UNITED STATES OF AMERICA
BEFORE THE
UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Craig Unit 1	))))	Order No. 202-26-49

The State Of Colorado's Request for Rehearing,
Motion To Intervene, And Stay Request

Exhibit AAAA: Department, Order No. 202-26-39 (Aug. 14, 2026)

Department of Energy
Washington, DC 20585

Consumers Energy Company and
Midcontinent Independent System Operator, Inc.
Regarding J.H. Campbell Generating Plant

Order No. 202-26-39

Pursuant to the authority vested in the Secretary of Energy (Secretary) by section 202(c) of the Federal Power Act (FPA),[1] and section 301(b) of the Department of Energy (DOE or the Department) Organization Act,[2] and for the reasons set forth below, I hereby determine that an emergency exists in portions of the Midcontinent Independent System Operator, Inc. (MISO) region due to a sudden increase in demand or a shortage of electric energy or facilities for the generation or transmission of electric energy, 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, 202-25-7, 202-25-9, 202-26-16, and 202-26-22, issued pursuant to FPA section 202(c), each required that the Campbell Plant remain in operation for 90 days, until August 21, 2025, November 19, 2025, February 17, 2026, May 18, 2026, and August 16, 2026, respectively. Those orders were based on my determination that emergency conditions existed in the region served by 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

[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/news-release-details/2021/06/23/consumers-energy-announces-plan-to-end-coal-use-by-2025-lead-michigans-clean-energy-transformation.

[4] *See, e.g.*, *Midcontinent Indep. Sys. Operator, Inc.*, DOE Order No. 202-25-9, at 1 (Nov. 18, 2025).

these periods, which would help prevent the potential loss of power to homes and 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, "Michigan's nuclear power plants typically 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 the plant will reportedly resume service in 2026.[11]

Third, the Campbell Plant's retirement would have further decreased available dispatchable generation within MISO's service territory, adding to the loss of 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 into their supply forecasts and Consumers acquired a 1,200 MW natural

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[5] *Id.* at 5; *see also id.* at 1, 8.

[6] *Id.* at 1.

[7] N. Am. Elec. Reliability Corp., *2025 Summer Reliability Assessment*, at 16 (May 2025), https://www.nerc.com/globalassets/programs/rapa/ra/nerc_sra_2025.pdf.

[8] *Id*.

[9] EIA, *Mich. State Profile & Energy Estimates* (Nov. 19, 2025), https://www.eia.gov/states/MI/analysis.

[10] *Id*.

[11] *See* Dustin Dwyer, *Palisades nuclear plant restart plans pushed back to "early 2026,"* MICH. PUB. (Dec. 17, 2025), https://www.michiganpublic.org/environment-climate-change/2025-12-17/palisades-nuclear-plant-restart-plans-pushed-back-to-early-2026; Will Wade, *Despite $80-billion commitment, nuclear plants face decadelong timeline to meet AI energy needs*, L.A. TIMES (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.

gas power plant in Covert, Michigan, NERC has noted that "[e]scalating demand forecasts and uncertainty around new resource commercialization timing contribute to heightened resource adequacy concerns in the MISO area."[12]

Fourth, MISO's Planning Resource Auction Results for the 2026–2027 Planning Year, released in April 2026, notes that "capacity additions need to continue, given expected growth from new large loads."[13] Further, MISO reiterates that "while our market reforms have helped hold the line amidst tighter reserve margin compared to the prior decade, resource adequacy remains at risk, especially as demand for large load additions accelerate."[14]

CONTINUING EMERGENCY CONDITIONS

The emergency conditions that necessitated the issuance of Order Nos. 202-25-3, 202-25-7, 202-25-9, 202-26-16, and 202-26-22 continue, both in the near and long term.[15] The production of electricity from the Campbell Plant will continue to be a critical asset to maintain reliability in MISO. According to the EIA-923 Power Plant Operations Report's monthly generation data for May 2026, the total net generation for the Campbell Plant was 1,431,336 MWh from January 2026 to May 2026 for an average of 286,267 MWh per month.[16] The historic data of consistent generation indicates the Campbell plant is 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

[12] NERC, *2025 Long-Term Reliability Assessment*, at 15 (Jan. 2026), https://www.nerc.com/globalassets/our-work/assessments/nerc_ltra_2025.pdf [hereinafter NERC *LTRA*].

[13] MISO, *Planning Res. Auction Results for Planning Year 2026/27*, at 3 (Apr. 2026) (Updated May 22, 2026) (MISO 2026–2027 Planning Resource Auction), https://cdn.misoenergy.org/2026%20PRA%20Results%20Posting%2020260522%20-%20Corrections754715.pdf.

[14] *Id.* at 7.

[15] It likely would be difficult for a coal-fired unit to resume operations once retired. Specifically, practical issues, such as employment, contracts, and permits, may greatly increase the timeline for resumption of operations during the period they are needed. Moreover, if Consumers was to begin disassembling the unit or other related facilities, the associated challenges would be greatly exacerbated. The costs and time of decommissioning a coal plant are extensive, and restarting such decommissioned plants would presumably cost the same as decommissioning in dollars and time, if not more. Thus, continuous operation is required in such cases so long as the Secretary determines a shortage exists and is likely to persist. *See* Jennifer Lessick et al., *Bus. Models for Coal Plant Decommissioning*, at 9–12 (Aug. 2021), https://www.pnnl.gov/main/publications/external/technical_reports/PNNL-31348.pdf.

[16] *See* EIA, *Form EIA-923 detailed data with previous form data (EIA-906/920)*, https://www.eia.gov/electricity/data/eia923/ (choose "2026: EIA-923 May 2026").

Central Region in response to hot weather, severe weather, high customer load, forced generation outages, and transfer capability limits.[17]

MISO's resource adequacy concerns were recently demonstrated during Winter Storm Fern, when it operated under a cold weather alert and declared conservative operations from January 23 through February 1, 2026. On January 24, MISO declared an Energy Emergency Alert (EEA) 1, as well as an EEA 2 "MaxGen" event for MISO's North and Central Regions due to generational outages, high demand, and transfer capability limits.[18]

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.[19] MISO justified this revision by explaining that "[r]eliability risks associated with resource adequacy have shifted from 'Summer only' to a year-round concern."[20] 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.[21]

In December 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."[22] 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.[23] MISO also projected that the risk of loss of load in the winter

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[17] MISO, *Operations Rep.* (Sept. 16, 2025), https://cdn.misoenergy.org/20250916%20Markets%20Committee%20of%20the%20BOD%20Item%2005%20MISO%20Operations%20Report717458.pdf.

[18] MISO, *Operations Rep.*, at 10 (Mar. 24, 2026), https://cdn.misoenergy.org/20260324%20Markets%20Committee%20of%20the%20BOD%20Item%2008%20MISO%20Operations%20Report746763.pdf.

[19] *Midcontinent Indep. Sys. Operator, Inc.*, Transmittal Letter, Docket No. ER22-495-000 (filed Nov. 30, 2021). FERC accepted MISO's proposed tariff revisions on August 31, 2022. *Midcontinent Indep. Sys. Operator, Inc.*, 180 FERC ¶ 61,141 (2022), *order on reh'g & compliance*, 182 FERC ¶ 61,096 (2023).

[20] MISO Transmittal Letter at 3.

[21] *Id.* at 3–4.

[22] MISO, *Attributes Roadmap*, at 3 (Dec. 2023), https://cdn.misoenergy.org/2023%20Attributes%20Roadmap631174.pdf.

[23] *Id.* at 11.

and spring seasons will nevertheless increase over time, although not as high as in the summer or fall.[24]

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*.[25] 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:

> 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.[26]

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

Further, in January 2026, NERC released its 2025 Long-Term Reliability Assessment (LTRA).[27] NERC assessed that the MISO region is at high risk of energy shortfalls over the next five years,[28] stating that it faces significant reliability challenges as "projected resource additions do not keep pace with escalating demand forecasts and announced generator retirements."[29] This determination is based on the combination of accelerating demand growth from new data centers and the retirement of existing thermal generators.[30] Moreover, the 2025 NERC LTRA 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."[31] The report observes that winter peak periods are a particular concern, with projections showing "shortfalls in planned resources for winter peak periods."[32] 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."[33]

The 2025–2026 NERC Winter Reliability Assessment (WRA) found the MISO region to be at normal risk in 2026 and elevated risk in 2027. The two previous winter

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[24] *Id.*

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

[26] *Id.* at 12.

[27] *See* NERC *LTRA*, *supra* note 12.

[28] *Id.* at 6, 8.

[29] *Id.* at 8.

[30] *Id.* at 43.

[31] *Id.* at 15.

[32] *Id*.

[33] *Id*.

studies respectively characterized MISO as a region at elevated risk with the "[p]otential for insufficient operating reserves in above-normal conditions"[34] and noted that "[g]enerating capacity is 10 GW lower (-6.8%) compared to the prior winter as generators have retired, withdrawn from MISO's capacity market, or received lower winter accredited capacity."[35]

NERC released its 2026 Summer Reliability Assessment (SRA) on May 19, 2026. In its assessment, NERC stated that "MISO's peak load has increased by 2.5 GW from the 2025 SRA."[36] The 2026 SRA also projects that data center load will continue to accelerate in 2027 and beyond, potentially increasing reliability risk if capacity additions do not keep pace.[37] Furthermore, the 2026 SRA states that "[a]bove-normal summer peak load combined with low resource conditions could result in the need to employ operating mitigations . . . and EEAs."[38]

There continues to be tight capacity available during summer despite the recent "gains in offered capacity outpacing pressure of load growth" in the MISO region, as reported in its PRA for the 2026-2027 Planning Year.[39] MISO noted that "new generation capacity is coming online, but faster resource additions are still needed to support large-load growth and ensure resource adequacy."[40]

On June 4, 2026, the Organization of MISO States (OMS) and MISO issued the results of their 2026 survey, which has been conducted annually for many years to determine the degree to which expected capacity resources satisfy planning reserve margin requirements.[41] The 2026 OMS-MISO Survey presented projections of resource adequacy for the summer of 2026 and subsequent years and states "growth as submitted by [load serving entities or LSEs] continues to accelerate, with a [compound annual growth rate or CAGR] projected between 3.1% and 5.1% over [the next] five years."[42]

The OMS-MISO Survey further indicates that "[v]arious projected capacity scenarios and large load additions highlight increasing uncertainty and evolving risk"[43]

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

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

[36] NERC, *2026 Summer Reliability Assessment*, at 16 (May 2026), https://www.nerc.com/globalassets/our-work/assessments/nerc_sra_2026.pdf.

[37] *Id.*

[38] *Id*.

[39] MISO 2026–2027 Planning Resource Auction at 3.

[40] *Id.* at 2.

[41] OMS & MISO, *OMS-MISO Survey Results* (updated June 4, 2026) (2026 OMS-MISO Survey), https://cdn.misoenergy.org/20260604%20OMS-MISO%20Survey%20Results%20Workshop%20Presentation761711.pdf.

[42] *Id.* at 2.

[43] *Id.* at 3.

and observes various negative risks. Examples include intensification of winter reliability risks based on resource availability/performance, which exacerbates seasonal reliability vulnerabilities; delay of new resource deployment owing to persistent supply-chain disruptions, labor constraints and permitting challenges; resource adequacy pressures continuing from load growth driven by data centers, new industrial, and commercial development; and continued backlog and uncertainty related to resources with signed Generator Interconnection Agreements (GIA).[44] In addition, 87 GW of signed GIAs are not yet online, and 192 GW of active GIAs still under study.[45]

Finally, the OMS-MISO Survey lists ongoing challenges such as more frequent extreme weather; accelerating demand for electricity and large load interconnections; loss of accredited capacity and reliability attributes as resource mixes evolve; the increasing pace of new resources additions; addressing local reliability issues (load pocket); and evolving storage participation.[46]

NERC released its 2026 State of Reliability (SOR) on June 24, 2026. In the SOR, NERC identifies worsening reliability concerns tied to large-load integration and localized operating stress. In its technical discussion of major system events, NERC states "shoulder seasons have become increasingly challenging for Bulk Power System operators to manage, resulting in several recent instances of pre-contingent load shedding."[47] The SOR also finds large load growth is increasing reliability risk and states that "data center and computational loads continued emerging as a major reliability consideration due to their scale, speed of development, and unique operational characteristics."[48] Finally, data in the SOR shows that 2025 MISO summer and winter peak demands of 121.6 GW and 108.8 GW, respectively, met or exceeded extreme scenario levels showing how rapid load growth and extreme weather continue to be a real risk in MISO.[49]

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.[50] MISO's 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

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[44] *Id.* at 4.

[45] *Id.*

[46] *Id.* at 16.

[47] NERC, *2026 State of Reliability: Tech. Assessment of 2025 Bulk Power Sys. Performance*, at 5 (June 24, 2026), https://www.nerc.com/globalassets/programs/rapa/pa/nerc_sor_2026_technical_assessment.pdf.

[48] *Id.* at vii.

[49] *Id.* at 28, 30.

[50] *Midcontinent Indep. Sys. Operator, Inc.*, 192 FERC ¶ 61,064 (2025).

operations.[51] 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.[52] 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, 202-25-9, 202-26-16, and 202-26-22 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 No. 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 threat to our Nation's economy, national security, and foreign policy."[53] 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."[54] In the subsequent Executive Order No. 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."[55]

In addition, President Trump issued a White House Memo to the Secretary of Energy that emphasized the findings of Executive Order No. 14156, stating that "ensuring reliable coal supply chains and baseload power generation capacity is essential to the United States national defense . . . [w]ithout sufficient coal-fired baseload power, the United States will lack the stable electricity required to support defense installations, industrial expansion, and the high-energy demands of emerging technologies, such as

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[51] NERC, *State of Reliability*, *supra* note 48, at 84.

[52] *See generally* Jared Anderson, *US Gas-Fired Turbine Wait Times as Much as Seven Years; Costs Up Sharply*, S&P GLOBAL (May 2025) ("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."), 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.

[53] Exec. Order No. 14156, 90 Fed. Reg. 8433 (Jan. 20, 2025), https://www.federalregister.gov/documents/2025/01/29/2025-02003/declaring-a-national-energy-emergency.

[54] *Id*.

[55] Exec. Order No. 14262, 90 Fed. Reg. 15521 (Apr. 8, 2025), https://www.federalregister.gov/documents/2025/04/14/2025-06381/strengthening-the-reliability-and-security-of-the-united-states-electric-grid.

artificial intelligence."[56] The President "further determine[d] that action to expand coal supply chain capacity and baseload generation availability is necessary to avert an industrial resource or critical technology item shortfall that would severely impair national defense capability."[57]

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 No. 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."[58] 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.[59] 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 . . . ."[60]

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, MISO's Senior Vice President for Planning and Operations, Jennifer Curran, 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."[61] Ms. Curran also described "much stronger growth [in demand

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[56] Memorandum from President Donald J. Trump to the Secretary of Energy (Apr. 20, 2026) ("Presidential Determination Pursuant to Section 303 of the Defense Production Act of 1950, as Amended, on Coal Supply Chains and Baseload Power Generation Capacity"), https://www.whitehouse.gov/presidential-actions/2026/04/presidential-determination-pursuant-to-section-303-of-the-defense-production-act-of-1950-as-amended-on-coal-supply-chains-and-baseload-power-generation-capacity/.

[57] *Id.*

[58] U.S. Dep't of Energy, *Res. Adequacy Rep.: Evaluating the Reliability & Sec. of the U.S. Elec. Grid*, at 1 (July 2025), https://www.energy.gov/sites/default/files/2025-07/DOE%20Final%20EO%20Report%20%28FINAL%20JULY%207%29.pdf.

[59] Ekku Jokinen, *Top 21 A.I. Cos. in Mich.* , INVEN (last accessed Aug. 13, 2025), https://www.inven.ai/company-lists/top-21-artificial-intelligence-companies-in-michigan.

[60] *See* Zachary Skidmore, *Mich. util. Consumers Energy to provide 1GW of power to new hyperscale data center*, DATA CENTER DYNAMICS (Aug. 5, 2025) (quoting Consumers CEO Garrick Rochow), https://www.datacenterdynamics.com/en/news/michigan-utility-consumers-energy-to-provide-1gw-of-power-to-new-hyperscale-data-center/.

[61] *Keeping the Lights On: Examining the State of Regional Grid Reliability; Hearing Before the House Committee on Energy and Commerce, Subcommittee on Energy*, 119th Cong. 5 (2025) (statement of Ms. Jennifer Curran, Senior Vice President

for electricity] from continued electrification efforts, a resurgence in manufacturing, and an unexpected demand for energy-hungry data centers to support artificial intelligence."[62] 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."[63]

Pursuant to section 202(c)(4)(B) of the FPA, DOE 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 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," the Secretary has the authority "to require by order . . . such generation, delivery, interchange, or transmission of electric energy as in [his] judgment will best meet the emergency and serve the public interest."[64] 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 operation will best meet an emergency.

As described above, the emergency conditions resulting from increasing demand and shortage of electric energy from premature retirement of the Campbell Plant 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 businesses in the areas affected by curtailments or outages, presenting a risk to public health and safety.

I have determined that, to best meet the emergency arising from increased demand, determined shortage, and other causes, and to serve the public interest under FPA section 202(c), the Campbell Plant shall be made available for operation through November 14, 2026.[65]

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for Planning and Operations, MISO), https://www.congress.gov/119/meeting/house/118040/witnesses/HHRG-119-IF03-Wstate-CurranJ-20250325.pdf.

[62] *Id.* at 6.

[63] *Id.* at 7.

[64] 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).

[65] 16 U.S.C. § 824a(c)(4).

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

A. From August 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 this Order.

C. All operations 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 conditions, or to use other geographic or temporal flexibilities available to generators.

D. By August 31, 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.

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 August 17, 2026, through November 14, 2026, with the exception of applicable compliance obligations in paragraph D.

Issued in Washington, D.C. on this 14th day of August 2026.

Chris Wright

Chris Wright
Secretary of Energy

cc:

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

Michigan Public Service Commission
Chairman Dan Scripps
Commissioner Katherine Peretick
Commissioner Shaquila Myers

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Federal Power Act Section 202(c) Emergency Order: Craig Unit 1	))))	Order No. 202-26-49

The State Of Colorado's Request for Rehearing,
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Exhibit BBBB: Department, Order No. 202-26-40 (Aug. 21, 2026)

Department of Energy
Washington, DC 20585

Constellation Energy Corp. and
PJM Interconnection, L.L.C.
Regarding Eddystone Unit 3 and Unit 4

Order No. 202-26-40

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

BACKGROUND

The Eddystone Generating Station is a power plant owned by Constellation Energy Corporation (Constellation Energy) and located in Eddystone, Pennsylvania. Units 3 and 4 (Eddystone Units), each with 380 MW of generation capacity, are subcritical steam boiler-turbine generator units that run on either natural gas or oil, depending on market conditions. The Eddystone Units were initially scheduled for retirement on May 31, 2025.

Order Nos. 202-25-04, 202-25-08, 202-25-10, 202-26-17, and 202-26-24, issued pursuant to FPA section 202(c), each required that the Eddystone Units remain available to operate for 90 days, until August 28, 2025, November 26, 2025, February 24, 2026, May 24, 2026, and August 22, 2026, respectively. Those orders were based on my determination that emergency conditions existed in the PJM region.

Specifically, I determined that there was a potential shortage of electric energy and a shortage of facilities for the generation of electric energy.[3] I stated that the potential loss of power to homes and local businesses presents a risk to public health and safety.[4] I determined that continued operation and economic dispatch of the Eddystone Units was necessary to best meet the emergency and serve the public interest.[5]

My determination was based on a number of different facts. First, in congressional testimony, PJM's then President and CEO stated that its system faces a "growing resource adequacy concern" due to load growth, the retirement of dispatchable

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[1] 16 U.S.C. § 824a(c).
[2] 42 U.S.C. § 7151(b).
[3] *See, e.g.*, *PJM Interconnection, L.L.C.*, Order No. 202-26-24, at 10 (May 21, 2026).
[4] *Id.* at 9.
[5] *Id.* at 9 & Ordering Para. A.

resources, and other factors.[6] Through 2030, PJM anticipates reliability risk from increasing electricity demand, generator retirement outpacing new resource construction, and characteristics of resources in PJM's interconnection queue.[7] Upcoming retirements, including the planned retirement of the Eddystone Units, would exacerbate these resource adequacy issues.

Second, PJM indicated that resource constraints could exist within its service territory under peak load conditions, stating that "available generation capacity may fall short of required reserves in an extreme planning scenario."[8] In its February 2023 assessment, *Energy Transition in PJM: Resource Retirements, Replacements & Risks*, PJM highlighted increasing reliability risks in the coming years due to the "potential timing mismatch between resource retirements, load growth and the pace of new generation entry" under "low new entry" scenarios for renewable generation.[9]

Third, in December 2024, PJM filed revisions with the Federal Energy Regulatory Commission (FERC) to Part VII of its Open Access Transmission Tariff, known as the Reliability Resource Initiative (RRI), to address near-term resource adequacy concerns. In a February 2025 order, FERC accepted the revisions and found "the possibility of a resource adequacy shortfall driven by significant load growth, premature retirements, and delayed new entry."[10]

Fourth, PJM's resource adequacy concerns were recently demonstrated during Winter Storm Fern, when PJM operated under a cold weather alert and declared conservative operations from January 24 to February 2, 2026. Due to concerns about resource adequacy from the high demand driven by the extreme cold, PJM also applied for an order pursuant to FPA section 202(c) "that broadly authorizes all electric

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[6] *Keeping the Lights On: Examining the State of Reg'l Reliability; Hearing Before the House Comm. on Energy & Com., Subcomm. on Energy*, 119th Cong. 4–5 (2025) (testimony of Mr. Manu Asthana, President and CEO, PJM) [hereinafter Asthana Test.], https://www.congress.gov/119/meeting/house/118040/witnesses/HHRG-119-IF03-Wstate-AsthanaM-20250325.pdf.

[7] *Id*.; *see also PJM Interconnection, L.L.C.*, 190 FERC ¶ 61,084, at P 15 (2025) ("PJM states . . . that, in 2023, it found that generator retirements, load growth, the pace of new entry, and the operating characteristics of the intermittent and limited duration resources that make up a large part of PJM's interconnection queue pose increasing reliability risks through 2030.").

[8] *PJM Summer Outlook 2025: Adequate Res. Available for Summer Amid Growing Risk*, PJM INSIDE LINES (May 9, 2025), https://insidelines.pjm.com/pjm-summer-outlook-2025-adequate-resources-available-for-summer-amid-growing-risk/.

[9] PJM, *Energy Transition in PJM: Res. Rets., Replacements & Risks*, at 1 (Feb. 24, 2023) [hereinafter *Four Rs Report*], https://www.pjm.com/-/media/DotCom/library/reports-notices/special-reports/2023/energy-transition-in-pjm-resource-retirements-replacements-and-risks.ashx.

[10] *PJM Interconnection*, 190 FERC ¶ 61,084 at P 14.

generating units located within the PJM Region to operate up to their maximum generation output levels, notwithstanding air quality or other permit limitations or fuel shortages during the pendency of this emergency."[11] DOE granted PJM's application and issued Order No. 202-26-02 on January 25, 2026.[12] From January 27, 2026, until early February 2026, PJM issued multiple alerts and warnings.[13]

On January 29, 2026, PJM applied for an extension of Order No. 202-26-02, which was designated as Order No. 202-26-02A, which was granted by the Department on the same day.[14] Furthermore, on March 17, 2026, in his testimony to the House Committee on Energy and Commerce, North American Electric Reliability Corporation (NERC) Chief Executive Officer Jim Robb stated that "PJM and other grid operators indicated that 202(c) facilities made material contributions" with regard to reliability during Winter Storm Fern.[15]

CONTINUING EMERGENCY CONDITIONS

The emergency conditions that necessitated the issuance of Order Nos. 202-25-04, 202-25-08, 202-25-10, 202-26-17, and 202-26-24 continue, both in the near and long term.[16] The production of electricity from the Eddystone Units will continue to be a critical asset for maintaining reliability in PJM. According to data from the U.S.

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[11] Letter from Michael E. Bryson, Senior Vice Pres., Operations, PJM, to Hon. Chris Wright, Sec'y, DOE, at 2 (Jan. 4, 2026) (requesting emergency order under FPA section 202(c)), https://www.energy.gov/documents/pjm-202c-application-2026-01-24.

[12] *PJM Interconnection, L.L.C.*, Order No. 202-26-02 (Jan. 25, 2026).

[13] *See PJM Interconnection, L.L.C., Emergency Procedures—Postings, https://emergencyprocedures.pjm.com/ep/pages/dashboard.jsf; see, e.g., Jan. 27 PJM Cold Weather Operations Update*, PJM INSIDE LINES (Jan. 27, 2026), https://insidelines.pjm.com/jan-26-pjm-cold-weather-operations-update/.

[14] *PJM Interconnection, L.L.C.*, Order No. 202-26-02A (Jan. 29, 2026).

[15] *Winter Storm Fern Lessons: Supplying Reliable Power to Meet Peak Demand; Hearing Before the House Comm. on Energy & Com., Subcomm. On Energy*, 119th Cong. 8 (2026) (statement of James B. Robb, President and CEO, NERC), https://www.congress.gov/119/meeting/house/119077/witnesses/HHRG-119-IF03-Wstate-RobbJ-20260317.pdf.

[16] Further, it likely would be difficult for these units to resume operations once retired. Specifically, practical issues, such as employment, contracts, and permits, may greatly increase the timeline for resumption of operations during the period they are needed. Moreover, if Constellation Energy were to begin disassembling the units or other related facilities, the associated challenges would be greatly exacerbated. Thus, continued operation is required in such cases so long as the Secretary determines that an emergency exists. The costs and time of decommissioning a power plant are extensive and includes various components. Therefore, restarting such decommissioned plants could have significant costs in terms of dollars and time. *See*, *e.g.*, Lessick, Jennifer et al. *Bus. Models for Coal Plant Decommissioning* § 4, PAC. NW. NAT'L LAB'Y (Aug. 2021), https://www.osti.gov/servlets/purl/1821476.

Environmental Protection Agency (EPA), the Eddystone Units generated 27,239 MWh between August 2025 and March 2026,[17,] providing vital generation capacity to the region. Over the summer of 2025, PJM issued multiple alerts and warnings to manage grid operations and reliability, covering a total of 20 days, including days in June, July, and August.[18] Similar actions have occurred already for summer 2026. In May, June, and July, PJM requested emergency orders for backup and non-backup generators due to high temperatures resulting in high demand forecasts, causing potential reliability issues. This resulted in the issuance of several emergency orders, namely, DOE Order Nos. 202-26-23, 202-26-24, 202-26-32, 202-26-32A, 202-26-33, 202-26-33A, and 202-26-35, with the last one ending at midnight of July 21, 2026.[19] These emergency orders helped PJM manage high demand, including an instantaneous peak demand of 162.7 GW on July 2, 2026, that was higher than PJM's previously forecasted peak summer demand of 156.4 GW.[20]

PJM's resource adequacy concerns are well documented. In January 2025, PJM reached a new record peak for winter demand, exceeding the previous winter peak set in 2015.[21] PJM notes that the "20-year annualized growth rate in the 2025 Long-Term Load Forecast for the winter peak is up to 2.4%."[22] Further, PJM's risk profile continues to shift from the summer season to the winter season. For example, in a March 2025

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[17] *See* EPA, *Custom Data Download, EPA CAMPD (Clean Air Mkts. Program Data)*, https://campd.epa.gov/data/custom-data-download (choose "Emissions" from Data Type dropdown; choose "Monthly Emissions" from Data Subtype dropdown; choose "Unit (No Aggregation)" from Aggregation dropdown; then click "Apply"; then type "2025" into "Time Period" filter and click "August, September, October, November, December"; then click "Apply Filter"; then click "Facility" filter and type "Eddystone Generating Station (3161)"; then click "Eddystone Generating Station (3161)"; then click "Apply Filter"; then click "Preview Data"; then change the "Time Period" to "2026" and click "January, February, March"; then click "Apply Filter"; then click "Preview Data").

[18] *See* PJM, *Emergency Procs.*, https://emergencyprocedures.pjm.com/ep/pages/dashboard.jsf (search Effective From 06/01/2025 Effective To 08/31/2025).

[19] *See 2026 DOE 202(c) Orders*, Department of Energy, https://www.energy.gov/ceser/2026-doe-202c-orders.

[20] Penn. Pub. Util. Comm'n, *Summer 2026 PJM Reliability Assessment*, at 5 (May 2026), https://www.puc.pa.gov/media/3965/2026_pjm_summer_readiness_report.pdf. *See also PJM Hot Weather Operations Update: July 3*, PJM INSIDE LINES (July 3, 2026), https://insidelines.pjm.com/pjm-hot-weather-operations-update-july-3/.

[21] *Jan. 22 Update: Extreme Cold Produces PJM Record for Winter Elec. Demand*, PJM INSIDE LINES (Jan. 22, 2025), https://insidelines.pjm.com/jan-22-update-extreme-cold-produces-pjm-record-for-winter-electricity-demand/.

[22] *2025 Long-Term Load Forecast Rep. Predicts Significant Increase in Elec. Demand*, PJM INSIDE LINES (Jan. 30, 2025), https://insidelines.pjm.com/2025-long-term-load-forecast-report-predicts-significant-increase-in-electricity-demand/.

presentation, PJM estimated that 87.8% of the expected unserved energy for the 2025/2026 delivery year falls in the winter season.[23]

Recognizing the need for and importance of additional generation resources, on April 20, 2026, a Consent Decree between the Commonwealth of Pennsylvania and Keystone-Conemaugh Projects, LLC (KEY-CON) authorized operations to continue at two coal-fired steam electric generating plants that were slated for permanent cessation. The Consent Decree explained that "[d]ue to recent changes in the long-term electricity market outlook based on recent projections by PJM Interconnection LLC and the U.S. Department of Energy, including the need for electricity generators to cover projected increased electrical demand driven by build-out of data centers, particularly within the Mid-Atlantic Area Council, a portion of the PJM Interconnection LLC regional transmission organization that KEY-CON has recently reevaluated its 2021 decision to achieve [permanent cessation of coal combustion] at the [Conemaugh Generating Station and Keystone Generating Station] by December 31, 2028."[24]

In the fall of 2025, Pennsylvania Governor Josh Shapiro recognized the need for and importance of securing more electricity generation for the grid. Governor Shapiro stated that "[c]hange is needed to keep energy costs low, bring new energy generation onto the grid more quickly, and meet the needs of the 67 million Americans who rely on this grid for everything from running a business to keeping the lights on at home."[25] Furthermore, PJM expressed support for Order No. 202-25-04, since it has "repeatedly documented and voiced its concerns over the growing risk of a supply and demand imbalance driven by the confluence of generator retirements and demand growth. Such an imbalance could have serious ramifications for reliability and affordability for consumers."[26]

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[23] PJM Res. Adequacy Planning Special Planning Comm., *2026/27 BRA IRM, FPR, & ELCC Class Ratings: Shift Towards More Winter Risk*, at 8 (Mar. 13, 2025), https://www.pjm.com/-/media/DotCom/committees-groups/committees/pc/2025/20250313-special/2026-2027-irm-fpr-elcc-and-winter-risk.pdf.

[24] COMMONWEALTH OF PENN., DEP'T OF ENV'T PROT. V. KEYSTONE-CONEMAUGH PROJECTS, LLC, No. 2169-CD-2025-1, slip op. at 4 (Apr. 20, 2026) (Unopposed Motion to Enter Consent Decree), https://www.pa.gov/content/dam/copapwp-pagov/en/governor/documents/motion%20to%20enter%20cd-as%20filed.pdf.

[25] Kate Huangpu, *How Josh Shapiro wants to reshape the region's power grid operator as prices rise*, SPOTLIGHT PA (Oct. 14, 2025), https://www.spotlightpa.org/news/2025/10/electricity-prices-shapiro-grid-operator-pjm-data-centers-environment/.

[26] *PJM Statement on the U.S. Dept. of Energy 202(c) Order of May 30*, PJM INSIDE LINES (May 31, 2025), https://insidelines.pjm.com/pjm-statement-on-the-u-s-department-of-energy-202c-order-of-may-30/. Further, PJM concluded, "In light of these concerns, PJM supports the U.S. Department of Energy's Order, issued May 30, pursuant to Section 202(c) of the Federal Power Act, to defer the retirements of certain generators operating in PJM's footprint." *Id*.

PJM has voiced these concerns for years. In its February 2023 *Four Rs Report*, PJM cautioned that 40 GW of thermal generation are at risk of retirement by 2030.[27] PJM also noted that, while there were then 290 GW of renewable generation capacity in the PJM interconnection queue, historically, the rate of completion for renewable projects is approximately 5%.[28] PJM determined that the pace of new capacity additions "would be insufficient to keep up with expected retirements and demand growth by 2030."[29] PJM estimated that, depending on the pace of new capacity additions, reserve margin erosion would occur between 2026 and 2028.[30]

In its December 2024 RRI filing with FERC, PJM stated that "[c]oncerns about resource adequacy . . . have only increased since the Four Rs Report."[31] PJM warned that its "resource adequacy concerns are increasing at an extraordinary pace."[32] PJM went on to explain that its "resource adequacy concerns are driven in large part by significant load growth caused by, among other things, large data centers" and that its preliminary analysis shows "substantial increases [in load additions] since the 2024 forecast" for both the summer and winter seasons.[33] According to PJM, "load growth and generator retirements are significantly outpacing the entry of new generation in the PJM Region with this trend expected to continue unabated based on all available evidence."[34] Although the RRI process will help expedite the construction of needed new capacity, it is unlikely to result in the addition of any new generation capacity in the next few years.[35]

In support of the RRI filing, PJM submitted an affidavit from Donald Bielak, PJM's Director of Interconnection Planning. Mr. Bielak characterized the increase in forecasted load growth throughout PJM as "extraordinary" and "unprecedented," stating that it "could not have been foreseen as recently as a year ago."[36] Mr. Bielak expressed the opinion that the "rapid" retirement of thermal generation resources, "extreme"

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[27] *Four Rs Report*, *supra* note 9, at 2.

[28] *Id*.

[29] *Id.* at 16 tbl. 1.

[30] *Id*.

[31] PJM, Filing, Dkt. No. ER25-712-000, at 10 (filed Dec. 13, 2024).

[32] *Id*.

[33] *Id.* at 10–11; *see also id.* at 13 (stating that "the exponential load growth resulting from development of new data centers and the intense energy needs of Artificial Intelligence technology overshadows any relaxation in the pace of fossil fuel generation retirements").

[34] *Id.* at 14.

[35] *See id.* attach. C (Affidavit of Mr. Donald Bielak), at 18–19 (explaining that projects studied in Transition Cycle #2, which includes RRI projects, "could be constructed and in commercial operation by the 2029/30 Delivery Year or sooner").

