorporation of Consumers effective June 7, 2000 (Form 10-K for the fiscal year ended December 31, 2000)
3.4	1-5611	3.2	—	Consumers Bylaws, amended and restated as of January 24, 2013 (Form 8-K filed January 29, 2013)
4.1	2-65973	(b)(1)–4	—	Indenture dated as of September 1, 1945 between Consumers and Chemical Bank (successor to Manufacturers Hanover Trust Company), as Trustee, including therein indentures supplemental thereto through the Forty-third Supplemental Indenture dated as of May 1, 1979 (Form S-16 filed November 13, 1979)
				Indentures Supplemental thereto:
4.1.a	1-5611	4.2	—	104th dated as of 8/11/05 (Form 8-K filed August 11, 2005)
4.1.b	1-5611	4.1	—	112th dated as of 9/1/10 (Form 8-K filed September 7, 2010)
4.1.c	1-5611	4.1	—	113th dated as of 10/15/10 (Form 8-K filed October 20, 2010)
4.1.d	1-5611	4.1	—	114th dated as of 3/31/11 (Form 8-K filed April 6, 2011)
4.1.e	1-5611	4.1	—	120th dated as of 12/17/12 (Form 8-K filed December 20, 2012)
4.1.f	1-5611	4.1	—	121st dated as of 5/17/13 (Form 8-K filed May 17, 2013)
4.1.g	1-5611	4.1	—	123rd dated as of 12/20/13 (Form 8-K filed December 27, 2013)
4.1.h	1-5611	4.1	—	124th dated as of 8/18/2014 (Form 8-K filed August 18, 2014)
4.1.i	1-5611	4.1	—	125th dated as of 11/6/2015 (Form 8-K filed November 6, 2015)
4.1.j	1-5611	4.1	—	127th dated as of 8/10/16 (Form 8-K filed August 10, 2016)

	Previously Filed			
Exhibits	With File Number	As Exhibit Number		Description
4.1.k	1-5611	4.1	—	128th dated as of 2/22/17 (Form 8-K filed February 22, 2017)
4.1.l	1-5611	4.1	—	129th dated as of 9/28/17 (Form 8-K filed September 28, 2017)
4.1.m	1-5611	4.1	—	130th dated as of 11/15/17 (Form 8-K filed November 15, 2017)
4.1.n	1-5611	4.1	—	131st dated as of 5/14/18 (Form 8-K filed May 14, 2018)
4.1.o	1-5611	4.1	—	132nd dated as of 6/5/18 (Form 8-K filed June 5, 2018)
4.1.p	1-5611	4.1	—	133rd dated as of 10/1/18 (Form 8-K filed October 1, 2018)
4.1.q	1-5611	4.1	—	134th dated as of 11/13/18 (Form 8-K filed November 13, 2018)
4.1.r	1-5611	4.1	—	135th dated as of 5/28/19 (Form 8-K filed May 28, 2019)
4.1.s	1-5611	4.1	—	136th dated as of 9/3/19 (Form 8-K filed September 3, 2019)
4.1.t	1-5611	4.1	—	137th dated as of 9/19/19 (Form 8-K filed September 19, 2019)
4.1.u	1-5611	4.3	—	138th dated as of 10/1/19 (Form 10-Q for the quarterly period ended September 30, 2019)
4.1.v	1-5611	4.1	—	139th dated as of 3/26/20 (Form 8-K filed March 26, 2020)
4.1.w	1-5611	4.1	—	140th dated as of 5/13/20 (Form 8-K filed May 13, 2020)
4.1.x	1-5611	4.1	—	141st dated as of 5/20/20 (Form 8-K filed May 20, 2020)
4.1.y	1-5611	4.1	—	142nd dated as of 10/7/20 (Form 8-K filed October 7, 2020)
4.1.z	1-5611	4.1	—	144th dated as of 8/12/21 (Form 8-K filed August 12, 2021)
4.1.aa	1-5611	4.1	—	145th dated as of 8/11/22 (Form 8-K filed August 11, 2022)
4.1.bb	1-5611	4.1	—	146th dated as of 12/14/22 (Form 8-K filed December 15, 2022)
4.1.cc	1-5611	4.1	—	147th dated as of 1/10/23 (Form 8-K filed January 10, 2023)
4.1.dd	1-5611	4.1	—	148th dated as of 2/23/23 (Form 8-K filed February 23, 2023)
4.1.ee	1-5611	4.1	—	149th dated as of 5/30/23 (Form 8-K filed May 30, 2023)
4.1.ff	1-5611	4.1	—	150th dated as of 8/4/23 (Form 8-K filed August 4, 2023)
4.1.gg	1-5611	4.1	—	151st dated as of 1/9/24 (Form 8-K filed January 9, 2024)
4.1.hh	1-5611	4.1	—	152nd dated as of 8/5/24 (Form 8-K filed August 5, 2024)
4.1.ii	1-5611	4.1	—	153rd dated as of 5/2/25 (Form 8-K filed May 2, 2025)
4.1.jj	1-5611	4.1	—	154th dated as of 11/21/25 (Form 8-K filed November 21, 2025)
4.1.kk			—	155th dated as of 11/28/2025
4.2	1-5611	(4)(b)	—	Indenture dated as of January 1, 1996 between Consumers and The Bank of New York Mellon, as Trustee (Form 10-K for the fiscal year ended December 31, 1995)
4.3	1-5611	(4)(c)	—	Indenture dated as of February 1, 1998 between Consumers and The Bank of New York Mellon (formerly The Chase Manhattan Bank), as Trustee (Form 10-K for the fiscal year ended December 31, 1997)
4.4[1]	33-47629	(4)(a)	—	Indenture dated as of September 15, 1992 between CMS Energy and NBD Bank, as Trustee (Form S-3 filed May 1, 1992)
				Indentures Supplemental thereto:
4.4.a[1]	1-9513	4.1	—	29th dated as of 3/22/13 (Form 8-K filed March 22, 2013)
4.4.b[1]	1-9513	4.2	—	31st dated as of 2/27/14 (Form 8-K filed February 27, 2014)

	Previously Filed			
Exhibits	With File Number	As Exhibit Number		Description
4.4.c[1]	1-9513	4.1	—	33rd dated as of 5/5/16 (Form 8-K filed May 5, 2016)
4.4.d[1]	1-9513	4.1	—	34th dated as of 11/3/16 (Form 8-K filed November 3, 2016)
4.4.e[1]	1-9513	4.1	—	35th dated as of 2/13/17 (Form 8-K filed February 13, 2017)
4.5[1]	1-9513	(4a)	—	Indenture dated as of June 1, 1997 between CMS Energy and The Bank of New York Mellon, as Trustee (Form 8-K filed July 1, 1997)
				Indentures Supplemental thereto:
4.5.a[1]	1-9513	4.5.a	—	5th dated as of 2/13/18 (Form 10-K for the fiscal year ended December 31, 2017)
4.5.b[1]	1-9513	4.1	—	6th dated as of 3/8/18 (Form 8-K filed March 8, 2018)
4.5.c[1]	1-9513	4.1	—	7th dated as of 9/26/18 (Form 8-K filed September 26, 2018)
4.5.d[1]	1-9513	4.1	—	8th dated as of 2/20/19 (Form 8-K filed February 20, 2019)
4.5.e[1]	1-9513	4.1	—	9th dated as of 5/28/20 (Form 8-K filed May 28, 2020)
4.5.f[1]	1-9513	4.1	—	10th dated as of 11/25/20 (Form 8-K filed November 25, 2020)
4.5.g[1]	1-9513	4.1	—	11th dated as of 2/21/25 (Form 8-K filed February 21, 2025)
4.6[1]	1-9513	4.1	—	Indenture dated as of May 5, 2023 between CMS Energy and The Bank of New York Mellon, as Trustee (Form 8-K filed May 5, 2023)
4.7[1]	1-9513	4.1	—	Indenture dated as of November 6, 2025 between CMS Energy and The Bank of New York Mellon, as Trustee (Form 8-K filed November 6, 2025)
4.8[1]	1-9513	4.6	—	Description of CMS Energy Securities (Form 10-K for the fiscal year ended December 31, 2021)
4.9	1-5611	4.7	—	Description of Consumers Securities (Form 10-K for the fiscal year ended December 31, 2019)
4.10[1]	1-9513	4.2	—	Deposit Agreement, dated as of July 1, 2021, among CMS Energy, Equiniti Trust Company, and the holders from time to time of the depositary receipts described therein, including Form of Depositary Receipt (Form 8-K filed July 1, 2021)
10.1[2]	1-9513	10.1	—	CMS Energy 2020 Performance Incentive Stock Plan, effective June 1, 2020 (Form 8-K filed May 5, 2020)
10.2[2]	1-9513	10.2	—	CMS Energy's Deferred Salary Savings Plan, as amended and restated, effective January 1, 2022 (Form 10-K for the fiscal year ended December 31, 2023)
10.3[2]	1-9513	10.5	—	CMS Energy and Consumers Directors' Deferred Compensation Plan, effective as of November 30, 2007 (Form 10-K for the fiscal year ended December 31, 2014)
10.4[2]	1-9513	10.6	—	Supplemental Executive Retirement Plan for Employees of CMS Energy/Consumers effective on January 1, 1982 and as amended effective April 1, 2011 (Form 10-Q for the quarterly period ended March 31, 2011)

Exhibits	Previously Filed With File Number	Previously Filed As Exhibit Number		Description
10.5[2]	1-9513	10.5	—	Defined Contribution Supplemental Executive Retirement Plan, amended December 21, 2023, effective January 1, 2024 (Form 10-K for the fiscal year ended December 31, 2023)
10.6[2]	1-9513	10.2	—	Form of Officer Separation Agreement as of July 1, 2023 (Form 10-Q for the quarterly period ended June 30, 2023)
10.7[1]	1-9513	(10)(y)	—	Environmental Agreement dated as of June 1, 1990 made by CMS Energy to The Connecticut National Bank and Others (Form 10-K for the fiscal year ended December 31, 1990)
10.8[1,2]	1-9513	(10)(a)	—	Form of Indemnification Agreement between CMS Energy and its Directors, effective as of November 1, 2007 (Form 10-Q for the quarterly period ended September 30, 2007)
10.9[2]	1-5611	(10)(b)	—	Form of Indemnification Agreement between Consumers and its Directors, effective as of November 1, 2007 (Form 10-Q for the quarterly period ended September 30, 2007)
10.10[2]	1-9513	10.10	—	CMS Incentive Compensation Plan for CMS Energy and Consumers Officers as amended, effective as of January 27, 2022 (Form 10-K for the fiscal year ended December 31, 2021)
10.11[2]	1-9513	10.3	—	Form of Change in Control Agreement as of July 1, 2023 (Form 10-Q for the quarterly period ended June 30, 2023)
10.12[2]	1-9513	10.12	—	Annual Employee Incentive Compensation Plan for Consumers amended December 11, 2023, effective July 1, 2023 (Form 10-K for the fiscal year ended December 31, 2023)
10.13[1,2]	1-9513	10.1	—	Annual NorthStar Clean Energy Employee Incentive Compensation Plan as amended, effective as of May 1, 2025 (Form 10-Q for the quarterly period ended June 30, 2025)
10.14[1]	1-9513	10.1	—	$750 million Sixth Amended and Restated Revolving Credit Agreement dated as of November 21, 2025 among CMS Energy, the Banks, as defined therein, and Barclays Bank PLC, as Agent (Form 8-K filed November 21, 2025)
10.15	1-5611	10.2	—	$1.1 billion Seventh Amended and Restated Revolving Credit Agreement dated as of November 21, 2025 among Consumers, the Banks, as defined therein, and JPMorgan Chase Bank, N.A., as Agent (Form 8-K filed November 21, 2025)
10.16	1-5611	10.1	—	$250 million Amended and Restated Revolving Credit Agreement dated as of November 19, 2018 among Consumers, the Banks, as defined therein, and The Bank of Nova Scotia, as Agent (Form 8-K filed November 20, 2018)
10.16.a	1-5611	10.1	—	Description of the Extension to the Amended and Restated $250 million Secured Revolving Credit Agreement (Form 8-K filed November 19, 2019)
10.16.b	1-5611	10.1	—	Description of the Second Extension to the Amended and Restated $250 million Secured Revolving Credit Agreement (Form 8-K filed November 19, 2020)

Exhibits	Previously Filed With File Number	Previously Filed As Exhibit Number		Description
10.16.c	1-5611	10.1	—	Description of the Third Extension to the Amended and Restated $250 million Secured Revolving Credit Agreement (Form 8-K filed November 22, 2021)
10.16.d	1-5611	10.1	—	First Amendment to the Amended and Restated $250 million Secured Revolving Credit Agreement (Form 8-K filed November 29, 2022)
10.16.e	1-5611	10.1	—	Amendment No. 2 to the Amended and Restated $250 million Secured Revolving Credit Agreement (Form 8-K filed November 29, 2023)
10.16.f	1-5611	10.3	—	Third Amendment to the Amended and Restated $250 Million Secured Revolving Credit Agreement (Form 8-K filed November 21, 2025)
10.17[2]	1-9513	10.1	—	Consumers and other CMS Energy Companies Retired Executives Survivor Benefit Plan for Management/Executive Employees, distributed July 1, 2011 (Form 10-Q for the quarterly period ended September 30, 2011)
10.18	1-5611	10.1	—	Form of Commercial Paper Dealer Agreement between Consumers, as Issuer, and the Dealer party thereto (Form 10-Q for the quarterly period ended September 30, 2014)
10.19	1-5611	10.1	—	Purchase and Sale Agreement dated June 21, 2021 by and among Consumers and New Covert Generating Company, LLC (Form 8-K filed June 23, 2021)
10.19.a	1-5611	10.4	—	Amendment No. 1 dated as of May 31, 2023 to the Purchase and Sale Agreement, dated June 21, 2021 by and among Consumers and New Covert Generating Company, LLC (Form 10-Q for the quarterly period ending June 30, 2023)
10.20[2]	1-9513	10.22	—	Annual Employee Incentive Compensation Plan for Consumers amended and restated effective January 1, 2024 (Form 10-K for the fiscal year ended December 31, 2023)
19.1	1-9513	19.1	—	Policy Prohibiting Illegal Insider Trading (Form 10-K for the fiscal year ended December 31, 2024)
21.1			—	Subsidiaries of CMS Energy and Consumers
23.1			—	Consent of PricewaterhouseCoopers LLP for CMS Energy
23.2			—	Consent of PricewaterhouseCoopers LLP for Consumers
31.1			—	CMS Energy's certification of the CEO pursuant to Section 302 of the Sarbanes-Oxley Act of 2002
31.2			—	CMS Energy's certification of the CFO pursuant to Section 302 of the Sarbanes-Oxley Act of 2002
31.3			—	Consumers' certification of the CEO pursuant to Section 302 of the Sarbanes-Oxley Act of 2002
31.4			—	Consumers' certification of the CFO pursuant to Section 302 of the Sarbanes-Oxley Act of 2002

	Previously Filed			
Exhibits	With File Number	As Exhibit Number		Description
32.1			—	CMS Energy's certifications pursuant to Section 906 of the Sarbanes-Oxley Act of 2002
32.2			—	Consumers' certifications pursuant to Section 906 of the Sarbanes-Oxley Act of 2002
97.1[2]	1-9513	97.1	—	CMS Energy/Consumers Clawback Policy (Form 10-K for the fiscal year ended December 31, 2023)
99.1[1]	333-275106	99.1	—	CMS Energy Stock Purchase Plan, as amended and restated October 20, 2023 (Form S-3ASR filed October 20, 2023)
101.INS			—	Inline XBRL Instance Document
101.SCH			—	Inline XBRL Taxonomy Extension Schema
101.CAL			—	Inline XBRL Taxonomy Extension Calculation Linkbase
101.DEF			—	Inline XBRL Taxonomy Extension Definition Linkbase
101.LAB			—	Inline XBRL Taxonomy Extension Labels Linkbase
101.PRE			—	Inline XBRL Taxonomy Extension Presentation Linkbase
104			—	Cover Page Interactive Data File (the cover page XBRL tags are embedded in the Inline XBRL document)

1 Obligations of CMS Energy or its subsidiaries, but not of Consumers.

2 Management contract or compensatory plan or arrangement.

Exhibits that have been previously filed with the SEC, designated above, are incorporated herein by reference and made a part hereof.

Item 16. Form 10-K Summary

None.

Signatures

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, CMS Energy Corporation has duly caused this Annual Report to be signed on its behalf by the undersigned, thereunto duly authorized.

/s/ Garrick J. Rochow

Name:	Garrick J. Rochow
Title:	President and Chief Executive Officer
Date:	February 10, 2026

Pursuant to the requirements of the Securities Exchange Act of 1934, this Annual Report has been signed below by the following persons on behalf of CMS Energy Corporation and in the capacities indicated and on February 10, 2026.

/s/ Garrick J. Rochow
Garrick J. Rochow
President, Chief Executive Officer, and Director
(Principal Executive Officer)

/s/ Rejji P. Hayes
Rejji P. Hayes
Executive Vice President and Chief Financial Officer
(Principal Financial Officer)

/s/ Scott B. McIntosh
Scott B. McIntosh
Vice President, Controller, and Chief Accounting Officer
(Controller)

/s/ Deborah H. Butler
Deborah H. Butler, Director

/s/ Ralph Izzo
Ralph Izzo, Director

/s/ John G. Russell
John G. Russell, Director

/s/ Suzanne F. Shank
Suzanne F. Shank, Director

/s/ Myrna M. Soto
Myrna M. Soto, Director

/s/ John G. Sznewajs
John G. Sznewajs, Director

/s/ Ronald J. Tanski
Ronald J. Tanski, Director

/s/ Laura H. Wright
Laura H. Wright, Director

Signatures

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, Consumers Energy Company has duly caused this Annual Report to be signed on its behalf by the undersigned, thereunto duly authorized.

/s/ Garrick J. Rochow

Name:	Garrick J. Rochow
Title:	President and Chief Executive Officer
Date:	February 10, 2026

Pursuant to the requirements of the Securities Exchange Act of 1934, this Annual Report has been signed below by the following persons on behalf of Consumers Energy Company and in the capacities indicated and on February 10, 2026.

/s/ Garrick J. Rochow
Garrick J. Rochow
President, Chief Executive Officer, and Director
(Principal Executive Officer)

/s/ Rejji P. Hayes
Rejji P. Hayes

Executive Vice President and Chief Financial Officer
(Principal Financial Officer)

/s/ Scott B. McIntosh
Scott B. McIntosh

Vice President, Controller, and Chief Accounting Officer
(Controller)

/s/ Deborah H. Butler
Deborah H. Butler, Director

/s/ Ralph Izzo
Ralph Izzo, Director

/s/ John G. Russell
John G. Russell, Director

/s/ Suzanne F. Shank
Suzanne F. Shank, Director

/s/ Myrna M. Soto
Myrna M. Soto, Director

/s/ John G. Sznewajs
John G. Sznewajs, Director

/s/ Ronald J. Tanski
Ronald J. Tanski, Director

/s/ Laura H. Wright
Laura H. Wright, Director

Exhibit 21.1

For the purpose of this filing, information is organized under the headings of CMS Energy Corporation (Tier 1), CMS Capital, L.L.C. (Tier 2), NorthStar Clean Energy Company, formerly known as CMS Enterprises Company (Tier 2), CMS Treasury Services, LLC (Tier 2), and Consumers Energy Company (Tier 2). As set forth in detail below, CMS Energy Corporation is the parent company of CMS Capital, L.L.C., NorthStar Clean Energy Company, CMS Treasury Services, LLC, and Consumers Energy Company. All ownership interests are 100 percent unless indicated parenthetically to the contrary and are accurate as of December 31, 2025.

NAME of COMPANY	JURISDICTION of ORGANIZATION
01 CMS ENERGY CORPORATION	Michigan
02 CMS Capital, L.L.C.	Michigan
03 CMS Land Company	Michigan
02 NorthStar Clean Energy Company	Michigan
Conducts business under the following assumed names:	
CMS Enterprises	
CMS Enterprises Company	
NorthStar Clean Energy	
NorthStar Clean Energy, A CMS Company	
NorthStar Clean Energy, A CMS Energy Company	
03 Genesee Solar Energy Holding Company, LLC	Michigan
03 NSCE Development Company, LLC (99%)	Michigan
04 Filer City Carbon Capture, LLC	Michigan
04 Nymphaea Solar, LLC	Delaware
04 Lake Iris Solar, LLC	Delaware
04 Hart Solar Partners, LLC	Delaware
04 Michigan Carbon Free Energy	Michigan
03 NSCE DevCo Partner, LLC	Michigan
04 NSCE Development Company, LLC (1%)	Michigan
03 Dearborn Industrial Energy, L.L.C.	Michigan
04 Dearborn Industrial Generation, L.L.C.	Michigan
03 CMS Energy Resource Management Company	Michigan
04 CMS ERM Michigan LLC	Michigan
03 CMS Enterprises Sustainable Energy, LLC	Michigan
04 NorthStar Onsite, LLC	Delaware
04 Grand River Solar, LLC	Michigan
05 Michigan Solar Holdings, LLC	Michigan
06 BG Solar Equity Holdings, LLC	Michigan
07 BG Solar Holdings I, LLC	Michigan
08 BG Solar Holdings, LLC	Michigan
09 Branch Solar, LLC	Delaware
08 Genesee Solar Holdings Partnership	Michigan
09 Genesee Solar Energy, LLC	Delaware
06 HL Solar Equity Holdings, LLC	Delaware
07 HL Solar Holdings II, LLC	Delaware
07 HL Solar Holdings I, LLC	Delaware
07 HL Solar Holdings, LLC	Delaware

NAME of COMPANY	JURISDICTION of ORGANIZATION
05 Delta Solar Equity Holdings, LLC (50%)	Delaware
06 Delta Solar Power I, LLC	Michigan
06 Delta Solar Power II, LLC	Michigan
05 Hart Solar Holdings II, LLC	Delaware
06 Hart Solar Holdings I, LLC	Delaware
05 Newport Solar Equity Holdings, LLC	Delaware
06 Newport Solar Holdings II, LLC (99%)	Delaware
07 Newport Solar Holdings I, LLC	Delaware
06 Newport Solar Holdings III, LLC	Delaware
07 Newport Solar, LLC	Delaware
06 Newport Solar Holdings IV, Inc.	Delaware
07 Newport Solar Holdings II, LLC (1%)	Delaware
05 Hercules Solar, LLC	Delaware
05 Diamond Solar, LLC	Missouri
05 Allegan Solar, LLC	Michigan
04 Grand River Wind, LLC	Michigan
05 NWO Wind Equity Holdings, LLC (50%)	Delaware
06 NWO Holdco I, LLC	Delaware
07 NWO Holdco, L.L.C.	Delaware
08 Northwest Ohio Wind, LLC	Ohio
09 Northwest Ohio IA, LLC (97%)	Delaware
05 Northwest Ohio Solar, LLC	Delaware
06 Northwest Ohio IA, LLC (3%)	Delaware
05 Aviator Wind Equity Holdings, LLC (51%)	Delaware
06 AW Holdings III, LLC	Delaware
07 AW Holdings II, LLC	Delaware
08 AW Holdings I, LLC	Delaware
09 Aviator Wind Holdings, LLC	Delaware
10 Aviator Wind, LLC	Delaware
03 CMS Gas Transmission Company	Michigan
04 CMS International Ventures, L.L.C. (37.01%) *(See Exhibit A for list of subsidiaries)*	Michigan
03 CMS International Ventures, L.L.C. (61.49%) *(See Exhibit A for list of subsidiaries)*	Michigan
03 HYDRA-CO Enterprises, Inc. *(See Exhibit B for list of subsidiaries)*	New York
02 CMS Treasury Services, LLC	Michigan
02 Consumers Energy Company *Conducts business under the following assumed names:* Consumers Business Energy Services Consumers Energy Consumers Energy Business Services Consumers Energy Consultants	Michigan

NAME of COMPANY	JURISDICTION of ORGANIZATION
Consumers Energy Contractor Network	
Consumers Energy Dealer Network	
Consumers Energy Finance	
Consumers Energy Fitness Audits	
Consumers Energy Group	
Consumers Energy HouseCall	
Consumers Energy HouseCall Services	
Consumers Energy Management	
Consumers Energy Resources	
Consumers Energy Security Services	
Consumers Energy Services	
Consumers Energy Systems	
Consumers Energy Traders	
Consumers Power	
Consumers Power Company	
Laboratory Commercial Services	
Laboratory Services	
Michigan Gas Storage	
Michigan Gas Storage Company	
Technical Training Centers	
Zeeland Power Company	
03 CMS Engineering Co.	Michigan
03 Consumers 2014 Securitization Funding LLC	Delaware
03 Consumers Campus Holdings, LLC	Michigan
03 Consumers Receivables Funding II, LLC	Delaware
03 ES Services Company	Michigan
03 Consumers 2023 Securitization Funding LLC	Delaware

Exhibit A

Subsidiaries of CMS International Ventures, L.L.C. (98.5%)

NAME of COMPANY	JURISDICTION of ORGANIZATION
04 CMS Electric & Gas, L.L.C.	Michigan
05 CMS Venezuela, S.A.	Venezuela
05 ENELMAR S.A.	Venezuela

Exhibit B

Subsidiaries of HYDRA-CO Enterprises, Inc.

NAME of COMPANY	JURISDICTION of ORGANIZATION
04 CMS Generation Filer City, Inc.	Michigan
05 T.E.S. Filer City Station Limited Partnership (50%)	Michigan
04 CMS Generation Filer City Operating LLC	Michigan
04 CMS Generation Genesee Company	Michigan
05 Genesee Power Station Limited Partnership (1% GP)	Delaware
04 CMS Generation Grayling Company	Michigan
05 Grayling Generating Station Limited Partnership (1% GP)	Michigan
06 AJD Forest Products Limited Partnership (49.5% LP)	Michigan
06 GGS Holdings Company	Michigan
07 AJD Forest Products Limited Partnership (0.5% GP)	Michigan
05 Grayling Partners Land Development, L.L.C. (1%)	Michigan
04 CMS Generation Grayling Holdings Company	Michigan
05 Grayling Generating Station Limited Partnership (49% LP)	Michigan
06 AJD Forest Products Limited Partnership (49.5%LP)	Michigan
06 GGS Holdings Company	Michigan
07 AJD Forest Products Limited Partnership (0.5% GP)	Michigan
05 Grayling Partners Land Development, L.L.C. (49%)	Michigan
04 CMS Generation Holdings Company	Michigan
05 Genesee Power Station Limited Partnership (48.75% LP)	Delaware
05 GPS Newco, L.L.C. (50%)	Kansas
06 Genesee Power Station Limited Partnership (0.5% LP)	Delaware
04 CMS Generation Michigan Power L.L.C.	Michigan
05 Kalamazoo Holdco, LLC	Michigan
05 Kalamazoo Generating Station, LLC	Michigan
05 Livingston Holdco, LLC	Michigan
05 Livingston Generating Station, LLC	Michigan
04 CMS Generation Operating Company II, Inc.	New York
04 CMS Generation Operating LLC	Michigan
04 CMS Generation Recycling Company	Michigan
05 Mid-Michigan Recycling, L.C. (50%)	Michigan
04 Craven County Wood Energy Limited Partnership (44.99% LP)	Delaware
04 Dearborn Generation Operating, L.L.C.	Michigan
04 HCE-Biopower, Inc.	New York
05 IPP Investment Partnership (51%)	Michigan
06 Craven County Wood Energy Limited Partnership (0.01% LP)	Delaware
04 IPP Investment Partnership (49%)	Michigan
05 Craven County Wood Energy Limited Partnership (0.01% LP)	Delaware
04 New Bern Energy Recovery, Inc.	Delaware
05 Craven County Wood Energy Limited Partnership (5% GP)	Delaware

Exhibit 23.1

Consent of Independent Registered Public Accounting Firm

We hereby consent to the incorporation by reference in the Registration Statements on Form S-3 (Nos. 333-275106 and 333-270060) and S-8 (No. 333-238842) of CMS Energy Corporation of our report dated February 10, 2026 relating to the financial statements, financial statement schedules and the effectiveness of internal control over financial reporting, which appears in this Form 10-K.