[36] Bielak Aff. at 10.

forecasted load growth, and "delays in new generation resources achieving commercial operation," would adversely affect resource adequacy throughout PJM's electricity grid.[37]

On February 11, 2025, FERC accepted PJM's proposed tariff revisions in its RRI filing.[38] In its order on rehearing, FERC concluded that "PJM identified increasing reliability risks arising in the next few years and significant resource adequacy issues anticipated by the 2030/31 delivery year. The record supports that these resource adequacy concerns are likely to manifest."[39]

NERC has raised similar concerns. In its 2025 Long-Term Reliability Assessment, released in January 2026, NERC observed that the PJM region is at high risk of energy shortfalls over the next five years[40] and faces significant reliability challenges as "[c]urrent projections for resource additions do not keep pace with escalating demand forecasts and expected generator retirements."[41] The assessment notes that "[d]emand for electricity in PJM is growing at its fastest pace in years, driven primarily by data centers, followed by electrification and manufacturing loads"; however, "[a]t the same time, PJM faces an extreme and rapid tightening of capacity resources in the near term because of generator retirements and project delays."[42] Overall, the assessment concludes that "[b]ased on the load increase and generation decrease, PJM is projecting potential reserve margin shortages during peak operating periods. As a result, there is an increased risk that emergency procedures may be required to meet load and reserve requirements."[43]

NERC released its 2026 State of Reliability (SOR) on June 24, 2026. In the SOR, NERC identifies worsening reliability concerns tied to large-load integration and localized operating stress. In its technical discussion of major system events, NERC states "shoulder seasons have become increasingly challenging for BPS operators to manage, resulting in several recent instances of pre-contingent load shedding."[44] The SOR also finds large load growth is increasing reliability risk and states that "data center and computational loads continued emerging as a major reliability consideration due to their scale, speed of development, and unique operational characteristics."[45] Finally, data in the SOR shows that 2025 PJM summer peak demand of 160.7 GW met or

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[37] *Id.*at 12.

[38] *PJM Interconnection, L.L.C.*, 190 FERC ¶ 61,084 (2025); *see also, e.g.*, *id.* P 263.

[39] *PJM Interconnection, L.L.C.*, 192 FERC ¶ 61,085, at P 25 (2025).

[40] NERC, *2025 Long-Term Reliability Assessment*, at 7 fig. 1 (Jan. 2026), https://www.nerc.com/globalassets/our-work/assessments/nerc_ltra_2025.pdf.

[41] *Id.* at 8.

[42] *Id.* at 16.

[43] *Id.* at 91.

[44] NERC, 2026 State of Reliability Technical Assessment of 2025 Bulk Power System Performance, at 5 (June 2026), https://nerc.com/globalassets/programs/rapa/pa/nerc_sor_2026_technical_assessment.pdf.

[45] *Id.* at vii.

exceeded extreme scenario levels showing how rapid load growth and extreme weather continue to be a risk in PJM.[46]

DOE Order Nos. 202-25-04, 202-25-08, 202-25-10, 202-26-17, and 202-26-24 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 No. 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 threat to our Nation's economy, national security, and foreign policy."[47] 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."[48] In the subsequent Executive Order No. 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."[49]

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 No. 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."[50] 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. For example, PPL Electric Utilities has 11.7 GW of advanced data center requests in Pennsylvania through to 2030.[51] As of December 2024, Dominion Energy has 40.2 GW

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[46] *Id.* at 30.

[47] Exec. Order No. 14156, 90 Fed. Reg. 8433 (Jan. 20, 2025), https://www.federalregister.gov/documents/2025/01/29/2025-02003/declaring-a-national-energy-emergency.

[48] *Id*.

[49] Exec. Order No. 14262, 90 Fed. Reg. 15521 (Apr. 8, 2025), https://www.federalregister.gov/documents/2025/04/14/2025-06381/strengthening-the-reliability-and-security-of-the-united-states-electric-grid.

[50] DOE, *Res. Adequacy Rep.: Evaluating the Reliability & Sec. of the U.S. Elec. Grid*, at 1 (July 2025) [hereinafter Resource Adequacy Report], https://www.energy.gov/sites/default/files/2025-07/DOE%20Final%20EO%20Report%20%28FINAL%20JULY%207%29.pdf.

[51] *See* PPL Corp., *PPL Corp. Q2 2025 Investor Update*, at 7 (July 31, 2025), https://filecache.investorroom.com/mr5ir_pplweb2/1245/PPL_2025_Q2_Investor_Update_vFINAL.pdf.

of contracted data center capacity, which is an 18.2 GW increase over the amount from July 2024, an approximately 88% increase.[52] In collaboration with the national labs, the Department has modeled the effects of approximately 25 GW of load growth in PJM, of which 15 GW came from data centers, as well as approximately 17 GW of announced coal, gas, and oil generation retirements.[53] Under these assumptions, the model estimated approximately 430.3 loss of load hours in an average weather year. Under worst weather year assumptions, the model estimated 1,052 loss of load hours and a maximum unserved load of approximately 21.335 GW.[54]

Grid operators, including PJM, have likewise acknowledged the Nation's current energy crisis. As mentioned earlier in this Order, PJM's then President Manu Astana testified that there was a "growing resource adequacy concern . . . impacting a significant part of our country."[55] Mr. Asthana explained that the "rate of electricity demand is anticipated to increase significantly in the future due to development of large data centers in the PJM service Area . . . [and] increases in demand coming from the transportation and heating sectors and from industrial growth."[56] Mr. Asthana noted that, though various reforms instituted by PJM had succeeded in bringing new generation online and preventing the retirement of existing units, supply conditions within PJM are still tightening.[57] Therefore, Mr. Asthana stated that PJM "encourage[s] all generation owners who have signaled an intent to retire their units to reconsider their decision to support resource adequacy and grid reliability."[58]

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 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," the Secretary has the authority "to require by order . . . such generation, delivery, interchange, or transmission of electric energy as in [his] judgment will best meet the

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[52] *See* Dominion Energy Virginia, *Q4 2024 Earnings Call*, at 18 (Feb. 12, 2025), https://s2.q4cdn.com/510812146/files/doc_financials/2024/q4/2025-02-12-DE-IR-4Q-2024-earnings-call-slides-vTCII.pdf.

[53] Resource Adequacy Report, *supra* note 50, at 28.

[54] *Id.* at 27.

[55] Asthana Test., *supra* note 6, at 4.

[56] *Id*.

[57] *Id.* at 9–10.

[58] *Id.* at 10.

emergency and serve the public interest."[59] This statutory language constitutes a specific grant of authority to the Secretary to require the continued operation of the Eddystone Units when the Secretary has determined that such operation will best meet an emergency caused by a sudden increase in the demand for electric energy or a shortage of generation capacity, or a shortage of electric energy or facilities for generation or transmission of electric energy.

As described above, the emergency conditions resulting from the increasing demand and shortage of electric energy from premature retirements of Eddystone Units 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 businesses in the areas affected by curtailments or outages, presenting a risk to public health, safety, and security.

I have determined that, to best meet the emergency arising from increased demand, determined shortage, and other causes, and serve the public interest under FPA section 202(c), the Eddystone Units shall be made available for operation through November 20, 2026.[60]

[59] 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).

[60] 16 U.S.C. § 824a(c)(4).

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

A. From August 23, 2026, PJM and Constellation Energy shall take all measures necessary to ensure that the Eddystone Units are available to operate. For the duration of this Order, PJM is directed to take every step to employ economic dispatch of the Eddystone Units to minimize cost to ratepayers. Constellation Energy is directed to comply with all orders from PJM related to the availability and dispatch of the Eddystone Units.

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

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

D. By September 8, 2026, PJM 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 Eddystone Units consistent with this Order. PJM shall also provide such additional information regarding the environmental impacts of this Order and its compliance with the conditions of this Order, in each case as requested by the Department from time to time.

E. Constellation Energy 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 Eddystone Units to comply with applicable state, local, or Federal laws 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 Eddystone Units shall not be considered capacity resource.

H. This Order shall be effective on August 23, 2026, through November 20, 2026, with the exception of applicable compliance obligations in paragraph D.

Issued in Washington, D.C. on this 21st day of August 2026.

Chris Wright

Chris Wright
Secretary of Energy

cc:

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

Pennsylvania Public Utility Commission
Chairman Stephen M. DeFrank
Vice Chair Kimberly M. Barrow
Commissioner Kathryn L. Zerfuss
Commissioner John F. Coleman, Jr.
Commissioner Ralph V. Yanora

UNITED STATES OF AMERICA
BEFORE THE
UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Craig Unit 1	))))	Order No. 202-26-49

The State Of Colorado's Request for Rehearing,
Motion To Intervene, And Stay Request

Exhibit CCCC: Department, Order No. 202-26-44 (Sept. 11, 2026)

Department of Energy
Washington, DC 20585

TransAlta Centralia Generation LLC,
GridForce Energy Management, LLC, and
Southwest Power Pool, Inc. Western RC
Regarding the TransAlta Centralia Generation Facility

Order No. 202-26-44

Pursuant to the authority vested in the Secretary of Energy (Secretary) by section 202(c) of the Federal Power Act (FPA),[1] and section 301(b) of the Department of Energy (DOE or the Department) Organization Act,[2] and for the reasons set forth below, I hereby determine that an emergency exists within the Western Electricity Coordinating Council (WECC)–Northwest assessment area[3] due to a sudden increase in demand, a shortage of electric energy, a shortage of facilities for the generation or transmission of electric energy, and other causes. Issuance of this Order will meet the emergency and serve the public interest.

BACKGROUND

TransAlta Centralia Generation Facility (Centralia) is an electric generating facility in Centralia, Washington. Centralia is owned and operated by TransAlta Centralia Generation LLC (TransAlta). Centralia consists of one remaining coal-fired generation unit, Unit 2, with a nameplate capacity of 729.9 MW.[4] Unit 2 began operations in 1973 and was slated to cease operations in December 2025. Unit 1 was retired in 2020. Unit 2 is slated to cease operation based on a 2011 Washington law[5] and a subsequent

[1] 16 U.S.C. § 824a(c).
[2] 42 U.S.C. § 7151(b).
[3] The terms "area" and "region" are used interchangeably herein.
[4] U.S. Energy Info. Admin., *Form EIA-860 detailed data with previous form data (EIA-860A/860B)*, https://www.eia.gov/electricity/data/eia860/ (click "2025 (early release)").
[5] Coal-Fired Elec. Generation Facilities, 2011 Wash. Sess. Laws, Ch. 180, https://lawfilesext.leg.wa.gov/biennium/2011-12/Pdf/Bills/Senate%20Bills/5769-S2.pdf.

agreement between TransAlta and the State of Washington.[6] TransAlta has announced plans to convert the unit to natural gas by 2028.[7]

Order Nos. 202-25-11, 202-25-11B, 202-26-18, and 202-26-28, issued pursuant to FPA section 202(c), required that Centralia remain in operation for 90 days, until March 16, 2026 (Order Nos. 202-25-11 and 202-25-11B), June 14, 2026, and September 12, 2026, respectively. Those orders were based on my determination that emergency conditions existed in the WECC–Northwest region.

Specifically, I determined that the WECC–Northwest region is at an elevated risk of insufficient operating reserves during periods of extreme weather.[8] I determined that the continued operation of Centralia would provide additional generation capacity during these periods, which would help prevent the potential loss of power to homes and

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[6] *See* Memorandum of Agreement between Christine O. Gregoire, Governor, State of Washington, & Paul Taylor, President, TransAlta Centralia Generation LLC (Dec. 23, 2011), https://ecology.wa.gov/getattachment/858591f6-dd25-47be-ba1d-0f58264ca147/20111223TransAltaMOA.pdf ("D. In exchange for the benefits of entering into an MOA with the State pursuant to RCW 80.80.100, the Company will . . . (5) permanently cease power generation operations of one Boiler in 2020 and the other Boiler in 2025, which dates are prior to the 2035 end of their expected useful lives . . . ."); *see also* First Amendment to Memorandum Of Agreement between Jay Inslee, Governor, State of Washington, & Bob Nelson, President, TransAlta Centralia Generation LLC (July 13, 2017), https://www.regulations.gov/document/EPA-R10-OAR-2020-0732-0010. As a coal-fired facility, it likely would be difficult for the Centralia 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. Further, if TransAlta 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. The costs and time of decommissioning a coal plant are extensive and include various components. Therefore, restarting such decommissioned plants would presumably cost the same as decommissioning in dollars and time, if not more. *See* Jennifer Lessick et al., *Bus. Models for Coal Plant Decommissioning* 9–12 (DOE, Pac. Nw. Nat'l Lab'y, Report, Aug. 2021), https://www.pnnl.gov/main/publications/external/technical_reports/PNNL-31348.pdf; *see also* U.S. Energy Info. Admin., *Capital Cost & Performance Characteristics for Util. Scale Elec. Power Generating Techs.* (Jan. 2024), https://www.eia.gov/analysis/studies/powerplants/capitalcost/pdf/capital_cost_AEO2025.pdf.

[7] TransAlta, *TransAlta Signs Long-Term Agreement for 700 MW at Centralia Facility Enabling Coal to Nat. Gas Conversion* (Dec. 9, 2025), https://transalta.com/newsroom/transalta-signs-long-term-agreement-for-700-mw-at-centralia-facility-enabling-coal-to-natural-gas-conversion/.

[8] *See*, *e.g.*, *TransAlta*, Order No. 202-25-11, at 1 (Dec. 16, 2025).

businesses in the areas that might have been affected by curtailments or outages that would otherwise pose a risk to public health and safety.[9] I determined that the continued operation of Centralia was necessary to alleviate immediate and anticipated threats to reliability.[10]

My determination was based on a number of facts. First, in its 2025–2026 Winter Reliability Assessment, the North American Electric Reliability Corporation (NERC) finds that the WECC–Northwest region, which includes Montana, Oregon, Washington, and parts of northern California and northern Idaho, is at elevated risk during periods of extreme weather.[11] The assessment notes that "there is sufficient capacity in the area for expected peak conditions; however, [balancing authorities] are likely to require external assistance during extreme winter weather that causes thermal plant outages and adverse wind turbine conditions for area internal resources. External assistance may not be available during region-wide extreme winter conditions. Winter peak demand for the area is forecast to be 2.9 GW higher (9.3%) compared to last year [i.e., in 2025–2026 compared to 2024–2025]."[12]

Second, in a September 2025 report evaluating Resource Adequacy in the Pacific Northwest, Energy + Environmental Economics (E3) determined that "[a]ccelerated load growth and continued retirements create a resource gap beginning in 2026 and growing to 9 GW by 2030"[13] and that "[l]oad growth and retirements mean the region faces a power supply shortfall in 2026."[14] E3 reported that nearly 9,000 MW of new capacity will be needed in the region by 2030, but currently only 3,000 MW of projects for new capacity are in active development.[15] Overall, E3 found that "[p]referred resources such as wind, solar and batteries make only small contributions to meeting resource adequacy needs" and "[t]imely development of all resources is extremely challenging due to permitting and interconnection delays, federal policy headwinds, and cost pressures."[16]

EMERGENCY SITUATION

[9] *See, e.g.*, *id.* at 1–3.

[10] *See, e.g.*, *id.* at 3–4.

[11] NERC, *2025–2026 Winter Reliability Assessment*, at 6 (Nov. 2025), https://www.nerc.com/globalassets/our-work/assessments/nerc_wra_2025.pdf.

[12] *Id*.

[13] E3, *Res. Adequacy & the Energy Transition in the Pac. Nw.: Phase 1 Results*, at 2 (Sep. 22, 2025), https://www.utc.wa.gov/sites/default/files/2025-10/Revised%20V3%20E3%20Presentation%20RA%20Study%20September%2022%20WA%20RA%20Meeting.pdf. *See also id.* (listing E3's study sponsors, which include certain "regional utilities and generation owners).

[14] *Id*. at 10.

[15] *Id*.

[16] *Id*. at 2.

The emergency conditions that necessitated the issuance of Order Nos. 202-25-11, 202-25-11B, 202-26-18, and 202-26-28 continue, both in the near and long term.[17] The production of electricity from Centralia will continue to be an asset to maintain reliability in the WECC–Northwest region. According to the U.S. Environmental Protection Agency's data, in 2025,[18] Centralia generated an average of approximately 340,000 MWh per month, providing vital generation capacity to the region.

In its 2025 Long-Term Reliability Assessment,[19] NERC assessed that the WECC–Northwest region is at high risk of energy shortfalls over the next five years,[20] noting that "[r]apid forecasted demand growth is driving the need for more resources" and that "[p]eriods of unserved energy are projected for both summer and winter."[21] The assessment notes that peak load in the region "is forecast to increase by 6.6 GW (19%) over the next 10 years, driven by an influx of data centers into the Pacific Northwest."[22] Additionally, while over 10 GW of new variable resources are in development, the assessment warns that "additional resources will be needed to avoid shortfalls in planning reserves and prevent energy risks from emerging."[23]

NERC's 2026 Summer Reliability Assessment (2026 SRA) classifies the WECC–Northwest region as an Elevated Risk[24] area with highest-risk conditions occurring in early evening hours (around 6 p.m.) in late summer.[25] The region faces "elevated risks of electricity supply shortfalls during periods of more extreme summer conditions or [is] subject to localized constraints that raise the risk levels of certain small areas within the broader system. 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

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[17] *See, e.g.*, Order No. 202-25-11 at 1.

[18] *See* EPA, *Custom Data Download, EPA CAMPD (Clean Air Mkts. Program Data)*, https://campd.epa.gov/data/custom-data-download (choose "Emissions" from Data Type dropdown; choose "Monthly Emissions" from Data Subtype dropdown; choose "Unit (No Aggregation)" from Aggregation dropdown; then click "Apply"; then type "2025" into "Time Period" filter and click "January, February, March, April, May, June, July, August, September, October, November, December"; then click "Apply Filter"; then click "Facility" filter and type "Centralia (3845)"; then click "Centralia (3845)"; then click "Apply Filter"; then click "Preview Data").

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

[20] *Id.* at 7.

[21] *Id.* at 8.

[22] *Id.* at 19.

[23] *Id.*

[24] Elevated risk refers to the potential for insufficient operating reserves in above-normal conditions. NERC*, 2026 Summer Reliability Assessment*, at 2–3 (May 2026), https://www.nerc.com/globalassets/our-work/assessments/nerc_sra_2026.pdf.

[25] NERC*, 2026 Summer Reliability Assessment*, at 2–3 (May 2026), https://www.nerc.com/globalassets/our-work/assessments/nerc_sra_2026.pdf.

low wind or solar photovoltaic (PV) energy conditions."[26] Under typical outage conditions the 2026 SRA forecasts reserve margins to be 25.2% and in a scenario with extreme conditions such as higher demand, outages, and derates, reserve margin is estimated to drop to 8.8%, below the 2026 SRA Reference Margin Level of 10.0%. In normal and typical outages, reserve margins in the 2026 SRA are expected to tighten compared to the 2025 SRA, partly due to net demand growth of 4.6% compared to an increase in energy availability by generation resources of 1.5%. NERC notes that "[t]hermal generators with diverse fuel sources can be an important electricity resource, especially during winter when solar PV and battery resources are less capable compared to summer months."[27] In addition, NERC's 2026 SRA notes:

> WECC–Northwest: The coming summer brings challenging hydrological conditions for regions in which hydropower makes up half or more of the supply fleet. Almost the entire Western Interconnection is in the grips of a persistent drought or in an area where drought development has a greater likelihood through the end of July. In Washington, for example, the snow water equivalent was at 52% of normal levels as of April 1 this year when snowpack typically reaches its peak. While the total water year supply is forecast to be nearly average in the Columbia River Basin, snowpack peaked at low elevation and melted early in the year. This has implications for the expected resources available to the Northwest, the generation mix for which is 55% hydropower. The region is contending with a nearly 5% increase in net internal demand from the 2025 SRA and a nearly 2% drop in existing resources as well as a roughly 43% drop in expected Tier 1 resources. Though higher modeled net transfers are projected to contribute double what they were projected to last year (albeit with the increase largely attributable to a modeling change that accounts for economic transfers), this was not enough to prevent the drop in the Anticipated Reserve Margin from 32% last year to 27% this year.[28]
>
> Peak net internal demand is projected to grow 4.6% over last summer's forecasts; however, anticipated resources are showing just a 1.5% increase in energy availability, leading to tighter margins. Wide-area heat events, wildfires, and low snow-water equivalents due to a changing climate impact generation resource and transmission availability and remain a continued reliability concern. Firm imports may be limited at this time if neighboring areas are also experiencing peak loads or derates, limiting energy availability. Supply chain constraints and economic uncertainty may impact Tier 1 resources. There have been instances where operators had difficulty maintaining frequency due to sudden disconnection of large loads necessitating additional regulation capability.

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[26] *Id*. at 2.
[27] *Id.* at 9.
[28] *Id*. at 2.

Expected resources do not meet operating reserve requirements under the assessed extreme scenarios.[29]

On March 2, 2026, an amended preliminary injunction was issued by the U.S. District Court for the District of Oregon that imposes operational constraints on the dams that comprise the Federal Columbia River Power System.[30] The restrictions imposed by the amended preliminary injunction will impact power and transmission system reliability, grid stability, and the ability to meet reserve requirements in the WECC–Northwest assessment region.[31] The District Court did not give adequate consideration to the impacts that the preliminary injunction measures will have on the Bonneville Power Administration's (BPA) ability to provide reliable power and transmission services. BPA submitted several declarations detailing the impacts on reliability that would result from the preliminary injunction sought.[32] BPA's modeling of the operational measures in the motion for preliminary injunction concluded that the Columbia River System generation would be greatly decreased in March through November (nine months out of the year) and substantially increase the risk during time periods of high demand such as summer heat waves.[33] Indeed, there is a substantial increased risk that the regional power system will not be able to operate reliably under the ordered spill levels.[34]

NERC released its 2026 State of Reliability (SOR) on June 24, 2026. In the SOR, NERC identifies worsening reliability concerns tied to large-load integration and localized operating stress. In its technical discussion of major system events, NERC states "shoulder seasons have become increasingly challenging for BPS operators to manage, resulting in several recent instances of pre-contingent load shedding."[35] The SOR also finds large load growth is increasing reliability risk and states that "data center and computational loads continued emerging as a major reliability consideration due to their scale, speed of development, and unique operational characteristics."[36]

Order Nos. 202-25-11, 202-25-11B, 202-26-18, and 202-26-28 were preceded by executive orders on January 20, 2025, and April 8, 2025, in which President Donald J.

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[29] *Id*. at 36.

[30] *Nat'l Wildlife Fed'n (NWF) v. Nat'l Marine Fisheries Serv. (NMFS)*, No. 3:01-cv-00640 (D. Or. Mar. 2, 2026) (order granting amended preliminary injunction).

[31] Fed. Def. Response to Minute Order at 4–5, *NWF v. NMFS*, No. 3:01-cv-00640.

[32] *See, e.g.*, Decl. of Rachel Dibble in Supp. of Fed. Def. Opp'n to Pls. Mot. for a Prelim. Inj., *NWF v. NMFS*, No. 3:01-00640, ECF No. 2574; Decl. of Audrey Stevenson in Supp. of Fed. Def. Opp'n to Pls. Mot. for a Prelim. Inj., *NWF v. NMFS*, No. 3:01-00640, ECF No. 2582.

[33] *See* Dibble Decl. ¶ 28; *id.* ¶ 42, fig. 3.

[34] *See, e.g.*, *id.* ¶ 26; Stevenson Decl. ¶ 18.

[35] NERC, *2026 State of Reliability: Tech. Assessment of 2025 Bulk Power Sys. Performance*, at 5 (June 24, 2026), https://www.nerc.com/globalassets/programs/rapa/pa/nerc_sor_2026_technical_assessment.pdf.

[36] *Id.* at vii.

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 No. 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 threat to our Nation's economy, national security, and foreign policy."[37] 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."[38] In a subsequent Executive Order No. 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."[39]

In addition, President Trump issued a White House Memo that emphasized the findings of Executive Order No. 14156 stating that "ensuring reliable coal supply chains and baseload power generation capacity is essential to the United States national defense . . . . Without sufficient coal-fired baseload power, the United States will lack the stable electricity required to support defense installations, industrial expansion, and the high-energy demands of emerging technologies, such as artificial intelligence."[40] President Trump "further determine[d] that action to expand coal supply chain capacity and baseload generation availability is necessary to avert an industrial resource or critical technology item shortfall that would severely impair national defense capability."[41]

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 No. 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

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[37] Exec. Order No. 14156, 90 Fed. Reg. 8433 (Jan. 20, 2025), https://www.federalregister.gov/documents/2025/01/29/2025-02003/declaring-a-national-energy-emergency.

[38] *Id.*

[39] Exec. Order No. 14262, 90 Fed. Reg. 15521 (Apr. 8, 2025), https://www.federalregister.gov/documents/2025/04/14/2025-06381/strengthening-the-reliability-and-security-of-the-united-states-electric-grid.

[40] The White House, *Presidential Determination Pursuant to Sec. 303 of the Def. Prod. Act of 1950, as Amended, on Coal Supply Chains & Baseload Power Generation Capacity*, (Apr. 20, 2026), https://www.whitehouse.gov/presidential-actions/2026/04/presidential-determination-pursuant-to-section-303-of-the-defense-production-act-of-1950-as-amended-on-coal-supply-chains-and-baseload-power-generation-capacity.

[41] *Id*.

(AI) innovation."[42] 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.

Pursuant to section 202(c)(4)(B) of the FPA, DOE 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 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 other causes," the Secretary has the authority "to require by order . . . such generation, delivery, interchange, or transmission of electric energy as in [his] judgment will best meet the emergency and serve the public interest."[43] This statutory language constitutes a specific grant of authority to the Secretary to require the continued availability of Centralia Unit 2 when the Secretary has determined that such continued availability will best meet the emergency.

As described above, the emergency conditions resulting from increasing demand and shortage of electric energy from premature retirement of the Centralia plant will continue in the near term and are also likely to continue in subsequent years. This could lead to the potential loss of power to homes, businesses, and facilities critical to national defense in the areas affected by curtailments or power outages, presenting a risk to public health and safety.

I have determined that, to best meet the emergency arising from increased demand, determined shortage, and other causes, and serve the public interest under FPA section 202(c), Centralia Unit 2 shall be made available for operation through December 11, 2026.

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[42] DOE, *Res. Adequacy Rep.: Evaluating the Reliability & Sec. of the U.S. Elec. Grid*, at 1 (July 2025), https://www.energy.gov/sites/default/files/2025-07/DOE_Fact_Sheet_Grid_Report_July_2025.pdf.

[43] 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).

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

A. From September 13, 2026, TransAlta shall take all measures necessary to ensure that Centralia Unit 2 is available to operate at the direction of either Gridforce Energy Management, LLC (in its role as Balancing Authority)[44] or Southwest Power Pool Western RC[45] (in its role as the Reliability Coordinator) or any successors thereto. Following the conclusion of this Order, sufficient time for orderly ramp down is permitted, consistent with industry practices.

B. To minimize adverse environmental impacts, this Order limits operation of Centralia Unit 2 to the times and within the parameters established in paragraph A. TransAlta shall provide a daily notification to the Department (via AskCR@hq.doe.gov) reporting whether Centralia Unit 2 has operated in compliance with this Order.

C. All operations of Centralia Unit 2 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 conditions or to use other geographic or temporal flexibilities available to generators.

D. By September 27, 2026, TransAlta is directed to provide the Department of Energy (via AskCR@hq.doe.gov) with information concerning the measures it has taken and is planning to take to ensure the operational availability of Centralia Unit 2, consistent with this Order. TransAlta shall also provide such additional information regarding the environmental impacts of this Order and its compliance with the conditions of this Order, as requested by the Department of Energy from time to time.

E. TransAlta is directed to file with the Federal Energy Regulatory Commission tariff revisions or waivers to effectuate this Order, as needed. Rate recovery is available pursuant to 16 U.S.C. § 824a(c).

F. BPA is directed to facilitate transmission service, as needed, to effectuate this Order.

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[44] *See* U.S. Energy Info. Admin., *Hourly Elec. Grid Monitor*, https://www.eia.gov/electricity/gridmonitor/about (click "EIA-930A 2024 data"). On EIA-930A 2024 SCH 2, the BA Code for TransAlta Central Generation is GRID. *See also id.* (click "EIA-930 data reference tables"). On EIA-930 data reference tables, BA Code GRID is associated with Gridforce Energy Management, LLC.

[45] *See* Sw. Power Pool, Map RTO and Western RC Footprint with Planned Expansion map, https://www.spp.org/documents/62914/rto%20and%20western%20rc%20footprint%20w%20planned%20expansion.png.

G. This Order shall not preclude the need for Centralia Unit 2 to comply with applicable state, local, or Federal law or regulations following the expiration of this Order.

H. Because this Order is predicated on the shortage of facilities for generation of electric energy and other causes, Centralia Unit 2 shall not be considered a capacity resource.

I. This Order shall be effective from September 13, 2026, through December 11, 2026, with the exception of applicable compliance obligations in paragraph D.

J. TransAlta is directed to provide written notice to the Department as soon as practicable, but no later than 15 days, following the receipt of any required permits necessary to convert the facility to natural gas.

Issued in Washington, D.C. on this 11th day of September, 2026.

Chris Wright
Secretary of Energy

cc: **Federal Energy Regulatory Commission**
Chairman Laura V. Swett
Commissioner David Rosner
Commissioner Lindsay S. See
Commissioner Judy W. Chang
Commissioner David A. LaCerte

Washington Utilities and Transportation Commission
Chair Brian Rybarik
Commissioner Milt Doumit
Commissioner Ann Rendahl

UNITED STATES OF AMERICA
BEFORE THE
UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Craig Unit 1	))))	Order No. 202-26-49

The State Of Colorado's Request for Rehearing,
Motion To Intervene, And Stay Request

Exhibit DDDD: Department, Order No. 202-26-46 (Sept. 18, 2026)

Department of Energy
Washington, DC 20585

Northern Indiana Public Service Company LLC and Midcontinent Independent System Operator, Inc.
Regarding R.M. Schahfer Generating Station

Order No. 202-26-46

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

BACKGROUND

The R.M. Schahfer Generating Station (Schahfer) is an electric generating facility in Wheatfield, Indiana. Schahfer is owned and operated by Northern Indiana Public Service Company (NIPSCO), a division of NiSource Inc. Schahfer consists of two 129 MW natural-gas fired electric generating units and two coal-fired electric generating units, Unit 17 (423.5 MW) and Unit 18 (423.5 MW), with a combined nameplate capacity of 1,105 MW.[3] Units 17 and 18 began operations in 1983 and 1986, respectively. They were both slated to cease operations in December 2025.[4]

Order Nos. 202-25-12, 202-26-19, and 202-26-29, issued pursuant to FPA section 202(c), required that Schahfer Unit 17 and Unit 18 remain in operation for 90 days, until March 23, 2026, June 21, 2026, and September 19, 2026, respectively.

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[1] 16 U.S.C. § 824a(c).

[2] 42 U.S.C. § 7151(b).

[3] U.S. Energy Info. Admin., *Form EIA-860 detailed data with previous form data (EIA-860A/860B)*, *)*, https://www.eia.gov/electricity/data/eia860/ (click "2025 (early release)").

[4] It likely would be difficult for the coal-fired units to resume operations once retired. Specifically, practical issues, such as employment, contracts, and permits, may greatly increase the timeline for resumption of operations during the period they are needed. Moreover, if NIPSCO were to begin disassembling the units or other related facilities, the associated challenges would be greatly exacerbated. The costs and time of decommissioning a coal plant are extensive, and restarting such decommissioned plants would presumably cost the same as decommissioning in dollars and time, if not more. Thus, continuous operation is required in such cases so long as the Secretary determines a shortage exists and is likely to persist. *See* Jennifer Lessick, et al., *Bus. Models for Coal Plant Decommissioning*, at 9-12 (DOE, Pac. Nw. Nat'l Lab'y, Report, Aug. 2021), https://www.pnnl.gov/main/publications/external/technical_reports/PNNL-31348.pdf.

Those orders were based on my determination that emergency conditions existed in the region served by MISO.

Specifically, I determined that MISO faced tight reserve margins due to well-documented year-round resource adequacy concerns, particularly during periods of high demand or low generation resource output.[5] I determined that the continued operation of Schahfer Units 17 and 18 would provide additional generation capacity during these periods, which would help prevent the loss of power to homes and businesses in the areas that might have been affected by curtailments or outages that would otherwise pose a risk to public health and safety.[6] I determined that the continued operation of Schahfer Units 17 and 18 was necessary to alleviate immediate and anticipated threats to reliability.[7]

My determination was based on several facts. First, in its 2024 Long-Term Reliability Assessment (2024 LTRA), the North American Electric Reliability Corporation (NERC) notes that the MISO assessment area, which covers portions of Arkansas, Illinois, Indiana, Iowa, Kentucky, Louisiana, Michigan, Minnesota, Mississippi, Missouri, Montana, North Dakota, South Dakota, Texas, and Wisconsin, is at an elevated risk, "because probabilistic assessments indicate above-normal generator outages during extreme weather can result in unserved energy or load loss. With uncertainty around new resource additions and existing generator retirements, MISO is also at risk of falling below [Reference Margin Levels] within the next five years."[8] Additionally, the 2024 LTRA notes that "[t]he departure of MISO's coal fleet has continued with a reduction in capacity of around 6 GW in the past year, and a projected reduction of a further 12 GW over the next five years."[9]

CONTINUING EMERGENCY CONDITIONS

The emergency conditions that necessitated the issuance of Order Nos. 202-25-12, 202-26-19, and 202-26-29 continue, both in the near and long term. The production of electricity from Schahfer Units 17 and 18 continue to be a critical asset to maintain reliability in MISO. MISO's resource adequacy concerns were recently demonstrated during Winter Storm Fern, when Schahfer operated under a cold weather alert and declared conservative operations from January 23 through February 1, 2026. On January 24, MISO declared an Energy Emergency Alert (EEA) 1, as well as an EEA 2 "MaxGen" event for MISO's North and Central Regions due to generation outages, high demand,

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[5] *See, e.g.*, *Midcontinent Indep. Sys. Operator, Inc*, DOE Order No. 202-26-29, at 2–5 (June 18, 2026,).

[6] *See, e.g.*, *id.*

[7] *See, e.g.*, *id.* at 5.

[8] N. Am. Elec Reliability Corp., *2024 Long-Term Reliability Assessment*, at 13 (Dec. 2024, corrected July 11, 2025), https://www.nerc.com/globalassets/our-work/assessments/2024-ltra_corrected_july_2025.pdf.

[9] *Id.* at 44.

and transfer capability limits.[10] From January 21–February 1, 2026, Schahfer Units 17 and 18 operated at roughly 285 MW almost every day.[11] According to the EIA-923 Power Plant Operations Report's monthly generation data for June 2026, the total net generation for Schahfer Units 17 and 18 was 303,344 MWh from January 2026 to June 2026 for an average of 50,557.3 MWh per month.[12] This generation data indicates that Schahfer Units 17 and 18 are providing vital generation capacity to the region.