/s/ PricewaterhouseCoopers LLP
Detroit, Michigan
February 10, 2026

Exhibit 23.2

Consent of Independent Registered Public Accounting Firm

We hereby consent to the incorporation by reference in the Registration Statement on Form S-3 (No. 333-270060-01) of Consumers Energy Company of our report dated February 10, 2026 relating to the financial statements, financial statement schedule and the effectiveness of internal control over financial reporting, which appears in this Form 10-K.

/s/ PricewaterhouseCoopers LLP
Detroit, Michigan
February 10, 2026

Exhibit 31.1

Certification of Garrick J. Rochow

I, Garrick J. Rochow, certify that:

1. I have reviewed this annual report on Form 10-K of CMS Energy Corporation;
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   a. Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   b. Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   c. Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   d. Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and
5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   a. All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   b. Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Dated: February 10, 2026

By: /s/ Garrick J. Rochow

Garrick J. Rochow
President and Chief Executive Officer

Exhibit 31.2

Certification of Rejji P. Hayes

I, Rejji P. Hayes, certify that:

1. I have reviewed this annual report on Form 10-K of CMS Energy Corporation;
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   a. Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   b. Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   c. Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   d. Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and
5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   a. All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   b. Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Dated: February 10, 2026

By: /s/ Rejji P. Hayes

Rejji P. Hayes
Executive Vice President and Chief Financial Officer

Certification of Garrick J. Rochow

I, Garrick J. Rochow, certify that:

1. I have reviewed this annual report on Form 10-K of Consumers Energy Company;
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   a. Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   b. Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   c. Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   d. Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and
5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   a. All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   b. Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Dated: February 10, 2026	By:	/s/ Garrick J. Rochow
		Garrick J. Rochow
		President and Chief Executive Officer

Exhibit 31.4

Certification of Rejji P. Hayes

I, Rejji P. Hayes, certify that:

1. I have reviewed this annual report on Form 10-K of Consumers Energy Company;
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant’s other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   a. Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   b. Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   c. Evaluated the effectiveness of the registrant’s disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   d. Disclosed in this report any change in the registrant’s internal control over financial reporting that occurred during the registrant’s most recent fiscal quarter (the registrant’s fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant’s internal control over financial reporting; and
5. The registrant’s other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant’s auditors and the audit committee of the registrant’s board of directors (or persons performing the equivalent functions):

   a. All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant’s ability to record, process, summarize and report financial information; and

   b. Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant’s internal control over financial reporting.

Dated: February 10, 2026 By: /s/ Rejji P. Hayes

Rejji P. Hayes

Executive Vice President and Chief Financial Officer

Certification of CEO and CFO Pursuant to 18 U.S.C. Section 1350, as Adopted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002

In connection with the Annual Report on Form 10-K of CMS Energy Corporation (the "Company") for the annual period ended December 31, 2025 as filed with the Securities and Exchange Commission on the date hereof (the "Report"), Garrick J. Rochow, as President and Chief Executive Officer of the Company, and Rejji P. Hayes, as Executive Vice President and Chief Financial Officer of the Company, each hereby certifies, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that, to the best of his knowledge:

1. The Report fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

2. The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

/s/ Garrick J. Rochow

Name:	Garrick J. Rochow
Title:	President and Chief Executive Officer
Date:	February 10, 2026

/s/ Rejji P. Hayes

Name:	Rejji P. Hayes
Title:	Executive Vice President and Chief Financial Officer
Date:	February 10, 2026

Certification of CEO and CFO Pursuant to 18 U.S.C. Section 1350, as Adopted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002

In connection with the Annual Report on Form 10-K of Consumers Energy Company (the "Company") for the annual period ended December 31, 2025 as filed with the Securities and Exchange Commission on the date hereof (the "Report"), Garrick J. Rochow, as President and Chief Executive Officer of the Company, and Rejji P. Hayes, as Executive Vice President and Chief Financial Officer of the Company, each hereby certifies, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that, to the best of his knowledge:

1. The Report fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

2. The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

/s/ Garrick J. Rochow

Name:	Garrick J. Rochow
Title:	President and Chief Executive Officer
Date:	February 10, 2026

/s/ Rejji P. Hayes

Name:	Rejji P. Hayes
Title:	Executive Vice President and Chief Financial Officer
Date:	February 10, 2026

ONE HUNDRED FIFTY-FIFTH SUPPLEMENTAL INDENTURE

Providing among other things for

FIRST MORTGAGE BONDS,

2025-2 Collateral Series (Interest Bearing)

Dated as of November 28, 2025

CONSUMERS ENERGY COMPANY

TO

THE BANK OF NEW YORK MELLON,

TRUSTEE

Counterpart ________ of 75

THIS ONE HUNDRED FIFTY-FIFTH SUPPLEMENTAL INDENTURE, dated as of November 28, 2025 (herein sometimes referred to as "this Supplemental Indenture"), made and entered into by and between CONSUMERS ENERGY COMPANY, a corporation organized and existing under the laws of the State of Michigan, with its principal executive office and place of business at One Energy Plaza, in Jackson, Jackson County, Michigan 49201, formerly known as Consumers Power Company (hereinafter sometimes referred to as the "Company"), and THE BANK OF NEW YORK MELLON (formerly known as The Bank of New York), a New York banking corporation, with its corporate trust offices at 240 Greenwich Street, New York, New York 10286 (hereinafter sometimes referred to as the "Trustee"), as Trustee under the Indenture dated as of September 1, 1945 between Consumers Power Company, a Maine corporation (hereinafter sometimes referred to as the "Maine corporation"), and City Bank Farmers Trust Company (Citibank, N.A., successor, hereinafter sometimes referred to as the "Predecessor Trustee"), securing bonds issued and to be issued as provided therein (hereinafter sometimes referred to as the "Indenture"),

WHEREAS, at the close of business on January 30, 1959, City Bank Farmers Trust Company was converted into a national banking association under the title "First National City Trust Company"; and

WHEREAS, at the close of business on January 15, 1963, First National City Trust Company was merged into First National City Bank; and

WHEREAS, at the close of business on October 31, 1968, First National City Bank was merged into The City Bank of New York, National Association, the name of which was thereupon changed to First National City Bank; and

WHEREAS, effective March 1, 1976, the name of First National City Bank was changed to Citibank, N.A.; and

WHEREAS, effective July 16, 1984, Manufacturers Hanover Trust Company succeeded Citibank, N.A. as Trustee under the Indenture; and

WHEREAS, effective June 19, 1992, Chemical Bank succeeded by merger to Manufacturers Hanover Trust Company as Trustee under the Indenture; and

WHEREAS, effective July 15, 1996, The Chase Manhattan Bank (National Association) merged with and into Chemical Bank which thereafter was renamed The Chase Manhattan Bank; and

WHEREAS, effective November 11, 2001, The Chase Manhattan Bank merged with Morgan Guaranty Trust Company of New York and the surviving corporation was renamed JPMorgan Chase Bank; and

WHEREAS, effective November 13, 2004, the name of JPMorgan Chase Bank was changed to JPMorgan Chase Bank, N.A.; and

WHEREAS, effective April 7, 2006, The Bank of New York succeeded JPMorgan Chase Bank, N.A. as Trustee under the Indenture; and

WHEREAS, effective July 1, 2008, the name of The Bank of New York was changed to The Bank of New York Mellon; and

WHEREAS, the Indenture was executed and delivered for the purpose of securing such bonds as may from time to time be issued under and in accordance with the terms of the Indenture, the aggregate principal amount of bonds to be secured thereby being limited to $16,000,000,000 at any one time outstanding (except as provided in Section 2.01 of the Indenture), and the Indenture describes and sets forth the property conveyed thereby and is filed in the Office of the Secretary of State of the State of Michigan and is of record in the Office of the Register of Deeds of each county in the State of Michigan in which this Supplemental Indenture is to be recorded; and

WHEREAS, the Indenture has been supplemented and amended by various indentures supplemental thereto, each of which is filed in the Office of the Secretary of State of the State of Michigan and is of record in the Office of the Register of Deeds of each county in the State of Michigan in which this Supplemental Indenture is to be recorded; and

WHEREAS, the Company and the Maine corporation entered into an Agreement of Merger and Consolidation, dated as of February 14, 1968, which provided for the Maine corporation to merge into the Company; and

WHEREAS, the effective date of such Agreement of Merger and Consolidation was June 6, 1968, upon which date the Maine corporation was merged into the Company and the name of the Company was changed from "Consumers Power Company of Michigan" to "Consumers Power Company"; and

WHEREAS, the Company and the Predecessor Trustee entered into a Sixteenth Supplemental Indenture, dated as of June 4, 1968, which provided, among other things, for the assumption of the Indenture by the Company; and

WHEREAS, said Sixteenth Supplemental Indenture became effective on the effective date of such Agreement of Merger and Consolidation; and

WHEREAS, the Company has succeeded to and has been substituted for the Maine corporation under the Indenture with the same effect as if it had been named therein as the mortgagor corporation; and

WHEREAS, effective March 11, 1997, the name of Consumers Power Company was changed to Consumers Energy Company; and

WHEREAS, the Company has entered into a $100,000,000 Bilateral Letter of Credit Facility dated as of November 28, 2025 (as amended, amended and restated, supplemented or otherwise modified from time to time, the "Agreement") with The Bank of Nova Scotia as agent (in such capacity, the "Agent") for the Banks (as such term is defined in the Agreement), providing for the issuing of Letters of Credit, and pursuant to such Agreement the Company has agreed to issue to the Agent, as evidence of and security for the Obligations (as such term is defined in the Agreement), a new series of bonds under the Indenture; and

WHEREAS, for such purposes the Company desires to issue a new series of bonds, to be designated First Mortgage Bonds, 2025-2 Collateral Series (Interest Bearing), each of which bonds shall also bear the descriptive title "First Mortgage Bond" (hereinafter provided for and hereinafter sometimes referred to as the "2025-2 Collateral Bonds"), the bonds of which series are to be issued as registered bonds without coupons and are to bear interest at the rate per annum specified herein and are to mature on the Termination Date (as such term is defined in the Agreement); and

WHEREAS, each of the registered bonds without coupons of the 2025-2 Collateral Bonds and the Trustee's Authentication Certificate thereon are to be substantially in the following form, to wit:

[FORM OF REGISTERED BOND

OF THE 2025-2 COLLATERAL BONDS]

[FACE]
CONSUMERS ENERGY COMPANY
FIRST MORTGAGE BOND
2025-2 COLLATERAL SERIES (INTEREST BEARING)

No. 1 $100,000,000

CONSUMERS ENERGY COMPANY, a Michigan corporation (hereinafter called the "Company"), for value received, hereby promises to pay to The Bank of Nova Scotia, as agent (in such capacity, the "Agent") for the Banks under and as defined in the $100,000,000 Bilateral Letter of Credit Facility, dated as of November 28, 2025 among the Company, the Banks named therein and from time to time party thereto (the "Banks"), The Bank of Nova Scotia, as the Agent (as amended, amended and restated, supplemented or otherwise modified from time to time, the "Agreement"), or registered assigns, on the Termination Date (defined below) the principal sum of One Hundred Million Dollars ($100,000,000) or such lesser principal amount as shall be equal to the aggregate principal amount of the Reimbursement Obligations (as defined in the Agreement) included in the Obligations (as defined in the Agreement) outstanding on the Termination Date (as defined in the Agreement) (the "Termination Date"), but not in excess, however, of the principal amount of this bond, and to pay interest thereon at the Interest Rate (as defined below) until the principal hereof is paid or duly made available for payment on the Termination Date, or, in the event of redemption of this bond, until the redemption date, or, in the event of default in the payment of the principal hereof, until the Company's obligations with respect to the payment of such principal shall be discharged as provided in the Indenture (as defined on the reverse hereof). Interest on this bond shall be payable on each Interest Payment Date (as defined below), commencing on the first Interest Payment Date next succeeding November 28, 2025. If the Termination Date falls on a day which is not a Business Day, as defined below, principal and any interest and/or fees payable with respect to the Termination Date will be paid on the immediately preceding Business Day. The interest payable, and punctually paid or duly provided for, on any Interest Payment Date will, subject to certain exceptions, be paid to the person in whose name this bond (or one or more predecessor bonds) is registered at the close of business on the Record Date (as defined below); *provided, however,* that interest payable on the Termination Date will be payable to the person to whom the principal hereof shall be payable. Should the Company default in the payment of interest ("Defaulted Interest"), the Defaulted Interest shall be paid to the person in whose name this bond (or one or more predecessor bonds) is registered on a subsequent record date fixed by the Company, which subsequent record date shall be fifteen (15) days prior to the payment of such Defaulted Interest. As used herein, (A) "Business Day" shall mean any day, other than a Saturday or Sunday, on which banks generally are open in New York, New York for the conduct of substantially all of their commercial lending activities and on which interbank wire transfers can be made on the Fedwire system; (B) "Interest Payment Date" shall mean each date on which Obligations constituting interest and/or fees are due and payable from time to time pursuant to the Agreement; (C) "Interest Rate" shall mean a rate of interest per annum, adjusted as necessary, to result in an interest payment equal to the aggregate amount of Obligations constituting interest and fees due under the Agreement on the applicable Interest Payment Date; and (D) "Record Date" with respect to any Interest Payment Date shall mean the day (whether or not a Business Day) immediately next preceding such Interest Payment Date.

Payment of the principal of and interest on this bond will be made in immediately available funds at the office or agency of the Company maintained for that purpose in the City of Jackson, Michigan, in such coin or currency of the United States of America as at the time of payment is legal tender for payment of public and private debts.

The provisions of this bond are continued below and such continued provisions shall for all purposes have the same effect as though fully set forth at this place.

This bond shall not be valid or become obligatory for any purpose unless and until it shall have been authenticated by the execution by the Trustee (as defined below) or its successor in trust under the Indenture (as defined below) of the certificate hereon.

IN WITNESS WHEREOF, Consumers Energy Company has caused this bond to be executed in its name by its Chairman of the Board, its President or one of its Vice Presidents by his or her signature or a facsimile thereof, and its corporate seal or a facsimile thereof to be affixed hereto or imprinted hereon and attested by its Secretary or one of its Assistant Secretaries by his or her signature or a facsimile thereof.

CONSUMERS ENERGY COMPANY

Dated:

By: ______________________________

Printed:

Title:

Attest: ______________________________

TRUSTEE'S AUTHENTICATION CERTIFICATE

This is one of the bonds, of the series designated therein, described in the within-mentioned Indenture.

THE BANK OF NEW YORK MELLON, Trustee

By: ______________________________

Authorized Officer

CONSUMERS ENERGY COMPANY

FIRST MORTGAGE BOND 2025-2 COLLATERAL SERIES (INTEREST BEARING)

This bond is one of the bonds of a series designated as First Mortgage Bonds, 2025-2 Collateral Series (Interest Bearing) (sometimes herein referred to as the "2025-2 Collateral Bonds") issued under and in accordance with and secured by an Indenture dated as of September 1, 1945, given by the Company (or its predecessor, Consumers Power Company, a Maine corporation) to City Bank Farmers Trust Company (The Bank of New York Mellon, successor) (hereinafter sometimes referred to as the "Trustee"), together with indentures supplemental thereto, heretofore or hereafter executed, to which indenture and indentures supplemental thereto (hereinafter referred to collectively as the "Indenture") reference is hereby made for a description of the property mortgaged and pledged, the nature and extent of the security and the rights, duties and immunities thereunder of the Trustee and the rights of the holders of said bonds and of the

Trustee and of the Company in respect of such security, and the limitations on such rights. By the terms of the Indenture, the bonds to be secured thereby are issuable in series which may vary as to date, amount, date of maturity, rate of interest and in other respects as provided in the Indenture.

The 2025-2 Collateral Bonds are to be issued and delivered to the Agent in order to evidence and secure the obligation of the Company under the Agreement to make payments to the Banks under the Agreement and to provide the Banks the benefit of the lien of the Indenture with respect to the 2025-2 Collateral Bonds.

The obligation of the Company to make payments with respect to the principal of 2025-2 Collateral Bonds shall be fully or partially, as the case may be, satisfied and discharged to the extent that, at the time that any such payment shall be due, the then due principal of the Reimbursement Obligations included in the Obligations shall have been fully or partially paid. Satisfaction of any obligation to the extent that payment is made with respect to the Reimbursement Obligations means that if any payment is made on the principal of the Reimbursement Obligations, a corresponding payment obligation with respect to the principal of the 2025-2 Collateral Bonds shall be deemed discharged in the same amount as the payment with respect to the Reimbursement Obligations discharges the outstanding obligation with respect to such Reimbursement Obligations. No such payment of principal shall reduce the principal amount of the 2025-2 Collateral Bonds.

The obligation of the Company to make payments with respect to the interest on 2025-2 Collateral Bonds shall be fully or partially, as the case may be, satisfied and discharged to the extent that, at the time that any such payment shall be due, the then due interest and/or fees under the Agreement shall have been fully or partially paid. Satisfaction of any obligation to the extent that payment is made with respect to the interest and/or fees under the Agreement means that if any payment is made on the interest and/or fees under the Agreement, a corresponding payment obligation with respect to the interest on the 2025-2 Collateral Bonds shall be deemed discharged in the same amount as the payment with respect to the interest and/or fees under the Agreement discharges the outstanding obligation under the Agreement with respect to such interest and/or fees.

The Trustee may at any time and all times conclusively assume that the obligation of the Company to make payments with respect to the principal of and interest on this bond, so far as such payments at the time have become due, has been fully satisfied and discharged unless and until the Trustee shall have received a written notice from the Agent stating (i) that timely payment of principal and interest on the 2025-2 Collateral Bonds has not been made, (ii) that the Company is in arrears as to the payments required to be made by it to the Agent in connection with the Obligations pursuant to the Agreement, and (iii) the amount of the arrearage.

If an Event of Default (as defined in the Agreement) with respect to the payment of the principal of the Reimbursement Obligations shall have occurred, it shall be deemed to be a default for purposes of Section 11.01 of the Indenture in the payment of the principal of the 2025-2 Collateral Bonds equal to the amount of such unpaid principal (but in no event in excess of the principal amount of the 2025-2 Collateral Bonds). If an Event of Default (as defined in the Agreement) with respect to the payment of interest on the Reimbursement Obligations or any fees shall have occurred, it shall be deemed to be a default for purposes of Section 11.01 of the Indenture in the payment of the interest on the 2025-2 Collateral Bonds equal to the amount of such unpaid interest or fees.

This bond is not redeemable except upon written demand of the Agent following the occurrence of an Event of Default under the Agreement and the acceleration of the Obligations, as provided in Section 9.2 of the Agreement. This bond is not redeemable by the operation of the improvement fund or the maintenance and replacement provisions of the Indenture or with the proceeds of released property or in any other manner except as set forth above.

In case of certain defaults as specified in the Indenture, the principal of this bond may be declared or may become due and payable on the conditions, at the time, in the manner and with the effect provided in the Indenture. The holders of certain specified percentages of the bonds at the time outstanding, including in certain cases specified percentages of bonds of particular series, may in certain cases, to the extent and as provided in the Indenture, waive certain defaults thereunder and the consequences of such defaults.

The Indenture contains provisions permitting the Company and the Trustee, with the consent of the holders of not less than seventy-five per centum in principal amount of the bonds (exclusive of bonds disqualified by reason of the Company's interest therein) at the time outstanding, including, if more than one series of bonds shall be at the time outstanding, not less than sixty per centum in principal amount of each series affected, to effect, by an indenture supplemental to the Indenture, modifications or alterations of the Indenture and of the rights and obligations of the Company and the rights of the holders of the bonds and coupons; provided, however, that no such modification or alteration shall be made without the written approval or consent of the holder hereof which will (a) extend the maturity of this bond or reduce the rate or extend the time of payment of interest hereon or reduce the amount of the principal hereof, or (b) permit the creation of any lien, not otherwise permitted, prior to or on a parity with the lien of the Indenture, or (c) reduce the percentage of the principal amount of the bonds the holders of which are required to approve any such supplemental indenture.

The Company reserves the right, without any consent, vote or other action by holders of the 2025-2 Collateral Bonds or any other series created after the Sixty-eighth Supplemental Indenture, to amend the Indenture to reduce the percentage of the principal amount of bonds the holders of which are required to approve any supplemental indenture (other than any supplemental indenture which is subject to the proviso contained in the immediately preceding sentence) (a) from not less than seventy-five per centum (including sixty per centum of each series affected) to not less than a majority in principal amount of the bonds at the time outstanding or (b) in case fewer than all series are affected, not less than a majority in principal amount of the bonds of all affected series, voting together.

No recourse shall be had for the payment of the principal of or interest on this bond, or for any claim based hereon, or otherwise in respect hereof or of the Indenture, to or against any incorporator, stockholder, director or officer, past, present or future, as such, of the Company, or of any predecessor or successor company, either directly or through the Company, or such predecessor or successor company, or otherwise, under any constitution or statute or rule of law, or by the enforcement of any assessment or penalty, or otherwise, all such liability of incorporators, stockholders, directors and officers, as such, being waived and released by the holder and owner hereof by the acceptance of this bond and being likewise waived and released by the terms of the Indenture.

This bond shall be exchangeable for other registered bonds of the same series, in the manner and upon the conditions prescribed in the Indenture, upon the surrender of such bonds at the Investor Services Department of the Company, as transfer agent. However, notwithstanding the provisions of Section 2.05 of the Indenture, no charge shall be made upon any registration of transfer or exchange of bonds of said series other than for any tax or taxes or other governmental charge required to be paid by the Company.

The Agent shall surrender this bond to the Trustee when all of the principal of and interest on the Reimbursement Obligations arising under the Agreement, and all of the fees payable pursuant to the Agreement with respect to the Obligations, shall have been duly paid, and the Agreement (including, without limitation, all Commitments thereunder) shall have been terminated.

[END OF FORM OF REGISTERED BOND

OF THE 2025-2 COLLATERAL BONDS]

AND WHEREAS all acts and things necessary to make the 2025-2 Collateral Bonds (the "Collateral Bonds"), when duly executed by the Company and authenticated by the Trustee or its agent and issued as prescribed in the Indenture, as heretofore supplemented and amended, and this Supplemental Indenture, the valid, binding and legal obligations of the Company, and to constitute the Indenture, as supplemented and amended as aforesaid, as well as by this Supplemental Indenture, a valid, binding and legal instrument for the security thereof, have been done and performed, and the creation, execution and delivery of this Supplemental Indenture and the creation, execution and issuance of bonds subject to the terms hereof and of the Indenture, as so supplemented and amended, have in all respects been duly authorized;

NOW, THEREFORE, in consideration of the premises, of the acceptance and purchase by the holders thereof of the bonds issued and to be issued under the Indenture, as supplemented and amended as above set forth, duly paid by the Trustee to the Company, and of other good and valuable considerations, the receipt whereof is hereby acknowledged, and for the purpose of securing the due and punctual payment of the principal of and premium, if any, and interest on all bonds now outstanding under the Indenture and the $100,000,000 principal amount of the Collateral Bonds and all other bonds which shall be issued under the Indenture, as supplemented and amended from time to time, and for the purpose of securing the faithful performance and observance of all covenants and conditions therein, and in any indenture supplemental thereto, set forth, the Company has given, granted, bargained, sold, released, transferred, assigned, hypothecated, pledged, mortgaged, confirmed, set over, warranted, alienated and conveyed and by these presents does give, grant, bargain, sell, release, transfer, assign, hypothecate, pledge, mortgage, confirm, set over, warrant, alienate and convey unto The Bank of New York Mellon, as Trustee, as provided in the Indenture, and its successor or successors in the trust thereby and hereby created and to its or their assigns forever, all the right, title and interest of the Company in and to all the property, described in Section 11 hereof, together (subject to the provisions of

Article X of the Indenture) with the tolls, rents, revenues, issues, earnings, income, products and profits thereof, excepting, however, the property, interests and rights specifically excepted from the lien of the Indenture as set forth in the Indenture;

TOGETHER WITH all and singular the tenements, hereditaments and appurtenances belonging or in any wise appertaining to the premises, property, franchises and rights, or any thereof, referred to in the foregoing granting clause, with the reversion and reversions, remainder and remainders and (subject to the provisions of Article X of the Indenture) the tolls, rents, revenues, issues, earnings, income, products and profits thereof, and all the estate, right, title and interest and claim whatsoever, at law as well as in equity, which the Company now has or may hereafter acquire in and to the aforesaid premises, property, franchises and rights and every part and parcel thereof;

SUBJECT, HOWEVER, with respect to such premises, property, franchises and rights, to excepted encumbrances as said term is defined in Section 1.02 of the Indenture, and subject also to all defects and limitations of title and to all encumbrances existing at the time of acquisition.

TO HAVE AND TO HOLD all said premises, property, franchises and rights hereby conveyed, assigned, pledged or mortgaged, or intended so to be, unto the Trustee, its successor or successors in trust and their assigns forever;

BUT IN TRUST, NEVERTHELESS, with power of sale for the equal and proportionate benefit and security of the holders of all bonds now or hereafter authenticated and delivered under and secured by the Indenture and interest coupons appurtenant thereto, pursuant to the provisions of the Indenture and of any supplemental indenture, and for the enforcement of the payment of said bonds and coupons when payable and the performance of and compliance with the covenants and conditions of the Indenture and of any supplemental indenture, without any preference, distinction or priority as to lien or otherwise of any bond or bonds over others by reason of the difference in time of the actual authentication, delivery, issue, sale or negotiation thereof or for any other reason whatsoever, except as otherwise expressly provided in the Indenture; and so that each and every bond now or hereafter authenticated and delivered thereunder shall have the same lien, and so that the principal of and premium, if any, and interest on every such bond shall, subject to the terms thereof, be equally and proportionately secured, as if it had been made, executed, authenticated, delivered, sold and negotiated simultaneously with the execution and delivery thereof;

AND IT IS EXPRESSLY DECLARED by the Company that all bonds authenticated and delivered under and secured by the Indenture, as supplemented and amended as above set forth, are to be issued, authenticated and delivered, and all said premises, property, franchises and rights hereby and by the Indenture and indentures supplemental thereto conveyed, assigned, pledged or mortgaged, or intended so to be, are to be dealt with and disposed of under, upon and subject to the terms, conditions, stipulations, covenants, agreements, trusts, uses and purposes expressed in the Indenture, as supplemented and amended as above set forth, and the parties hereto mutually agree as follows:

SECTION 1. There is hereby created a series of bonds (the "2025-2 Collateral Bonds" or the "Collateral Bonds") designated as hereinabove provided, which shall also bear the descriptive title “First Mortgage Bond”, and the forms thereof shall be substantially as hereinbefore set forth (collectively, the “Sample Bond”). The 2025-2 Collateral Bonds shall be issued in the aggregate principal amount of $100,000,000, shall mature on the Termination Date (as such term is defined in the Agreement) and shall be issued only as registered bonds without coupons in denominations of $1,000 and any multiple thereof. The serial numbers of the Collateral Bonds shall be such as may be approved by any officer of the Company, the execution thereof by any such officer either manually or by facsimile signature to be conclusive evidence of such approval. The Collateral Bonds are to be issued to and registered in the name of the Agent under the Agreement (as such terms are defined in the Sample Bond) to evidence and secure any and all Obligations (as such term is defined in the Agreement) of the Company under the Agreement.

The 2025-2 Collateral Bonds shall bear interest as set forth in the Sample Bond. The principal of and the interest on said bonds shall be payable as set forth in the Sample Bond.