MISO's year-round resource adequacy concerns are well-documented. 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.[13] MISO justified this revision by explaining that "[r]eliability risks associated with [r]esource [a]dequacy have shifted from 'Summer only' to a year-round concern."[14] 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.[15]

In December 2023, MISO released an "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."[16] 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.[17] MISO also projected that the risk of loss of load in the winter

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[10] MISO, *Operations Rep.*, at 10 (Mar. 24, 2026), https://cdn.misoenergy.org/20260324%20Markets%20Committee%20of%20the%20BOD%20Item%2008%20MISO%20Operations%20Report746763.pdf.

[11] DOE, *FACT SHEET: Energy Dep't Prevented Blackouts & Saved Am. Lives During Winter Storms* (Feb. 6, 2026), https://www.energy.gov/articles/fact-sheet-energy-department-prevented-blackouts-saved-american-lives-during-winter-storms.

[12] *See* EIA, *Form EIA-923 detailed data with previous form data (EIA-906/920)*, https://www.eia.gov/electricity/data/eia923/ (choose "2026: EIA-923 May 2026").

[13] *Midcontinent Indep. Sys. Operator, Inc.*, Transmittal Letter, FERC Dkt. No. ER22-495-000 (filed Nov. 30, 2021). FERC accepted MISO's proposed tariff revisions on August 31, 2022. *See also Midcontinent Indep. Sys. Operator, Inc.*, 180 FERC ¶ 61,141 (2022), *order on reh'g & compliance*, 182 FERC ¶ 61,096 (2023).

[14] *MISO*, Transmittal Letter, FERC Dkt. No. ER22-495-000, at 3.

[15] *Id.* at 3–4.

[16] MISO, *Attributes Roadmap*, at 3 (Dec. 2023), https://cdn.misoenergy.org/2023%20Attributes%20Roadmap%20Executive%20Summary631175.pdf.

[17] *Id.* at 11.

and spring seasons will nevertheless increase over time, although not as high as in the summer or fall.[18]

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.*"[19] In a section of that report entitled, "Risks in Non-Summer Seasons," MISO again stressed that it has resource reliability concerns outside of the summer season:

> 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 historic risk profile, creating risks in non-summer months that rarely posed challenges in the past.[20]

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 (2025 LTRA).[21] NERC assessed that the MISO region is at high risk of energy shortfalls over the next five years,[22] stating that it faces significant reliability challenges as "projected resource additions do not keep pace with escalating demand forecasts and announced generator retirements."[23] This determination is based on the combination of accelerating demand growth from new data centers and the retirement of existing thermal generators.[24] The 2025 LTRA 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."[25] NERC observes that winter peak periods are a particular concern, with projections showing "shortfalls in planned resources for winter peak periods."[26] 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."[27]

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[18] *Id*.

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

[20] *Id.* at 12.

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

[22] *Id.* at 6, 8.

[23] *Id.* at 8.

[24] *Id.* at 43.

[25] *Id.* at 15.

[26] *Id*.

[27] *Id.*

The 2025–2026 NERC Winter Reliability Assessment found the MISO region to be at normal risk in 2026 and elevated risk in 2027. The two previous winter studies respectively characterized MISO as a region at elevated risk with the "[p]otential for insufficient operating reserves in above-normal conditions"[28] and noted that "[g]enerating capacity is 10 GW lower (-6.8%) compared to the prior winter as generators have retired, withdrawn from MISO's capacity market, or received lower winter accredited capacity."[29]

NERC released its 2026 Summer Reliability Assessment (SRA) on May 19, 2026. In its assessment, NERC stated that "MISO's peak load has increased by 2.5 GW from the 2025 SRA."[30] The 2026 SRA also projects that data center load will continue to accelerate in 2027 and beyond, potentially increasing reliability risk if capacity additions do not keep pace.[31] Furthermore, the 2026 SRA states that "[a]bove-normal summer peak load combined with low resource conditions could result in the need to employ operating mitigations (e.g., load-modifying resources) and EEAs [Energy Emergency Alerts]."[32] Since the region benefits from transmission connections with neighbors to meet extreme conditions, MISO's reliance on electricity imports will increase when extreme conditions arise."[33]

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 2025–26 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 Indiana.[34]

There continues to be tight capacity available during summer despite the recent "gains in offered capacity outpacing pressure of load growth" in the MISO region, as reported in its PRA for the 2026-2027 Planning Year.[35] MISO noted that "new generation

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

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

[30] NERC, *2026 Summer Reliability Assessment*, at 16 (May 2026), https://www.nerc.com/globalassets/our-work/assessments/nerc_sra_2026.pdf.

[31] *Id.*

[32] *Id.*

[33] *Id*.

[34] MISO, *Planning Res. Auction: Results for Planning Year 2025–26*, at 13 (Apr. 2025), https://cdn.misoenergy.org/2025%20PRA%20Results%20Posting%2020250529_Corrections694160.pdf.

[35] MISO, *Planning Res. Auction Results for Planning Year 2026/27*, at 3 (Apr. 2026, updated May 22, 2026), https://cdn.misoenergy.org/2026%20PRA%20Results%20Posting%2020260522%20-%20Corrections754715.pdf.

capacity is coming online, but faster resource additions are still needed to support large-load growth and ensure resource adequacy."

On June 4, 2026, the Organization of MISO States (OMS) and MISO issued the results of their 2026 survey, which has been conducted annually for many years to determine the degree to which expected capacity resources satisfy planning reserve margin requirements.[36] The 2026 OMS-MISO Survey presented projections of resource adequacy for the summer of 2026 and subsequent years and states "growth as submitted by [load serving entities or LSEs] continues to accelerate, with a [compound annual growth rate or CAGR] projected between 3.1% and 5.1% over [the next] five years."[37]

The OMS-MISO Survey further indicates that "[v]arious projected capacity scenarios and large load additions highlight increasing uncertainty and evolving risk"[38] and observes various negative risks. Examples include intensification of winter reliability risks based on resource availability/performance, which exacerbates seasonal reliability vulnerabilities; delay of new resource deployment owing to persistent supply-chain disruptions, labor constraints and permitting challenges; resource adequacy pressures continuing from load growth driven by data centers, new industrial, and commercial development; and continued backlog and uncertainty related to resources with signed Generator Interconnection Agreements (GIA).[39] In addition, 87 GW of signed GIAs are not yet online, and 192 GW of active GIAs still under study.[40]

Finally, the OMS-MISO Survey lists ongoing challenges such as more frequent extreme weather; accelerating demand for electricity and large load interconnections; loss of accredited capacity and reliability attributes as resource mixes evolve; the increasing pace of new resources additions; addressing local reliability issues (load pocket); and evolving storage participation.[41]

NERC released its 2026 State of Reliability (SOR) on June 24, 2026. In the SOR, NERC identifies worsening reliability concerns tied to large-load integration and localized operating stress. In its technical discussion of major system events, NERC states "shoulder seasons have become increasingly challenging for Bulk Power System operators to manage, resulting in several recent instances of pre-contingent load shedding."[42] The SOR also finds large load growth is increasing reliability risk and states

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[36] OMS & MISO, *OMS-MISO Survey Results* (updated June 4, 2026) (2026 OMS-MISO Survey), https://cdn.misoenergy.org/20260604%20OMS-MISO%20Survey%20Results%20Workshop%20Presentation761711.pdf.

[37] *Id.* at 2.

[38] *Id.* at 3.

[39] *Id.* at 4.

[40] *Id.*

[41] *Id.* at 16.

[42] NERC, *2026 State of Reliability: Tech. Assessment of 2025 Bulk Power Sys. Performance*, at 5 (June 24, 2026), https://www.nerc.com/globalassets/programs/rapa/pa/nerc_sor_2026_technical_assessment.pdf.

that "data center and computational loads continued emerging as a major reliability consideration due to their scale, speed of development, and unique operational characteristics."[43] Finally, data in the SOR shows that 2025 MISO summer and winter peak demands of 121.6 GW and 108.8 GW, respectively, met or exceeded extreme scenario levels showing how rapid load growth and extreme weather continue to be a real risk in MISO.[44]

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.[45] MISO's 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.[46] 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.[47] Consequently, the new ERAS process is unlikely to result in the addition of any new generation capacity in the next few years.

Order Nos. 202-25-12, 202-26-19, and 202-26-29 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 No. 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 threat to our Nation's economy, national security, and foreign policy."[48] The Executive Order adds that "hostile state and non-state foreign actors have targeted our domestic energy infrastructure, weaponized our

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[43] *Id.* at vii.

[44] *Id.* at 28, 30.

[45] *Midcontinent Indep. Sys. Operator, Inc.*, 192 FERC ¶ 61,064 (2025).

[46] NERC, *State of Reliability*, *supra* note 48, at 84.

[47] *See generally* Jared Anderson, *US Gas-Fired Turbine Wait Times as Much as Seven Years; Costs Up Sharply*, S&P GLOBAL (May 2025) ("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."), 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.

[48] Exec. Order No. 14156, 90 Fed. Reg. 8433 (Jan. 20, 2025), https://www.federalregister.gov/documents/2025/01/29/2025-02003/declaring-a-national-energy-emergency.

reliance on foreign energy, and abused their ability to cause dramatic swings within international commodity markets."[49] In the subsequent Executive Order No. 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."[50]

In addition, President Trump issued a White House Memo for the Secretary that emphasized the findings of Executive Order No. 14156, stating that "ensuring reliable coal supply chains and baseload power generation capacity is essential to the United States national defense . . . . Without sufficient coal-fired baseload power, the United States will lack the stable electricity required to support defense installations, industrial expansion, and the high-energy demands of emerging technologies, such as artificial intelligence."[51] The President "further determine[d] that action to expand coal supply chain capacity and baseload generation availability is necessary to avert an industrial resource or critical technology item shortfall that would severely impair national defense capability."[52]

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," which was issued pursuant to the President's directive in Executive Order No. 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."[53] 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 NiSource's announcement of executed long-

[49] *Id*.

[50] Exec. Order No. 14262, 90 Fed. Reg. 15521 (Apr. 8, 2025), https://www.federalregister.gov/documents/2025/04/14/2025-06381/strengthening-the-reliability-and-security-of-the-united-states-electric-grid.

[51] Memorandum from President Donald J. Trump to the Secretary of Energy (Apr. 20, 2026) (*Presidential Determination Pursuant to Sec. 303 of the Def. Prod. Act of 1950, as Amended, on Coal Supply Chains & Baseload Power Generation Capacity*), https://www.whitehouse.gov/presidential-actions/2026/04/presidential-determination-pursuant-to-section-303-of-the-defense-production-act-of-1950-as-amended-on-coal-supply-chains-and-baseload-power-generation-capacity/.

[52] *Id.*

[53] DOE, *Res. Adequacy Rep.: Evaluating the Reliability & Sec. of the U.S. Elec. Grid*, at 1 (July 2025), https://www.energy.gov/sites/default/files/2025-07/DOE%20Final%20EO%20Report%20%28FINAL%20JULY%207%29.pdf.

term agreements[54] to deliver energy solutions and energy capacity for approximately 4 GW of large-scale data centers in Northern Indiana.[55]

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, MISO's Senior Vice President for Planning and Operations, Jennifer Curran, 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."[56]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."[57] She added that "[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."[58]

Pursuant to section 202(c)(4)(B) of the FPA, DOE 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 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," the Secretary has the authority "to require by order . . . such generation, delivery, interchange, or transmission of electric energy as in [his] judgment will best meet the

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[54] *NiSource announces strategic energy infrastructure agreements to enhance customer value and economic growth in Indiana,* NIPSCO (Apr. 16, 2026), https://www.nipsco.com/our-company/news-room/news-article/nisource-announces-strategic-energy-infrastructure-agreements-to-enhance-customer-value-and-economic-growth-in-indiana.

[55] NiSource Inc., *Supplemental Slides 1Q 2026 Results,* (May 6, 2026), https://s1.q4cdn.com/829981032/files/doc_earnings/2026/q1/supplemental-info/NiSource-1Q_2026-Earnings-Slides-FINAL.pdf.

[56] *Keeping the Lights On: Examining the State of Reg'l Grid Reliability; Hearing Before the House Comm. on Energy & Commerce*, *Subcommittee on Energy,* 119th Cong. 5 (2025) (statement of Ms. Jennifer Curran, Senior Vice President for Planning and Operations, MISO), https://www.congress.gov/119/meeting/house/118040/witnesses/HHRG-119-IF03-Wstate-CurranJ-20250325.pdf.

[57] *Id.* at 6.

[58] *Id.* at 7.

emergency and serve the public interest."[59] This statutory language constitutes a specific grant of authority to the Secretary to require the continued operation of Schahfer Units 17 and 18 when the Secretary has determined that such operation will best meet an emergency.

As described above, the emergency conditions resulting from increasing demand and shortage of electric energy from premature retirement of generation facilities 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 businesses in the areas that may be affected by curtailments or power outages, presenting a risk to public health and safety.

I have determined that, to best meet the emergency arising from increased demand, determined shortage, and other causes, and serve the public interest under FPA section 202(c), Schahfer Units 17 and 18 shall be made available for operation through December 18, 2026.[60]

[59] 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).

[60] 16 U.S.C. § 824a(c)(4).

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

A. From September 20, 2026, NIPSCO and MISO shall take all measures necessary to ensure that Schahfer Units 17 and 18 are available to operate. For the duration of this Order, MISO is directed to take every step to employ economic dispatch of Schahfer Units 17 and 18 to minimize cost to ratepayers. Following the conclusion of this Order, sufficient time for orderly ramp down is permitted, consistent with industry practices. NIPSCO is directed to comply with all orders from MISO related to the availability and dispatch of Schahfer Units 17 and 18.

B. To minimize adverse environmental impacts, this Order limits operation of Schahfer Units 17 and 18 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 Schahfer Units 17 and 18 have operated in compliance with this Order.

C. All operations of Schahfer Units 17 and 18 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 conditions or to use other geographic or temporal flexibilities available to generators.

D. By October 3, 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 Schahfer Units 17 and 18 consistent with this Order. NIPSCO and 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.

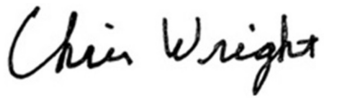
E. NIPSCO is directed to file with FERC tariff revisions or waivers to effectuate this Order, as needed. Rate recovery is available pursuant to 16 U.S.C. § 824a(c).

F. This Order shall not preclude the need for Schahfer Units 17 and 18 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, Schahfer Units 17 and 18 shall not be considered capacity resources.

H. This Order shall be effective from September 20, 2026, through December 18, 2026, with the exception of applicable compliance obligations in paragraph D.

Issued in Washington, D.C. on this 18th Day of September 2026.



Chris Wright
Secretary of Energy

cc: **Federal Energy Regulatory Commission**
Chairman Laura V. Swett
Commissioner David Rosner
Commissioner Lindsay S. See
Commissioner Judy W. Chang
Commissioner David A. LaCerte

Indiana Utility Regulatory Commission
Chairman Anthony Swinger
Commissioner Joshua Bain
Commissioner Bob Deig
Commissioner Joby Jerrells
Commissioner David Ziegner

UNITED STATES OF AMERICA
BEFORE THE
UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Craig Unit 1	)	Order No. 202-26-49

The State Of Colorado's Request for Rehearing,
Motion To Intervene, And Stay Request

Exhibit EEEE: Department, Order No. 202-26-47 (Sept. 18, 2026)

Department of Energy
Washington, DC 20585

CenterPoint Energy and
Midcontinent Independent System Operator, Inc.
Regarding F.B. Culley Generating Station

Order No. 202-26-47

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

BACKGROUND

The F.B. Culley Generating Station (Culley) is an electric generating facility in Warrick County, Indiana. Culley is owned and operated by CenterPoint Energy and consists of two coal-fired electric generating units, Unit 2 (103.7 MW) and Unit 3 (265.2 MW), with a combined nameplate capacity of 368.9 MW.[3] Unit 2 and Unit 3 began operations in 1966 and 1973, respectively. Unit 2 was slated to cease operations in December 2025.[4]

Order Nos. 202-25-13, 202-26-20, and 202-26-30, issued pursuant to FPA section 202(c), required that Culley Unit 2 remain in operation for 90 days, until March 23, 2026, June 21, 2026, and September 19, 2026, respectively. Those orders

[1] 16 U.S.C. § 824a(c).

[2] 42 U.S.C. § 7151(b).

[3] U.S. Energy Info. Admin., *Form EIA-860 detailed data with previous form data (EIA-860A/860B)*, https://www.eia.gov/electricity/data/eia860/ (click "2025 (early release)").

[4] It likely would be difficult for the coal-fired units to resume operations once retired. Specifically, practical issues, such as employment, contracts, and permits, may greatly increase the timeline for resumption of operations during the period they are needed. Moreover, if CenterPoint Energy were to begin disassembling the units or other related facilities, the associated challenges would be greatly exacerbated. The costs and time of decommissioning a coal plant are extensive, and restarting such decommissioned plants would presumably cost the same as decommissioning in dollars and time, if not more. Thus, continuous operation is required in such cases so long as the Secretary determines a shortage exists and is likely to persist. *See* Jennifer Lessick et al., *Bus. Models for Coal Plant Decommissioning*, at 9–12 (DOE, Pac. Nw. Nat'l Lab'y, Report, Aug. 2021), https://www.pnnl.gov/main/publications/external/technical_reports/PNNL-31348.pdf.

were based on my determination that emergency conditions existed in the region served by MISO.

Specifically, I determined that MISO faced tight reserve margins due to well-documented year-round resource adequacy concerns, particularly during periods of high demand or low generation resource output.[5] I determined that the continued operation of Culley Unit 2 would provide additional generation capacity during these periods, which would help prevent the loss of power to homes and businesses in the areas that might have been affected by curtailments or outages that would otherwise pose a risk to public health and safety.[6] I determined that the continued operation of Culley Unit 2 was necessary to alleviate immediate and anticipated threats to reliability.[7]

My determination was based on several facts. First, in its 2024 Long-Term Reliability Assessment (2024 LTRA), the North American Electric Reliability Corporation (NERC) notes that the MISO assessment area, which covers portions of Arkansas, Illinois, Indiana, Iowa, Kentucky, Louisiana, Michigan, Minnesota, Mississippi, Missouri, Montana, North Dakota, South Dakota, Texas, and Wisconsin, is at an elevated risk, "because probabilistic assessments indicate above-normal generator outages during extreme weather can result in unserved energy or load loss. With uncertainty around new resource additions and existing generator retirements, MISO is also at risk of falling below [Reference Margin Levels] within the next five years."[8] Additionally, the 2024 LTRA notes that "[t]he departure of MISO's coal fleet has continued with a reduction in capacity of around 6 GW in the past year, and a projected reduction of a further 12 GW over the next five years."[9]

CONTINUING EMERGENCY CONDITIONS

The emergency conditions that necessitated the issuance of Order Nos. 202-25-13, 202-26-20, and 202-26-30 continue, both in the near and long term. The production of electricity from Culley Unit 2 continues to be a critical asset to maintain reliability in MISO. MISO's resource adequacy concerns were recently demonstrated during Winter Storm Fern, when Culley operated under a cold weather alert and declared conservative operations from January 23 through February 1, 2026. On January 24, MISO declared an Energy Emergency Alert (EEA) 1, as well as an EEA 2 "MaxGen" event for MISO's North and Central Regions due to generation outages, high demand, and transfer

[5] *See, e.g.*, *Midcontinent Indep. Sys. Operator, Inc*, DOE Order No. 202-26-30, at 2–5 (June 18, 2026).

[6] *See, e.g.*, *id.*

[7] *See, e.g.*, *id.* at 5.

[8] N. Am. Elec Reliability Corp., *2024 Long-Term Reliability Assessment*, at 13 (Dec. 2024, corrected July 11, 2025), https://www.nerc.com/globalassets/our-work/assessments/2024-ltra_corrected_july_2025.pdf.

[9] *Id.* at 44.

capability limits.[10] From January 21–February 1, 2026, Culley operated at roughly 30 MW almost every day.[11] According to the EIA-923 Power Plant Operations Report's monthly generation data for June 2026, the total net generation for the Culley Unit 2was 48,923 MWh from January 2026 to June 2026 for an average of 8,154 MWh per month.[12] This generation data indicates that Culley Unit 2 is providing vital generation capacity to the region.

MISO's year-round resource adequacy concerns are well-documented. 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.[13] MISO justified this revision by explaining that "[r]eliability risks associated with [r]esource [a]dequacy have shifted from 'Summer only' to a year-round concern."[14] 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.[15]

In December 2023, MISO released an "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."[16] 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.[17] MISO also projected that the risk of loss of load in the winter

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[10] MISO, *Operations Rep.*, at 10 (Mar. 24, 2026), https://cdn.misoenergy.org/20260324%20Markets%20Committee%20of%20the%20BOD%20Item%2008%20MISO%20Operations%20Report746763.pdf.

[11] DOE, *FACT SHEET: Energy Dep't Prevented Blackouts & Saved Am. Lives During Winter Storms* (Feb. 6, 2026), https://www.energy.gov/articles/fact-sheet-energy-department-prevented-blackouts-saved-american-lives-during-winter-storms.

[12] *See* U.S. Energy Info. Admin., *Form EIA-923 detailed data with previous form data (EIA-906/920)*, https://www.eia.gov/electricity/data/eia923/ (choose "2026: EIA-923 June 2026").

[13] *Midcontinent Indep. Sys. Operator, Inc.*, Transmittal Letter, FERC Dkt. No. ER22-495-000 (filed Nov. 30, 2021). FERC accepted MISO's proposed tariff revisions on August 31, 2022. *See also Midcontinent Indep. Sys. Operator, Inc.*, 180 FERC ¶ 61,141 (2022), *order on reh'g & compliance*, 182 FERC ¶ 61,096 (2023).

[14] *MISO*, Transmittal Letter, FERC Dkt No. ER22-495-000, at 3.

[15] *Id.* at 3–4.

[16] MISO, *Attributes Roadmap*, at 3 (Dec. 2023), https://cdn.misoenergy.org/2023%20Attributes%20Roadmap%20Executive%20Summary631175.pdf.

[17] *Id.* at 11.

and spring seasons will nevertheless increase over time, although not as high as in the summer or fall.[18]

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.*"[19] In a section of that report entitled, "*Risks in Non-Summer Seasons*," MISO again stressed that it has resource reliability concerns outside of the summer season:

> 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 historic risk profile, creating risks in non-summer months that rarely posed challenges in the past.[20]

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 (2025 LTRA).[21] NERC assessed that the MISO region is at high risk of energy shortfalls over the next five years,[22] stating that it faces significant reliability challenges as "projected resource additions do not keep pace with escalating demand forecasts and announced generator retirements."[23] This determination is based on the combination of accelerating demand growth from new data centers and the retirement of existing thermal generators.[24] The 2025 LTRA 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."[25] NERC observes that winter peak periods are a particular concern, with projections showing "shortfalls in planned resources for winter peak periods."[26] 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."[27]

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[18] *Id*.

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

[20] *Id.* at 12.

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

[22] *Id.* at 6, 8.

[23] *Id.* at 8.

[24] *Id.* at 43.

[25] *Id.* at 15.

[26] *Id*.

[27] *Id.*

The 2025–2026 NERC Winter Reliability Assessment found the MISO region to be at normal risk in 2026 and elevated risk in 2027. The two previous winter studies respectively characterized MISO as a region at elevated risk with the "[p]otential for insufficient operating reserves in above-normal conditions"[28] and noted that "[g]enerating capacity is 10 GW lower (-6.8%) compared to the prior winter as generators have retired, withdrawn from MISO's capacity market, or received lower winter accredited capacity."[29]

NERC released its 2026 Summer Reliability Assessment (SRA) on May 19, 2026. In its assessment, NERC stated that "MISO's peak load has increased by 2.5 GW from the 2025 SRA."[30] The 2026 SRA also projects that data center load will continue to accelerate in 2027 and beyond, potentially increasing reliability risk if capacity additions do not keep pace.[31] Furthermore, the 2026 SRA states that "[a]bove-normal summer peak load combined with low resource conditions could result in the need to employ operating mitigations (e.g., load-modifying resources) and EEAs [Energy Emergency Alerts]."[32] Since the region benefits from transmission connections with neighbors to meet extreme conditions, MISO's reliance on electricity imports will increase when extreme conditions arise."[33]

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 2025–26 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 Indiana.[34]

There continues to be tight capacity available during summer despite the recent "gains in offered capacity outpacing pressure of load growth" in the MISO region, as reported in its PRA for the 2026-2027 Planning Year.[35] MISO noted that "new generation

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

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

[30] NERC, *2026 Summer Reliability Assessment*, at 16 (May 2026), https://www.nerc.com/globalassets/our-work/assessments/nerc_sra_2026.pdf.

[31] *Id.*

[32] *Id.*

[33] *Id*.

[34] MISO, *Planning Res. Auction: Results for Planning Year 2025–26*, at 13 (Apr. 2025), https://cdn.misoenergy.org/2025%20PRA%20Results%20Posting%2020250529_Corrections694160.pdf.

[35] MISO, *Planning Res. Auction Results for Planning Year 2026/27*, at 3 (Apr. 2026, updated May 22, 2026), https://cdn.misoenergy.org/2026%20PRA%20Results%20Posting%2020260522%20-%20Corrections754715.pdf.

capacity is coming online, but faster resource additions are still needed to support large-load growth and ensure resource adequacy."

On June 4, 2026, the Organization of MISO States (OMS) and MISO issued the results of their 2026 survey, which has been conducted annually for many years to determine the degree to which expected capacity resources satisfy planning reserve margin requirements.[36] The 2026 OMS-MISO Survey presented projections of resource adequacy for the summer of 2026 and subsequent years and states "growth as submitted by [load serving entities or LSEs] continues to accelerate, with a [compound annual growth rate or CAGR] projected between 3.1% and 5.1% over [the next] five years."[37]

The OMS-MISO Survey further indicates that "[v]arious projected capacity scenarios and large load additions highlight increasing uncertainty and evolving risk"[38] and observes various negative risks. Examples include intensification of winter reliability risks based on resource availability/performance, which exacerbates seasonal reliability vulnerabilities; delay of new resource deployment owing to persistent supply-chain disruptions, labor constraints and permitting challenges; resource adequacy pressures continuing from load growth driven by data centers, new industrial, and commercial development; and continued backlog and uncertainty related to resources with signed Generator Interconnection Agreements (GIA).[39] In addition, 87 GW of signed GIAs are not yet online, and 192 GW of active GIAs still under study.[40]

Finally, the OMS-MISO Survey lists ongoing challenges such as more frequent extreme weather; accelerating demand for electricity and large load interconnections; loss of accredited capacity and reliability attributes as resource mixes evolve; the increasing pace of new resources additions; addressing local reliability issues (load pocket); and evolving storage participation.[41]

NERC released its 2026 State of Reliability (SOR) on June 24, 2026. In the SOR, NERC identifies worsening reliability concerns tied to large-load integration and localized operating stress. In its technical discussion of major system events, NERC states "shoulder seasons have become increasingly challenging for Bulk Power System operators to manage, resulting in several recent instances of pre-contingent load shedding."[42] The SOR also finds large load growth is increasing reliability risk and

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[36] OMS & MISO, *OMS-MISO Survey Results* (updated June 4, 2026) (2026 OMS-MISO Survey), https://cdn.misoenergy.org/20260604%20OMS-MISO%20Survey%20Results%20Workshop%20Presentation761711.pdf.

[37] *Id.* at 2.

[38] *Id.* at 3.

[39] *Id.* at 4.

[40] *Id.*

[41] *Id.* at 16.

[42] NERC, *2026 State of Reliability: Tech. Assessment of 2025 Bulk Power Sys. Performance*, at 5 (June 24, 2026), https://www.nerc.com/globalassets/programs/rapa/pa/nerc_sor_2026_technical_assessment.pdf.

states that "data center and computational loads continued emerging as a major reliability consideration due to their scale, speed of development, and unique operational characteristics."[43] Finally, data in the SOR shows that 2025 MISO summer and winter peak demands of 121.6 GW and 108.8 GW, respectively, met or exceeded extreme scenario levels showing how rapid load growth and extreme weather continue to be a real risk in MISO.[44]

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.[45] MISO's 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.[46] 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.[47] Consequently, the new ERAS process is unlikely to result in the addition of any new generation capacity in the next few years

Order Nos. 202-25-13, 202-26-20, and 202-26-30 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 No. 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 threat to our Nation's economy, national security, and foreign policy."[48] The Executive Order adds that "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

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[43] *Id.* at vii.

[44] *Id.* at 28, 30.

[45] *Midcontinent Indep. Sys. Operator, Inc.*, 192 FERC ¶ 61,064 (2025).

[46] NERC, *State of Reliability*, *supra* note 48, at 84.

[47] *See generally* Jared Anderson, *US Gas-Fired Turbine Wait Times as Much as Seven Years; Costs Up Sharply*, S&P GLOBAL (May 2025) ("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."), 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.

[48] Exec. Order No. 14156, 90 Fed. Reg. 8433 (Jan. 20, 2025), https://www.federalregister.gov/documents/2025/01/29/2025-02003/declaring-a-national-energy-emergency.

swings within international commodity markets."[49] In the subsequent Executive Order No. 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."[50]

In addition, President Trump issued a White House Memo for the Secretary that emphasized the findings of Executive Order No. 14156, stating that "ensuring reliable coal supply chains and baseload power generation capacity is essential to the United States national defense . . . . Without sufficient coal-fired baseload power, the United States will lack the stable electricity required to support defense installations, industrial expansion, and the high-energy demands of emerging technologies, such as artificial intelligence."[51] The President "further determine[d] that action to expand coal supply chain capacity and baseload generation availability is necessary to avert an industrial resource or critical technology item shortfall that would severely impair national defense capability."[52]

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," which was issued pursuant to the President's directive in Executive Order No. 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."[53]

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, MISO's Senior Vice President for Planning and Operations, Jennifer Curran, testified that "the MISO region faces resource adequacy and reliability challenges due to the changing characteristics of the electric generating fleet,

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[49] *Id*.

[50] Exec. Order No. 14262, 90 Fed. Reg. 15521 (Apr. 8, 2025), https://www.federalregister.gov/documents/2025/04/14/2025-06381/strengthening-the-reliability-and-security-of-the-united-states-electric-grid.

[51] Memorandum from President Donald J. Trump to the Secretary of Energy (Apr. 20, 2026) (*Presidential Determination Pursuant to Sec. 303 of the Def. Prod. Act of 1950, as Amended, on Coal Supply Chains & Baseload Power Generation Capacity*), https://www.whitehouse.gov/presidential-actions/2026/04/presidential-determination-pursuant-to-section-303-of-the-defense-production-act-of-1950-as-amended-on-coal-supply-chains-and-baseload-power-generation-capacity/.

[52] *Id.*

[53] DOE, *Res. Adequacy Rep.: Evaluating the Reliability & Sec. of the U.S. Elec. Grid*, at 1 (July 2025), https://www.energy.gov/sites/default/files/2025-07/DOE%20Final%20EO%20Report%20%28FINAL%20JULY%207%29.pdf.

inadequate transmission system infrastructure, growing pressures from extreme weather, and rapid load growth."[54] 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."[55] She added that "[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."[56]

Pursuant to section 202(c)(4)(B) of the FPA, DOE 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 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," the Secretary has the authority "to require by order . . . such generation, delivery, interchange, or transmission of electric energy as in [his] judgment will best meet the emergency and serve the public interest."[57] This statutory language constitutes a specific grant of authority to the Secretary to require the continued operation of Culley Unit 2 when the Secretary has determined that such operation will best meet an emergency.

As described above, the emergency conditions resulting from increasing demand and shortage of electric energy from premature retirement of generation facilities 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 businesses in the areas that may be affected by curtailments or power outages, presenting a risk to public health and safety.

I have determined that, to best meet the emergency arising from increased demand, determined shortage, and other causes, and serve the public interest under FPA

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[54] *Keeping the Lights On: Examining the State of Reg'l Grid Reliability Before the House Comm. on Energy & Commerce*, Subcomm. on Energy, 119th Cong., at 5 (Mar. 25, 2025) (statement of Ms. Jennifer Curran, Senior Vice President for Planning and Operations, MISO), https://www.congress.gov/119/meeting/house/118040/witnesses/HHRG-119-IF03-Wstate-CurranJ-20250325.pdf.

[55] *Id.* at 6.

[56] *Id.* at 7.

[57] 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).

section 202(c), Culley Unit 2 shall be made available for operation through December 18, 2026.[58]

[58] 16 U.S.C. § 824a(c)(4).

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

A. From September 20, 2026, MISO and CenterPoint Energy shall take all measures necessary to ensure that Culley Unit 2 is available to operate. For the duration of this Order, MISO is directed to take every step to employ economic dispatch of Culley Unit 2 to minimize cost to ratepayers. Following the conclusion of this Order, sufficient time for orderly ramp down is permitted, consistent with industry practices. CenterPoint Energy is directed to comply with all orders from MISO related to the availability and dispatch of Culley Unit 2.

B. To minimize adverse environmental impacts, this Order limits operation of Culley Unit 2 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 Culley Unit 2 has operated in compliance with this Order.

C. All operations of Culley Unit 2 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 conditions or to use other geographic or temporal flexibilities available to generators.

D. By October 3, 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 Culley Unit 2 consistent with this Order. CenterPoint Energy and 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.

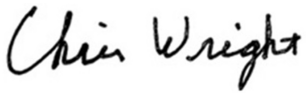
E. CenterPoint Energy is directed to file with FERC tariff revisions or waivers to effectuate this Order, as needed. Rate recovery is available pursuant to 16 U.S.C. § 824a(c).

F. This Order shall not preclude the need for Culley Unit 2 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, Culley Unit 2 shall not be considered a capacity resource.

H. This Order shall be effective from September 20, 2026, through December 18, 2026, with the exception of applicable compliance obligations in paragraph D.

Issued in Washington, D.C. on this 18th Day of September 2026.



Chris Wright
Secretary of Energy

cc: **Federal Energy Regulatory Commission**
Chairman Laura V. Swett
Commissioner David Rosner
Commissioner Lindsay S. See
Commissioner Judy W. Chang
Commissioner David A. LaCerte

Indiana Utility Regulatory Commission
Chairman Anthony Swinger
Commissioner Joshua Bain
Commissioner Bob Deig
Commissioner Joby Jerrells
Commissioner David Ziegner

UNITED STATES OF AMERICA
BEFORE THE
UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Craig Unit 1	))))	Order No. 202-26-49

The State Of Colorado's Request for Rehearing,
Motion To Intervene, And Stay Request

Exhibit FFFF: Department, Order No. 202-26-42 (Sept. 1, 2026)

Department of Energy
Washington, DC 20585

Orlando Utilities Commission
Regarding the Stanton Energy Center

Order No. 202-26-42

Pursuant to the authority vested in the Secretary of Energy (Secretary) by section 202(c) of the Federal Power Act (FPA),[1] and section 301(b) of the Department of Energy (DOE or the Department) Organization Act,[2] and for the reasons set forth below, I hereby determine that an emergency exists within the SERC Reliability Corporation (SERC)–Florida Peninsula assessment area due to a sudden increase in demand for electric energy, or a shortage of electric energy or facilities for the generation or transmission of electric energy, and other causes. Issuance of this Order will meet the emergency and serve the public interest.

BACKGROUND

The Stanton Energy Center (Stanton) is an electric generating facility in Orlando, Florida. Stanton Unit 1 (464.5 MW)[3] is a coal-fired generator owned[4] and operated by the Orlando Utilities Commission (OUC). Unit 1 began operations in July 1987.[5] The OUC Board of Commissioners had approved the retirement of Unit 1 by 2025,[6] and OUC anticipated placing Stanton Unit 1 in an "extended cold shutdown" in June 2026.[7] OUC expects to make a determination as to Stanton Unit 2 by year's end based on an Integrated Resource Plan currently underway.

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[1] 16 U.S.C. § 824a(c).

[2] 42 U.S.C. § 7151(b).

[3] U.S. Energy Info. Admin., *Preliminary Monthly Elec. Generator Inventory (based on Form EIA-860M as a supplement to Form EIA-860)*, https://www.eia.gov/electricity/data/eia860m/ (choose "June 2026") [hereinafter EIA, *Form EIA-860M*]. Stanton also includes a second coal-fired generation unit, Unit 2 (464.5 MW), as well as two natural gas-fired combined cycle generation units, Unit B (129.8 MW) and Unit B1 (203.2 MW).

[4] nFront Consulting LLC, *Orlando Utils. Comm'n: 2026 Ten-Year Site Plan*, at 2–3, https://www.floridapsc.com/pscfiles/website-files/pdf/Utilities/Electricgas/TenYearSitePlans/2026/Orlando%20Utilities%20Commission.pdf [hereinafter nFront, *OUC 2026 Ten-Year Site Plan*].

[5] EIA, *Form EIA-860M*, *supra* note 3.

[6] *See, e.g.*, Michelle Lynch, *Fla. Mun. Elec. Ass'n, OUC's Bd. of Comm'rs moves to retire Unit 1 coal plant by no later than 2025* (Dec. 15, 2021), https://www.flpublicpower.com/news/oucs-board-of-commissioners-moves-to-retireunit-1-coal-plant-by-no-later-than-2025.

[7] *See* nFront, *OUC 2026 Ten-Year Site Plan*, *supra* note 4, at 6–2. It likely would be difficult for the coal-fired unit to resume operations once retired. Specifically, practical issues, such as employment, contracts, and permits, may greatly increase the

Order No. 202-26-26, which was issued pursuant to FPA section 202(c) on June 4, 2026, required that Stanton Unit 1 continue to be available to operate for 90 days, through September 1, 2026. That order was based on my determination that emergency conditions existed within the SERC Reliability Corporation (SERC)–Florida Peninsula assessment area.

Specifically, I determined that there was a potential shortage of electric energy and a shortage of facilities for the generation of electric energy.[8] I stated that the potential loss of power to homes and local businesses presents a risk to public health and safety.[9] I determined that continued operation of the Stanton Unit 1 was necessary to best meet the emergency and serve the public interest.[10]

In its 2025 Long-Term Reliability Assessment (2025 LTRA), released in January 2026, the North American Electric Reliability Corporation (NERC) notes that the SERC–Florida Peninsula assessment area is currently at a "Normal Risk" for long-term energy adequacy.[11] Nevertheless, the 2025 LTRA highlights that within the SERC–Florida Peninsula assessment area projections for resource and transmission growth lag behind what is needed to support new data centers and other large loads that drive escalating demand forecasts.[12] Additionally, the 2025 LTRA maintains that new data centers for artificial intelligence and the digital economy account for most of the projected increase in North American electricity demand over the next 10 years.[13] As of April 2026, eight data centers are planned for construction in Florida.[14] Total peak demand in Florida is expected to increase from 48,628 MW in 2025/2026 to 54,931 MW in 2034/2035.[15]

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timeline for resumption of operations during the period they are needed. Moreover, if OUC were to begin disassembling the unit or other related facilities, the associated challenges would be greatly exacerbated. The costs and time of decommissioning a coal plant are extensive, and restarting such decommissioned plants would presumably cost the same as decommissioning in dollars and time, if not more. Thus, continuous operation is required in such cases so long as the Secretary determines a shortage exists and is likely to persist. *See* Jennifer Lessick et al., *Bus. Models for Coal Plant Decommissioning*, at 9–12 (Aug. 2021), https://www.osti.gov/servlets/purl/1821476.

[8] *See, e.g.*, *PJM Interconnection, L.L.C.*, Order No. 202-26-24, at 10 (May 21, 2026).

[9] *Id*.

[10] *Id.*

[11] N. Am. Elec. Reliability Corp., *2025 Long-Term Reliability Assessment*, at 23 (Jan. 2026), https://prod.nerc.com/globalassets/our-work/assessments/nerc_ltra_2025.pdf.

[12] *Id.* at 6.

[13] *Id.* at 9.

[14] *See* Skyler Seets & Kaitlyn Radde, *Most new data centers in the U.S. are coming to rural areas*, PEW RESEARCH CENTER (Apr. 13, 2026), https://www.pewresearch.org/?p=299017.

[15] *See* Fla. Reliability Coordinating Council, Inc., *2025 Reg'l Load & Res. Plan FRCC-MS-PL-642 Version: 1*, at 6 (2025), https://www.floridapsc.com/pscfiles/website-files/PDF/Utilities/Electricgas/TenYearSitePlans//2025/FRCC_RLRP.pdf.

The 2025 LTRA also notes that, with "the heavy dependence on natural gas in the SERC–Florida Peninsula subregion, fuel diversity could become an area of future concern."[16] Further, the 2025 LTRA states that:

> [t]he growing penetration of renewable energy means that SERC and the SERC–Florida Peninsula entities will need to continue to monitor the resource adequacy studies and the impact that renewable resources will have. As solar generation continues to grow, the need to ensure the availability of quick start generating units to meet the ramp in demand will increase.[17]

OUC resource adequacy concerns were most recently demonstrated during Winter Storm Fern, when OUC requested two section 202(c) emergency orders to preserve the reliability of the bulk electric power system due to anticipated unusually high load forecasts from unusual cold weather conditions throughout the entire state of Florida: (i) one application for 2.7 GW of specified resources (generating units)[18] and (ii) a second application for 55 MW of back-up generators.[19] As a result, DOE issued two 202(c) emergency orders to OUC from January 31 through February 6, 2026: (i) Order No. 202-26-11 for specified resources[20] and (ii) Order No. 202-26-15 for back-up generators.[21] OUC leveraged the 202(c) orders to meet demand during the extreme cold weather conditions. Stanton Unit 1 produced 66,230 MWh between January 31 and February 6, 2026.[22] The back-up generating units reported over 400 hours of run-time under the respective Order.

According to OUC, customer demand was projected to exceed record-breaking thresholds for OUC on Sunday, February 1, 2026, and again on Monday, February 2, 2026, and maybe throughout the following week.[23] OUC had projected that it may not have

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[16] *See* NERC, *LTRA*, *supra* note 9, at 116.

[17] *Id.*

[18] Application, ex. A (Specified Resources) (Jan. 31, 2026).

[19] Application, ex. A (Backup Generators) (Jan. 31, 2026).

[20] *Orlando Utils. Comm'n*, Order No. 202-26-11 (Jan. 31, 2026).

[21] *Orlando Utils. Comm'n*, Order No. 202-26-15 (Jan. 31, 2026).

[22] *See* U.S. Env't Prot. Agency, *CAMPD (Clean Air Markets Program Data)*, https://campd.epa.gov/data/custom-data-download (choose "Emissions" from "Data Type" dropdown; then choose "Daily Emissions" from "Data Subtype" dropdown; then choose "Unit (No Aggregation)" from the "Aggregation" dropdown; then click "Apply"; then click "Time Period" button and enter "January 31, 2026" as "Start Date" and February 6, 2026 as "End Date"; then click "Facility" and select "Curtis H. Stanton Energy Center"; then click "Apply Filter"; then click "Preview Data").

[23] Letter from Clint Bullock, Gen. Manager & CEO, Orlando Utils. Comm'n, to The Honorable Chris Wright, Sec'y, Dept. of Energy (Jan. 31, 2026) (requesting emergency order under FPA section 202(c)), https://www.energy.gov/documents/ouc-202c-application-backup-generators.

sufficient generation available to meet the unusually high demand and may be forced to curtail load in order to maintain the security and reliability of the grid.[24] In January 2026, Stanton Units 1 and 2 produced a total of 249,473 MWh from coal-fired generation.[25]

CONTINUING EMERGENCY CONDITIONS

The emergency conditions that necessitated the issuance of Order No. 202-26-26 continue, both in the near and long term. The production of electricity from Stanton Unit 1 continues to be critical to maintain reliability in the SERC–Florida Peninsula assessment area.

According to NERC's 2026 Summer Reliability Assessment, the SERC–Florida Peninsula is a summer-peaking assessment area.[26] In its 2026 Summer Reliability Assessment, NERC further notes that "[t]emperature and precipitation forecasts for the coming summer show a higher likelihood of hotter-than-normal temperatures in the U.S. South . . . ."[27] For the SERC–Florida Peninsula, the anticipated reserve margin is projected to be 25.8%; however, the anticipated reserve margin drops to 13.6% in the event of "higher demand, outages, [or] derates in extreme conditions."[28]

NERC released its 2026 State of Reliability (SOR) on June 24, 2026. In the SOR, NERC identifies worsening reliability concerns tied to large-load integration and localized operating stress. In its technical discussion of major system events, NERC states "shoulder seasons have become increasingly challenging for [bulk power system] operators to manage, resulting in several recent instances of pre-contingent load shedding."[29] The SOR also finds large load growth is increasing reliability risk and states that "data center and computational loads continued emerging as a major reliability consideration due to their scale, speed of development, and unique operational characteristics."[30]

DOE Order No. 202-26-26 was preceded by executive orders issued by President Donald J. Trump on January 20, 2025, and April 8, 2025, which underscored the dire energy challenges facing the Nation due to growing resource adequacy concerns. President Trump declared a national energy emergency in Executive Order No. 14156,

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[24] *Id.*

[25] EIA, *Form EIA-923 detailed data with previous form data (EIA-906/920)*, *Page 4: Generator Data* (May 2026), https://www.eia.gov/electricity/data/eia923/.

[26] N. Am. Elec. Reliability Corp., *2026 Summer Reliability Assessment*, at 28 (May 2026), https://www.nerc.com/globalassets/our-work/assessments/nerc_sra_2026.pdf.

[27] *Id.* at 4.

[28] *Id* at 10.

[29] N. Am. Elec. Reliability Corp., *2026 State of Reliability: Tech. Assessment of 2025 Bulk Power Sys. Performance*, at 5 (June 24, 2026), https://nerc.com/globalassets/programs/rapa/pa/nerc_sor_2026_technical_assessment.pdf.

[30] *Id.* at vii.

"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 threat to our Nation's economy, national security, and foreign policy."[31] 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." In the subsequent Executive Order No. 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."[32]

Further, the Department of Energy 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," which was issued pursuant to the President's directive in Executive Order No. 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."[33]

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 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 [his] judgment will best meet the emergency and serve the public interest."[34] This statutory language constitutes

[31] Exec. Order No. 14156, 90 Fed. Reg. 8433 (Jan. 20, 2025), https://www.federalregister.gov/documents/2025/01/29/2025-02003/declaring-a-national-energy-emergency.

[32] Exec. Order No. 14262, 90 Fed. Reg. 15521 (Apr. 8, 2025), https://www.federalregister.gov/documents/2025/04/14/2025-06381/strengthening-the-reliability-and-security-of-the-united-states-electric-grid.

[33] DOE, *Res. Adequacy Rep.: Evaluating the Reliability & Sec. of the U.S. Elec. Grid* (July 7, 2025), https://www.energy.gov/sites/default/files/2025-07/DOE%20Final%20EO%20Report%20%28FINAL%20JULY%207%29.pdf.

[34] 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).

a specific grant of authority to the Secretary to require the operation of Stanton Unit 1, 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, or a shortage of electric energy or facilities for generation or transmission of electric energy.

As described above, the conditions resulting from the increasing demand and shortage of electric energy from the premature retirement of Stanton Unit 1 will continue on in the near term and are also likely to continue in subsequent years. This could lead to the loss of power to homes and businesses in the areas affected by curtailments or power outages, presenting a risk to public health and safety.

I have determined that, to best meet the emergency arising from increased demand, determined shortage, and other causes, and to serve the public interest under FPA section 202(c), Stanton Unit 1 shall be made available for operation through November 30, 2026.

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

A. From September 2, 2026, OUC shall take all measures necessary to ensure that Stanton Unit 1 is available to operate.[35] Following the conclusion of this Order, sufficient time for orderly ramp down is permitted, consistent with industry practices.

B. To minimize adverse environmental impacts, this Order limits operation of Stanton Unit 1 to the times and within the parameters as determined by OUC pursuant to paragraph A. OUC shall provide a daily notification to the Department (via AskCR@hq.doe.gov) reporting whether Stanton Unit 1 has operated in compliance with this Order.

C. All operations of Stanton Unit 1 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 conditions, or to use other geographic or temporal flexibilities available to generators.

D. By September 16, 2026, OUC 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 Stanton Unit 1 consistent with this Order. OUC shall also provide such additional information regarding the

[35] According to OUC, neither Florida Municipal Power Pool (FMPP) in its role as the Balancing Authority nor Florida Reliability Coordinating Council (FRCC) in its role as the Reliability Coordinator directs OUC to operate Stanton 1 in a manner similar to organized markets.

environmental impacts of this Order and its compliance with the conditions of this Order, as requested by the Department of Energy from time to time.

E. OUC is directed to file with the Federal Energy Regulatory Commission any 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 Stanton Unit 1 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, Stanton Unit 1 shall not be considered a capacity resource.

H. This Order shall be effective from September 2, 2026, through November 30, 2026, with the exception of applicable compliance obligations in paragraph D.

I. OUC is directed to provide the Department at least fifteen days' prior notice in writing before any anticipated change in operational status, or as soon as practicable if an unexpected change in status of Stanton Unit 2 occurs.

Issued in Washington, D.C. on this 1st day of September 2026.

Chris Wright

Chris Wright
Secretary of Energy

cc: **Federal Energy Regulatory Commission**
Chairman Laura V. Swett
Commissioner David Rosner
Commissioner Lindsay S. See
Commissioner Judy W. Chang
Commissioner David A. LaCerte

Florida Public Service Commission
Chairman Gabriella Passidomo Smith
Commissioner Gary F. Clark
Commissioner Mike La Rosa
Commissioner Bobby Payne
Commissioner Ana Ortega

UNITED STATES OF AMERICA
BEFORE THE
UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Craig Unit 1	))))	Order No. 202-26-49

The State Of Colorado's Request for Rehearing,
Motion To Intervene, And Stay Request

Exhibit GGGG: Decision, *Michigan v. Dept. of Energy, et al.*,
No. 25-1159 (D.C. Cir May 15, 2026)

United States Court of Appeals

FOR THE DISTRICT OF COLUMBIA CIRCUIT

Argued May 15, 2026 Decided September 11, 2026

No. 25-1159

PEOPLE OF THE STATE OF MICHIGAN,
PETITIONER

v.

UNITED STATES DEPARTMENT OF ENERGY AND CHRISTOPHER A. WRIGHT, SECRETARY, UNITED STATES DEPARTMENT OF ENERGY,
RESPONDENTS

MIDCONTINENT INDEPENDENT SYSTEM OPERATOR, INC. AND CONSUMERS ENERGY COMPANY,
INTERVENORS

Consolidated with 25-1160, 25-1162

On Petitions for Review of a Final Order
of the Department of Energy

Lucas Wollenzien, Assistant Attorney General, Office of the Attorney General for the State of Michigan, argued the cause for petitioners States of Illinois, Michigan, and Minnesota. With him on the briefs were *Dana Nessel*, Attorney

General, *Michael E. Moody*, Assistant Attorney General, *Christopher Bzdok*, Special Assistant Attorney General, *Peter Surdo*, Special Assistant Attorney General, Office of the Attorney General for the State of Minnesota, and *Jason E. James*, Assistant Attorney General, Office of the Attorney General for the State of Illinois.

Benjamin P. Chagnon argued the cause for the Public Interest Organization petitioners. With him on the briefs were *Jennifer J. Yun*, *Michael Lenoff*, *Gregory E. Wannier*, *Sanjay Narayan*, *Elena Saxonhouse*, *Caroline Reiser*, *Gavin G. McCabe*, *Simi Bhat*, *Lauren Piette*, *Sameer H. Doshi*, *Christine A. Powell*, *Howard Learner*, *Danielle Fidler*, *Francis W. Sturges Jr., Veronica Saltzman*, and *Tomas Carbonell*. *Michael C. Soules* and *Ada Statler* entered appearances.

Jennifer Danis was on the brief for amicus curiae Institute for Policy Integrity at New York University School of Law in support of petitioners.

Jonas Monast, *James P. Duffy*, *Alexandra L. St. Romain*, and *Susannah Landes Weaver* were on the brief for amici curiae Energy Law Scholars in support of petitioners.

Nicholas M. Gladd, *John B. Kenney*, and *Zachary Norris* were on the brief for amici curiae The Niskanen Center, et al., in support of petitioners.

Robert N. Stander, Deputy Assistant Attorney General, U.S. Department of Justice, argued the cause for respondents. With him on the brief were *Adam R. Gustafson*, Principal Deputy Assistant Attorney General, *Robert J. Lundman*, *Kyle Glynn*, and *Rebecca Jaffe*, Attorneys, and *Jonathan Brightbill*, General Counsel, United States Department of Energy.

Zachary C. Schauf argued the cause and filed the brief for respondent-intervenor Consumers Energy Company. With him on the brief was *Juliana Brint.* *Arjun R. Ramamurti* entered an appearance.

Adam S. Carlesco, *Daniel C.W. Narvey*, and *John Liskey* were on the brief for amici curiae Citizens Action Coalition of Indiana, et al., in support of respondent.

Before: SRINIVASAN, *Chief Judge*, PILLARD and WILKINS, *Circuit Judges*.

Opinion for the Court filed by *Circuit Judge* PILLARD.

PILLARD, *Circuit Judge*: Consumers Energy Company is a private business that owns and operates the J.H. Campbell Generating Plant, an aging coal-fired power plant in Michigan that was scheduled to shut down last year. The Company worked for several years to develop plans and secure regulatory approval to retire the old Campbell plant and replace it with a mix of expanded and new electricity-generation sources. Consumers Energy coordinated its planning with Michigan regulators and the Midwest Independent System Operator (MISO)—the 15-state regional transmission organization in which Michigan and Consumers Energy participate. The Company's closure-and-replacement proposal received comprehensive scrutiny from the public, private industry, and expert regulators. Finding that Consumers Energy's substitute sources would meet applicable reliability criteria, provide less polluting electricity at lower prices, and more than offset generation lost when the old plant closed, the Michigan Public Service Commission and MISO expressly approved the plan.

Shortly before Campbell's scheduled retirement, the Department of Energy (DOE or Department) unilaterally

commanded the unit's continued operation. The Department invoked a rarely used, short-term, federal emergency authority conferred in section 202(c) of the Federal Power Act to order the Campbell coal unit to stay open. Michigan petitioned for review of DOE's order. Illinois and Minnesota also petitioned, as did a group of environmental organizations, including the Sierra Club, Natural Resources Defense Council, Michigan Environmental Council, Environmental Defense Fund, Environmental Law and Policy Center, Vote Solar, the Ecology Center, Urban Core Collective, and the Union of Concerned Scientists. Consumers Energy intervened to "protect[] the company's right to recover the costs associated with DOE's order" from ratepayers, which is at issue in separate proceedings regarding recovery and allocation of costs currently pending before FERC. Resp.-Interv. Br. iv, 7.

We evaluate Petitioners' challenge to DOE's interpretation of its emergency power under section 202(c) by reference to statutory text and structure. And we deploy those interpretive tools against the backdrop of states' exclusive regulatory power over the generation of electricity.

The plain meaning of the text limits section 202(c) emergency authority to address an identified risk of a substantial energy supply shortfall that calls for immediate action. Section 202(c) gives DOE limited authority to sidestep states' jurisdiction over electricity generation to briefly compel generation or interconnection in times of war or other "emergency" situations. By its terms, section 202(c) allows DOE to command certain action "[d]uring the continuance of any war in which the United States is engaged," or when the Secretary determines that "an emergency exists" due to "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. § 824a(c)(1).

The structure of the Federal Power Act and the history of the respective regulatory roles of federal and state governments show that Congress intended to further limit DOE's section 202(c) emergency power to circumstances necessitating action by DOE in particular, as opposed to action by states.

Start with the Act's structure: The statutory provisions immediately preceding section 202(c)—sections 202(a) and (b)—confirm the primacy of states and their utilities in planning to prevent and responding to emergency electricity shortfalls. First, section 202(a) facilitates states' and utilities' planning to generate and contract for adequate supplies of electrical power. It does so by enabling them to coordinate their efforts through voluntary participation in Regional Transmission Organizations (RTOs). Next, section 202(b) provides for coercive federal action to ensure adequate supply—but only at the request of states or their utilities. When "necessary or appropriate in the public interest," a state or utility may request that the Federal Energy Regulatory Commission (FERC) order a generator to connect to and sell or exchange energy with other facilities. Lastly, section 202(c) authorizes DOE to intervene to temporarily order similar action—connection of facilities and provision of electricity—to avert an emergency. Congress's placement of section 202(c) after subsections (a) and (b), which more broadly authorize state-level means of preventing and responding to emergency electricity shortages, strongly implies that it meant use of subsection (c) to be essentially the last alternative among the three.

Consider next the history of states' jurisdiction over generation of electricity: The last-resort character of section

202(c) is strongly supported by the respective regulatory powers of states and the federal government under the Federal Power Act. There is no dispute that for almost a century states have exercised authority, preserved by the Federal Power Act, to regulate in-state power plants for the economic and environmental benefit of their citizens. It is the states—informed by federal, regional, and load-serving entities' assessments of available supply and reliability needs—that bear the responsibility to plan for and avert reliability risks on an ongoing basis. To that end, states decide which generation resources must be built, expanded, reduced, or shut down. The Act empowers the federal government, in contrast, to regulate wholesale marketing and interstate transmission of electricity. That demarcation of federal and state regulatory power is further reason to treat DOE intervention under section 202(c) as rare and authorized only when states, their utilities, and RTOs are unable or unwilling to respond. That is exactly how the federal government has used its section 202(c) authority until today—to address short-term crises, such as blackouts caused by war or extreme weather events, not as a substitute for the states' long-term reliability planning.

Our reading of the text, structure, and history leaves us unpersuaded by DOE's sweeping conception of its "emergency" authority under section 202(c). The Department's position would empower it to pick its preferred power sources in Michigan—or, presumably, any other state—and order them to operate without regard to the multiple procedural and substantive constraints built into state reliability planning processes. We hold that section 202(c) is best read to apply where the Department identifies a risk of substantial harm from inadequate electricity supply that calls for immediate action by DOE in particular, as opposed to by the states. Because the circumstances DOE identified in the challenged order do not warrant resort to section 202(c) as

correctly interpreted, we grant the petitions for review and vacate the Order.

I.

A.

1.

Until 1935, the federal government had no regulatory authority over the nation's electricity supply. Instead, "state and local agencies oversaw nearly all generation, transmission, and distribution of electricity." *FERC v. Elec. Power Supply Ass'n*, 577 U.S. 260, 265-66 (2016); *see Pacific Gas & Elec. Co. v. State Energy Res. Conservation & Dev. Comm'n*, 461 U.S. 190, 205 (1983). In 1935, after the Supreme Court held that the Dormant Commerce Clause prohibited state regulation of certain interstate electricity transactions, *see Pub. Util. Comm'n of R.I. v. Attleboro Steam & Elec. Co.*, 273 U.S. 83, 89-90 (1927), Congress enacted the Federal Power Act (FPA or Act) to fill the resulting "regulatory void," *Elec. Power Supply Ass'n*, 577 U.S. at 266; *see* 16 U.S.C. §§ 824-824w.

The FPA affords the federal government authority to regulate "the transmission of electric energy in interstate commerce," *i.e.*, the movement of electric energy over long distances via high-voltage power lines. 16 U.S.C. § 824(b)(1). It also grants federal authority over "the sale of electric energy at wholesale in interstate commerce." *Id*. But the Act denies federal authority "over facilities used for the generation of electric energy." *Id.*

Federal regulatory authority over the nation's electrical supply is exercised by the Department of Energy (DOE), the Federal Energy Regulatory Commission (FERC), and the North American Electric Reliability Corporation (NERC), each

of which plays a distinct role. The principal and substantial federal agency acting in the electricity sector is FERC, which is responsible for rules and practices directly affecting rates for wholesale electricity sales and interstate transmission. *See generally* 16 U.S.C. §§ 824(a), 824a(f), 824d(a), 824e(a); *see also Elec. Power Supply Ass'n*, 577 U.S. at 266. NERC, which FERC designated in 2006 as an independent entity to "develop and enforce . . . reliability standards that provide for an adequate level of reliability of the bulk-power system," conducts periodic reliability assessments of the electric grid and sets and modifies nationwide reliability standards that inform but do not control levels of energy generation within each state. 16 U.S.C. § 824*o*(c), (d), (g); *see also* NERC, 2025 Summer Reliability Assessment ("NERC Reliability Assessment") (J.A. 103-56). For its part, the Department of Energy's only direct authority over the generation of electricity is its temporary emergency power under section 202(c).

Because the Federal Power Act extends federal authority "only to those matters which are not subject to regulation by the States," 16 U.S.C. § 824(a), it "maintains a zone of exclusive state jurisdiction," *Elec. Power Supply Ass'n*, 577 U.S. at 266. The Act generally preserves states' "control over in-state 'facilities used for the generation of electric energy,'" *Hughes v. Talen Energy Mktg., LLC*, 578 U.S. 150, 154 (2016) (quoting 16 U.S.C. § 824(b)(1)); it contemplates incidental federal control of only those generation practices that "directly affect" FERC's exercise of its statutory authority over wholesale rates or interstate transmission. *Elec. Power Supply Ass'n*, 577 U.S. at 278. Accordingly, we have long and repeatedly recognized that the federal government "may regulate the transmission [interstate], but not the generation, of electricity." *NextEra Energy Res., LLC v. FERC*, 118 F.4th 361, 365 (D.C. Cir. 2024); *see La. Pub. Serv. Comm'n v. FERC*, 522 F.3d 378, 389-90 (D.C. Cir. 2008) (similar

regarding FERC authority over wholesale rates). States "retain the right to regulate the facilities responsible for the generation of electric energy," *New England Power Generators Ass'n, Inc. v. FERC*, 757 F.3d 283, 285 (D.C. Cir. 2014), and they determine their own mix of electricity generation, *see Citizens Action Coal. of Ind. v. FERC*, 125 F.4th 229, 238 (D.C. Cir. 2025).

States, as the regulators of electricity generation, are largely responsible for meeting the core policy goal of achieving "resource adequacy." That means it is up to the states to make sure that enough electricity is generated to safely and reliably meet users' needs. *See Sacramento Mun. Util. Dist. v. FERC*, 616 F.3d 520, 526 (D.C. Cir. 2010) (quoting *Cal. Indep. Sys. Operator Corp*., 116 FERC ¶ 61,274, P 3 (2006)) (defining resource adequacy). Indeed, FERC itself expressly recognizes that "[r]esource adequacy is a matter that has traditionally rested with the states, and it should continue to rest there." *Devon Power, LLC*, 109 FERC ¶ 61,154, P 47 (2004). The supply of reliable electricity to serve fluctuating demand and avoid blackouts is accordingly a key consideration of state regulators when they determine whether to permit generation sources to be added to the grid or existing sources to retire.

In making those determinations, state regulators must meet additional legal obligations and policy priorities. Those obligations and priorities may include energy affordability, the environment and climate, and diversity of generation supply. *See, e.g.*, Mich. Comp. Laws. Ann. § 460.6t(8)(a). To achieve long-term resource adequacy consistently, efficiently, and with optimal legal compliance and public support, states, load-serving entities, voluntary regional transmission organizations (RTOs), and various other stakeholders engage in extensive, coordinated planning.

Under Michigan law, the state's public utility regulator, the Michigan Public Service Commission (Michigan Commission, Commission, or simply Michigan) is responsible for monitoring the supply and demand of electricity and ensuring resource adequacy. It reviews and approves applications to construct, expand, reduce, or retire generation resources as consistent with detailed and evolving projections of state and regional energy needs. *See* Mich. Comp. Laws. Ann. §§ 460.6a, 460.6s. As most directly relevant here, the Michigan Commission ensures that any retirement of a generation resource in Michigan is accomplished consistently with the adequacy of electrical supply to meet demands of electricity consumers.

Because Michigan law makes load-serving utilities responsible for securing sufficient generating capacity to serve their customers, *see* Mich. Comp. Laws. Ann. §§ 460.6t, 460.6w, much of the Michigan Commission's power over electrical supply is exercised by regulating those utilities' investment decisions. "Load" generally refers to customers' demand for electricity—the power that users draw from the grid—at a given time. A load-serving entity is a "a utility with an obligation created under law or contract to provide electricity service to end-use customers or to a distribution utility." *S. Car. Pub. Serv. Auth. v. FERC*, 762 F.3d 41, 90 n.12 (D.C. Cir. 2014); *see NRG Power Mktg., LLC v. FERC*, 862 F.3d 108, 110 (D.C. Cir. 2017). Michigan's State Reliability Mechanism requires load-serving utilities to demonstrate annually that they have sufficient generation capacity to meet projected demand four years in the future. *See id.* § 460.6w; *State Reliability Mechanism*, Mich. Pub. Serv. Comm'n (Nov. 21, 2017), https://perma.cc/CHH6-6NZ8. Separately, every five years, load-serving entities must file with the Michigan Commission longer-term "integrated resource plans" (IRPs) that report five-, ten-, and fifteen-year projections of the

capacity they will generate or procure to satisfy resource adequacy and reliability requirements calibrated by MISO to meet future capacity needs. *See* Mich. Comp. Laws. Ann. § 460.6t(3). Each load-serving entity's integrated resource plan reports its forecasted capacity needs, the supply-side generating resources it will draw on, and available demand-side resources it will deploy (*e.g.*, energy waste reduction measures and measures to reduce consumption). *Id.* § 460.6t(5).

By exercising the state's various regulatory powers over electrical supply as contemplated by the Federal Power Act, the Michigan Commission plays the leading role in ensuring sufficient generation to serve the state's electricity needs. To approve an integrated resource plan, the state Commission must determine that the load-serving entity's plan represents "the most reasonable and prudent means of meeting" that utility's current and future commitments to supply electricity. *See id.* § 460.6t(8)(a).

Michigan has authority to protect energy supply in the face of risks of imminent shortage. The Michigan Commission regularly monitors energy supply in the state and publishes a semiannual "energy appraisal" that highlights recent events affecting supply and prices, expected conditions, and changes over the upcoming six months. *See* Mich. Pub. Serv. Comm'n, *Michigan Energy Supply Monitoring*, https://perma.cc/MVF9-YGMU. In the event of an unexpected shortage, the Commission may issue a special update of its energy appraisal. *Id.* And, as explained below, state regulators can request that FERC order an interconnection and sale of energy to address a shortfall. If needed, Michigan's governor can declare a state energy emergency and order various mitigation measures, including restrictions on energy use in non-residential buildings, restrictions on energy sales to consumers, and

directives to an energy supplier to provide energy to any facility that provides essential services to the state. Mich. Comp. Laws. Ann. §§ 10.83-10.84.

States play the primary role in assuring resource adequacy, but they do not act alone. Regional entities are instrumental to Michigan's planning for resource adequacy. Michigan and its electric utilities participate in the Midcontinent Independent System Operator (MISO), the 15-state RTO whose territory stretches from Montana to Louisiana and includes Michigan. RTOs are "independent organizations that manage the transmission of electricity over the electric grid and ensure electricity is reliably available for consumers." *Md. Off. of People's Couns. v. FERC*, 164 F.4th 920, 924 (D.C. Cir. 2026) (quotation omitted). Here, we focus on MISO's role in ensuring reliable supplies of electric energy to serve expected load in member states.

MISO—like other RTOs—works in tandem with state regulators, including the Michigan Commission, to help ensure resource adequacy. MISO recognizes that "the states have the primary responsibility to maintain resource adequacy, including overseeing the planning or securing of new resources by load-serving entities . . . to adequately meet demand." *Resource Adequacy Metrics and Criteria Roadmap*, Midcontinent Indep. Sys. Operator 9 (Dec. 2024), https://perma.cc/8WNH-W33N. MISO supports the states to ensure resource adequacy in several ways. *Id.*

For starters, MISO sets a regional resource-adequacy standard, *i.e.*, it develops a mathematical model to estimate how much generation capacity the system will need to run reliably. Every year, MISO updates that model with new data, such as hourly load forecasts. *Id.* Next, MISO determines whether existing capacity can meet projected peak demand—

the highest projected level of energy consumption at any given time—under various conditions. In so doing, MISO builds in several time-tested reliability safeguards.

Most importantly, MISO subjects the existing generation capacity to a process called "resource accreditation." *Midcontinent Indep. Sys. Operator, Inc.*, 189 FERC ¶ 61,065, PP 3-4 (2024) (tariff revisions establishing accreditation methodology). Rather than simply adding up all the available generation units' nominal maximum-capacity figures, MISO assigns a realistic capacity value to each unit's expected contribution to system adequacy during periods of high demand. *See id*. In the case of a coal plant, the assigned capacity value discounts its total "nameplate" capacity to account for historical limits on its actual generation due to forced outages, required maintenance, and the like. *See* Midcontinent Indep. Sys. Operator, Inc., *Resource Accreditation White Paper Version 2.1*, at 10-11 (Mar. 2024), https://perma.cc/KP39-DKBX. In the case of solar- and wind-powered electrical generation units, their intermittent character is also accounted for. *Id.* at 11-12.

On the demand side, MISO does not stop with seasonal projections of system-wide peak demand. It also establishes annual "reserve margin" requirements to prevent shortages even in the face of extraordinary disruptions like extreme weather or outages that defy ordinary projection. *See Midcontinent Indep. Sys. Operator, Inc.*, 189 FERC ¶ 61,065, P 1; Energy Scholars Amicus Br. 15-16. States using MISO's projections of peak demand thus require load-serving entities to procure enough capacity to cover the specified reserve margin increment above expected peak demand. By adding a reserve margin to projected peak demand, MISO builds a reliability buffer into the target load figures states use in planning for resource adequacy.

MISO's resource adequacy standards provide an additional benchmark, not a substitute, for state reliability requirements such as integrated resource plans. *See Midcontinent Indep. Sys. Operator, Inc.*, 170 FERC ¶ 61,215, P 13 (2020); *see also Midwest Indep. Sys. Operator, Inc.*, 119 FERC ¶ 61,311, P 75 (2007) ("From the beginning . . . , [FERC] has recognized the role that state resource planning plays in managing the resource adequacy of [MISO]."). MISO coordinates with states by supplying determinations of the electric capacity needed and that which is available in the system so that state regulators, generators, and load-serving entities can incorporate those figures into their resource-adequacy planning. Energy Law Scholars Amicus Br. 14.