The obligation of the Company to make payments with respect to the principal of 2025-2 Collateral Bonds shall be fully or partially, as the case may be, satisfied and discharged to the extent that, at the time that any such payment shall be due, the then due principal of the Reimbursement Obligations included in the Obligations shall have been fully or partially paid. Satisfaction of any obligation to the extent that payment is made with respect to the Reimbursement Obligations means that if any payment is made on the principal of the Reimbursement Obligations, a corresponding payment obligation with respect to the principal of the 2025-2 Collateral Bonds shall be deemed discharged in the same amount as the payment with respect to the Reimbursement Obligations discharges the outstanding obligation with respect to such Reimbursement Obligations. No such payment of principal shall reduce the principal amount of the 2025-2 Collateral Bonds.

The obligation of the Company to make payments with respect to interest on 2025-2 Collateral Bonds shall be fully or partially, as the case may be, satisfied and discharged to the extent that, at the time that any such payment shall be due, the then due interest and/or fees under the Agreement shall have been fully or partially paid. Satisfaction of any obligation to the extent that payment is made with respect to the interest and/or fees under the Agreement means that if any payment is made on the interest and/or fees under the Agreement, a corresponding payment obligation with respect to the interest on the 2025-2 Collateral Bonds shall be deemed discharged in the same amount as the payment with respect to the interest and/or fees under the Agreement discharges the outstanding obligation under the Agreement with respect to such interest and/or fees.

The Trustee may at any time and all times conclusively assume that the obligation of the Company to make payments with respect to the principal of and interest on the Collateral Bonds, so far as such payments at the time have become due, has been fully satisfied and discharged unless and until the Trustee shall have received a written notice from the Agent stating (i) that timely payment of principal and interest on the 2025-2 Collateral Bonds has not been made, (ii) that the Company is in arrears as to the payments required to be made by it to the Agent pursuant to the Agreement, and (iii) the amount of the arrearage.

The Collateral Bonds shall be exchangeable for other registered bonds of the same series, in the manner and upon the conditions prescribed in the Indenture, upon the surrender of such bonds at the Investor Services Department of the Company, as transfer agent. However, notwithstanding the provisions of Section 2.05 of the Indenture, no charge shall be made upon any registration of transfer or exchange of bonds of said series other than for any tax or taxes or other governmental charge required to be paid by the Company.

SECTION 2. The Collateral Bonds are not redeemable by the operation of the maintenance and replacement provisions of this Indenture or with the proceeds of released property.

SECTION 3. Upon the occurrence of an Event of Default under the Agreement and the acceleration of the Obligations, the Collateral Bonds shall be redeemable in whole upon receipt by the Trustee of a written demand from the Agent stating that there has occurred under the Agreement both an Event of Default and a declaration of acceleration of the Obligations and demanding redemption of the Collateral Bonds (including a description of the amount of principal, interest and fees which comprise such Obligations). The Company waives any right it may have to prior notice of such redemption under the Indenture. Upon surrender of the Collateral Bonds by the Agent to the Trustee, the Collateral Bonds shall be redeemed at a redemption price equal to the aggregate amount of the Obligations subject to the receipt by the Trustee of the redemption price from the Company.

SECTION 4. The Company reserves the right, without any consent, vote or other action by the holder of the Collateral Bonds or of any subsequent series of bonds issued under the Indenture, to make such amendments to the Indenture, as supplemented, as shall be necessary in order to amend Section 17.02 to read as follows:

> SECTION 17.02. With the consent of the holders of not less than a majority in principal amount of the bonds at the time outstanding or their attorneys-in-fact duly authorized, or, if fewer than all series are affected, not less than a majority in principal amount of the bonds at the time outstanding of each series the rights of the holders of which are affected, voting together, the Company, when authorized by a resolution, and the Trustee may from time to time and at any time enter into an indenture or indentures supplemental hereto for the purpose of adding any provisions to or changing in any manner or eliminating any of the provisions of this Indenture or of any supplemental indenture or modifying the rights and obligations of the Company and the rights of the holders of any of the bonds and coupons; provided, however, that no such supplemental indenture shall (1) extend the maturity of any of the bonds or reduce the rate or extend the time of payment of interest thereon, or reduce the amount of the principal thereof, or reduce any premium payable on the redemption thereof, without the consent of the holder of each bond so affected, or (2) permit the creation of any lien, not otherwise permitted, prior to or on a parity with the lien of this Indenture, without the consent of the holders of all the bonds then outstanding, or (3) reduce the aforesaid percentage of the principal amount of bonds the holders of which are required to approve any such supplemental indenture, without the consent of the holders of all the bonds then outstanding. For the purposes of this

Section, bonds shall be deemed to be affected by a supplemental indenture if such supplemental indenture adversely affects or diminishes the rights of holders thereof against the Company or against its property. The Trustee may in its discretion determine whether or not, in accordance with the foregoing, bonds of any particular series would be affected by any supplemental indenture and any such determination shall be conclusive upon the holders of bonds of such series and all other series. Subject to the provisions of Sections 16.02 and 16.03 hereof, the Trustee shall not be liable for any determination made in good faith in connection herewith.

Upon the written request of the Company, accompanied by a resolution authorizing the execution of any such supplemental indenture, and upon the filing with the Trustee of evidence of the consent of bondholders as aforesaid (the instrument or instruments evidencing such consent to be dated within one year of such request), the Trustee shall join with the Company in the execution of such supplemental indenture unless such supplemental indenture affects the Trustee’s own rights, duties or immunities under this Indenture or otherwise, in which case the Trustee may in its discretion but shall not be obligated to enter into such supplemental indenture.

It shall not be necessary for the consent of the bondholders under this Section to approve the particular form of any proposed supplemental indenture, but it shall be sufficient if such consent shall approve the substance thereof.

The Company and the Trustee, if they so elect, and either before or after such consent has been obtained, may require the holder of any bond consenting to the execution of any such supplemental indenture to submit his bond to the Trustee or to ask such bank, banker or trust company as may be designated by the Trustee for the purpose, for the notation thereon of the fact that the holder of such bond has consented to the execution of such supplemental indenture, and in such case such notation, in form satisfactory to the Trustee, shall be made upon all bonds so submitted, and such bonds bearing such notation shall forthwith be returned to the persons entitled thereto.

Prior to the execution by the Company and the Trustee of any supplemental indenture pursuant to the provisions of this Section, the Company shall publish a notice, setting forth in general terms the substance of such supplemental indenture, at least once in one daily newspaper of general circulation in each city in which the principal of any of the bonds shall be payable, or, if all bonds outstanding shall be registered bonds without coupons or coupon bonds registered as to principal, such notice shall be sufficiently given if mailed, first class, postage prepaid, and registered if the Company so elects, to each registered holder of bonds at the last address of such holder appearing on the registry books, such publication or mailing, as the case may be, to be made not less than thirty days prior to such execution. Any failure of the Company to give such notice, or any defect therein, shall not, however, in any way impair or affect the validity of any such supplemental indenture.

SECTION 5. As supplemented and amended as above set forth, the Indenture is in all respects ratified and confirmed, and the Indenture and all indentures supplemental thereto shall be read, taken and construed as one and the same instrument.

SECTION 6. Nothing contained in this Supplemental Indenture shall, or shall be construed to, confer upon any person other than a holder of bonds issued under the Indenture, as supplemented and amended as above set forth, the Company, the Trustee and the Agent, for the benefit of the Banks (as such term is defined in the Agreement), any right or interest to avail himself of any benefit under any provision of the Indenture, as so supplemented and amended.

SECTION 7. The Trustee assumes no responsibility for or in respect of the validity or sufficiency of this Supplemental Indenture or of the Indenture as hereby supplemented or the due execution hereof by the Company or for or in respect of the recitals and statements contained herein (other than those contained in the tenth and eleventh recitals hereof), all of which recitals and statements are made solely by the Company.

The Trustee shall have the right to accept and act upon instructions, including funds transfer instructions ("Instructions") given pursuant to this Supplemental Indenture and delivered using Electronic Means; provided, however, that the Company shall provide to the Trustee an incumbency certificate listing officers with the authority to provide such Instructions ("Authorized Officers") and containing specimen signatures of such Authorized Officers, which incumbency certificate shall be amended by the Company whenever a person is to be added or deleted from the listing. If the Company elects to give the Trustee Instructions using Electronic Means and the Trustee in its reasonable discretion elects to act upon such Instructions, the Trustee's understanding of such Instructions shall be deemed controlling in the absence of negligence or willful misconduct. The Company understands and agrees that the Trustee cannot determine the identity of the actual sender of such Instructions and that the Trustee shall conclusively presume that directions that purport to have been sent by an Authorized Officer listed on the incumbency certificate provided to the Trustee have been sent by such Authorized Officer. The Company shall be responsible for ensuring that only Authorized Officers transmit such Instructions to the Trustee and that the Company and all Authorized Officers are solely responsible to safeguard the use and confidentiality of applicable user and authorization codes, passwords and/or authentication keys upon receipt by the Company. In the absence of negligence or willful misconduct, the Trustee shall not be liable for any losses, costs or expenses arising directly or indirectly from the Trustee's reliance upon and compliance with such Instructions notwithstanding such directions conflict or are inconsistent with a subsequent written instruction. The Company agrees: (i) to assume all risks arising out of the use of Electronic Means to submit Instructions to the Trustee, including without limitation the risk of the Trustee acting on unauthorized Instructions, and the risk of interception and misuse by third parties; (ii) that it is fully informed of the protections and risks associated with the various methods of transmitting Instructions to the Trustee and that there may be more secure methods of transmitting Instructions than the method(s) selected by the Company; (iii) that the security procedures (if any) to be followed in connection with its transmission of Instructions provide to it a commercially reasonable degree of protection in light of its particular needs and circumstances; and (iv) to notify the Trustee immediately upon learning of any compromise or unauthorized use of the security procedures.

"Electronic Means" shall mean the following communications methods: e-mail, facsimile transmission, secure electronic transmission containing applicable authorization codes, passwords and/or authentication keys issued by the Trustee, or another method or system specified by the Trustee as available for use in connection with its services hereunder.

SECTION 8. This Supplemental Indenture may be simultaneously executed in several counterparts and all such counterparts executed and delivered, each as an original, shall constitute but one and the same instrument.

SECTION 9. In the event the date of any notice required or permitted hereunder shall not be a Business Day, then (notwithstanding any other provision of the Indenture or of any supplemental indenture thereto) such notice need not be made on such date, but may be made on the next succeeding Business Day with the same force and effect as if made on the date fixed for such notice. “Business Day” means, with respect to this Section 9, any day, other than a Saturday or Sunday, on which banks generally are open in New York, New York for the conduct of substantially all of their commercial lending activities and on which interbank wire transfers can be made on the Fedwire system.

SECTION 10. This Supplemental Indenture and the Collateral Bonds shall be governed by and deemed to be a contract under, and construed in accordance with, the laws of the State of Michigan, and for all purposes shall be construed in accordance with the laws of such state, except as may otherwise be required by mandatory provisions of law.

SECTION 11. Detailed Description of Property Mortgaged:

I.

ELECTRIC GENERATING PLANTS AND DAMS

All the electric generating plants and stations of the Company, constructed or otherwise acquired by it and not heretofore described in the Indenture or any supplement thereto and not heretofore released from the lien of the Indenture, including all powerhouses, buildings, reservoirs, dams, pipelines, flumes, structures and works and the land on which the same are situated and all water rights and all other lands and easements, rights of way, permits, privileges, towers, poles, wires, machinery, equipment, appliances, appurtenances and supplies and all other property, real or personal, forming a part of or appertaining to or used, occupied or enjoyed in connection with such plants and stations or any of them, or adjacent thereto.

II.

ELECTRIC TRANSMISSION LINES

All the electric transmission lines of the Company, constructed or otherwise acquired by it and not heretofore described in the Indenture or any supplement thereto and not heretofore released from the lien of the Indenture, including towers, poles, pole lines, wires, switches, switch racks, switchboards, insulators and other appliances and equipment, and all other property, real or personal, forming a part of or appertaining to or used, occupied or enjoyed in connection with such transmission lines or any of them or adjacent thereto; together with all real property, rights of way, easements, permits, privileges, franchises and rights for or relating to the construction, maintenance or operation thereof, through, over, under or upon any private property or any public streets or highways, within as well as without the corporate limits of any municipal corporation. Also all the real property, rights of way, easements, permits, privileges and rights for or relating to the construction, maintenance or operation of certain transmission lines, the land and rights for which are owned by the Company, which are either not built or now being constructed.

III.

ELECTRIC DISTRIBUTION SYSTEMS

All the electric distribution systems of the Company, constructed or otherwise acquired by it and not heretofore described in the Indenture or any supplement thereto and not heretofore released from the lien of the Indenture, including substations, transformers, switchboards, towers, poles, wires, insulators, subways, trenches, conduits, manholes, cables, meters and other appliances and equipment, and all other property, real or personal, forming a part of or appertaining to or used, occupied or enjoyed in connection with such distribution systems or any of them or adjacent thereto; together with all real property, rights of way, easements, permits, privileges, franchises, grants and rights, for or relating to the construction, maintenance or operation thereof, through, over, under or upon any private property or any public streets or highways within as well as without the corporate limits of any municipal corporation.

IV.

ELECTRIC SUBSTATIONS, SWITCHING STATIONS AND SITES

All the substations, switching stations and sites of the Company, constructed or otherwise acquired by it and not heretofore described in the Indenture or any supplement thereto and not heretofore released from the lien of the Indenture, for transforming, regulating, converting or distributing or otherwise controlling electric current at any of its plants and elsewhere, together with all buildings, transformers, wires, insulators and other appliances and equipment, and all other property, real or personal, forming a part of or appertaining to or used, occupied or enjoyed in connection with any of such substations and switching stations, or adjacent thereto, with sites to be used for such purposes.

V.

GAS COMPRESSOR STATIONS, GAS PROCESSING PLANTS, DESULPHURIZATION STATIONS, METERING STATIONS, ODORIZING STATIONS, REGULATORS AND SITES

All the compressor stations, processing plants, desulphurization stations, metering stations, odorizing stations, regulators and sites of the Company, constructed or otherwise acquired by it and not heretofore described in the Indenture or any supplement thereto and not heretofore released from the lien of the Indenture, for compressing, processing, desulphurizing, metering, odorizing and regulating manufactured or natural gas at any of its plants and elsewhere, together with all buildings, meters and other appliances and equipment, and all other property, real or personal, forming a part of or appertaining to or used, occupied or enjoyed in connection with any of such purposes, with sites to be used for such purposes.