MISO also administers its territory's electric capacity market. "In a capacity market, in contrast to a [real-time] wholesale-energy market, [a load-serving entity] purchases from a generator an option to buy a quantity of energy, rather than purchasing the energy itself." *NRG Power Mktg., LLC v. Maine Pub. Utils Comm'n*, 558 U.S. 165, 168 (2010). With those options contracts in hand, a load-serving entity "can meet high demands for electricity by calling on the generators to produce it when the need arises. Purchasing capacity, in other words, ensures that distributors can reliably meet predicted peak power demands in an upcoming month, season, or year." *Pub. Citizen, Inc. v. FERC*, 7 F.4th 1177, 1186 (D.C. Cir. 2021) (citation omitted). Load-serving entities "generally purchase more capacity, *i.e.*, rights to acquire energy, than necessary to meet their customers' anticipated demand." *NRG Power Mktg.*, 558 U.S. at 169; *see also Maine Pub. Utils Comm'n v. FERC*, 520 F.3d 464, 467 (D.C. Cir. 2008).

Concretely, MISO runs a competitive annual planning resource auction to enable load-serving entities to procure capacity to meet projected demand and satisfy their resource

adequacy requirements. *See* MISO, Planning Resource Auction Results for Planning Year 2025-26 ("MISO Planning Resource Auction") (J.A. 58-101). In the auction, generators offer capacity and load-serving entities submit bids for the amount needed to meet their "reserve margin" requirements. A crucial benefit of a competitive capacity market over command-and-control capacity requirements (including the Campbell Order at issue here) is that rising capacity prices in the market facilitate efficient resource adequacy planning by signaling to generators and regulators when they should invest in new generation resources or retain existing ones to ensure reliable supply of electricity; low or falling prices prevent over-investment in generation at ratepayers' expense. *See Midcontinent Indep. Sys. Operator, Inc.*, 187 FERC ¶ 61,202, P 9 (2024) (MISO tariff revisions aimed at "improving investment and retirement decisions by using price signals to properly time resource entry and exit"); Niskanen Center Amicus Br. 26-27.

If, despite states' best efforts at planning for resource adequacy, MISO identifies an imminent generation-shortage risk, it has numerous tools, like energy alerts and emergency energy procurements, to ensure adequate supply. *See* MISO Market Capacity Emergency 1-3 (J.A. 676-78). And, like the Michigan Commission, MISO has some power to defer a load-serving entity's decision to retire or suspend operations of a generation resource as needed to prevent a shortage. *See* MISO Tariff Section 38.2.7 (J.A. 887-893); *Generator Interconnection and Retirement*, Midcontinent Indep. Sys. Operator, https://perma.cc/WSS9-9AY7.

2.

The federal government, too, plays an important—albeit limited—role in the resource-adequacy scheme. Even as the

Federal Power Act generally preserves states' jurisdiction over electricity generation, it vests certain powers in the federal government to help protect the coordinated resource-adequacy system. Section 202 of the Act authorizes three tiers of federal action.

In the first tier, section 202(a), Congress called on FERC to "divide the country into regional districts for the voluntary interconnection and coordination of facilities for the generation, transmission, and sale of electric energy." 16 U.S.C. § 824a(a). Acting under that provision, FERC encouraged the voluntary formation of RTOs to administer the transmission grid on a regional basis, and the formation of independent system operators (ISOs) that perform a similar function on a smaller scale. *See Amaren Servs. Co. v. FERC*, 880 F.3d 571, 574 (D.C. Cir. 2018); *see also Elec. Power Supply Ass'n*, 577 U.S. at 267-68. Regional coordination promotes efficient interstate sales of power from a state with available capacity to another state that may find itself short, for example, and prevents free-riding whereby load-serving entities in one state might "count on the capacity they expect others to buy in order to support their own reliability." *Conn. Dep't of Pub. Util. Control v. FERC*, 569 F.3d 477, 479 (D.C. Cir. 2009). FERC oversees ISOs and RTOs, including MISO, and reviews their electric capacity requirements, rates, and other rules under the "just and reasonable" standard. 16 U.S.C. §§ 824d, 824e; *see, e.g.*, *Conn. Dep't of Pub. Util. Control*, 569 F.3d at 478-79, 485 (reviewing FERC order affecting ISO capacity requirements).

The second tier, established by section 202(b), permits FERC to direct generators to connect to and sell or exchange energy with other facilities—a power afforded to FERC only upon "application of any State commission or of any person engaged in the transmission or sale of electric energy."

16 U.S.C. § 824a(b). So, if a state energy regulator, transmission entity (*e.g.*, an RTO or ISO), or load-serving entity requests FERC to do so, FERC may—"after notice to each State commission and public utility affected and after opportunity for hearing" and a finding that action is "necessary or appropriate in the public interest"—mandate a connection or sale. *Id.*

Importantly, even as the Federal Power Act gives FERC narrow authority to respond to requests to order electricity sales or exchanges, the Act expressly denies FERC authority to regulate generation facilities directly. *See* 16 U.S.C. § 824(b)(1). It is the prerogative of states "to forbid new entrants from providing new capacity, to require retirement of existing generators, to limit new construction to more expensive, environmentally friendly units, or to take any other action in their role as regulators of generation facilities without direct interference from the Commission." *Conn. Dep't of Pub. Util. Control*, 569 F.3d at 481. The final tier of federal power, conferred by section 202(c), is the sole exception.

The third tier falls outside of the coordinated resource-adequacy system altogether. Section 202(c) establishes a limited backstop mechanism empowering DOE to address certain electricity supply emergencies. That section authorizes the Secretary of Energy (Secretary) to compel generation of electricity only "[d]uring the continuance of any war in which the United States is engaged" or when the Secretary "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. § 824a(c)(1).

Congress enacted section 202(c) in response to a "serious power shortage" during World War I and contemplated that its use would be limited to addressing wartime shocks and "similar crises" like "[d]rought and other natural emergencies." S. Rep. No. 74-621, at 49 (1935). Until now, the Department has exercised its section 202(c) authority sparingly. During nearly a century of state responsibility for sufficient supply of electricity under the FPA, the federal government has rarely used section 202(c) authority outside of wartime. It "has never used its section 202(c) authority to require additional generation to address long-term resource-adequacy concerns; instead, it has always used that authority to address discrete and unexpected events that threaten immediate grid needs." Energy Scholars Amicus Br. 21 (citing Benjamin Rolsma, *The New Reliability Override*, 57 Conn. L. Rev. 789 (2025)). The federal government has, until now, issued stopgap generation orders in response only to transitory emergencies caused by war, extreme weather events, market manipulation, or unplanned, short-term unavailability of specific generation units. *See* Rolsma, *supra* at 805-07, 839-46 tbls. 1 & 2. When a section 202(c) emergency arises, the Department can order generation that "in its judgment will best meet the emergency and serve the public interest." 16 U.S.C. § 824a(c)(1).

Congress amended the Federal Power Act in 2015 to provide that section 202(c) emergency orders may override federal, state, and local environmental laws and regulations. Such an override must be cabined to circumstances in which compliance is not "practicable," any "adverse environmental impacts" are "minimize[d]," and the facility is ordered to operate only "during hours necessary to meet the emergency and serve the public interest." Pub. L. 114-94 § 61002, 129 Stat. 1772 (2015) (codified at 16 U.S.C. § 824a(c)(2)). Congress further specified that a section 202(c) order that "may

conflict" with environmental law "shall expire not later than 90 days after it is issued." 16 U.S.C. § 824a(c)(4).

As described above, Michigan's resource-adequacy regulation entails continuous, complex planning processes with intensive coordination by the state and MISO. That planning starts years in advance to prepare for future needs as well as near-term demand. FERC has peripheral—and limited—oversight of those entities, but no power to directly regulate generation facilities. And DOE has no role whatsoever in the resource-adequacy planning process. Instead, Congress in section 202(c) gave DOE narrow authority to intervene that is triggered only in the face of an electricity emergency not otherwise addressable by states or their utilities.

B.

The J.H. Campbell Generating Plant (Campbell), an aging coal-fired power plant in Michigan, is owned and operated by Consumers Energy Company, a load-serving entity that is part of MISO. Given its decades-old units, Campbell has become increasingly inefficient, polluting, and expensive to maintain. When in operation, the Campbell facility produces dangerous emissions, including SO_2, NO_x, and PM2.5, that cause approximately thirty excess deaths every year. Order Approving Settlement Agreement 9 (J.A. 454); State Add. 213. In June 2021, Consumers Energy filed with the Michigan Commission an integrated resource plan that proposed to retire the Campbell plant. Once an integrated resource plan is filed, the Michigan Commission reviews the plan through a year-long "contested case" process. *See* Mich. Comp. Laws. Ann. § 460.6t(a)(7). Interested parties may intervene, take discovery, submit expert testimony, and present and cross-examine witnesses at an evidentiary hearing. *See id.* §§ 460.6t(7)(ii), 24.271-24.288.

Dozens of interested parties, including environmental groups, the Michigan Attorney General, and several power companies, intervened in the Consumers Energy proceedings. In April 2022, Consumers Energy entered a multi-party settlement agreement with the environmental groups, the Michigan Attorney General, and the Michigan Commission's enforcement staff under which it memorialized its plan to retire the Campbell plant and obtain newer, cleaner, cheaper, and more reliable resources that would increase available generation capacity. *See* Settlement Agreement (J.A. 543-63). Specifically, the agreement provided that Consumers Energy would retire the Campbell plant on or before May 31, 2025. *See id*. 4-5 (J.A. 546-47). And it directed Consumers Energy to acquire a new gas plant, extend operations of two oil- and gas-fired units at one of its other plants, and add new solar energy generation and battery storage. *See id*. 3-9 (J.A. 545-51). The parties sought approval of the settlement by the Michigan Public Service Commission, Order Approving Settlement Agreement 1 (J.A. 446), which ruled on objections and granted approval on June 23, 2022, *id*. 95-97 (J.A. 540-42); *see also id*. 45-95 (J.A. 490-540).

In reviewing the settlement agreement, the Michigan Commission assessed whether the integrated resource plan Consumers Energy filed following the settlement met statutory requirements. *See id*. 4, 95 (J.A. 449, 540). By statute, the Michigan Commission must approve an integrated resource plan if it determines that "[t]he proposed integrated resource plan represents the most reasonable and prudent means of meeting the electric utility's energy and capacity needs." Mich. Comp. Laws. Ann. § 460.6t(8)(a). In making that determination about the post-settlement integrated resource plan, the Michigan Commission assessed its impact on resource adequacy and on Consumers Energy's ability to serve

anticipated peak electric load. *See* Order Approving Settlement Agreement 88-95 (J.A. 533-40).

Upon review of Consumers Energy's expected procurements and operating adjustments, the Commission determined that "the approval of the settlement agreement will enhance resource adequacy in [the Campbell region] in both the near-term and long term." *Id.* 93 (J.A. 538). Ultimately, the Commission concluded, Consumers Energy's retirement plan was "the most reasonable and prudent means of meeting Consumers' energy and capacity needs and otherwise meets the requirements of MCL 460.6t(8)." *Id.* 95 (J.A. 540). On appeal, the Michigan Court of Appeals affirmed the Michigan Commission's order approving the settlement agreement and determined that there was substantial evidence that the agreement would improve resource adequacy. *In re Consumers Energy*, No. 3622954, 2023 WL 2620437, at *5-6 (Mich. Ct. App. Mar. 23, 2023).

MISO, too, determined that Campbell's retirement as planned—with substitute generation provided by cheaper, cleaner, and more reliable new and expanded generation—would support reliability. *See* Attachment Y Notice 156 (J.A. 322). That determination followed a technical evaluation of transmission system conditions that would result from the plant's retirement. *See* MISO Tariff Section 38.2.7 2-3 (J.A. 888-89). MISO's analysis confirmed that Consumers Energy did not need to operate Campbell to satisfy the RTO's reliability criteria.

As Campbell's May 2025 retirement approached, Consumers Energy, the Michigan Commission, and MISO continued to prioritize resource adequacy. Consumers Energy had already begun winding down the Campbell unit, transitioning to new generation resources, and developing

additional capacity. In its annual capacity-demonstration filing with the Michigan Commission, *see* Mich. Comp. Laws. Ann. § 460.6w(8)(a), Consumers Energy documented that it had procured sufficient capacity to meet the projected demand of its customers in summer 2025 and beyond, *see* Motion to Intervene 24 (J.A. 357); Consumers Energy Capacity Demonstration 15 (J.A. 632). And MISO's planning resource auction results for summer 2025 through spring 2026, published in April 2025, "demonstrated sufficient capacity at the regional, subregional and zonal levels." MISO Planning Resource Auction 12 (J.A. 69); *see also id.* 5 (J.A. 62) (showing that MISO attained a reserve margin of 9.8% for summer 2025, nearly two percentage points above its target).

The Michigan Commission, utilities in the state, and MISO saw no need to invoke 202(b) to request that FERC order provision of additional electricity. Neither did the governor of Michigan see any ground to declare an energy emergency in response to Campbell's planned closure. *See* Mich. Comp. Laws. Ann. §§ 10.83-10.84.

Just days before Campbell's scheduled retirement, however, DOE sidestepped Michigan's coordinated, years-long process of planning, including the detailed, judicially reviewed, multiparty settlement.

On May 23, 2025, the Secretary issued a section 202(c) Order declaring an emergency and compelling Consumers Energy to keep Campbell in operation for at least 90 days. The Order asserts 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." DOE Order 202-25-3 1 (J.A. 1). As support, the Order identifies "potential tight reserve margins during the summer 2025" in MISO and

potential electricity supply shortfalls due to the "retirement of thermal generation capacity." DOE Order 202-25-3 1 (J.A. 1).

DOE pointed to fragments of two documents as showing that the region faced an emergency within the meaning of section 202(c). First, it quoted a statement in a NERC report that MISO is "at elevated risk of operational reserve shortfalls during periods of high demand or low resource output." DOE Order 202-25-3 1 (J.A. 1); *see* NERC Reliability Assessment 5 (J.A. 107). DOE characterized that statement as describing an emergency even though the very same report concluded that MISO had "adequate anticipated resources" for "peak load conditions." NERC Reliability Assessment 5 (J.A. 107).

Second, DOE quoted a slide from a deck describing MISO's planning resource auction results for its North/Central region, which stated that "new capacity additions were insufficient to offset the negative impacts of decreased accreditation, suspensions/retirements and external resources" and that the summer months reflected the "highest risk and a tighter supply-demand balance." DOE Order 202-25-3 2 (J.A. 2); *see* MISO Planning Resource Auction 12-13 (J.A. 69-70). The first statement means that fewer capacity resources were *offered* in that region than in 2024; it does not conclude that the amount of capacity *purchased* was inadequate to serve load. *See* Michigan Attorney General Request for Rehearing 31 (J.A. 188). And, in context, the second statement is merely comparative: It explains that the supply-demand gap in summer 2025 was narrower than in fall, winter, or spring of that year. *See id.* 30-31 (J.A. 187-88). DOE acknowledges that both "MISO and Consumers ha[d] incorporated [Campbell's] planned retirement into their supply forecasts," and that MISO procured "sufficient capacity" for summer 2025. DOE Order 202-25-3 1-2 (J.A. 1-2). Brushing aside that vital context, DOE nonetheless concluded there was a risk of insufficient capacity

that warranted a section 202(c) emergency order. And it concluded, without explanation, that additional dispatch of Campbell in particular is "necessary to best meet the emergency and serve the public interest." DOE Order 202-25-3 2 (J.A. 2).

In June 2025, Michigan sought administrative rehearing, as did Illinois, Minnesota, and several environmental nonprofit groups. Rehearing was denied by operation of law when DOE failed to respond within 30 days. 16 U.S.C. § 825l(a). Petitioners then sought our review of the Order. On September 8, 2025, DOE issued a Rehearing Order that "modified" the Order in some respects and otherwise sustained it. DOE Order 202-25-3B 24 (J.A. 29).

The Rehearing Order reiterates that section 202(c) "specifically applies to the potential 'shortage of electric energy or of facilities for the generation or transmission of electric energy,'" which it describes as "exactly the situation that led to the issuance of the Emergency Order." Order 202-25-3B 4 (J.A. 9). DOE also announced a new interpretation of section 202(c) to authorize it to countermand the state's approval of a plant closing, even in the absence of a need for federal intercession to avert an imminent reliability risk beyond state or RTO control. Order 202-25-3B 7 (J.A. 12). It is enough, in DOE's view, that the Order "addresses [the] risk" that, in DOE's view, "if current retirement schedules and incremental additions remain unchanged, most regions—including the MISO region relevant to the Emergency Order—will face unacceptable reliability risks within five years," Order 202-25-3B 14 (J.A. 19).

The Act limits to 90 days the duration of a section 202(c) order that conflicts with environmental law, *see* 16 U.S.C. § 824a(c)(4)(A)—which this one indisputably does. DOE has

nonetheless extended the Order's 90-day period four times. Order No. 202-25-7 (DOE Aug. 20, 2025); Order No. 202-25-9 (DOE Nov. 18, 2025); Order No. 202-26-16 (DOE Feb. 17, 2026); Order No. 202-26-22 (DOE May 18, 2026). In each extension, DOE asserted that the emergency conditions "will continue in the near term and are also likely to continue in subsequent years." *See, e.g.*, Order No. 202-25-7 7 (State Add. 88); Order No. 202-25-9 8 (State Add. 99). Thus, DOE has compelled Campbell's continued operation for a total of 450 days, claiming that extended compulsion is appropriate "[t]o ensure that the Campbell Plant will be available if needed to address emergency conditions." *See* Order No. 202-25-9 8 (State Add. 99). Petitioners timely sought review of the extension orders, and we held those petitions in abeyance pending the outcome here.

II.

We have jurisdiction to review the initial Order challenged in these petitions. 16 U.S.C. § 825*l*(b); *see* 42 U.S.C. § 7192(a). We must set aside an agency action that is "in excess of statutory jurisdiction, authority, or limitations, or short of statutory right." *Erie Blvd. Hydropower, LP v. FERC*, 878 F.3d 258, 266 (D.C. Cir. 2017) (quoting 5 U.S.C. § 706(2)(A), (C)). When determining whether an agency has exceeded its statutory authority, we interpret the relevant statutory provisions *de novo*. *See Loper Bright Enterprises v. Raimondo*, 603 U.S. 369, 400-01 (2024).

Petitioners claim that the Order exceeds DOE's statutory authority. Specifically, they argue that the circumstances DOE has identified—including an out-of-context quotation about an "elevated risk" of operational reserve shortfalls in summer 2025 and unspecified long-term reliability risks—do not constitute an "emergency" under section 202(c). The very

document DOE drew from established that there was in fact sufficient capacity due to Michigan's planning measures for resource adequacy and no anticipated electricity shortfall, so no "emergency." Petitioners also claim that the Order's finding that Michigan faced a section 202(c) emergency is not supported by substantial evidence and contravenes other limitations imposed by section 202(c). DOE responds that the Secretary has broad latitude to determine that a section 202(c) emergency exists and that the Order correctly identifies one here.

A.

We first address petitioners' statutory argument. And because we find that argument dispositive, we need go no further. DOE relies not on its core power to compel electricity connection or generation to meet emergency needs in wartime, but on its power to compel generation of electric energy when the Secretary "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. § 824a(c)(1). The Act gives the Secretary authority to determine whether an emergency exists. That grant of authority does not grant a boundless license to ignore the statutory text; it allows the Secretary to exercise discretion within the Act's statutory limits. The statutory limits in section 202(c) confine DOE's authority to temporary emergencies that the Secretary reasonably determines are and will be unmet by the state's resource planning.

The parties disagree about what counts as an "emergency" under section 202(c). Petitioners contend that an "emergency" for section 202(c) purposes must be sudden, unexpected,

imminent, and require an immediate response. State Pet'rs Br. 26-27. DOE contends that the term encompasses any anticipated shortage of electric power, even if neither imminent nor beyond the capability of the state to address. DOE Br. 23-25.

We hold that a section 202(c) "emergency" means a grid-reliability risk that calls for an immediate response by DOE in particular. If the Department finds the state has not and will not timely take steps that must be taken immediately to avert unacceptable risk to reliability, the need for immediate action can trigger statutory authority for DOE to step in.

In arriving at the best interpretation, "we begin with the text." *Pacific Gas & Electric Co. v. FERC*, 113 F.4th 943, 948 (D.C. Cir. 2024) (citation omitted). The Federal Power Act does not define "emergency," so "we look to the word's ordinary definition." *CSX Transp., Inc v. Ala. Dep't of Revenue*, 562 U.S. 277, 284 (2011). Definitions of "emergency" include an "unforeseen occurrence or combination of circumstances which calls for immediate action or remedy," a "pressing necessity," and an "exigency." *Webster's New Int'l Dictionary of the English Language* 716 (2d ed. 1930); *see also* 3 *Oxford English Dictionary* 119 (1933) (defining emergency as "a state of things unexpectedly arising, and urgently demanding immediate action").

The key consideration in determining whether a situation amounts to an emergency is whether it demands immediate action by DOE outside the ordinary process for assuring reliability. While the suddenness, imminence, and unexpectedness of a reliability risk will often make it more likely to warrant immediate action, it is, as we explain further below, *see infra* at 29-32, the combination of urgent need for action with circumstances showing that a federal response is

called for that epitomizes a section 202(c) emergency. And, contrary to petitioners' arguments that an emergency can stem only from an imminent and unforeseen energy shortage, *see* PI Pet'rs Br. 24; State Pet'rs Br. 25, the need for an immediate federal response might arise even when a crisis is foreseeable or will occur in the future: If, for example, a deteriorating nuclear power plant poses risks of a serious outage in three years absent immediate action to ensure repairs, and if DOE has reason to believe that the state cannot or will not act in time to reasonably respond, an emergency may exist even though the outage is foreseeable and far-off.

Based on the text, the need for immediate federal action to ensure adequate supply of electricity is the touchstone for a section 202(c) emergency. DOE's arguments to the contrary are unpersuasive.

DOE contends that the text of section 202(c) uses "emergency" broadly to include any shortages of electric energy. DOE Br. 23-25. The Department asserts that section 202(c) "spells out what constitutes a section 202(c) 'emergency' by capacious examples," including "'a shortage of electric energy'; 'a sudden increase in the demand for electric energy'; a shortage 'of facilities for the generation or transmission of electric energy'; a shortage 'of fuel or water for generating facilities'; or for 'other causes.'" DOE Br. 24 (quoting 16 U.S.C. § 824a(c)(1)). But DOE misreads the text. What it quotes in section 202(c) as statutorily identified emergencies are no such thing. They are potential *causes* of emergencies, not *examples* of emergencies. As the statute says, an emergency may "exist[] by reason of" a shortage of electric energy or of facilities for the generation or transmission of electric energy. 16 U.S.C. § 824a(c)(1). The statutory text plainly does not say those potential causes are themselves emergencies.

Next, DOE argues that the text of neighboring section 202(d) shows that the term "emergency" in section 202(c) cannot mean that immediate action is required. DOE Br. 28. Section 202(d) permits a utility that is not subject to FERC's jurisdiction to connect temporarily to the interstate grid during "any emergency requiring immediate action," and to do so without thereby subjecting itself to FERC's jurisdiction. 16 U.S.C. § 824a(d). The apparent role of this provision is to encourage such voluntary connection to help meet emergency conditions. DOE argues that the word "emergency" by itself in section 202(c) cannot refer to circumstances requiring immediate action because that would treat the modifying phrase accompanying the word "emergency" in section 202(d)—"requiring immediate action"—as surplusage. That is wrong. Even if there were no section 202(c) at all, the phrase in section 202(d) would be surplusage because, as the dictionaries and common usage establish, the word "emergency" standing alone denotes an acute situation requiring an immediate response. *See supra* at 27. The fact that "emergency" conveys the same meaning more succinctly than the more emphatically worded "emergency requiring immediate action" is no reason to eschew the word's ordinary meaning in section 202(c). After all, "the canon against surplusage is not an absolute rule," and it "certainly does not require us to favor an unusual meaning that will avoid surplusage over a more natural one." *Stanley v. City of Sanford*, 606 U.S. 46, 56 (2025) (quotation omitted).

For purposes of section 202(c), the ordinary meaning of "emergency" as an event that requires immediate action does not complete the analysis. "It is a fundamental canon of statutory construction that the words of a statute must be read in their context and with a view to their place in the overall statutory scheme." *Sturgeon v. Frost*, 577 U.S. 424, 438 (2016) (quotation omitted). Given the structure and context of the

Federal Power Act, section 202(c)'s grant of emergency authority is triggered only when there is a need for immediate, essentially last-resort action *and* the circumstances require action by DOE in particular, as opposed to action by the state or states responsible for resource adequacy.

To start, Congress carefully structured the Federal Power Act, and section 202 within it, to preserve the primacy of state authority over electricity generation. At its outset, the Act clarifies that the limited federal authority it confers extends "only to those matters which are not subject to regulation by the States." 16 U.S.C. § 824(a). And it expressly denies federal authority "over facilities used for the generation of electric energy." *Id.* § 824(b)(1). To help ensure that generation suffices to meet long-term demand, section 215 authorizes NERC to establish nationwide reliability standards. 16 U.S.C. § 824*o*(d). But that section, which expressly denies NERC power to demand additional generation capacity, makes clear that NERC's standards are to guide state planning, not to authorize federal intervention to direct electricity generation. FERC, too, facilitates production of an "abundant supply of electric energy," principally by prompting states and their utilities to engage in "voluntary interconnection and coordination" at the regional level. 16 U.S.C. § 824a(a). If those efforts prove deficient, a state, transmission organization, or load-serving entity may request, under section 202(b), that FERC direct a generator to sell or exchange energy with other facilities. *Id.* § 824a(b). But FERC only has authority to do that in response to a request. Permitting DOE to compel generation in a situation that can be resolved through the ordinary resource adequacy planning mechanisms or a request under section 202(b) would render meaningless the constraints on federal power that Congress imposed throughout the Act.

The only other court to consider Section 202(c)'s scope has come to the same conclusion. In *Otter Tail*, the court distinguished section 202(c), which enables a federal response "to react to a war or national disaster and order immediate interconnection of the facilities to maintain electrical service during such emergency," from section 202(b), which "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 [Federal Power] Commission." *Otter Tail Power Co. v. Fed. Power Comm'n*, 429 F.2d 232, 234 (8th Cir. 1970). So there, too, the court treated the federal government's section 202(c) power as limited by the primacy of other, less top-down and coercive mechanisms to ensure resource adequacy.

The structure of the Federal Power Act makes clear that compelled generation under section 202(c) is generally appropriate only when DOE faces a type of reliability emergency that is unaddressed by actions contemplated by sections 202(a) and (b), so necessitates federal intervention. Section 202(c) is essentially a narrow, last-resort backstop. It provides for DOE to exercise emergency authority when coordinated state and regional resource adequacy planning, per section 202(a), and invocation of section 202(b) both fall short. When those mechanisms function as intended to address potential resource adequacy issues, there will typically be no "emergency" within the meaning of section 202(c).

The circumstances requiring use of section 202(c) are rare. If generation shortfalls or other reliability risks are anticipated, states, generators, and regional entities have every incentive and tool to make plans to procure replacement resources or prevent scheduled retirements. And even for imminent or unforeseen shortfalls, the coordinated resource-adequacy system includes alternative solutions. For instance, MISO may provide for energy imports from neighboring systems or deploy

operating mitigations like load-modifying resources—that is, demand-side measures to reduce energy consumption. *See* NERC Reliability Assessment 16 (J.A. 118); MISO, *Market Redefinition: Load Modifying Resource Reforms* 6 (Nov. 6, 2024), https://perma.cc/AZ69-Q3VN. MISO may also issue energy emergency alerts or operational alerts that require its stakeholders to take energy conservation actions. *See* MISO Market Capacity Emergency 21-26 (J.A. 696-701). States may declare energy emergencies pursuant to which they restrict consumption or command an energy supplier to redirect its energy to a needed facility. *See, e.g.*, Mich. Comp. Laws. Ann. §§ 10.83-10.84. And states, transmission organizations, or load-serving entities contemplating imminent shortages can call on FERC under section 202(b) to require generators to sell or exchange energy with other facilities. *See* 16 U.S.C. § 824a(b). For virtually all risks of energy shortages, alternatives to DOE intercession suffice.

When DOE exercises its section 202(c) authority to compel generation other than as a last resort, including by reversing a generator's long and carefully planned retirement as it did with Consumers Energy's Campbell unit, the results are disruptive. Unjustified use of section 202(c) upends existing resource-adequacy decisions made based on years of planning with intensive expert input and broad stakeholder participation. As DOE itself acknowledges, resource adequacy planning and adding generation capacity is a "many-year" process. *See* DOE Br. 33. States and RTOs closely scrutinize the impact of generation retirement or reduction and engage in sophisticated planning of expansion or construction of generation units and facility interconnections. They do so with public notice and input by a broad range of stakeholders. And they seek to achieve resource adequacy in a manner that serves the public interest in affordable, environmentally sound, reliable resources going forward. *See id.* at 33-34. Contrary to

DOE's position, DOE Br. 31-36, the complexity and advance planning that go into states' assurances of resource adequacy do not imply that DOE must have vast, top-down emergency power to pick its favorite generators to run at all costs, or to abruptly order disfavored units to shut down earlier than planned. Rather, the complexity of state planning processes helps to explain why the Federal Power Act leaves resource adequacy to be managed by states, utilities, and their RTOs.

The Department's reading of "emergency" invites frequent federal interventions that are unsupported by the statute and threaten the stability of the energy market. By directing a generator approved for retirement to remain operative while effectively walling it off from planning and market frameworks, the Order challenged here interferes with ordinary methods to assess a region's true generation capacity and distorts price signals that otherwise prompt appropriate capacity investments. *See* Energy Law Scholars Amicus Br. 16. DOE's use of its expansive interpretation of "emergency" to prevent planned retirements of generators slated to close, for example, will likely discourage development of needed new resources by artificially lowering capacity market prices and destabilizing those markets. *See id.* 16-20. Such distortions may be justified in the face of the rare emergency requiring DOE's immediate, short-term intervention. But unless DOE's involvement is needed in response to a genuine emergency as defined by section 202(c), it must be avoided.

The text and statutory structure are alone sufficient to settle the "best" understanding of FERC's section 202(c) authority. *See Loper Bright*, 603 U.S. at 370. The correctness of our reading is powerfully confirmed by the executive branch's consistent interpretation and limited exercise of that

authority over nearly a century. *See id.* at 386 (citations omitted).

The reading of section 202(c) we provide today is a familiar one. In *Richmond Power & Light v. FERC*, 574 F.2d 610 (D.C. Cir. 1978), we held that the Federal Power Commission (predecessor to both FERC and DOE) acted within its sound discretion in eschewing reliance on Section 202(c) to address electric supply problems caused by the 1973 oil embargo. 614-15. The Commission had determined to "invoke section 202(c) only if its emergency powers could have provided the sole authorization" to alleviate the shortage. *Id.* at 614. Rejecting the position of midwestern generators seeking compelled purchases of their capacity under section 202(c), the Commission treated continued reliance on foreign oil, despite a national policy discouraging such reliance, as not among the "'temporary' emergencies, epitomized by wartime disturbances" to which section 202(c) applies. *Id.* at 615. Given that the anticipated need could be mitigated by a temporary regional agreement to increase energy conservation and transfers from energy-rich states to those facing shortages, the Commission saw no role for last-resort federal compulsion under section 202(c). *Id*. at 613-14.

DOE's own rule—adopted shortly after we decided *Richmond Power & Light*—defines a section 202(c) "emergency" along similar lines 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." 10 C.F.R. § 205.371. That rule lists as examples of events that might cause an emergent inadequacy in electricity supply "weather conditions, acts of God, or unforeseen occurrences not reasonably within the power of the affected 'entity' to prevent"; unanticipated shortfalls might also 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." *Id*. DOE explained when it adopted the rule that section 202(c) did not empower it to issue orders to "replace prudent utility planning and system expansion." Department of Energy, Emergency Interconnection of Electric Facilities and the Transfer of Electricity to Alleviate an Emergency Shortage of Electric Power, 46 Fed. Reg. 39,984, 39,985 (Aug. 6, 1981). As the rule specifies, a section 202(c) order is "envisioned as meeting a specific inadequate power supply situation," not solving a long-term problem. 10 C.F.R. § 205.371.

The historical uses of section 202(c) further reinforce its limited scope. *See Loper Bright*, 603 U.S. at 386 (emphasizing that the "'longstanding practice of the government'—like any other interpretive aid—'can inform [a court's] determination of what the law is'" (quoting *NLRB v. Noel Canning*, 573 U.S. 513, 525 (2014) (modification in original))). Outside of wartime, section 202(c) has been used sparingly. Between World War II and the Federal Power Commission's dissolution and replacement by the Department of Energy in 1977, the Commission issued only seven section 202(c) orders, typically in response to local requests and based on impending outages, operating and construction difficulties, or drought. *See, e.g.*, *City of Cleveland v. Cleveland Elec. Illuminating Co.*, 47 F.P.C. 747, 748-50 (1972) (operating difficulties); *Crisp Cnty. Power Comm'n v. Ga. Power Co*., 35 F.P.C. 629, 630-31 (1966) (multiple system outages); *Tex. Elec. Serv. Co*., 7 F.P.C. 574, 575 (1948) (construction delays, generator outage, and drought); *see also* Rolsma, *supra*, at 843-46 tbl. 2.

After Congress transferred section 202(c) authority from the Federal Power Commission to DOE in 1977, DOE saw no

need to use it for decades. Before 2025, DOE had issued section 202(c) orders only at the request of local entities and to alleviate discrete crises, such as those caused by severe weather events or unexpected construction delays that required an immediate response. *See, e.g.*, DOE Order 202-20-2 1-2 (Sept. 6, 2020), https://perma.cc/7GEU-86C8 (extreme heat wave); DOE Order 202-17-1 1 (Apr. 14, 2017), https://perma.cc/6QJC-2SEG (unpredicted convergence of lightning strike and flooding); DOE Order 202-05-2 (Sept. 30, 2005), https://perma.cc/WH4A-LV8A (serial strikes of Hurricanes Rita and Katrina); *see also* Rolsma, *supra*, at 839-42 tbl 1.

In sum, an emergency under section 202(c) refers to an electricity shortage that is or will in the future be acute and is not being timely addressed by planning for resource adequacy by the state, its utilities, or an RTO. Those circumstances require immediate, essentially last-resort action by DOE outside the ordinary reliability planning process.

We next consider whether the circumstances identified by DOE are facially sufficient to meet the statutory requirement of an emergency. Because we conclude that they are not, we need not reach petitioners' substantial-evidence claims or their challenges to DOE's decision to choose Campbell as the source of additional capacity and to command it to run beyond the "hours necessary to meet the emergency." 16 U.S.C. § 824a(c)(2).

B.

The Order initially describes the emergency as "the potential for electricity supply shortfalls" in summer 2025 caused by the "retirement of thermal generation capacity." DOE Order 202-25-3 1 (J.A. 1). It warns that summer 2025 presented a risk of "potential loss of power to homes and local

businesses in the areas that may be affected by curtailments or outages." DOE Order 202-25-3 2 (J.A. 2). DOE continues to defend the Order on that basis, arguing that "emergency conditions existed . . . due to a shortage that would cause unacceptable reliability risks in the near-term." DOE Br. 31.