VI.

GAS STORAGE FIELDS

The natural gas rights and interests of the Company, including wells and well lines (but not including natural gas, oil and minerals), the gas gathering system, the underground gas storage rights, the underground gas storage wells and injection and withdrawal system used in connection therewith, constructed or otherwise acquired by it and not heretofore described in the Indenture or any supplement thereto and not heretofore released from the lien of the Indenture: In the Overisel Gas Storage Field, located in the Township of Overisel, Allegan County, and in the Township of Zeeland, Ottawa County, Michigan; in the Northville Gas Storage Field located in the Township of Salem, Washtenaw County, Township of Lyon, Oakland County, and the Townships of Northville and Plymouth and City of Plymouth, Wayne County, Michigan; in the Salem Gas Storage Field, located in the Township of Salem, Allegan County, and in the Township of Jamestown, Ottawa County, Michigan; in the Ray Gas Storage Field, located in the Townships of Ray and Armada, Macomb County, Michigan; in the Lenox Gas Storage Field, located in the Townships of Lenox and Chesterfield, Macomb County, Michigan; in the Ira Gas Storage Field, located in the Township of Ira, St. Clair County, Michigan; in the Puttygut Gas Storage Field, located in the Township of Casco, St. Clair County, Michigan; in the Four Corners Gas Storage Field, located in the Townships of Casco, China, Cottrellville and Ira, St. Clair County, Michigan; in the Swan Creek Gas Storage Field, located in the Townships of Casco and Ira, St. Clair County, Michigan; and in the Hessen Gas Storage Field, located in the Townships of Casco and Columbus, St. Clair County, Michigan.

VII.

GAS TRANSMISSION LINES

All the gas transmission lines of the Company, constructed or otherwise acquired by it and not heretofore described in the Indenture or any supplement thereto and not heretofore released from the lien of the Indenture, including gas mains, pipes, pipelines, gates, valves, meters and other appliances and equipment, and all other property, real or personal, forming a part of or appertaining to or used, occupied or enjoyed in connection with such transmission lines or any of them or adjacent thereto; together with all real property, right of way, easements, permits, privileges, franchises and rights for or relating to the construction, maintenance or operation thereof, through, over, under or upon any private property or any public streets or highways, within as well as without the corporate limits of any municipal corporation.

VIII.

GAS DISTRIBUTION SYSTEMS

All the gas distribution systems of the Company, constructed or otherwise acquired by it and not heretofore described in the Indenture or any supplement thereto and not heretofore released from the lien of the Indenture, including tunnels, conduits, gas mains and pipes, service pipes, fittings, gates, valves, connections, meters and other appliances and equipment, and all other property, real or personal, forming a part of or appertaining to or used, occupied or enjoyed in connection with such distribution systems or any of them or adjacent thereto; together with all real property, rights of way, easements, permits, privileges, franchises, grants and rights, for or relating to the construction, maintenance or operation thereof, through, over, under or upon any private property or any public streets or highways within as well as without the corporate limits of any municipal corporation.

IX.

OFFICE BUILDINGS, SERVICE BUILDINGS, GARAGES, ETC.

All office, garage, service and other buildings of the Company, wherever located, in the State of Michigan, constructed or otherwise acquired by it and not heretofore described in the Indenture or any supplement thereto and not heretofore released from the lien of the Indenture, together with the land on which the same are situated and all easements, rights of way and appurtenances to said lands, together with all furniture and fixtures located in said buildings.

X.

TELEPHONE PROPERTIES AND
RADIO COMMUNICATION EQUIPMENT

All telephone lines, switchboards, systems and equipment of the Company, constructed or otherwise acquired by it and not heretofore described in the Indenture or any supplement thereto and not heretofore released from the lien of the Indenture, used or available for use in the operation of its properties, and all other property, real or personal, forming a part of or appertaining to or used, occupied or enjoyed in connection with such telephone properties or any of them or adjacent thereto; together with all real estate, rights of way, easements, permits, privileges, franchises, property, devices or rights related to the dispatch, transmission, reception or reproduction of messages, communications, intelligence, signals, light, vision or sound by electricity, wire or otherwise, including all telephone equipment installed in buildings used as general and regional offices, substations and generating stations and all telephone lines erected on towers and poles; and all radio communication equipment of the Company, together with all property, real or personal (except any in the Indenture expressly excepted), fixed stations, towers, auxiliary radio buildings and equipment, and all appurtenances used in connection therewith, wherever located, in the State of Michigan.

XI.

OTHER REAL PROPERTY

All other real property of the Company and all interests therein, of every nature and description (except any in the Indenture expressly excepted) wherever located, in the State of Michigan, acquired by it and not heretofore described in the Indenture or any supplement thereto and not heretofore released from the lien of the Indenture. Such real property includes but is not limited to the following described property, such property is subject to any interests that were excepted or reserved in the conveyance to the Company:

ALCONA COUNTY

Certain land in Caledonia Township, Alcona County, Michigan described as:

The East 330 feet of the South 660 feet of the SW 1/4 of the SW 1/4 of Section 8, T28N, R8E, except the West 264 feet of the South 330 feet thereof; said land being more particularly described as follows: To find the place of beginning of this description, commence at the Southwest corner of said section, run thence East along the South line of said section 1243 feet to the place of beginning of this description, thence continuing East along said South line of said section 66 feet to the West 1/8 line of said section, thence N 02 degrees 09’ 30” E along the said West 1/8 line of said section 660 feet, thence West 330 feet, thence S 02 degrees 09’ 30” W, 330 feet, thence East 264 feet, thence S 02 degrees 09’ 30” W, 330 feet to the place of beginning.

ALLEGAN COUNTY

Certain land in Lee Township, Allegan County, Michigan described as:

The NE 1/4 of the NW 1/4 of Section 16, T1N, R15W.

ALPENA COUNTY

Certain land in Wilson and Green Townships, Alpena County, Michigan described as:

All that part of the S’ly 1/2 of the former Boyne City-Gaylord and Alpena Railroad right of way, being the Southerly 50 feet of a 100 foot strip of land formerly occupied by said Railroad, running from the East line of Section 31, T31N, R7E, Southwesterly across said Section 31 and Sections 5 and 6 of T30N, R7E and Sections 10, 11 and the E 1/2 of Section 9, except the West 1646 feet thereof, all in T30N, R6E.

ANTRIM COUNTY

Certain land in Mancelona Township, Antrim County, Michigan described as:

The S 1/2 of the NE 1/4 of Section 33, T29N, R6W, excepting therefrom all mineral, coal, oil and gas and such other rights as were reserved unto the State of Michigan in that certain deed running from the State of Michigan to August W. Schack and Emma H. Schack, his wife, dated April 15, 1946 and recorded May 20, 1946 in Liber 97 of Deeds on page 682 of Antrim County Records.

ARENAC COUNTY

Certain land in Standish Township, Arenac County, Michigan described as:

A parcel of land in the SW 1/4 of the NW 1/4 of Section 12, T18N, R4E, described as follows: To find the place of beginning of said parcel of land, commence at the Northwest corner of Section 12, T18N, R4E; run thence South along the West line of said section, said West line of said section being also the center line of East City Limits Road 2642.15 feet to the W 1/4 post of said section and the place of beginning of said parcel of land; running thence N 88 degrees 26’ 00” E along the East and West 1/4 line of said section, 660.0 feet; thence North parallel with the West line of said section, 310.0 feet; thence S 88 degrees 26’ 00” W, 330.0 feet; thence South parallel with the West line of said section, 260.0 feet; thence S 88 degrees 26’ 00” W, 330.0 feet to the West line of said section and the center line of East City Limits Road; thence South along the said West line of said section, 50.0 feet to the place of beginning.

BARRY COUNTY

Certain land in Johnstown Township, Barry County, Michigan described as:

A strip of land 311 feet in width across the SW 1/4 of the NE 1/4 of Section 31, T1N, R8W, described as follows: To find the place of beginning of this description, commence at the E ¼ post of said section; run thence N 00 degrees 55’ 00” E along the East line of said section, 555.84 feet; thence N 59 degrees 36’ 20” W, 1375.64 feet; thence N 88 degrees 30’ 00” W, 130 feet to a point on the East 1/8 line of said section and the place of beginning of this description; thence continuing N 88 degrees 30’ 00” W, 1327.46 feet to the North and South 1/4 line of said section; thence S 00 degrees 39’35” W along said North and South 1/4 line of said section, 311.03 feet to a point, which said point is 952.72 feet distant N’ly from the East and West 1/4 line of said section as measured along said North and South 1/4 line of said section; thence S 88 degrees 30’ 00” E, 1326.76 feet to the East 1/8 line of said section; thence N 00 degrees 47’ 20” E along said East 1/8 line of said section, 311.02 feet to the place of beginning.

BAY COUNTY

Certain land in Frankenlust Township, Bay County, Michigan described as:

The South 250 feet of the N 1/2 of the W 1/2 of the W 1/2 of the SE 1/4 of Section 9, T13N, R4E.

BENZIE COUNTY

Certain land in Benzonia Township, Benzie County, Michigan described as:

A parcel of land in the Northeast 1/4 of Section 7, Township 26 North, Range 14 West, described as beginning at a point on the East line of said Section 7, said point being 320 feet North measured along the East line of said section from the East 1/4 post; running thence West 165 feet; thence North parallel with the East line of said section 165 feet; thence East 165 feet to the East line of said section; thence South 165 feet to the place of beginning.

BRANCH COUNTY

Certain land in Girard Township, Branch County, Michigan described as:

A parcel of land in the NE 1/4 of Section 23 T5S, R6W, described as beginning at a point on the North and South quarter line of said section at a point 1278.27 feet distant South of the North quarter post of said section, said distance being measured along the North and South quarter line of said section, running thence S89 degrees21’E 250 feet, thence North along a line parallel with the said North and South quarter line of said section 200 feet, thence N89 degrees 21’W 250 feet to the North and South quarter line of said section, thence South along said North and South quarter line of said section 200 feet to the place of beginning.

CALHOUN COUNTY

Certain land in Convis Township, Calhoun County, Michigan described as:

A parcel of land in the SE 1/4 of the SE 1/4 of Section 32, T1S, R6W, described as follows: To find the place of beginning of this description, commence at the Southeast corner of said section; run thence North along the East line of said section 1034.32 feet to the place of beginning of this description; running thence N 89 degrees 39’ 52” W, 333.0 feet; thence North 290.0 feet to the South 1/8 line of said section; thence S 89 degrees 39’ 52” E along said South 1/8 line of said section 333.0 feet to the East line of said section; thence South along said East line of said section 290.0 feet to the place of beginning. (Bearings are based on the East line of Section 32, T1S, R6W, from the Southeast corner of said section to the Northeast corner of said section assumed as North.)

CASS COUNTY

Certain easement rights located across land in Marcellus Township, Cass County, Michigan described as:

The East 6 rods of the SW 1/4 of the SE 1/4 of Section 4, T5S, R13W.

CHARLEVOIX COUNTY

Certain land in South Arm Township, Charlevoix County, Michigan described as:

A parcel of land in the SW 1/4 of Section 29, T32N, R7W, described as follows: Beginning at the Southwest corner of said section and running thence North along the West line of said section 788.25 feet to a point which is 528 feet distant South of the South 1/8 line of said section as measured along the said West line of said section; thence N 89 degrees 30’ 19” E, parallel with said South 1/8 line of said section 442.1 feet; thence South 788.15 feet to the South line of said section; thence S 89 degrees 29’ 30” W, along said South line of said section 442.1 feet to the place of beginning.

CHEBOYGAN COUNTY

Certain land in Inverness Township, Cheboygan County, Michigan described as:

A parcel of land in the SW frl 1/4 of Section 31, T37N, R2W, described as beginning at the Northwest corner of the SW frl 1/4, running thence East on the East and West quarter line of said Section, 40 rods, thence South parallel to the West line of said Section 40 rods, thence West 40 rods to the West line of said Section, thence North 40 rods to the place of beginning.

CLARE COUNTY

Certain land in Frost Township, Clare County, Michigan described as:

The East 150 feet of the North 225 feet of the NW 1/4 of the NW 1/4 of Section 15, T20N, R4W.

CLINTON COUNTY

Certain land in Watertown Township, Clinton County, Michigan described as:

The NE 1/4 of the NE 1/4 of the SE 1/4 of Section 22, and the North 165 feet of the NW 1/4 of the NE 1/4 of the SE 1/4 of Section 22, T5N, R3W.

CRAWFORD COUNTY

Certain land in Lovells Township, Crawford County, Michigan described as:

A parcel of land in Section 1, T28N, R1W, described as: Commencing at NW corner said section; thence South 89 degrees53’30” East along North section line 105.78 feet to point of beginning; thence South 89 degrees53’30” East along North section line 649.64 feet; thence South 55 degrees 42’30” East 340.24 feet; thence South 55 degrees 44’ 37”“ East 5,061.81 feet to the East section line; thence South 00 degrees 00’ 08”“ West along East section line 441.59 feet; thence North 55 degrees 44’ 37” West 5,310.48 feet; thence North 55 degrees 42’30” West 877.76 feet to point of beginning.

EATON COUNTY

Certain land in Eaton Township, Eaton County, Michigan described as:

A parcel of land in the SW 1/4 of Section 6, T2N, R4W, described as follows: To find the place of beginning of this description commence at the Southwest corner of said section; run thence N 89 degrees 51’ 30” E along the South line of said section 400 feet to the place of beginning of this description; thence continuing N 89 degrees 51’ 30” E, 500 feet; thence N 00 degrees 50’ 00” W, 600 feet; thence S 89 degrees 51’ 30” W parallel with the South line of said section 500 feet; thence S 00 degrees 50’ 00” E, 600 feet to the place of beginning.

EMMET COUNTY

Certain land in Wawatam Township, Emmet County, Michigan described as:

The West 1/2 of the Northeast 1/4 of the Northeast 1/4 of Section 23, T39N, R4W.