Those indeterminate assertions of summer electricity shortfalls are not what Congress meant by "emergency" in section 202(c). Had DOE pinpointed a concrete supply issue beyond the state's competency that was likely to trigger a blackout in an identified area if temperatures peaked, immediate intervention might have been appropriate. But the mere possibility of an electricity supply shortfall—with no specifics about its potential severity, timing, location, or likelihood—does not warrant an emergency federal response. Rather, reasonable alternatives to DOE's intervention were available, and in fact appear to have forestalled outages.

Because the circumstances DOE identified plainly did not necessitate immediate action by DOE, it did not meet the definition of an emergency under section 202(c). NERC's Reliability Assessment—the very document on which the Department relies to support its emergency determination—describes MISO mitigation measures to prevent operating shortfalls, including accessing load-modifying resources, requesting energy transfers from neighboring systems, and issuing energy emergency alerts. *See* NERC Reliability Assessment 16 (J.A. 118). MISO also instructs its stakeholders to lower energy use and increase output from backup generators. *See* MISO Market Capacity Emergency 21-26 (J.A. 696-701). Michigan's governor can declare an energy emergency to restrict energy consumption and direct supply to needed areas. *See* Mich. Comp. Laws. Ann. § 10.84. Such an intervention is modulated—in ways that DOE's section 202(c) order is not—by the governor's direct political accountability

to electricity users in the state and familiarity with state energy conditions. And, as already discussed, state regulators, transmission organizations, and load-serving entities have other mechanisms to address shortages, including requesting intervention from FERC under section 202(b).

DOE's Rehearing Order identifies an alternative basis for its emergency determination. The agency asserts that "most regions—including the MISO region relevant to the Emergency Order—will face unacceptable reliability risks within five years," and that requiring Campbell's continued operation "addresses that risk." DOE Order 202-25-3B 14 (J.A. 19). On appeal, DOE continues to defend the Order by pointing to longer-term reliability and resource adequacy concerns. *See* DOE Br. 79.

That added rationale falls even farther outside the meaning of "emergency" under section 202(c) than did the first. Long-term resource adequacy risks generally do not necessitate immediate action by DOE. They are routinely resolved through coordinated, forward-looking decision making within the ordinary resource adequacy system. That entire system prioritizes averting unacceptable long-term reliability risks. Again, Michigan addresses long-term reliability risks by reviewing generators' integrated resource plans and by approving or rejecting the construction and retirement of generation facilities. Regional entities like MISO facilitate states' responses to long-term reliability risks by setting resource adequacy requirements and encouraging new resource entry through effective administration of the capacity market. MISO has also adopted reliability initiatives aimed at improving its processes and transmission capabilities, such as implementing resource accreditation reforms, constructing new transmission lines, and expediting approval of new electric generation resources. *See* Testimony of Jennifer Curran 2

(J.A. 1140) (House Subcommittee testimony of MISO executive). And, if long-term resource adequacy continues to present a threat, NERC may modify its nationwide reliability standards. The federal government generally lacks statutory authority to address long-term reliability risks; much less is DOE empowered to make unauthorized use of section 202(c) emergency authority as a partial substitute for and disruption to the states' planning processes.

Because we conclude that DOE exceeded its statutory authority, we do not address petitioners' other challenges to the Order. *See MCI Telecomms Corp. v. FCC*, 765 F.2d 1186, 1188 (D.C. Cir. 1985).

III.

We vacate the Order. An order of a federal agency "that exceeds the scope of its statutory authority is, by definition, not in accordance with the law and subject to vacatur." *All Am. Telephone Co., Inc. v. FCC*, 867 F.3d 81, 89 (D.C. Cir. 2017); *see Calif. Indep. Sys. Operator Corp. v. FERC*, 372 F.3d 395, 396 (D.C. Cir. 2004) (vacating order that FERC had no authority to make or enforce). To determine whether vacatur is the appropriate remedy, we evaluate (1) "the likelihood that deficiencies in an order can be redressed on remand" and (2) "the disruptive consequences of vacatur." *N.J. Conservation Found. v. FERC*, 111 F.4th 42, 64 (D.C. Cir. 2024) (quotation omitted).

The Order's deficiency cannot be redressed on remand because it depends on DOE's misconception of the nature and scope of its emergency authority under section 202(c). Because the circumstances identified by DOE do not amount to a section 202(c) emergency, the agency cannot claim any serious possibility that it will be able to "substantiate its decision on remand." *Id.* (quoting *Allied-Signal, Inc. v.*

Nuclear Regul. Comm'n, 988 F.2d 146, 151 (D.C. Cir. 1993)). And vacatur will not be disruptive because the Order under review has already expired.

***

For the foregoing reasons, we grant the petitions and vacate the Order.

So ordered.

UNITED STATES OF AMERICA
BEFORE THE
UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Craig Unit 1	)	Order No. 202-26-49

The State Of Colorado's Request for Rehearing,
Motion To Intervene, And Stay Request

Exhibit HHHH: EIA, *Datasheet* (July 2026) Provided in Native Format

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UNITED STATES OF AMERICA
BEFORE THE
UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Craig Unit 1	))))	Order No. 202-26-49

The State Of Colorado's Request for Rehearing,
Motion To Intervene, And Stay Request

Exhibit IIII: NERC, 2026 State of Reliability Overview (June 24, 2026)

NERC

2026 State of Reliability

Assessment Overview of 2025 Bulk Power System Performance

June 24, 2026

2026 SOR Snapshot

2026 SOR Technical Assessment

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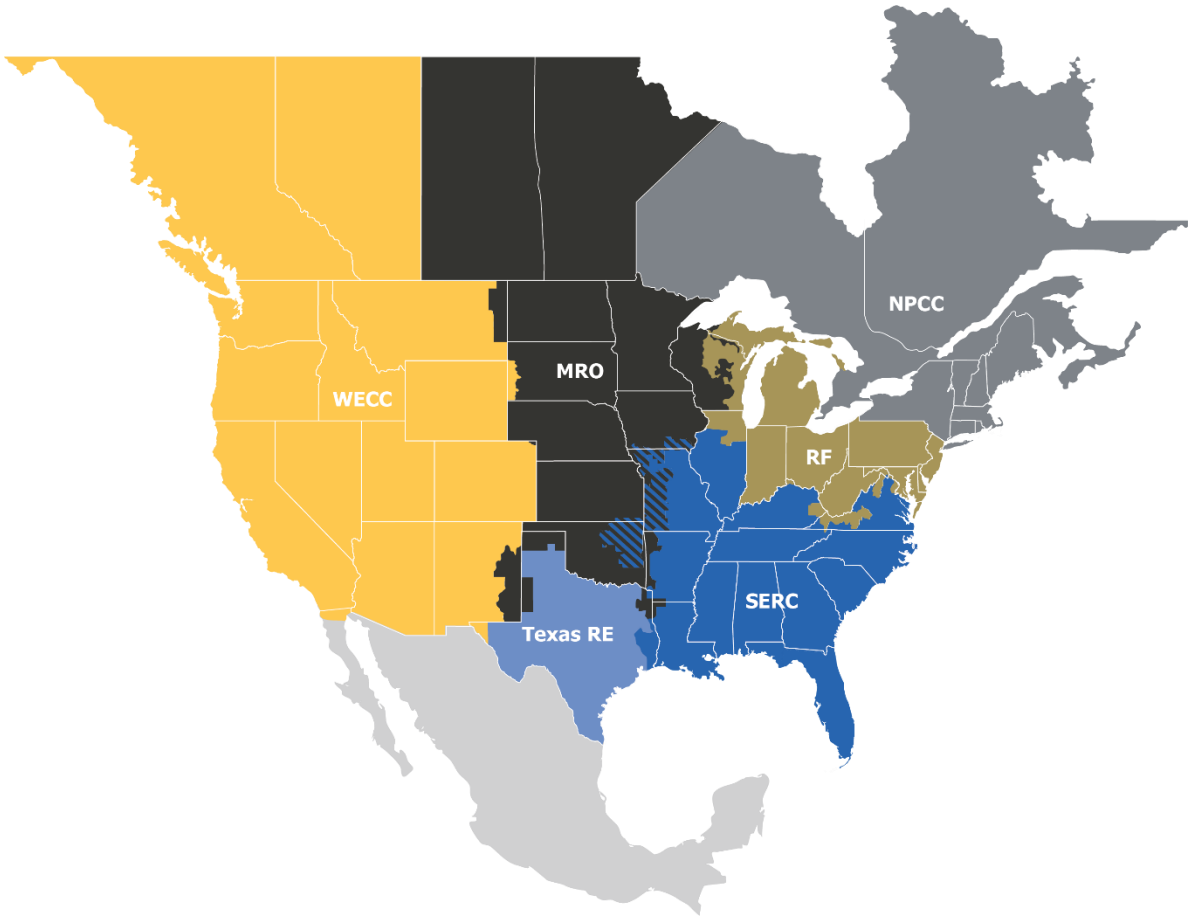
Preface

Electricity powers our modern life and is the bedrock of our economic wellbeing. The Electric Reliability Organization (ERO) Enterprise—comprised of NERC and the six Regional Entities—is firmly committed to assuring a highly reliable, resilient, and secure bulk power system (BPS) in North America. The ERO Enterprise enables collaborative engagement with industry, regulators, and stakeholders, embracing innovation and supporting the needs of nearly 400 million people.

RELIABILITY | RESILIENCE | SECURITY
POWERING TODAY. PROTECTING TOMORROW.

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



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

About This Overview

NERC delivers the *State of Reliability* (SOR) as a two-part report that consists of the *2026 SOR Overview* and the *2026 SOR Technical Assessment*.[1] The *2026 SOR Overview* serves as a high-level summary of the most important and actionable topics impacting the BPS and how they are being addressed, while the *2026 SOR Technical Assessment* provides NERC's comprehensive annual analytical review of BPS reliability for the 2025 calendar year. The analysis within the SOR report fulfills a key role in NERC's mission by providing an unbiased, data-driven look at the BPS's reliability, identifying ongoing challenges, and informing future-looking assessments. This overview seeks to inform regulators, policymakers, and industry leaders of the most significant reliability risks facing the BPS and describes the actions that the ERO Enterprise has taken, and will take, to address them.

Development Process

ERO staff developed this overview and the corresponding *2026 SOR Technical Assessment* with support from the Performance Analysis Subcommittee (PAS). Both documents draw conclusions from an established set of reliability indicators and mandatory information reported by industry to the Transmission Availability Data System (TADS), the Generating Availability Data System (GADS), the Misoperation Information Data Analysis System (MIDAS), voluntary reporting into the Event Analysis Management System (TEAMS), Bulk Power System Awareness monitoring and processes, the Institute of Electrical and Electronics Engineers (IEEE) Distribution Reliability Working Group, and other sources as available.

Considerations

- Data in the SOR represents the performance for the January–December 2025 operating year unless otherwise noted.
- Analysis in this report is based on data from 2021–2025 that was available in Spring 2026 and provides a basis to evaluate 2025 performance relative to performance from the last five years. All dates and times shown are in Coordinated Universal Time (UTC).
- The SOR is a review of industry-wide trends—not a review of the performance of individual entities.
- When analysis is presented by Interconnection, the Québec Interconnection is combined with the Eastern Interconnection unless specific analysis for the Québec Interconnection is shown.

[1] NERC SOR 2026 Technical Assessment

Executive Summary

The North American BPS continues to deliver reliable electric service under increasingly challenging conditions. Key performance indicators remain stable overall even as the system experiences rising demand growth, more frequent extreme weather events, and significantly higher penetrations of inverter-based resources (IBR).

At the same time, the report highlights a critical shift in the nature of reliability risk. Many of the emerging concerns facing the system are no longer driven by single contingencies or localized disturbances but by correlated and system-wide stresses, including energy limitations, operational challenges associated with maintaining reliability in lower-inertia systems, and declining availability of aging combustion generation. Although fuel supply uncertainty and extreme weather exposure were not major drivers in this year's assessment, they remain subject to ongoing monitoring given their continuing potential to affect reliability. The findings emphasize that continued reliability success will depend not only on maintaining infrastructure and resource adequacy but also on improving industry's ability to anticipate, model, and manage these evolving risks before they manifest as reliability events.

While the SOR focuses on historical occurrences in the past year, it is also important to recognize future resource adequacy concerns. NERC's forward-looking *Long-Term Reliability Assessment*[2] and related non-NERC reports[3] continue to highlight that generation development has not and is not expected to keep pace with needs as new projects face delays and cancellations due to supply chain constraints, changing economies, and increasing grid upgrade costs. Similarly, while existing transmission performance continues to improve, its development, particularly of major interstate lines, is not advancing at a pace that can adequately support future reliability needs.

Reliability Indicators

Table 1 provides an overview of key performance measures of the BPS that compares 2025 performance to the previous four years. The results show that while a majority of these measures continue to improve or remain stable, several indicators are identified for monitoring or further attention, highlighting areas that warrant industry focus. The table is intended to contextualize known and emerging trends and areas of operational focus to help stakeholders understand where reliability risks may be evolving or re-emerging as the grid continues to transform.

[2] Long-Term Reliability Assessments
[3] MISO *2026 Reliability Imperative Report*

Table 1: Reliability Indicators[4]			
Improving	**Stable**	**Monitor**	**Actionable**
Frequency Response: Eastern, Texas, and Western Interconnections	**Frequency Response:** Québec Interconnection	**Winter Reserve Margin:** NPCC Maritimes	**Inertia and Rate-of-Change-of-Frequency:** Québec Interconnection[5]
Inertia and Rate-of-Change-of-Frequency: Eastern, Texas, and Western Interconnections	**Protection System Misoperations Rate**	**Transmission-Related Events Resulting in Loss of Load:** Supported by Event Analysis Data	
Energy Emergency Alerts	**Transmission Outages Caused by Failed Protection System Equipment:** AC Circuits	**Interconnection Reliability Operating Limit (IROL) Exceedance**	
Transmission Outages Caused by Failed Protection System Equipment: Transformers	**Automatic AC Transmission Outages Caused by Failed AC Substation Equipment:** AC Circuits	**Transmission Outages Caused by Failed AC Substation Equipment:** Transformers	
Automatic Transmission Outage Events Involving Human Error: AC Circuits and Transformers	**Transmission Element Availability:** AC Circuits	**Transmission Element Availability:** Transformers	
Transmission Outages Caused by Failed AC Circuit Equipment	**Transmission Outage Severity**		
	Transmission Physical Security Metric		

Emerging Trends

While the BPS remains reliable and continues to perform well operationally, underlying reliability risk is increasing and changing in nature; the margin for error continues to decrease while dependence on operational mitigations increases.

NERC's analysis in the SOR report also identifies several important emerging trends:

1. **Conventional generation forced outage rates are up.**
   The report identifies a meaningful increase in conventional generator forced outage rates in 2025, with annual weighted equivalent forced outage rates (WEFOR) increasing to 9.2% compared to historical norms rarely exceeding 8%. Coal and combined-cycle units were the primary drivers of this increase with an increase of over 39.8 TWh and 19.1 TWh of unavailable energy year over year, respectively. In contrast to recent years' generation challenges, operational performance during the

[4] Some metrics are evaluated for multiple sub-topics. These metrics are either listed multiple times, with the different sub-topics beneath the bolded metric name (e.g. different interconnections for Frequency Response), or the criteria driving the overall status is listed (e.g. NPCC Maritimes causing Winter Reserve Margin to have the Monitor status).

[5] The Québec Interconnection has been experiencing low hydraulicity conditions since 2023. In 2025, this resulted in reduced energy exports and increased energy imports. Therefore, fewer hydro generating units were synchronized within the Interconnection, particularly under summer light-load conditions, leading to lower system inertia during this period. These conditions have been cyclical historically and are expected to improve in the coming years.

most challenging winter week of 2025[6] improved as industry winterization efforts continued. Instead, the reduction in availability was distributed throughout the year, suggesting a broader baseline degradation in much of the coal and combined-cycle fleets' performance.

2. **Demand growth and large load integration continue challenging operators.**
   Projected annual energy demand rose to nearly 4.95 million GWh in 2025, while actual summer peak demand in several areas approached or exceeded the normal forecast. Data center and computational loads continued emerging as a major reliability consideration due to their scale, speed of development, and unique operational characteristics. In 2025, two instances of data center customer-initiated load reduction (CILR) exceeded 1,000 MWs, with many more exceeding 100 MWs. NERC continued to work with the electric and data center industries to issue new alerts, host technical conferences, perform standards work, and offer large load guidance activities, reflecting the growing importance of load modeling, operational coordination, and frequency response impacts associated with these rapidly growing loads.

3. **Resource mix transformation is fundamentally changing system operations and reliability management.**
   Solar, wind, and battery energy storage systems (BESS), all IBRs, continued to expand rapidly in 2025, with BESS growth approximately matching solar growth. In several peak demand periods, solar and/or wind production materially exceeded planning assumptions and supported system operations during stressed conditions. Additionally, BESS continued to demonstrate the capability to provide rapid frequency response. At the same time, IBRs are increasing operational complexity associated with inertia, protection systems, dynamic performance, and disturbance response. NERC continued extensive IBR mitigation work in 2025 and early 2026, including new technical requirements related to IBR performance, ride-through capability, and model validation.

4. **Industry mitigation actions are tracking well in many foundational reliability areas.**
   The *2026 SOR Technical Assessment* also documents continued improvement in several important controllable reliability metrics, including overall transmission system outage severity, protection system misoperations, failed protection-system-related outages, and transmission-related loss-of-load events.

[6] Comparisons across winter storm events should be interpreted with caution, as outage risk remains elevated and storm impacts vary significantly by the area impacted, duration, system condition, and event severity.

Conventional Generation Forced Outage Rates Up

Forced outage performance is a foundational indicator of BPS reliability because it illustrates the ability of generating resources to perform daily as well as when they are most needed, during periods of high demand, stressed system conditions, and extreme weather. While reserve margins and accredited capacity metrics provide a static view of resource sufficiency, an analysis of year-over-year forced outage rate changes provides insights into the availability of the conventional resource fleet, revealing trends in outage behavior and emerging reliability vulnerabilities.

Analysis of 2025 Weighted Equivalent Forced Outage Rate

Our 2025 analysis of the conventional GADS[7] revealed an increase in reported units' annual WEFOR[8] to 9.2%, which is higher than the historical norms of 7–8% (see **Figure 2**). This increase was not the result of any particular event but an increase distributed across most months throughout the year, with three months' WEFORs being comparable to the months when winter storms Elliott and Uri occurred. The lack of specific major events is indicative of a more subtle baseline increase in conventional forced outage rates. This, combined with tightening reserve margins[9] in some areas that have continued into 2025 from prior years—as well as performance improvements during the most challenging winter week of the year (January 19–25), highlighted by NERC, the Federal Energy Regulatory Commission (FERC), and industry—emphasizes the overall operational improvements while underscoring the increasingly precarious position of the BPS. As WEFOR increases, planning reserve margins may also increase at a higher rate to accommodate the associated uncertainty[10] (see **Figure 1**).[11]

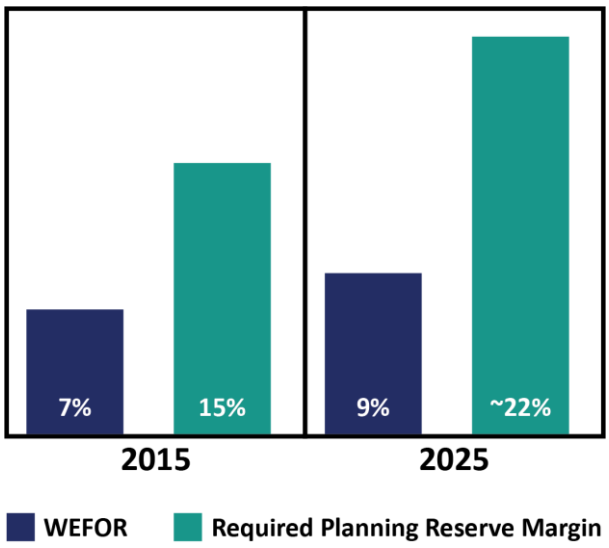


Figure 1: Conceptual Example of Forced Outage Rates Impacting Reserves

[7] GADS reporting is mandatory for units with a capacity >20 MW owned by NERC-registered Generator Owners (GO) per Section 1600 of NERC's Rules of Procedure. The conventional data set is separate from wind, solar, and hybrid energy storage data collection. Standalone energy storage is not currently collected by NERC under a Section 1600 data request.

[8] GADS Data Reporting Instructions - Appendix F Equations - WEFOR is an equation used throughout the electric industry to assess generator reliability by looking at how much units' time and generating capacity is reduced due to forced outages and derates relative to the amount of time they could be generating, weighting that value by each units' net maximum capacity.

[9] Reserve margins refer to the amount of excess generation an area is required to have available as a contingency for major system events to reduce the likelihood of cascading blackouts and load shedding. They are also key to NERC's Reliability Assessments' ability to forecast adequate generation.

[10] Many factors impact reserve margin calculations and vary from season to season throughout the year. Higher impact drivers include forced outage rates, planned maintenance rates, load forecasts, extreme weather outage adders, resource fleet composition, variable energy performance, and resource age.

[11] Figure is for demonstrative purposes. Proportions are not perfectly representative to actual value relations.

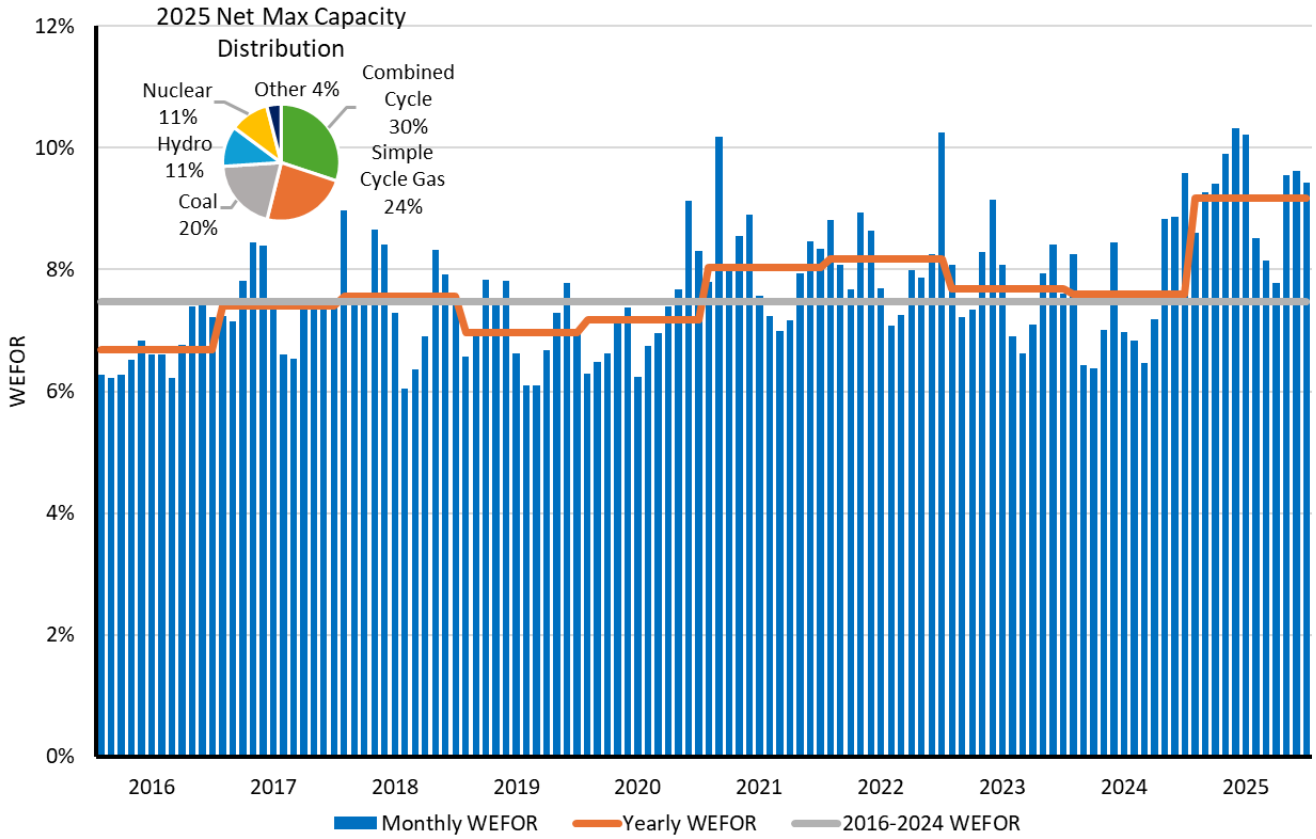


Figure 2: Monthly, Annual, and Five-Year WEFOR

Further analysis (see **Table 2**) identified that the increase in unavailability was primarily driven by a variety of combustion-based generators. The largest year-over-year increases in TWh of unavailability were observed in coal (39.8 TWh increase from 2024 to 2025) and combined-cycle units (19.1 TWh increase from 2024 to 2025). Combining this information with each type of unit's installed net maximum capacity and WEFOR identifies coal-fueled generators as being of more concern than others.

Table 2: 2024 vs. 2025 Year-Over-Year Forced Unavailability Comparison

Primary Fuel Type	Change in GWh[12]	2024 WEFOR	2025 WEFOR
Gas - Steam Turbine	8,772	19.2%	22.4%
Gas - Simple Cycle Combustion Turbine	5,938	20.7%	22.8%
Gas - Simple Cycle w/Heat Recovery Steam Generator (HRSG)	-203	7.7%	7.0%
Combined Cycle	19,154	4.2%	5.7%
Coal	39,835	11.2%	14.1%
Oil - Steam Turbine	1,857	24.6%	25.6%
Oil - Combustion Turbine	2,427	48.2%	69.4%
Hydro	-3,171	8.4%	7.7%
Nuclear	-3,862	2.7%	2.2%
Other	-2,308	11.1%	8.4%
Total/Overall	68,440	7.6%	9.2%

[12] Measured by WEFOR numerator:
$\sum(([Forced\ Outage\ Hours] + [Equivalent\ Forced\ Derate\ Hours]) * [Net\ Maximum\ Capacity])$

To identify possible commonalities, the owners of 41 generators that had a year-over-year increase of at least 1 TWh[13] of unavailability were asked to voluntarily provide additional context to their 2025 GADS data by NERC and the Regional Entities. Of those contacted, responses for 26 generators were provided, which identified several key insights to drive further investigation:

- Sixteen of the units experienced equipment destruction extensive enough to significantly prolong their 2025 outage(s).
- Eight of the units indicated that supply chain constraints significantly prolonged their 2025 outage(s).
  - Constraints were all indicated as occurring at the manufacturer; however, constraints may have occurred deeper into the supply chain unknown to the Generator Owner (GO).
  - Constraints identified included being unable to obtain materials for the repairs, challenges locating part specifications, inexperienced project management, and lack of staff to perform the work.
- Six of the units indicated complete or partial turbine blade release or vibration, which, upon further inspection, would have likely resulted in eventual release.
- Multiple units[14] leveraged the forced outage downtime to perform additional maintenance and inspections. Some indicated that these actions also extended the duration of the outage(s) but resulted in future benefits by either functionally moving up scheduled outages or identifying opportunities to prevent future outages.

After entity responses were evaluated, cause code components were also evaluated by an approximated MWh of forced capacity reduction since 2016. The largest groups were then trended to identify which ones had the largest and/or most consistent increases, with the following component groups being identified:

- **Catastrophe:** Increases over prior year in 2017, 2020, and 2024
  - Largely driven by an increase in use in 2020 because of COVID-19. NERC directed reporters to utilize this code for outages relating to the pandemic at that time prior to the addition of a more appropriate cause code.
  - 2017 and 2024 increases were higher than usual but would not have warranted inclusion on their own.
- **Turbines (High, Intermediate, and Low Pressure):** Increases over prior year in 2017, 2020, 2023, and 2025
  - All three individual turbine component groups were independently identified and represent the largest, most consistently increasing group if combined.
- **Regulatory:** Increases over prior year in 2017, 2018, 2019, 2022, 2023, and 2025
  - Most consistently increasing component group.
  - Initial analysis did not indicate any alignment with a particular policy objective, with both decreases and increases throughout various governmental phases.

[13] Year-over-year variation in MWhs of unavailable generation was used intentionally used in lieu of WEFOR or a single year's MWhs of unavailable generation. This was to focus on units that experienced issues starting in or shortly before 2025 and were most impactful to the overall annual WEFOR. A cutoff was applied to limit overall industry burden and receive a processable amount of input given the timeframe while also being a large enough group to identify common issues. The exact 1 TWh amount provided a clean cut point with a sufficient population but was ultimately arbitrary.

[14] Because this specific information was not directly requested and this is a common industry practice, an exact number of units is not available.

- **Safety:** Increases over prior year in 2018, 2020, 2022, and 2025
- **Nox Reduction Systems:** Increases over prior year in 2017, 2018, 2022, and 2025
- **Boiler Fuel Supply to Bunker:** Increases over prior year in 2017, 2020, 2022, 2024, and 2025

Further data analysis of these component groups and investigation into the underlying cause codes and submitted verbal descriptions are necessary.

The results of this analysis align with, but do not prove, industry assertions concerning coal and combined-cycle units. Most large coal units are over 40 years old and are expected to be retired in the relatively near future. These large coal and combined-cycle units were not designed for regular cycling, which has become an operational requirement in some areas and a necessity to maintain economic viability in others. These factors compound to increase the likelihood of failure over time and act to reduce the incentive to prioritize expensive restoration. Recent Federal Power Act section 202(c) emergency energy orders requested through the Department of Energy (DOE) have also received mixed reception among GOs. These mandates do improve system capacity, but that capacity may not be from reliable units.

Related Actions

Recommendations

- NERC will pursue further analysis and collaborate with the GADS user group (GADSUG) to better understand the causes driving this increase in WEFOR.
- NERC will work with industry to develop specific, measurable reliability indicators for generation performance.
- NERC and the relevant stakeholders should consider adjusting or at least be prepared to adjust reserve requirements to account for lower conventional generation availability.
- GOs should consider bolstering turbine inspection procedures at required intervals. GOs should also consider performing these inspections more frequently or when other major maintenance/outages provide the opportunity.
- Regulators should consider implementing alternative operating requirements during energy emergencies to ensure that regulations do not hinder BPS reliability during critical periods.
- GOs should ensure that manufacturers have capability and plan to replace major components in the event of failure.
- Manufacturers should consider immediately increasing the number of trained technical maintenance personnel to bolster expertise due to the increasing frequency of outages involving major equipment failure and the lack of adequate or sufficiently experienced staff, which was cited multiple times.
- Manufacturers should verify material procurement and processing capabilities.

Demand Growth and Large Load Integration Challenges Continue

Recent events involving data centers and cryptocurrency mining facilities continue to demonstrate the importance of improving industry's understanding of these loads' characteristics and risks as well as the considerations and mitigations needed to reliably integrate them into the BPS.

In a February 2025 event in the Eastern Interconnection, 1,800 MW of data center CILR occurred due to a transmission fault. An additional Eastern Interconnection event in February 2025 resulted in 428 MW of data center CILR. Similar Eastern Interconnection events were observed in March 2025 (227 MW of data center CILR), May 2025 (540 MW of data center CILR), and June 2025 (1,300 MW of data center CILR). ERCOT continues to experience cryptocurrency mining facility CILR events with nine events occurring in 2025 in which at least 100 MW of CILR occurred from computational load facilities.[15] **Figure 3** provides a summary of the Eastern Interconnection and ERCOT data center and cryptocurrency mining facility events.

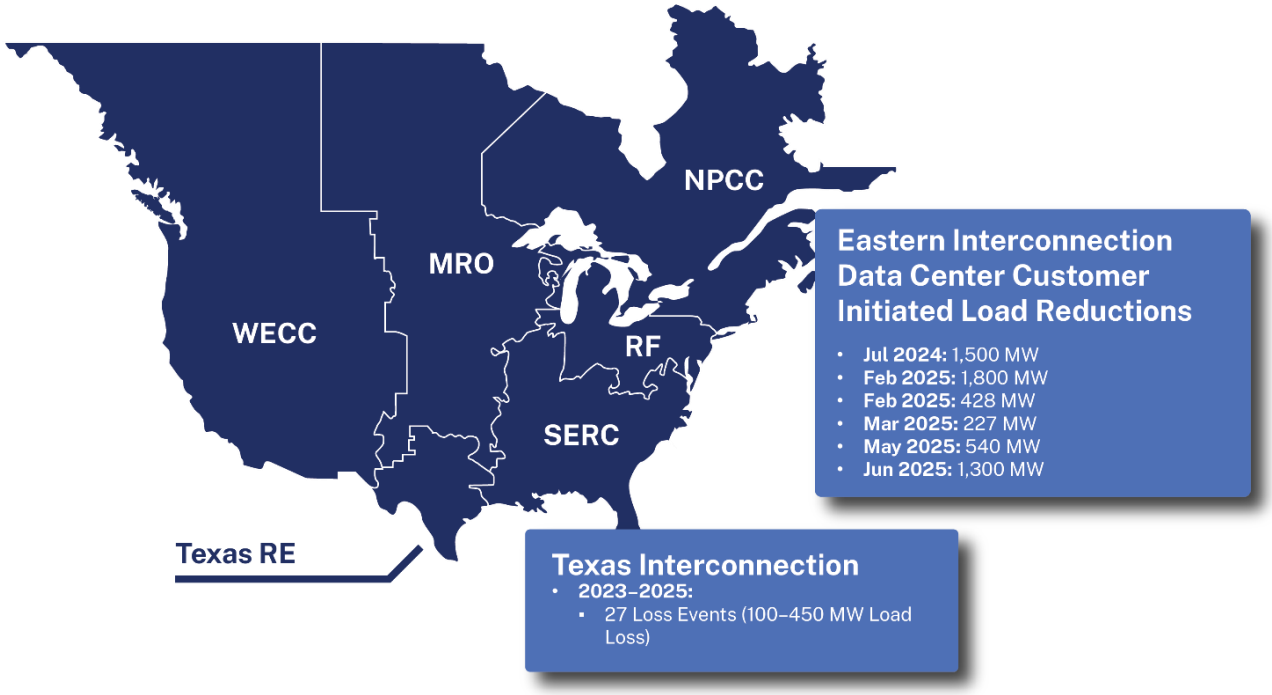


Figure 3: Customer-Initiated Load Reduction Events

Figure 4 provides a breakdown of the large CILRs tracked in ERCOT since 2023. Compared to 2023, the number of events in 2024 and 2025 increased, without indicating improvement. Most events were large computational load events; however, several non-computational load events did occur.

[15] See the Incident Review: Considering Voltage-Sensitive Crypto Load Reductions for an analysis of cryptocurrency mining facility ride-through events in ERCOT.