GENESEE COUNTY

Certain land in Argentine Township, Genesee County, Michigan described as:

A parcel of land of part of the SW 1/4 of Section 8, T5N, R5E, being more particularly described as follows:

Beginning at a point of the West line of Duffield Road, 100 feet wide, (as now established) distant 829.46 feet measured N01 degrees42’56”W and 50 feet measured S88 degrees14’04”W from the South quarter corner, Section 8, T5N, R5E; thence S88 degrees14’04”W a distance of 550 feet; thence N01 degrees42’56”W a distance of 500 feet to a point on the North line of the South half of the Southwest quarter of said Section 8; thence N88 degrees14’04”E along the North line of South half of the Southwest quarter of said Section 8 a distance 550 feet to a point on the West line of Duffield Road, 100 feet wide (as now established); thence S 01 degrees 42’56”E along the West line of said Duffield Road a distance of 500 feet to the point of beginning.

GLADWIN COUNTY

Certain land in Secord Township, Gladwin County, Michigan described as:

The East 400 feet of the South 450 feet of Section 2, T19N, R1E.

GRAND TRAVERSE COUNTY

Certain land in Mayfield Township, Grand Traverse County, Michigan described as:

A parcel of land in the Northwest 1/4 of Section 3, T25N, R11W, described as follows: Commencing at the Northwest corner of said section, running thence S 89 degrees19’15” E along the North line of said section and the center line of Clouss Road 225 feet, thence South 400 feet, thence N 89 degrees19’15” W 225 feet to the West line of said section and the center line of Hannah Road, thence North along the West line of said section and the center line of Hannah Road 400 feet to the place of beginning for this description.

GRATIOT COUNTY

Certain land in Fulton Township, Gratiot County, Michigan described as:

A parcel of land in the NE 1/4 of Section 7, Township 9 North, Range 3 West, described as beginning at a point on the North line of George Street in the Village of Middleton, which is 542 feet East of the North and South one-quarter (1/4) line of said Section 7; thence North 100 feet; thence East 100 feet; thence South 100 feet to the North line of George Street; thence West along the North line of George Street 100 feet to place of beginning.

HILLSDALE COUNTY

Certain land in Litchfield Village, Hillsdale County, Michigan described as:

Lot 238 of Assessors Plat of the Village of Litchfield.

HURON COUNTY

Certain easement rights located across land in Sebewaing Township, Huron County, Michigan described as:

The North 1/2 of the Northwest 1/4 of Section 15, T15N, R9E.

INGHAM COUNTY

Certain land in Vevay Township, Ingham County, Michigan described as:

A parcel of land 660 feet wide in the Southwest 1/4 of Section 7 lying South of the centerline of Sitts Road as extended to the North-South 1/4 line of said Section 7, T2N, R1W, more particularly described as follows: Commence at the Southwest corner of said Section 7, thence North along the West line of said Section 2502.71 feet to the centerline of Sitts Road; thence South 89 degrees54’45” East along said centerline 2282.38 feet to the place of beginning of this description; thence continuing South 89 degrees54’45” East along said centerline and said centerline extended 660.00 feet to the North-South 1/4 line of said section; thence South 00 degrees07’20” West 1461.71 feet; thence North 89 degrees34’58” West 660.00 feet; thence North 00 degrees07’20” East 1457.91 feet to the centerline of Sitts Road and the place of beginning.

IONIA COUNTY

Certain land in Sebewa Township, Ionia County, Michigan described as:

A strip of land 280 feet wide across that part of the SW 1/4 of the NE 1/4 of Section 15, T5N, R6W, described as follows:

To find the place of beginning of this description commence at the E 1/4 corner of said section; run thence N 00 degrees 05’ 38” W along the East line of said section, 1218.43 feet; thence S 67 degrees 18’ 24” W, 1424.45 feet to the East 1/8 line of said section and the place of beginning of this description; thence continuing S 67 degrees 18’ 24” W, 1426.28 feet to the North and South 1/4 line of said section at a point which said point is 105.82 feet distant N’ly of the center of said section as measured along said North and South 1/4 line of said section; thence N 00 degrees 04’ 47” E along said North and South 1/4 line of said section, 303.67 feet; thence N 67 degrees 18’ 24” E, 1425.78 feet to the East 1/8 line of said section; thence S 00 degrees 00’ 26” E along said East 1/8 line of said section, 303.48 feet to the place of beginning. (Bearings are based on the East line of Section 15, T5N, R6W, from the E 1/4 corner of said section to the Northeast corner of said section assumed as N 00 degrees 05’ 38” W.)

IOSCO COUNTY

Certain land in Alabaster Township, Iosco County, Michigan described as:

A parcel of land in the NW 1/4 of Section 34, T21N, R7E, described as follows: To find the place of beginning of this description commence at the N 1/4 post of said section; run thence South along the North and South 1/4 line of said section, 1354.40 feet to the place of beginning of this description; thence continuing South along the said North and South 1/4 line of said section, 165.00 feet to a point on the said North and South 1/4 line of said section which said point is 1089.00 feet distant North of the center of said section; thence West

440.00 feet; thence North 165.00 feet; thence East 440.00 feet to the said North and South 1/4 line of said section and the place of beginning.

ISABELLA COUNTY

Certain land in Chippewa Township, Isabella County, Michigan described as:

The North 8 rods of the NE 1/4 of the SE 1/4 of Section 29, T14N, R3W.

JACKSON COUNTY

Certain land in Waterloo Township, Jackson County, Michigan described as:

A parcel of land in the North fractional part of the N fractional 1/2 of Section 2, T1S, R2E, described as follows: To find the place of beginning of this description commence at the E 1/4 post of said section; run thence N 01 degrees 03’ 40” E along the East line of said section 1335.45 feet to the North 1/8 line of said section and the place of beginning of this description; thence N 89 degrees 32’ 00” W, 2677.7 feet to the North and South 1/4 line of said section; thence S 00 degrees 59’ 25” W along the North and South 1/4 line of said section 22.38 feet to the North 1/8 line of said section; thence S 89 degrees 59’ 10” W along the North 1/8 line of said section 2339.4 feet to the center line of State Trunkline Highway M-52; thence N 53 degrees 46’ 00” W along the center line of said State Trunkline Highway 414.22 feet to the West line of said section; thence N 00 degrees 55’ 10” E along the West line of said section 74.35 feet; thence S 89 degrees 32’ 00” E, 5356.02 feet to the East line of said section; thence S 01 degrees 03’ 40” W along the East line of said section 250 feet to the place of beginning.

KALAMAZOO COUNTY

Certain land in Alamo Township, Kalamazoo County, Michigan described as:

The South 350 feet of the NW 1/4 of the NW 1/4 of Section 16, T1S, R12W, being more particularly described as follows: To find the place of beginning of this description, commence at the Northwest corner of said section; run thence S 00 degrees 36’ 55” W along the West line of said section 971.02 feet to the place of beginning of this description; thence continuing S 00 degrees 36’ 55” W along said West line of said section 350.18 feet to the North 1/8 line of said section; thence S 87 degrees 33’ 40” E along the said North 1/8 line of said section 1325.1 feet to the West 1/8 line of said section; thence N 00 degrees 38’ 25” E along the said West 1/8 line of said section 350.17 feet; thence N 87 degrees 33’ 40” W, 1325.25 feet to the place of beginning.

KALKASKA COUNTY

Certain land in Kalkaska Township, Kalkaska County, Michigan described as:

The NW 1/4 of the SW 1/4 of Section 4, T27N, R7W, excepting therefrom all mineral, coal, oil and gas and such other rights as were reserved unto the State of Michigan in that certain deed running from the Department of Conservation for the State of Michigan to George Welker and Mary Welker, his wife, dated October 9, 1934 and recorded December 28, 1934 in Liber 39 on page 291 of Kalkaska County Records, and subject to easement for pipeline purposes as granted to Michigan Consolidated Gas Company by first party herein on April 4, 1963 and recorded June 21, 1963 in Liber 91 on page 631 of Kalkaska County Records.

KENT COUNTY

Certain land in Caledonia Township, Kent County, Michigan described as:

A parcel of land in the Northwest fractional 1/4 of Section 15, T5N, R10W, described as follows: To find the place of beginning of this description commence at the North 1/4 corner of said section, run thence S 0 degrees 59’ 26” E along the North and South 1/4 line of said section 2046.25 feet to the place of beginning of this description, thence continuing S 0 degrees 59’ 26” E along said North and South 1/4 line of said section 332.88 feet, thence S 88 degrees 58’ 30” W 2510.90 feet to a point herein designated “Point A” on the East bank of the Thornapple River, thence continuing S 88 degrees 53’ 30” W to the center thread of the Thornapple River, thence NW’ly along the center thread of said Thornapple River to a point which said point is S 88 degrees 58’ 30” W of a point on the East bank of the Thornapple River herein designated “Point B”, said “Point B” being N 23 degrees 41’ 35” W 360.75 feet from said above-described “Point A”, thence N 88 degrees 58’ 30” E to said “Point B”, thence continuing N 88 degrees 58’ 30” E 2650.13 feet to the place of beginning. (Bearings are based on the East line of Section 15, T5N, R10W between the East 1/4 corner of said section and the Northeast corner of said section assumed as N 0 degrees 59’ 55” W.)

LAKE COUNTY

Certain land in Pinora and Cherry Valley Townships, Lake County, Michigan described as:

A strip of land 50 feet wide East and West along and adjoining the West line of highway on the East side of the North 1/2 of Section 13 T18N, R12W. Also a strip of land 100 feet wide East and West along and adjoining the East line of the highway on the West side of following described land: The South 1/2 of NW 1/4, and the South 1/2 of the NW 1/4 of the SW 1/4, all in Section 6, T18N, R11W.

LAPEER COUNTY

Certain land in Hadley Township, Lapeer County, Michigan described as:

The South 825 feet of the W 1/2 of the SW 1/4 of Section 24, T6N, R9E, except the West 1064 feet thereof.

LEELANAU COUNTY

Certain land in Cleveland Township, Leelanau County, Michigan described as:

The North 200 feet of the West 180 feet of the SW 1/4 of the SE 1/4 of Section 35, T29N, R13W.

LENAWEE COUNTY

Certain land in Madison Township, Lenawee County, Michigan described as:

A strip of land 165 feet wide off the West side of the following described premises: The E 1/2 of the SE 1/4 of Section 12. The E 1/2 of the NE 1/4 and the NE 1/4 of the SE 1/4 of Section 13, being all in T7S, R3E, excepting therefrom a parcel of land in the E 1/2 of the SE 1/4 of Section 12, T7S, R3E, beginning at the Northwest corner of said E 1/2 of the SE 1/4 of Section 12, running thence East 4 rods, thence South 6 rods, thence West 4 rods, thence North 6 rods to the place of beginning.

LIVINGSTON COUNTY

Certain land in Cohoctah Township, Livingston County, Michigan described as:

Parcel 1

The East 390 feet of the East 50 rods of the SW 1/4 of Section 30, T4N, R4E.

Parcel 2

A parcel of land in the NW 1/4 of Section 31, T4N, R4E, described as follows: To find the place of beginning of this description commence at the N 1/4 post of said section; run thence N 89 degrees 13’ 06” W along the North line of said section, 330 feet to the place of beginning of this description; running thence S 00 degrees 52’ 49” W, 2167.87 feet; thence N 88 degrees 59’ 49” W, 60 feet; thence N 00 degrees 52’ 49” E, 2167.66 feet to the North line of said section; thence S 89 degrees 13’ 06” E along said North line of said section, 60 feet to the place of beginning.

MACOMB COUNTY

Certain land in Macomb Township, Macomb County, Michigan described as:

A parcel of land commencing on the West line of the E 1/2 of the NW 1/4 of fractional Section 6, 20 chains South of the NW corner of said E 1/2 of the NW 1/4 of Section 6; thence South on said West line and the East line of A. Henry Kotner's Hayes Road Subdivision #15, according to the recorded plat thereof, as recorded in Liber 24 of Plats, on page 7, 24.36 chains to the East and West 1/4 line of said Section 6; thence East on said East and West 1/4 line 8.93 chains; thence North parallel with the said West line of the E 1/2 of the NW 1/4 of Section 6, 24.36 chains; thence West 8.93 chains to the place of beginning, all in T3N, R13E.

MANISTEE COUNTY

Certain land in Manistee Township, Manistee County, Michigan described as:

A parcel of land in the SW 1/4 of Section 20, T22N, R16W, described as follows: To find the place of beginning of this description, commence at the Southwest corner of said section; run thence East along the South line of said section 832.2 feet to the place of beginning of this description; thence continuing East along said South line of said section 132 feet; thence North 198 feet; thence West 132 feet; thence South 198 feet to the place of beginning, excepting therefrom the South 2 rods thereof which was conveyed to Manistee Township for highway purposes by a Quitclaim Deed dated June 13, 1919 and recorded July 11, 1919 in Liber 88 of Deeds on page 638 of Manistee County Records.

MASON COUNTY

Certain land in Riverton Township, Mason County, Michigan described as:

Parcel 1: The South 10 acres of the West 20 acres of the S 1/2 of the NE 1/4 of Section 22, T17N, R17W.

Parcel 2: A parcel of land containing 4 acres of the West side of highway, said parcel of land being described as commencing 16 rods South of the Northwest corner of the NW 1/4 of the SW ¼ of Section 22, T17N, R17W, running thence South 64 rods, thence NE'ly and N'ly and NW'ly along the W'ly line of said highway to the place of beginning, together with any and all right, title, and interest of Howard C. Wicklund and Katherine E. Wicklund in and to that portion of the hereinbefore mentioned highway lying adjacent to the E'ly line of said above described land.

MECOSTA COUNTY

Certain land in Wheatland Township, Mecosta County, Michigan described as:

A parcel of land in the SW 1/4 of the SW 1/4 of Section 16, T14N, R7W, described as beginning at the Southwest corner of said section; thence East along the South line of Section 133 feet; thence North parallel to the West section line 133 feet; thence West 133 feet to the West line of said Section; thence South 133 feet to the place of beginning.

MIDLAND COUNTY

Certain land in Ingersoll Township, Midland County, Michigan described as:

The West 200 feet of the W 1/2 of the NE 1/4 of Section 4, T13N, R2E.