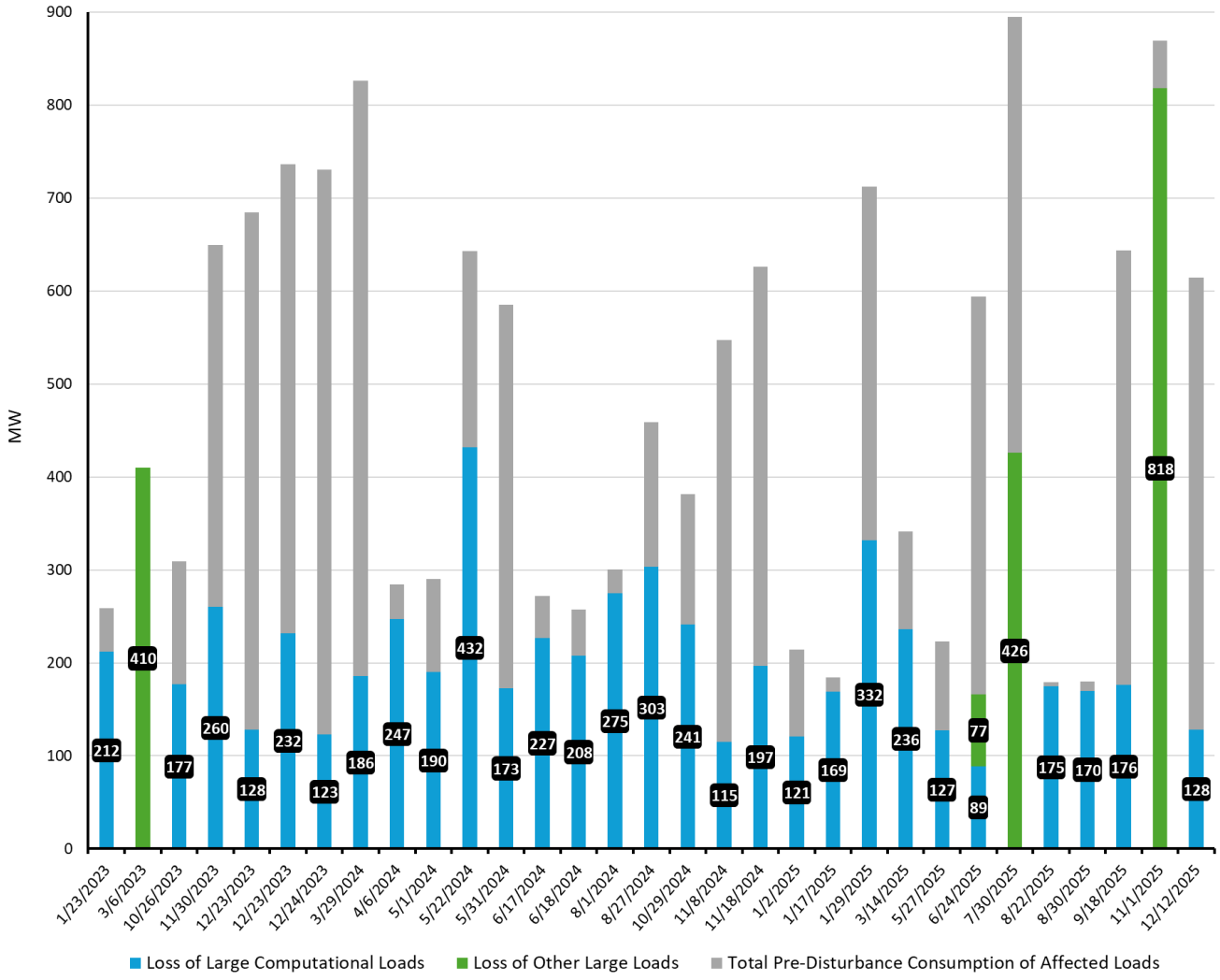


Figure 4: ERCOT Large Load Ride-Through Events

These events demonstrate that the reliability challenges from large loads will increase as these facilities become more prevalent on the grid. As the size of individual large load facilities increases and if large load facilities are located near one another, the sizes of these large load events will likely increase. This could lead to measurable frequency or voltage stability issues. It remains important for grid planners and operators to understand and study the expected performance of the large load facilities during grid disturbances. For the reliability risks to be studied and addressed, load models and study practices that reflect the behavior of the large loads and the risks to the BPS are essential. Continued collaboration between large load facility owners and operators as well as grid planners and operators is essential to ensure the reliable operation of the BPS.

Related Actions

Existing and Ongoing Efforts

- NERC developed a Large Loads Action Plan to address the BPS risks related to emerging large loads.[16]
- The Large Loads Working Group (LLWG) continues to provide technical guidance, industry collaboration, and reliability risk assessment and monitoring for the increasing integration of large loads. The LLWG has published the following white papers and reliability guideline:

[16] Large Loads Action Plan

- A white paper discussing the characteristics of emerging large loads and the risks they pose to the BPS[17]
- A white paper discussing the gaps in NERC Reliability Standards and industry practices related to emerging large loads[18]
- A reliability guideline providing industry with the best practices for mitigating BPS risks related to emerging large loads[19]

- The Load Modeling Working Group (LMWG) continues to address gaps in modeling the dynamic characteristics of the emerging large loads. The LMWG's activities include the following:
  - Developed a technical reference guide for industry on modeling data centers for transient stability studies
  - Endorsed and continues to improve a performance model called Power Electronic Reconnecting and Ceasing (PERC1) for modeling data centers in 2025
  - Continues to educate industry with workshops and by developing tools to help industry develop useful data center models, such as a data center questionnaire[20]
- NERC issued a Level 2 Industry Recommendation Alert to address risks related to large loads.[21]
- Additionally, NERC issued a Level 3 Essential Actions Alert providing specific actions deemed essential to address BPS risks posed by computational large loads,[22] including the following:
  - Transmission Planners and Planning Coordinators developing requirements for computational load modeling data, settings, and parameters
  - Transmission Planners and Planning Coordinators focusing on computational load impacts in system studies
  - Planning Coordinators updating their qualified change definition to reflect the changes that can occur to computational loads
  - Transmission Operators establishing a commissioning process that ensures operational readiness for the integration of large loads
  - Transmission Planners and Planning Coordinators implementing actions to ensure that non-consequential loss of firm computational load does not occur for typically cleared faults
  - Transmission Owners taking actions to capture and share fault recording data for computational load facilities
  - Transmission Operators, Reliability Coordinators, and Balancing Authorities establishing interpersonal communication capabilities and joint operating procedures with computational loads as well as issuing operating instructions to prevent Bulk Electric System (BES) emergencies
- NERC hosted a technical conference focused on the BPS risks posed by emerging large loads and the mitigations needed to integrate emerging large loads into the BPS.[23]

[17] Characteristics and Risks of Emerging Large Loads
[18] NERC LLWG White Paper - Assessment of Gaps
[19] Risk Mitigation for Emerging Large Loads
[20] Data Center Information Collection Questionnaire
[21] Large Load Interconnection, Study, Commissioning, and Operations
[22] Level 3 Computational Load Alert
[23] 02-24-26 Emerging Large Loads Technical Conference

- NERC posted draft updates to the NERC Rules of Procedure for establishing a new registered entity for computational load entities. Additionally, the NERC Standards Committee has launched a standards project to develop Reliability Standards that address the risks posed by computational loads.
- The frequency response metric will continue to be monitored to measure the response to frequency events during large load tripping events.

Recommendations

- The following recommendations are discussed in the LLWG white papers:[24]
  - Registered entities should coordinate with large load entities to address the risks posed by emerging large loads.
  - Relevant NERC Reliability and Security Technical Committee (RSTC) subgroups (including the LLWG, the LMWG, the Security Working Group, and the System Protection and Control Working Group) should continue to assess and address the risks posed by emerging large loads.
  - Regulators should work with utilities to address the risks posed by emerging large loads.
  - Policymakers should review interactions between interconnection requirements, existing state regulations and planning processes, and regional grid operator requirements. Additionally, policymakers should review requirements for large load customers to provide operational data and information to Transmission Owners (TO), Transmission Operators (TOP), Transmission Planners (TP), and other entities.
- NERC registered entities should implement the recommendations provided in the Level 2 Industry Recommendation Alert and the Level 3 Essential Actions Alert.[25]
- NERC will continue incident analysis and lessons learned and share findings with industry.
  - NERC will consider the necessity of mandatory data collection requirements.
- Communication and coordination with the Electric Power Research Institution (EPRI), the Energy Systems Integration Group (ESIG), large load industry groups, and the electric industry at large should be continued.

[24] Characteristics and Risks of Emerging Large Loads, NERC LLWG White Paper - Assessment of Gaps
[25] Large Load Interconnection, Study, Commissioning, and Operations, Level 3 Computational Load Alert

Resource Mix Transformation

The BPS and BES continue to experience a rapid resource mix transformation as conventional generation retirements continue to be replaced primarily by natural gas and increasing IBR penetration. This reduction in conventional resource diversity and increased reliance on variable energy resources continued to pose risks and challenge grid operations in 2025. Additionally, the magnitude of BESS helping to smooth solar generation coming on-line in the morning and going off-line in the evening has increased, with installed capacity roughly matching solar additions last year.

IBR Reliability Considerations

As detailed in NERC's *2025 SOR Overview*,[26] IBR reliability risks remain a priority as these resources continue to grow across the BPS. The primary concern is that some IBRs have unexpectedly reduced or ceased output in response to normally occurring grid disturbances, including generator faults, then rapidly resume output within minutes. These events are driven by a combination of ride-through performance limitations, inverter and plant-level controls, protection systems, and modeling quality deficiencies. Following several major IBR-driven disturbances since 2017, NERC has pursued numerous activities to mitigate related reliability concerns.[27] The *2025 SOR* identified continued unexpected IBR output reductions following normally occurring system disturbances with four events four events exceeding 500 MW reported in 2024 and 16 such events reported since 2020.

Available operational data in 2025 suggests improvements in several key areas. Industry participation in model validation and disturbance review activities increased substantially following implementation of the alert recommendations. While no major widespread disturbance events associated with previously observed common-mode IBR tripping mechanisms were identified during the assessment period, there was a loss of 1,132 MW due to sub-synchronous oscillation protection tripping generation off, a failure mode previously unobserved at this scale. Additionally, rapidly increasing IBR penetration continues to increase operational complexity, particularly in regions experiencing reduced inertia, high renewable penetration during light-load conditions, or rapidly changing power flow conditions. Throughout 2025 and the first half of 2026, several additional major efforts have been undertaken and/or completed as highlighted below.

IBR-Related Actions

Existing and Ongoing Efforts

Level 3 Alert[28]

NERC issued *Level 3 Alert: Essential Actions for Inverter-Based Resource (IBR) Performance and Modeling* to TOs, TPs, Planning Coordinators (PC), and currently registered GOs to enhance technical minimum requirements, study processes, and improve modeling to mitigate risks posed by IBR performance during system disturbances.

- **Essential Action #1**: Each TO and TP, in coordination with their PC, should enhance the existing criteria and policies in their generator interconnection and planning activities, respectively, with additional technical details and IBR-specific performance criteria. These performance-based factors help ensure uniform IBR performance both in normal and post-disturbance operations and include reactive power control, frequency response control, ride-through behavior and post-disturbance performance, and full use of reactive power capability.

[26] 2025 NERC State of Reliability - Overview
[27] Quick Reference Guide: Inverter-Based Resource Activities
[28] NERC Level 3 Alert: Essential Actions for Inverter-Based Resource (IBR) Performance and Modeling

- **Essential Action #2**: Each TP and PC should enhance their modeling and study practices to ensure that sufficient study work and model quality verification are performed and documented to reflect models that are representative of installed, or to-be installed, equipment by establishing model quality and accuracy criteria as well as model performance tests and conformity criteria and by enhancing existing criteria used throughout the generator interconnection.
- **Essential Action #3**: TOs, TPs, or PCs should perform a detailed review of currently operating IBRs on their systems to understand the extent of condition of both real-world performance and accuracy of their models.
- **Essential Action #4**: Each GO should create and implement processes to help ensure that the models used for the evaluation of their design and submitted to TPs and PCs for use in generator interconnection and planning processes are accurate and high-fidelity representations of their IBRs.

To follow up on the Level 3 Alert, the ERO has developed an outreach strategy for 2026 to gather information about why entities are not adopting essential actions or are reporting substandard performance expectations and to address legitimate challenges through clarification of essential actions or, where appropriate, through regulatory processes.

New Standards

Significant reliability gaps associated with modeling are addressed by the updated MOD standards finalized in 2025: MOD-026-2,[29] MOD-032-2,[30] and MOD-033-2.[31] Model validation and verification requirements in MOD-026-2 improve model accuracy and documentation. Enhancements in MOD-032-2 help ensure that validated and verified models are collected and used for both local reliability studies and Interconnection-wide case creation. Improvements in MOD-033-2 allow PCs to assess individual generator performance against their model behaviors as part of system model validation efforts and to remedy discrepancies through MOD-032-2 processes.

Inverter-Based Resource Subcommittee and Electromagnetic Transient Modeling Working Group

The Inverter-Based Resource Subcommittee (IRPS) and Electromagnetic Transient Modeling Working Group (EMTWG) continue to develop reliability guidelines and white papers to share best practices among industry to further reduce IBR risks associated with modeling, studies, commissioning, and testing. Many of these risks can be traced back to poor commissioning and testing of IBRs before they enter commercial operation. These gaps are addressed in the *Draft Reliability Guideline: IBR Commissioning Best Practices*[32] and an upcoming white paper, *IBR Equipment EMT Model Validation*, which aims to provide model validation acceptance criteria, thereby complementing model validation requirements in MOD-026-2 and closing risks posed by inaccurate models.

Category 2 Generator Owner Registration[33]

On May 18, 2023, FERC issued an order approving the NERC Work Plan filed on February 15, 2023, as amended on March 13, 2023, to address registration of IBRs that are connected to the BPS but not within NERC's definition of the BES (referred to hereafter as "Category 2 GO/GOP"). The ERO Enterprise has identified and communicated with 531 IBR facilities that meet the Category 2 GO/Generator Operator (GOP) registry criteria across all the Regional Entities and are, or planned to be, interconnected as of May 15, 2026.

[29] MOD-026-2
[30] MOD-032-2
[31] MOD-033-3 – Further revisions have been implemented in 2026.
[32] Draft Reliability Guideline: Commissioning Best Practices
[33] NERC Files IBR Registration Update, Marking Milestone for Grid Reliability

Beginning on May 15, 2026, entities with identified IBR facilities that meet the Category 2 GO/GOP registry criteria were registered and are now subject to compliance with applicable Reliability Standards, as required by the IBR Order. As part of the Inverter-Based Resource Registration Initiative, NERC staff developed a document identifying the finalized and pending compliance dates for the applicability and enforceability of Reliability Standards applicable to Category 2 GO and GOP registrations. As of May 15, 2026, entities registered as Category 2 GOs or Category 2 GOPs are required to comply with, as applicable, BAL-001-TRE, IRO-010-5, MOD-032-2, PRC-012-2, PRC-017-1, TOP-003-6.1, VAR-001-5, and VAR-002-4.1.

Additional technical conferences will be pursued to assist in identifying which Reliability Standards must be revised to establish applicability to Category 2 IBRs and in which order and grouping they should be developed.

The ERO Enterprise is integrating the new Category 2 GO and GOP registrants into relevant ERO Enterprise efforts, including Compliance Monitoring and Enforcement Program activities related to Reliability Standards applicable to those entities. The ERO Enterprise will continue to identify and register additional entities that meet the Category 2 GO and GOP registry criteria as additional IBR facilities are developed and connected to the BPS.

The completion of the NERC Work Plan represents the conclusion of a substantial three-year ERO Enterprise effort to address the risk to BPS reliability posed by unregistered IBR facilities.

BESS Reliability Considerations

As the BES resource mix continues to rapidly evolve, BESS penetration has rapidly increased over the past several years (see **Figure 5**) to approximately match solar growth in 2025. This growth is projected to continue, requiring observation and analysis of this resource's capabilities.

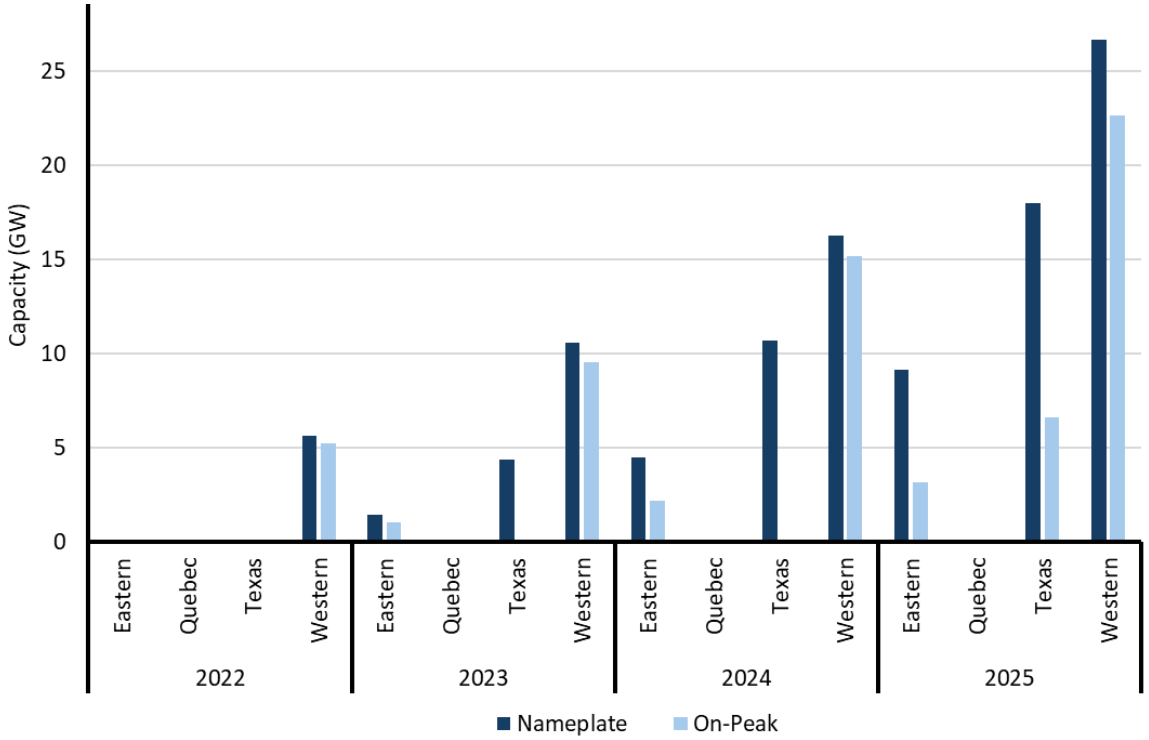


Figure 5: 2022–2025 Battery and Hybrid Capacity by Interconnection

Unique Failure Event

In January 2025, a 300 MW BESS facility experienced thermal runaway during routine testing that ultimately resulted in the functional destruction of a previous-generation warehouse-style facility.[34] While outages internal to the plant regularly occur with other generation resources of similar or greater capacities, the permanent, unplanned loss of a non-BESS facility is exceedingly rare. As such, this type of failure represents a risk consideration unique to BESS that needs to be taken into consideration as the resource continues to expand. Improvements to BESS reliability, thermal runaway mitigation, failure isolation, fire suppression, and updates to fire codes have all acted to significantly reduce the likelihood of these events occurring. NERC will continue to monitor these failure events, but they do not represent a significant concern to overall system reliability at this time.

Load Curve Smoothing

BESS is typically installed to take advantage of price differences between high-generation/low-load and low-generation/high-load conditions. As a result, it provides a smoothing effect that functionally reduces expected and unexpected variability from increasingly prevalent wind and solar generation (see **Figure 6**).

As a result, conventional generators have more time to come off-line and on-line during the most strenuous portions of the day in areas most impacted by as the period when solar resources are going off-line just before peak load conditions in the evening. Because many older, larger conventional generators were not designed to cycle on- and off-line daily, increasing the ramp period can reduce wear and tear, improving their reliability.

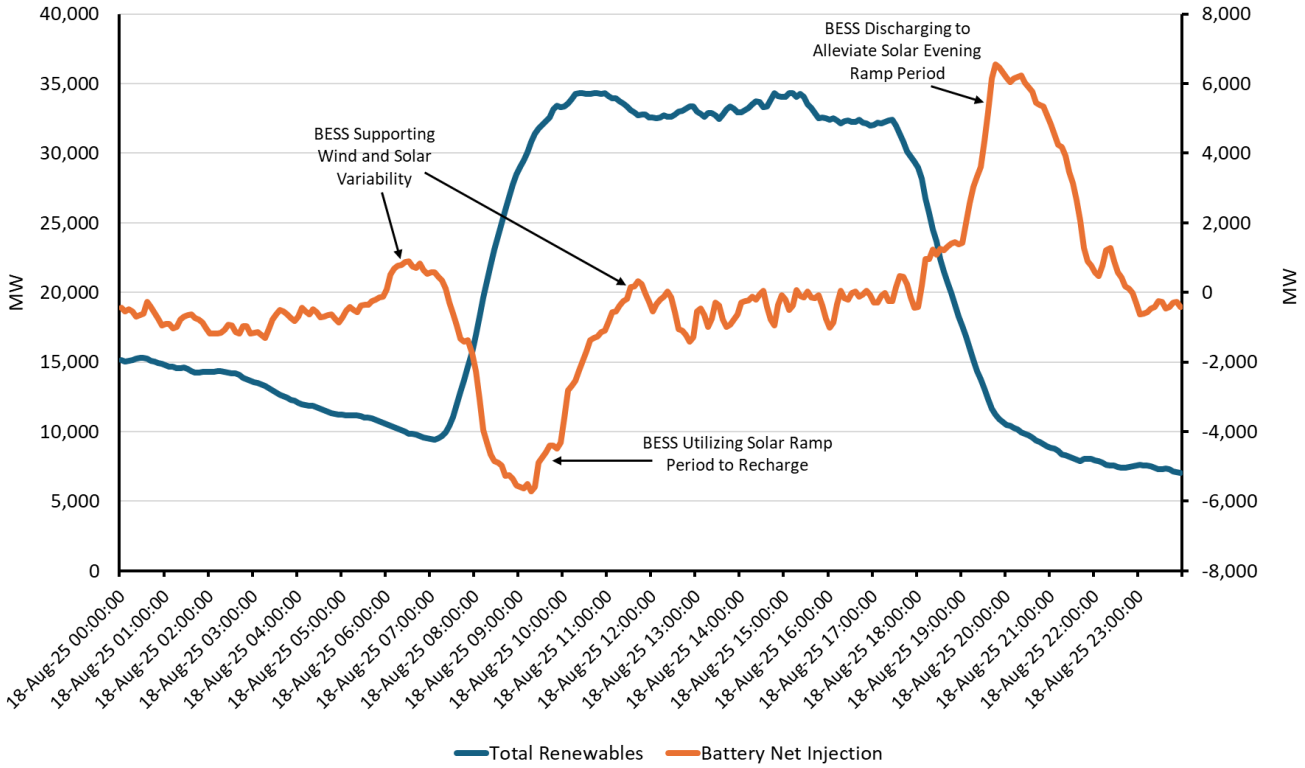


Figure 6: Total Renewables Plus Evening Solar Ramp[35]

[34] Moss Landing BESS Fire Report Final 12.22.25.pdf

[35] Secondary Y-axis has been shifted and scaled for visual clarity.

Frequency Response Impacts

As detailed earlier in the *2025 SOR Overview*,[36] BESS has demonstrated the capability to rapidly respond to frequency disturbances. In 2025, areas with sufficiently dense BESS installations and primary frequency response support initiatives continued to demonstrate the resource's ability to arrest frequency decline and restore frequency to deadband more quickly than conventional generators.

It should be noted that BESS are energy storage resources with limited capacity, typically intended to last a few hours. As a result, BESS's role in frequency disturbance events is ultimately to rapidly recover and maintain frequency until additional resources can come on-line for indefinite system support. This introduces a functional limitation during long-term widespread system degradation events, meaning that BESS is not a complete solution for events like major winter storms.

BESS-Related Actions

Recommendations

- BESS data collection and sharing value and viability are being evaluated by NERC's Performance Analysis team.
- NERC encourages BESS facilities to provide information on services that they are providing with relevant parties.
- NERC encourages policymakers to consider revisions to fire codes if they have not already.
- NERC will continue to monitor BESS performance and major events for risks.
- In November 2025, ERCOT stakeholders approved Nodal Operating Guide Revision Request 272 and Planning Guide Revision Request 121. These revisions require new BESS resources with a standard generation interconnection agreement (SGIA) date on or after April 1, 2026, to demonstrate the capability of providing advanced grid-support (grid-forming) functions as well as to provide appropriate models for these functions.

[36] 2025 NERC State of Reliability - Overview

Industry Mitigation Actions

Performance data reported to NERC enables a risk-based approach to reliability management across major emerging reliability issues prior to the creation of formal reliability indicators. Current areas of focus include severe weather, conventional generator performance, large loads, BESS, and IBRs (see **Table 3**). In response to these evolving risks, industry and the ERO Enterprise implemented a broad range of mitigation activities throughout 2025 detailed in the body of this report.

In addition to these top priorities, more cautionary mitigation activities included more conservative operating practices during stressed and cold-weather conditions, increased use of probabilistic and all-hours reliability assessments, improved model validation requirements, transmission planning resilience analysis for extreme weather events, and new planning and operational guidance associated with load-pocket reliability risks.

Table 3: Monitoring Emerging Trends and Mitigation Resolution

Monitored Reliability Challenge	Key Measures Tracked	2025 Trends	Mitigation Effectiveness Indicators	Indicators that Additional Attention is Required
Increasing Incidence of Severe Weather	Severity risk index (SRI), transmission outages, restoration duration, MVA-days lost, load loss	Worst SRI days remained within historically favorable ranges; overall weather conditions considered favorable	Reduced outage severity, faster restoration, lower cumulative SRI	Increasing high-SRI days, longer restoration times, larger correlated outages
Generator Forced Outage and Performance Trends	Annual/monthly WEFOR, fuel-specific outage rates, unavailable MWh, seasonal outage spikes	Overall WEFOR increased to 9.2%; coal 11.2% to 14.1% (39.8 TWh change), combined cycle 4.2% to 5.7% (19.1 TWh change)	Improved winter performance, reduced outage severity during extreme events	Elevated WEFOR, correlated winter outage spikes
Reliable Large Load Integration	Peak demand growth, frequency response, load forecast error, transmission constraints, CILR	Annual energy demand increased to ~4.95 million GWh; actual summer peak higher than forecast; two CILRs exceeding 1,000 MWs	Stable frequency performance, improved operational visibility	Rapid localized demand growth, frequency volatility, planning uncertainty
Reliable BESS Integration and Performance	Frequency arrest performance, recovery speed, BESS availability	BESS deployment approximately matched solar growth; improved fast frequency response performance observed when incentivized in high-BESS areas	Improved frequency recovery, successful grid-forming performance	Thermal runaway/fire events, duration limitations, unavailable BESS capacity
Reliable IBR Integration	Ride-through performance, rate-of-change-of-frequency (RoCoF), IBR trip events, model validation	Expanded IBR mitigation activities continued through 2025	Reduced disturbance-related tripping, improved model accuracy	Weak-grid instability, repeated tripping events, model-performance divergence

UNITED STATES OF AMERICA
BEFORE THE
UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Craig Unit 1	))))	Order No. 202-26-49

The State Of Colorado's Request for Rehearing,
Motion To Intervene, And Stay Request

Exhibit JJJJ: NERC, 2026 State of Reliability Technical Assessment (June 24, 2026)

NERC

2026 State of Reliability

Technical Assessment of 2025 Bulk Power System Performance

June 24, 2026

2026 SOR Snapshot

2026 SOR Overview

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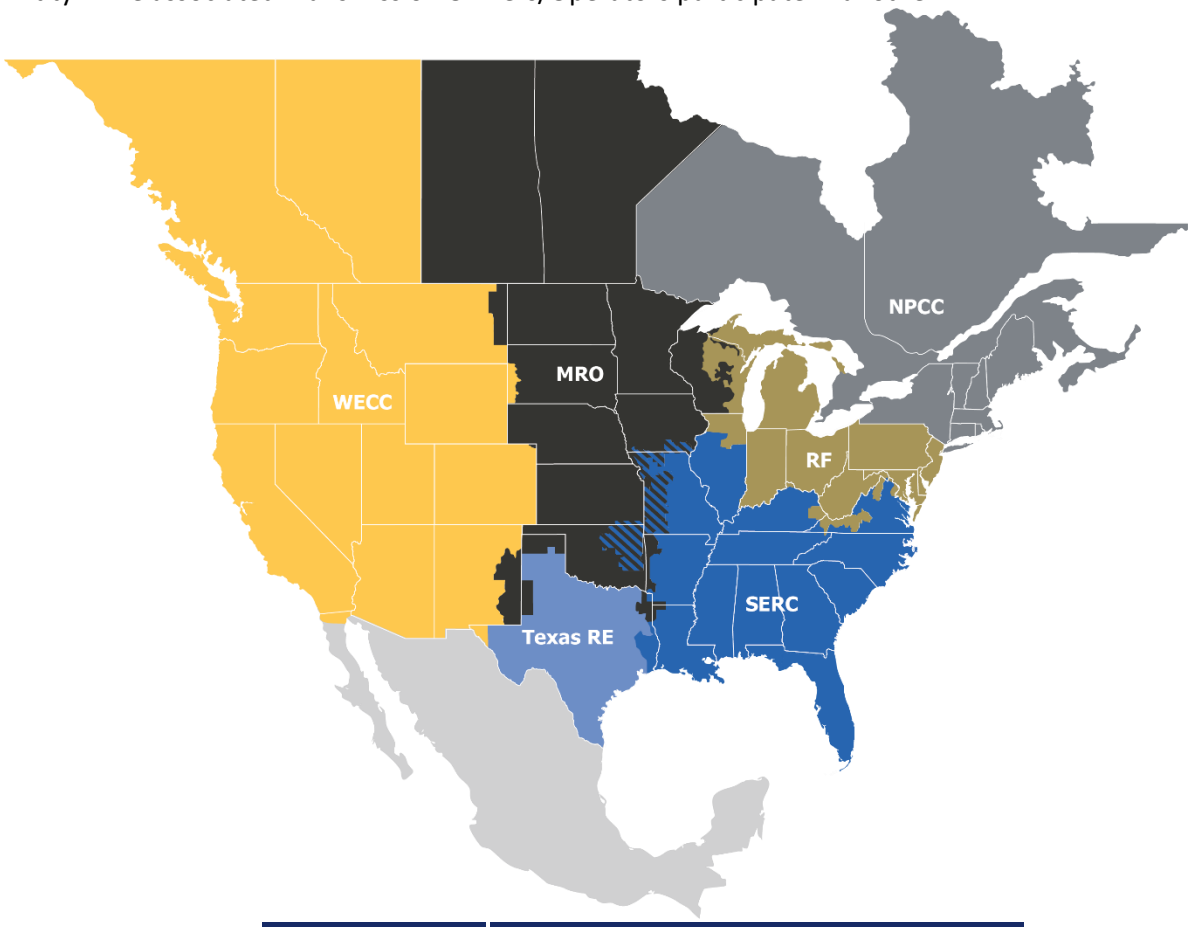
Preface

Electricity powers our modern life and is the bedrock of our economic wellbeing. The Electric Reliability Organization (ERO) Enterprise—comprised of NERC and the six Regional Entities—is firmly committed to assuring a highly reliable, resilient, and secure bulk power system (BPS) in North America. The ERO Enterprise enables collaborative engagement with industry, regulators, and stakeholders, embracing innovation and supporting the needs of nearly 400 million people.

RELIABILITY | RESILIENCE | SECURITY
POWERING TODAY. PROTECTING TOMORROW.

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



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

About This Technical Assessment

Introduction

The *State of Reliability* (SOR) report seeks to inform regulators, policymakers, and industry leaders on the most significant reliability risks facing the BPS and describe the actions that the ERO Enterprise has taken and will take to address them. This year's SOR report is comprised of two publications: this *2026 SOR Technical Assessment*, which provides NERC's comprehensive annual technical review of BPS reliability for the 2025 operating (calendar) year, and the *2026 SOR Overview*, which is a high-level summary of the Technical Assessment with the following details:

- The *2026 SOR Overview* replaces the key findings previously found in the Technical Assessment.
- This *2026 SOR Technical Assessment* details major occurrences and provides in-depth analysis of risks and resilience, grid transformation and performance, and related performance metrics.

Purpose of the SOR

Both the Overview and the Technical Assessment provide objective and concise information for policymakers, industry leaders, and regulators on issues that affect the reliability and resilience of the North American BPS. Specifically, the SOR report does the following:

- Analyzes performance trends and emerging reliability risks
- Reports on the relative health of the interconnected system
- Measures the success of mitigation activities

NERC, as the ERO, works to assure the effective and efficient reduction of reliability and security risks to the North American BPS. Annual and seasonal risk assessments look to the future, and special reports on emergent risks serve to identify and mitigate potential risks. This assessment identifies performance trends and provides strong technical support for those interested in the detailed analytics.

NERC defines the reliability[1] of the interconnected BPS in terms of two basic and functional aspects: adequacy and operating reliability.

The *2026 SOR* report focuses on BPS[2] performance during the prior calendar year as measured by an established set of performance metrics, other reliability indicators, and more detailed analysis performed by ERO staff and technical committee participants. Data used in the analysis comes from the Transmission Availability Data System (TADS), the Generating Availability Data System (GADS), the Misoperation Information Data Analysis System (MIDAS), voluntary reporting into the Event Analysis Management System (TEAMS), Bulk Power System Awareness monitoring and processes, and the Institute of Electrical and Electronics Engineers (IEEE) Distribution Reliability Working Group. ERO staff developed this independent assessment with support from the Performance Analysis Subcommittee (PAS).

[1] **Learn About NERC** provides background information about NERC, the definition of reliability, and the electric grid.

[2] The term BPS is defined in Section 215 of the Federal Power Act as facilities and control systems necessary for operating an interconnected electric energy transmission network (or any portion thereof); and electric energy from generating facilities needed to maintain transmission system reliability. The term does not include facilities used in the local distribution of electric energy. 16 U.S.C. § 824o(a)(1). Bulk Electric System (BES) is a subset of the BPS and is a defined term under the NERC Glossary as approved by the Federal Energy Regulatory Commission (FERC). As the Electric Reliability Organization, NERC is responsible for developing and enforcing Reliability Standards to ensure an adequate level of reliability of the BPS and assessing reliability of the BPS. NERC's regulatory model is designed to ensure that entities capable of affecting the reliability of the BPS are registered and subject to Reliability Standards. North Am. Elec. Reliability Corp., 187 FERC ¶ 61,196, P 53 (2024).