MISSAUKEE COUNTY

Certain land in Norwich Township, Missaukee County, Michigan described as:

A parcel of land in the NW 1/4 of the NW 1/4 of Section 16, T24N, R6W, described as follows: Commencing at the Northwest corner of said section, running thence N 89 degrees 01’ 45” E along the North line of said section 233.00 feet; thence South 233.00 feet; thence S 89 degrees 01’ 45” W, 233.00 feet to the West line of said section; thence North along said West line of said section 233.00 feet to the place of beginning. (Bearings are based on the West line of Section 16, T24N, R6W, between the Southwest and Northwest corners of said section assumed as North.)

MONROE COUNTY

Certain land in Whiteford Township, Monroe County, Michigan described as:

A parcel of land in the SW1/4 of Section 20, T8S, R6E, described as follows: To find the place of beginning of this description commence at the S 1/4 post of said section; run thence West along the South line of said section 1269.89 feet to the place of beginning of this description; thence continuing West along said South line of said section 100 feet; thence N 00 degrees 50’ 35” E, 250 feet; thence East 100 feet; thence S 00 degrees 50’ 35” W parallel with and 16.5 feet distant W’ly of as measured perpendicular to the West 1/8 line of said section, as occupied, a distance of 250 feet to the place of beginning.

MONTCALM COUNTY

Certain land in Crystal Township, Montcalm County, Michigan described as:

The N 1/2 of the S 1/2 of the SE 1/4 of Section 35, T10N, R5W.

MONTMORENCY COUNTY

Certain land in the Village of Hillman, Montmorency County, Michigan described as:

Lot 14 of Hillman Industrial Park, being a subdivision in the South 1/2 of the Northwest 1/4 of Section 24, T31N, R4E, according to the plat thereof recorded in Liber 4 of Plats on Pages 32-34, Montmorency County Records.

MUSKEGON COUNTY

Certain land in Casnovia Township, Muskegon County, Michigan described as:

The West 433 feet of the North 180 feet of the South 425 feet of the SW 1/4 of Section 3, T10N, R13W.

NEWAYGO COUNTY

Certain land in Ashland Township, Newaygo County, Michigan described as:

The West 250 feet of the NE 1/4 of Section 23, T11N, R13W.

OAKLAND COUNTY

Certain land in Wixcom City, Oakland County, Michigan described as:

The E 75 feet of the N 160 feet of the N 330 feet of the W 526.84 feet of the NW 1/4 of the NW 1/4 of Section 8, T1N, R8E, more particularly described as follows: Commence at the NW corner of said Section 8, thence N 87 degrees 14’ 29” E along the North line of said Section 8 a distance of 451.84 feet to the place of beginning for this description; thence continuing N 87 degrees 14’ 29” E along said North section line a distance of 75.0 feet to the East line of the West 526.84 feet of the NW 1/4 of the NW 1/4 of said Section 8; thence S 02 degrees 37’ 09” E along said East line a distance of 160.0 feet; thence S 87 degrees 14’ 29” W a distance of 75.0 feet; thence N 02 degrees 37’ 09” W a distance of 160.0 feet to the place of beginning.

OCEANA COUNTY

Certain land in Crystal Township, Oceana County, Michigan described as:

The East 290 feet of the SE 1/4 of the NW 1/4 and the East 290 feet of the NE 1/4 of the SW 1/4, all in Section 20, T16N, R16W.

OGEMAW COUNTY

Certain land in West Branch Township, Ogemaw County, Michigan described as:

The South 660 feet of the East 660 feet of the NE 1/4 of the NE 1/4 of Section 33, T22N, R2E.

OSCEOLA COUNTY

Certain land in Hersey Township, Osceola County, Michigan described as:

A parcel of land in the North 1/2 of the Northeast 1/4 of Section 13, T17N, R9W, described as commencing at the Northeast corner of said Section; thence West along the North Section line 999 feet to the point of beginning of this description; thence S 01 degrees 54’ 20” E 1327.12 feet to the North 1/8 line; thence S 89 degrees 17’ 05” W along the North 1/8 line 330.89 feet; thence N 01 degrees 54’ 20” W 1331.26 feet to the North Section line; thence East along the North Section line 331 feet to the point of beginning.

OSCODA COUNTY

Certain land in Comins Township, Oscoda County, Michigan described as:

The East 400 feet of the South 580 feet of the W 1/2 of the SW 1/4 of Section 15, T27N, R3E.

OTSEGO COUNTY

Certain land in Corwith Township, Otsego County, Michigan described as:

Part of the NW 1/4 of the NE 1/4 of Section 28, T32N, R3W, described as: Beginning at the N 1/4 corner of said section; running thence S 89 degrees 04’ 06” E along the North line of said section, 330.00 feet; thence S 00 degrees 28’ 43” E, 400.00 feet; thence N 89 degrees 04’ 06” W, 330.00 feet to the North and South 1/4 line of said section; thence N 00 degrees 28’ 43” W along the said North and South 1/4 line of said section, 400.00 feet to the point of beginning; subject to the use of the N’ly 33.00 feet thereof for highway purposes.

OTTAWA COUNTY

Certain land in Robinson Township, Ottawa County, Michigan described as:

The North 660 feet of the West 660 feet of the NE 1/4 of the NW 1/4 of Section 26, T7N, R15W.

PRESQUE ISLE COUNTY

Certain land in Belknap and Pulawski Townships, Presque Isle County, Michigan described as:

Part of the South half of the Northeast quarter, Section 24, T34N, R5E, and part of the Northwest quarter, Section 19, T34N, R6E, more fully described as: Commencing at the East ¼ corner of said Section 24; thence N 00 degrees15’47” E, 507.42 feet, along the East line of said Section 24 to the point of beginning; thence S 88 degrees15’36” W, 400.00 feet, parallel with the North 1/8 line of said Section 24; thence N 00 degrees15’47” E, 800.00 feet, parallel with said East line of Section 24; thence N 88 degrees15’36”E, 800.00 feet, along said North 1/8 line of Section 24 and said line extended; thence S 00 degrees15’47” W, 800.00 feet, parallel with said East line of Section 24; thence S 88 degrees15’36” W, 400.00 feet, parallel with said North 1/8 line of Section 24 to the point of beginning.

Together with a 33 foot easement along the West 33 feet of the Northwest quarter lying North of the North 1/8 line of Section 24, Belknap Township, extended, in Section 19, T34N, R6E.

ROSCOMMON COUNTY

Certain land in Gerrish Township, Roscommon County, Michigan described as:

A parcel of land in the NW 1/4 of Section 19, T24N, R3W, described as follows: To find the place of beginning of this description commence at the Northwest corner of said section, run thence East along the North line of said section 1,163.2 feet to the place of beginning of this description (said point also being the place of intersection of the West 1/8 line of said section with the North line of said section), thence S 01 degrees 01’ E along said West 1/8 line 132 feet, thence West parallel with the North line of said section 132 feet, thence N 01 degrees 01’ W parallel with said West 1/8 line of said section 132 feet to the North line of said section, thence East along the North line of said section 132 feet to the place of beginning.

SAGINAW COUNTY

Certain land in Chapin Township, Saginaw County, Michigan described as:

A parcel of land in the SW 1/4 of Section 13, T9N, R1E, described as follows: To find the place of beginning of this description commence at the Southwest corner of said section; run thence North along the West line of said section 1581.4 feet to the place of beginning of this description; thence continuing North along said West line of said section 230 feet to the center line of a creek; thence S 70 degrees 07’ 00” E along said center line of said creek 196.78 feet; thence South 163.13 feet; thence West 185 feet to the West line of said section and the place of beginning.

SANILAC COUNTY

Certain easement rights located across land in Minden Township, Sanilac County, Michigan described as:

The Southeast 1/4 of the Southeast 1/4 of Section 1, T14N, R14E, excepting therefrom the South 83 feet of the East 83 feet thereof.

SHIAWASSEE COUNTY

Certain land in Burns Township, Shiawassee County, Michigan described as:

The South 330 feet of the E 1/2 of the NE 1/4 of Section 36, T5N, R4E.

ST. CLAIR COUNTY

Certain land in Ira Township, St. Clair County, Michigan described as:

The N 1/2 of the NW 1/4 of the NE 1/4 of Section 6, T3N, R15E.

ST. JOSEPH COUNTY

Certain land in Mendon Township, St. Joseph County, Michigan described as:

The North 660 feet of the West 660 feet of the NW 1/4 of SW 1/4, Section 35, T5S, R10W.

TUSCOLA COUNTY

Certain land in Millington Township, Tuscola County, Michigan described as:

A strip of land 280 feet wide across the East 96 rods of the South 20 rods of the N 1/2 of the SE 1/4 of Section 34, T10N, R8E, more particularly described as commencing at the Northeast corner of Section 3, T9N, R8E, thence S 89 degrees 55’ 35” W along the South line of said Section 34 a distance of 329.65 feet, thence N 18 degrees 11’ 50” W a distance of 1398.67 feet to the South 1/8 line of said Section 34 and the place of beginning for this description; thence continuing N 18 degrees 11’ 50” W a distance of 349.91 feet; thence N 89 degrees 57’ 01” W a distance of 294.80 feet; thence S 18 degrees 11’ 50” E a distance of 350.04 feet to the South 1/8 line of said Section 34; thence S 89 degrees 58’ 29” E along the South 1/8 line of said section a distance of 294.76 feet to the place of beginning.

VAN BUREN COUNTY

Certain land in Covert Township, Van Buren County, Michigan described as:

All that part of the West 20 acres of the N 1/2 of the NE fractional 1/4 of Section 1, T2S, R17W, except the West 17 rods of the North 80 rods, being more particularly described as follows: To find the place of beginning of this description commence at the N 1/4 post of said section; run thence N 89 degrees 29’ 20” E along the North line of said section 280.5 feet to the place of beginning of this description; thence continuing N 89 degrees 29’ 20” E along said North line of said section 288.29 feet; thence S 00 degrees 44’ 00” E, 1531.92 feet; thence S 89 degrees 33’ 30” W, 568.79 feet to the North and South 1/4 line of said section; thence N 00 degrees 44’ 00” W along said North and South 1/4 line of said section 211.4 feet; thence N 89 degrees 29’ 20” E, 280.5 feet; thence N 00 degrees 44’ 00” W, 1320 feet to the North line of said section and the place of beginning.

WASHTENAW COUNTY

Certain land in Manchester Township, Washtenaw County, Michigan described as:

A parcel of land in the NE 1/4 of the NW 1/4 of Section 1, T4S, R3E, described as follows: To find the place of beginning of this description commence at the Northwest corner of said section; run thence East along the North line of said section 1355.07 feet to the West 1/8 line of said section; thence S 00 degrees 22’ 20” E along said West 1/8 line of said section 927.66 feet to the place of beginning of this description; thence continuing S 00 degrees 22’ 20” E along said West 1/8 line of said section 660 feet to the North 1/8 line of said section; thence N 86 degrees 36’ 57” E along said North 1/8 line of said section 660.91 feet; thence N 00 degrees22’ 20” W, 660 feet; thence S 86 degrees 36’ 57” W, 660.91 feet to the place of beginning.

WAYNE COUNTY

Certain land in Livonia City, Wayne County, Michigan described as:

Commencing at the Southeast corner of Section 6, T1S, R9E; thence North along the East line of Section 6 a distance of 253 feet to the point of beginning; thence continuing North along the East line of Section 6 a distance of 50 feet; thence Westerly parallel to the South line of Section 6, a distance of 215 feet; thence Southerly parallel to the East line of Section 6 a distance of 50 feet; thence easterly parallel with the South line of Section 6 a distance of 215 feet to the point of beginning.

WEXFORD COUNTY

Certain land in Selma Township, Wexford County, Michigan described as:

A parcel of land in the NW 1/4 of Section 7, T22N, R10W, described as beginning on the North line of said section at a point 200 feet East of the West line of said section, running thence East along said North section line 450 feet, thence South parallel with said West section line 350 feet, thence West parallel with said North section line 450 feet, thence North parallel with said West section line 350 feet to the place of beginning.

SECTION 12. The Company is a transmitting utility under Section 9501(2) of the Michigan Uniform Commercial Code (M.C.L. 440.9501(2)) as defined in M.C.L. 440.9102(1)(aaaa).

IN WITNESS WHEREOF, said Consumers Energy Company has caused this Supplemental Indenture to be executed in its corporate name by its Chairman of the Board, President, a Vice President or its Treasurer, and said The Bank of New York Mellon, as Trustee as aforesaid, to evidence its acceptance hereof, has caused this Supplemental Indenture to be executed in its corporate name by a Vice President, in several counterparts, all as of the day and year first above written.

CONSUMERS ENERGY COMPANY

By: /s/ Jason M. Shore
Name: Jason M. Shore
Title: Vice President and Treasurer

STATE OF MICHIGAN)
ss.
COUNTY OF JACKSON)

The foregoing instrument was acknowledged before me this 28th day of November, 2025, by Jason M. Shore, Vice President and Treasurer of CONSUMERS ENERGY COMPANY, a Michigan corporation, on behalf of the corporation.

/s/ Lindsey White
Lindsey White, Notary Public
State of Michigan, County of Ingham
My Commissions Expires: February 25, 2027
Acting in the County of Jackson

[SEAL]

THE BANK OF NEW YORK MELLON, AS TRUSTEE

By: /s/ Melissa Matthews
Name: Melissa Matthews
Title: Vice President

STATE OF NEW YORK)
ss.
COUNTY OF NEW YORK)

The foregoing instrument was acknowledged before me this 25th day of November 2025, Melissa Matthews, a Vice President of THE BANK OF NEW YORK MELLON, a New York banking corporation, on behalf of the bank, as trustee.

/s/ Rafal Bar
Rafal Bar, Notary Public
NOTARY PUBLIC, STATE OF NEW YORK
Registration No. 01BA6293822
Qualified in Kings County
My Commission Expires: 01/31/2026

[SEAL]

Prepared by:
Melissa M. Gleespen
One Energy Plaza, EP12-246
Jackson, MI 49201

When recorded, return to:
Consumers Energy Company
Attn: Lindsey White
One Energy Plaza
Jackson, MI 49201