NERC also produces the following regular assessments to evaluate BPS security as well as present and future BPS reliability:

- *Long-Term Reliability Assessment* (LTRA)
- Summer and Winter Assessments
- Electricity Information Sharing and Analysis Center (E-ISAC) *End-of-Year Report*

Considerations

- Data in the SOR report represents the performance for the January–December 2025 operating year unless otherwise noted.
- Unless specified otherwise, analysis in this report is based on data from 2021–2025 that was available in Spring 2026, and it provides a basis to evaluate 2025 performance relative to performance over the last five years. All dates and times shown are in Coordinated Universal Time (UTC).
- The SOR report is a review of industry-wide trends and not the performance of individual entities.
- When analysis is presented by Interconnection, the Québec Interconnection (QI) is combined with the Eastern Interconnection (EI) unless specific analysis for the QI is shown.

Chapter 1: Major Occurrences for 2025

Overall, the BPS was reliable[3] throughout 2025. This chapter highlights major occurrences and reports that were issued in 2025. These occurrences and reports did not constitute a key finding but had a notable impact on the BPS.

Figure 1.1 highlights important numbers and facts about the North American BPS. **Table 1.1** shows the five-year trend of these numbers.

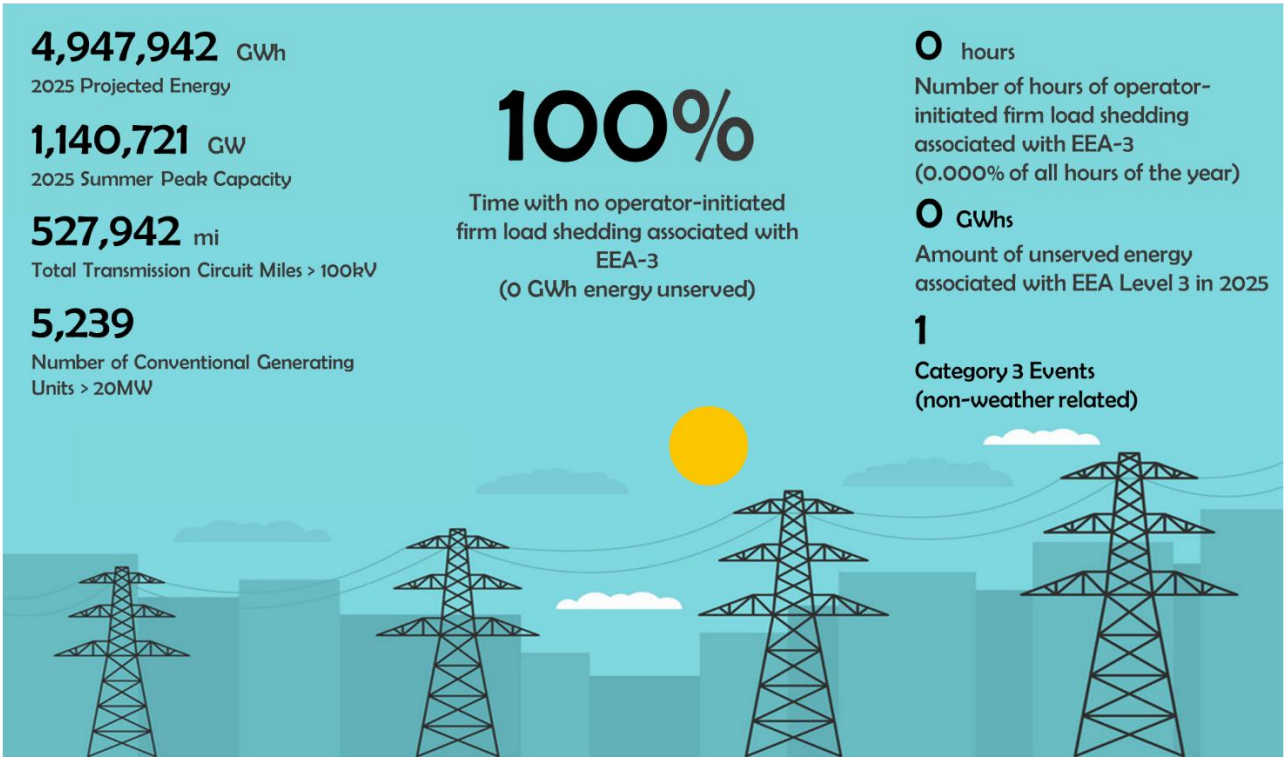


Figure 1.1: 2025 BPS Inventory and Performance Statistics

Table 1.1: Five-Year BPS Inventory and Performance Statistics

Rank	2021	2022	2023	2024	2025
Projected Energy (GWh)	4,585,939	4,674,290	4,687,894	4,856,251	4,947,942
Actual Energy (GWh)	4,626,790	4,695,921	4,663,574	4,787,277	N/A
Summer Peak Capacity (MW)	1,056,980	1,057,455	1,071,370	1,087,354	1,140,721
Total Transmission Circuit Miles >100 kV miles	508,766	522,433	529,344	526,853	527,942
Count of Transmission Circuits >100 kV	28,411	29,165	29,932	30,014	30,666
Count of Transformers with a Low-Side Voltage >100 kV	5,715	5,773	5,805	5,832	5,866
Number of Conventional Generating Units >20 MW[4]	5,375	5,453	5,290	5,243	5,239

[3] Learn About NERC provides background information about NERC, the definition of reliability, and understanding the grid.
[4] 2025 methodology was updated to only include mandatorily reported units that submitted at least one performance record.

Table 1.1: Five-Year BPS Inventory and Performance Statistics					
Rank	2021	2022	2023	2024	2025
Reported MW of Installed Conventional Generation[5]	913,103	926,302	902,018	896,430	876,982
Reported MW of Installed Wind Generation[6]	112,811	124,039	129,963	135,866	138,190
Reported MW of Installed Solar Generation[7]	N/A	N/A	N/A	N/A	N/A
Portion of Hours in the Year with No Operator-Initiated Firm Load Shedding Associated with Energy Emergency Alert Level 3 (EEA 3)	99.2%	99.4%	100%	>99.9%	100%
Category 3 Events (Non-Weather Related)	0	1	0	1	1
Amount of Unserved Energy Associated with EEA 3 (GWh)	1,015.5	96.2	0	0.1	0
Number of Hours with Operator-Initiated Load Shed	71	56.5	0	0.4	0

Major Weather Events

Although 2025 was generally temperate, major weather events continue to be considered the greatest risk to reliability due to the increase in frequency, footprint, and duration; NERC's *ERO Reliability Risk Priorities Report*[8] identified resilience to extreme events, including extreme natural weather events, as one of the five risk groupings that represent evolving risks to reliability. Major weather events in 2025, including severe winter storms, thunderstorms, and tornadoes, were analyzed and collectively found to have had less of an impact on the BPS than in previous years. Of the 23 billion-dollar events highlighted in **Figure**,[9] only three appeared in the **Severity Risk Index** and six in the **Analysis of Transmission System Resilience** section. Although numerous economically impactful events also occurred in Canada in 2025 (**Figure**), none were considered to have had a major impact on the BPS based on data used in the severity risk index (SRI) and transmission system resilience analysis.

[5] MW of installed conventional generation is calculated based on highest net dependable capacity reported in GADS performance for the given year. Only units >20 MW are required to report for GADS. Units that did not complete performance reporting are excluded from this total.

[6] Includes plants with a total installed capacity >75 MW.

[7] During this year's data analysis, NERC identified significant GADS solar data reporting errors and numerous missing plants compared to EIA 860 data. NERC will be coordinating with Regional Entity staff to perform industry outreach and resolve these errors in 2026.

[8] NERC's ERO Reliability Risk Priorities Report

[9] In alignment with evolving priorities, NOAA's National Centers for Environmental Information (NCEI) will no longer be updating the Billion Dollar Weather and Climate Disasters product. Climate Central, a policy-neutral 501(c)(3) nonprofit now generates a similar product.

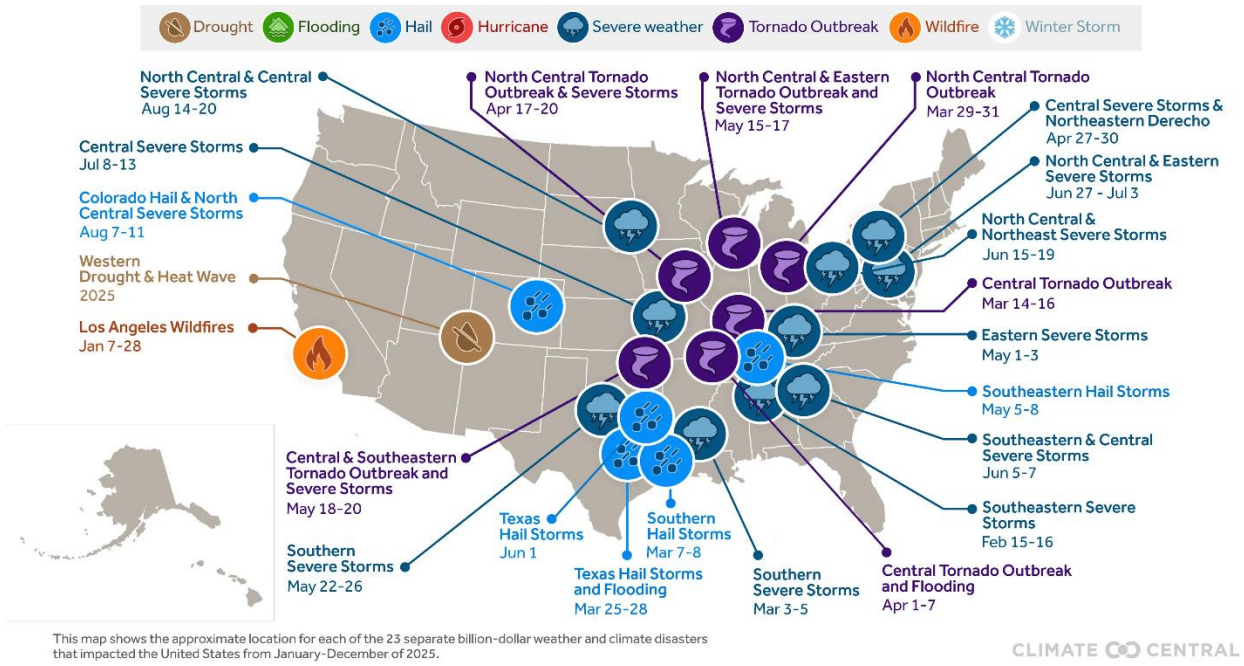


Figure 1.2: 2025 U.S. Billion-Dollar Weather and Climate Disasters[10]



Figure 1.3: 2025 Canadian Insured Catastrophic Losses[11]

[10] The peer-reviewed methodologies behind this dataset remain unchanged at Climate Central, where the project will continue to be led by Adam Smith, who served as the lead scientist for the project at NOAA from 2010 to 2025. U.S. Billion-Dollar Weather and Climate Disasters | Climate Central

[11] Severe weather-related insured losses in Canada exceed $2.4 billion in 2025

Major System Events and Observations

The following sections highlight major system events and observations that occurred last year. While these events were notable and may have impacted many customers, NERC has determined that they do not belong in the SOR Overview as no industry-wide or policy action is being proposed.

Wyoming System Event

As further detailed in the WECC and NERC joint disturbance report,[12] in the early afternoon of November 13, 2025, the northeast portion of the Western Interconnection (WI) experienced a system disturbance that triggered cascading outages affecting about 250,000 customers for up to nine hours. The event impacted parts of several states, including Montana, South Dakota, Wyoming, and Nebraska, with one Transmission Operator (TOP) experiencing a complete blackout across facilities located on the seam between two Reliability Coordinators (RC). This is a low-load, generation-rich portion of the Interconnection.

The disturbance began with a planned outage of a 500 kV transmission line, part of a critical path necessary to deliver wind and thermal generation to distant load centers in the WI. The outage was scheduled for 8:00 a.m. Mountain but postponed until 12:00 p.m. Mountain due to delays in field personnel availability at remote stations. During this delay, wind generation increased more than 50% above the day-ahead operational planning analysis (OPA) studied flows.

A remedial action scheme (RAS) is in place to automatically trip wind generation for unplanned outages to ensure system balance. Prior to switching, the TOP raised the RAS arming setpoint, effectively disabling its tripping function. Operators relied on real-time contingency analysis (RTCA) tools but were unaware of disabled alarms in their RTCA contingency modeling and the inaccurate megavolt-ampere reactive (Mvar) generation parameters that masked the issues that would occur for opening the 500 kV line.

With real-time tools showing no issues, the TOP removed the line from service. Power shifted to an adjacent 500 kV line, causing a rapid voltage collapse to approximately .30 per unit. Protective relays correctly tripped the line within 0.4 seconds, and, with the RAS disabled, there was no action to reduce wind generation.

Most of the western grid remained intact as power flows shifted across the area; however, the system experienced a rapid loss of more than 4,800 MW of coal, natural gas, solar photovoltaic (PV), and wind generation within six seconds. The sudden imbalance caused frequency to dip to 59.758 Hz, after which it gradually recovered and stabilized over the next six minutes. Underfrequency load shedding mechanisms were appropriately triggered in the region before the blackout occurred. Total load loss was just over 1,100 MW.

Coordinated restoration was delayed due to limited RC visibility and competing mitigation priorities. High voltages and seam coordination challenges slowed progress, including instances where equipment was energized across TOP boundaries without prior notification. Most load was restored within nine hours. The entity performing the initial line switching returned most of its generation within eight hours, but one thermal plant required more than four days, and one thermal unit experienced catastrophic damage.

Opportunities for Improvement

Personnel

- Communications during system events should be clear and concise and ensure that mutual understanding has been achieved prior to actions being taken.

[12] WECC and NERC Joint Wyoming Disturbance Report

- System restoration training should be re-evaluated for effectiveness with respect to the RCs and TOPs to improve the effectiveness of restoration, focusing on their system status by thorough assessments, and communication and coordination among the entities.

Processes

- RCs should verify how far to model across seams to provide overlapping visibility of potential contingencies and operating limits.
- Entities should use conservative decision making in verifying any discrepancies between RTCA results.
- RCs/TOPs should evaluate the variability of the generation resources in their OPA and set appropriate max/min parameters within system operating limits (SOL) to prompt additional operator actions.

Tools

- Entities should investigate the use of additional offline tools to confirm/evaluate online tool results.
- To ensure mutual understanding, RCs and TOPs should clearly define the information needed and the means of communication to be used.
- Entities should ensure consistent modeling of system parameters such as RAS status.

Load-Pocket Shoulder Season Challenges

In recent years, shoulder seasons have become increasingly challenging for BPS operators to manage, resulting in several recent instances of pre-contingent load shedding.[13] In all these cases, RTCA indicated that significant issues, such as cascading outages or widespread voltage instability, would likely occur following the next loss of a transmission element.

Shoulder seasons are the spring and fall periods between summer and winter peak load periods and have historically been used for planned maintenance. Because of this common industry practice, fewer generators and transmission lines are available for operators to utilize during these periods, which has historically been offset by the lower peak loads. Spring in particular also coincides with more frequent thunderstorms. In recent years, tightening reserve margins and an increasing baseline load have compounded with a rapid increase in variable energy resources (VER), which present an inherent level of uncertainty, to significantly increase operating challenges during these periods.

Instances where these challenges align in specific small areas within a Balancing Authority's (BA) footprint that have limited transmission lines connecting them to the remainder of the system, also known as load pockets, have been the catalyst of several recent instances of pre-contingent load shedding.[14]

Opportunities for Improvement

As the Interconnections are changing in both resource mix and load characteristics coupled with weather variability during shoulder seasons, a different approach may be needed when coordinating facility outages. Entities should consider the following:

- Planning a higher level of operating margin and committing additional generation in load pockets to account for larger real-time variabilities in generation, load, and weather
- Including demand-side management in the mitigation plans for insufficient capacity in load pockets

[13] *Incident Review: Load-Pocket Shoulder Season Challenges*

- Considering more extreme scenarios when determining which outage requests to approve
- Considering PRC-023 loadability requirements when determining contingent overload thresholds that trigger cascading analysis
- Periodically revisiting planned outages and considering updated and expected system conditions to determine whether such outages should be postponed
- In market areas, reviewing processes to ensure that reliability studies (OPA) are using accurate generation dispatch and availability as determined from the latest day-ahead market analysis (coordinating processes that eliminate discrepancies between the day-ahead market unit commitment plan and the OPA studies)

Chapter 2: Severity Risks, Impact, and Resilience

This chapter identifies and examines the highest-stress days on the BPS in 2025 using established measures.

Severity Risk Index (SRI)

The SRI provides a quantitative measure of the relative severity of the combined impact of load, generation, and transmission loss on the BPS daily and offers a comprehensive picture of the performance of the BPS, allowing NERC to assess year-on-year reliability trends. For 2025, load-loss data voluntarily reported to the IEEE Distribution Reliability Working Group was used to estimate the daily load-loss component; generation and transmission components are calculated from data collected by NERC.

By comparing the daily SRI scores in descending order for each of the past five years, the overall performance of the BPS can be evaluated (**Figure 2.1**). The inset chart in the upper right of **Figure 2.1.** provides a detailed comparison of the top 10 SRI days for each year. The annual cumulative SRI shown in **Table 2.1** sums each day's SRI for the year by component.

The cumulative performance of the BPS is calculated by summing each day's SRI for the year. **Table 2.1** shows the annual cumulative SRI for the five-year period of 2021–2025.

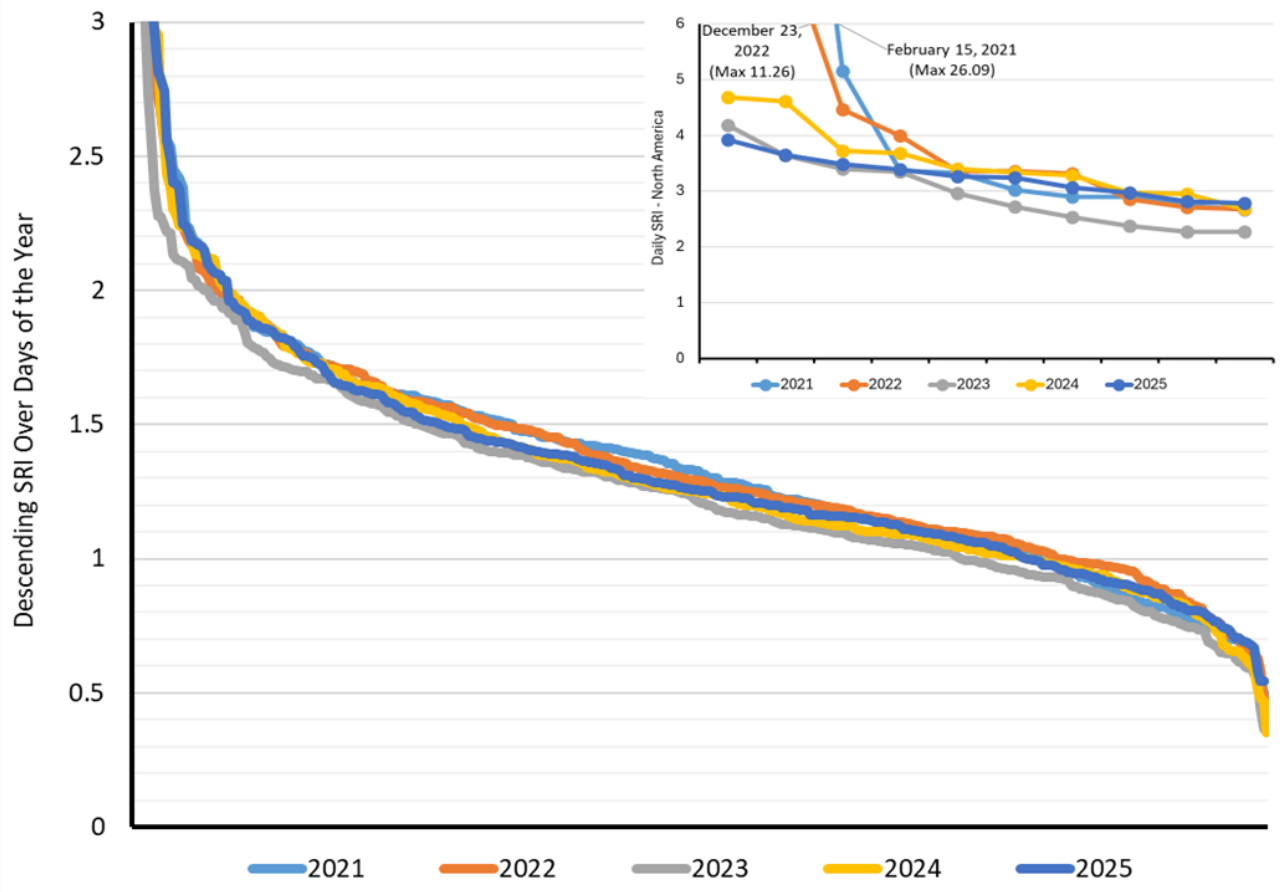


Figure 2.1: NERC Descending SRI by Day of the Year

Table 2.1: Annual Cumulative SRI					
Year	Cumulative Weighted Generation	Cumulative Weighted Transmission	Cumulative Weighted Load Loss	Annual Cumulative SRI	Average Daily SRI
2021	375.9	63.9	96.6	536.4	1.47
2022	404.1	59.7	55.2	518.9	1.42
2023	356.9	64.1	50.5	471.5	1.29
2024	383.7	60.6	51.8	496.1	1.36
2025	395.0	55.7	45.3	496.0	1.36

Figure 2.2 plots the 10 highest SRI days daily and the SRI scores for 2025 against control limits that were calculated by using the seasonal daily performance of the prior four years. A general normal range of performance is represented by the gray-colored band, showing the daily seasonal 90% control limits.[14] Days that extend above the seasonal control limit indicate irregularities for the season but may not have a high enough SRI to rank in the top 10.

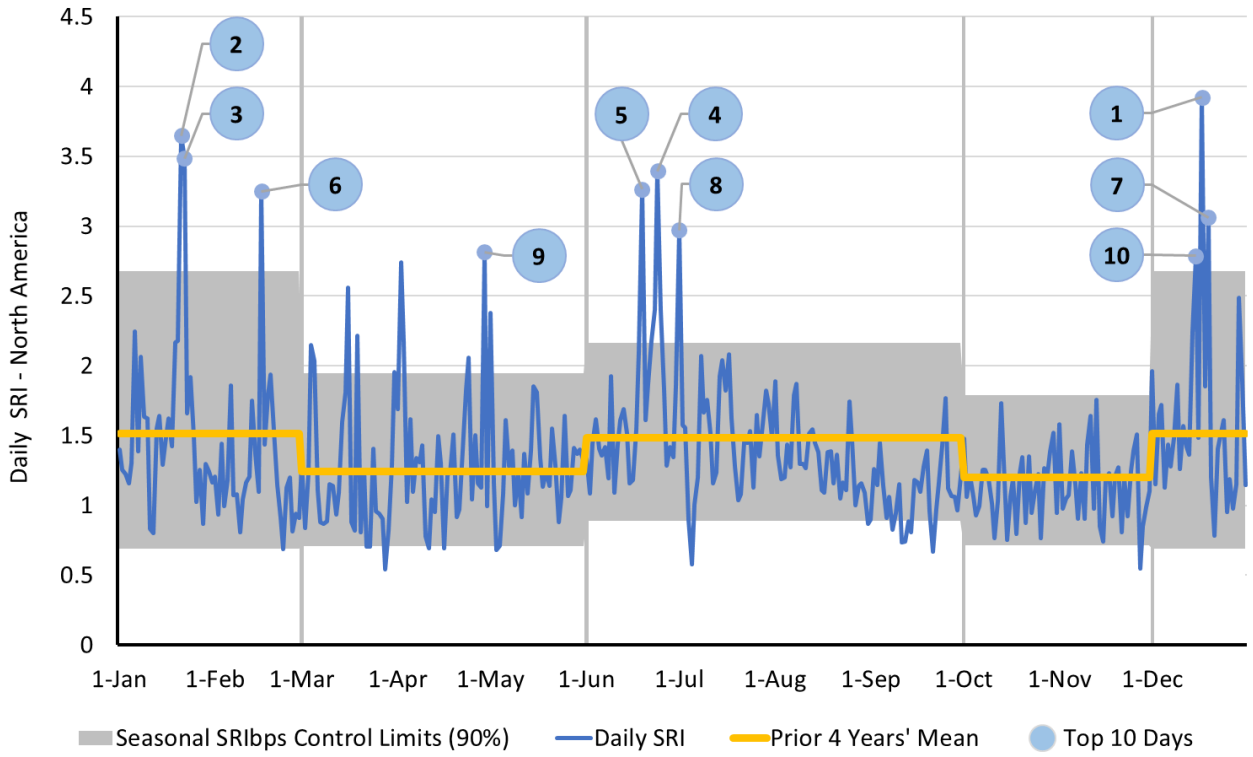


Figure 2.2: 2025 Daily SRI with Top 10 Days Labeled, 90% Confidence Interval

Table 2.2 details the scores for the top 10 SRI days during 2025. The table identifies where atypical weather conditions were ongoing during the day and the general location by Regional Entity. Weather conditions in 2025 were fairly temperate with no hurricanes making landfall and only a few large, major winter storms and thunderstorms. The most impacted day was the result of an atmospheric river, a phenomenon that resulted in high winds and heavy rainfall in the Northwestern United States.

[14] The shaded area reflects the 90% confidence interval (CI) of the historic values between the 5th and 95th percentiles.

Table 2.2: 2025 Top 10 SRI Days							
Rank	Date	SRI and Weighted Components 2025				Atypical Weather Conditions	Regional Entities
		SRI	Weighted Generation	Weighted Transmission	Weighted Load Loss		
1	17-Dec	3.92	2.34	0.95	0.64	Northwestern Atmospheric River	WECC
2	21-Jan	3.65	3.24	0.32	0.09	Winter Storm Enzo	RF, SERC
3	22-Jan	3.49	3.27	0.14	0.07	Winter Storm Enzo	RF, SERC
4	24-Jun	3.39	2.75	0.24	0.40	Thunderstorms	NPCC, RF, SERC
5	19-Jun	3.27	1.35	0.26	1.65	Thunderstorms, Tornadoes	MRO, RF, SERC
6	16-Feb	3.25	1.91	0.21	1.13	Severe Storm in Southeast	SERC
7	19-Dec	3.06	1.56	0.31	1.19	Northwestern Atmospheric River	WECC
8	1-Jul	2.97	2.75	0.16	0.06	Coincidental Generator Outages	All Regions
9	29-Apr	2.81	1.03	0.28	1.51	Thunderstorms	MRO, NPCC, RF
10	15-Dec	2.79	2.47	0.10	0.22	Winter Storm	RF, SERC, Texas RE

SRI Performance Trends

To put the severity of days in 2025 into context with historic BPS performance, the top 10 days over the five-year period are updated annually. Historically, the PAS has identified days with an SRI below 5 to generally be low impact to the BPS. **Table 2.3** identifies the top 10 SRI days occurring for 2021–2025 with the contribution of the generation, transmission, and load-loss components to the SRI for each day; contributing event information; and the Regional Entities impacted by the event. For 2025, there were no days severe enough to be added to the top 10 SRI days of the past five years, with all days having an SRI under 4, which has historically been considered a very good year.

Table 2.3: 2021–2025 Top 10 SRI Days							
Rank	Date	SRI and Weighted Components				Atypical Weather Conditions	Regional Entities
		SRI	Weighted Generation	Weighted Transmission	Weighted Load Loss		
1	February 15, 2021	61.35[15]	5.54	0.78	55.02[16]	Winter Storm Uri	MRO, RF, SERC, Texas RE, WECC
2	February 16, 2021	18.31[17]	5.01	0.53	12.78[18]	Winter Storm Uri	MRO, RF, SERC, Texas RE, WECC

[15] IEEE DRWG data supplemented with Eagle-I information.
[16] Ibid.
[17] Ibid.
[18] Ibid.

Table 2.3: 2021–2025 Top 10 SRI Days							
Rank	Date	SRI and Weighted Components				Atypical Weather Conditions	Regional Entities
		SRI	Weighted Generation	Weighted Transmission	Weighted Load Loss		
3	December 23, 2022	11.25	8.16	0.84	2.26	Winter Storm Elliott	All
4	December 24, 2022	7.44	6.43	0.95	0.05	Winter Storm Elliott	All
5	December 11, 2021	5.16	1.01	0.70	3.45	Severe Storms	MRO, NPCC, RF, SERC, WECC
6	September 27, 2024	4.69	1.44	2.40	0.85	Hurricane Helene	SERC
7	January 9, 2024	4.61	1.59	0.68	2.35	Northwestern Winter Storm, Eastern Tornadoes and Severe Storms	RF, SERC, Texas RE, WECC
8	June 14, 2022	4.46	1.52	0.38	2.57	High Temperatures and Derecho	MRO, NPCC, RF, SERC, Texas RE
9	April 1, 2023	4.19	1.10	0.44	2.65	Hurricane Florence	MRO, NPCC, RF, SERC
10	June 15, 2022	3.99	1.59	0.19	2.21	High Temperatures and Derecho	MRO, NPCC, RF, SERC, Texas RE

Impact of Extreme Event Days

Extreme Event Days

Extreme event days are identified as event days above the 95th percentile upper bound relative to the past four years' severity measures for any season within North America or a specified Interconnection. This analysis expands on the transmission and generation components that contribute to the SRI reported in the previous **SRI Performance Trends** section to explore the causes of the extreme days.

The impacts of extreme days on BPS resources are characterized by the amount of transmission or generation reporting immediate forced outages or derates starting on a given day. By analyzing the impact and causes of extreme event days, it is possible to identify which conditions pose the highest risk to the BPS. While this analysis does not address every potential scenario, learning from performance during extreme events helps provide insight into how the system may respond to a range of conditions and events.

- Extreme-day outages for transmission and generation by Interconnection are presented in **0**. The analysis provided in the following subsections is reported separately for transmission and generation. The total estimated megavolt-amperes (MVA) transfer capacity[19] reported in TADS or

[19] Severity Risk Index

net maximum capacity reported to GADS for all Regional Entities or by Interconnection is shown at the top of each figure in this chapter.

Transmission Impacted

In 2025, 12 days met the criteria of extreme transmission days for the BPS as compared to 19 in 2024. The most extreme transmission-impacting day was December 17, primarily due to a combination of storms throughout the Northwestern United States as part of an atmospheric river phenomenon, affecting a total of 16 states (**Figure 2.3**), where the MVA capacity impacted due to automatic transmission outages was 5.8 times as high as the associated season's average. Other extreme days include March 14–15 due to a widespread winter storm, March 9 due to a series of severe thunderstorms, and the November 13 **Wyoming System Event**.

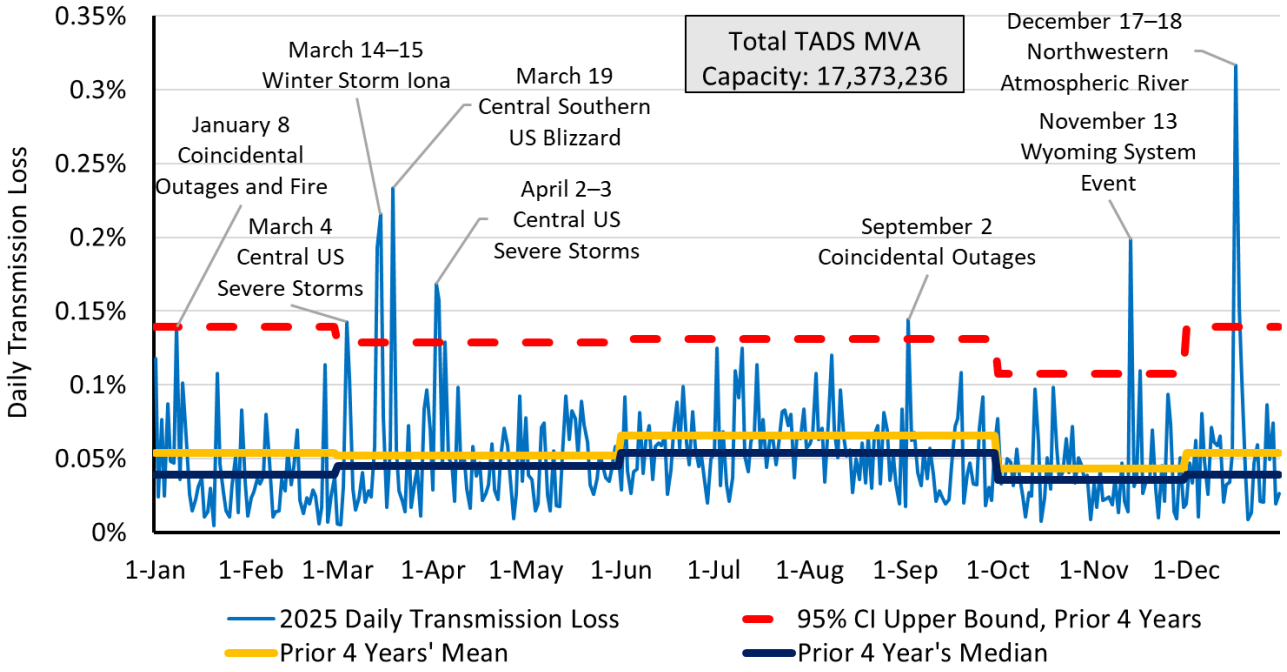


Figure 2.3: 2025 Sustained Transmission Outages During Extreme Days

The top causes reported for outages that occurred on extreme days are shown in rank order of MVA loss for North America and each Interconnection (**Table 2.4**). Causes for outages are based on those Interconnections' extreme days, shown in **Appendix A**. The number one outage cause for 2025 was Weather (Excluding Lightning), which affected almost five times more MVA capacity than any of the other top causes for the year across the Bulk Electric System (BES) and within each Interconnection.

Table 2.4: Top Transmission Initiating Outage Causes on Extreme Days Ranked by MVA Capacity					
Area	**Cause #1**	**Cause #2**	**Cause #3**	**Cause #4**	**Cause #5**
All NERC Regional Entities	Weather (Excluding Lightning) 156,789	Failed AC Substation Equipment 31,586	Unknown 31,515	Power System Condition 28,585	Contamination 23,963
Eastern–Québec Interconnections	Weather (Excluding Lightning) 142,446	Failed AC Substation Equipment 35,696	Lightning 24,057	Human Error 19,268	Failed AC Circuit Equipment 15,094
Texas Interconnection	Weather (Excluding Lightning) 18,052	Failed AC Substation Equipment 10,536	Lightning 6,993	Power System Condition 4,911	Unknown 4,315
Western Interconnection	Weather (Excluding Lightning) 49,701	Unknown 39,187	Fire 37,074	Power System Condition 30,008	Other 20,165

Conventional Generation Impacted

Based on analysis of GADS data, a total of 20 days in 2025 qualified as extreme for North America's BPS (**Figure 2.4**) compared to 26 in 2024. The four highest-impact days for generation loss were the January 19–22 winter storms. On these days, conventional generating units experienced outages that were 1.8–2.9 times as severe as the associated season's average. One of the extreme generation loss days coincided with extreme days identified for transmission (December 17 Atmospheric River Event). The days on which generation outages were slightly above the seasonal bounds that do not have a specific cause listed have been investigated and were either found to coincide with severe thunderstorms or high temperatures or saw many coincidental outages that were not a result of adverse weather conditions.

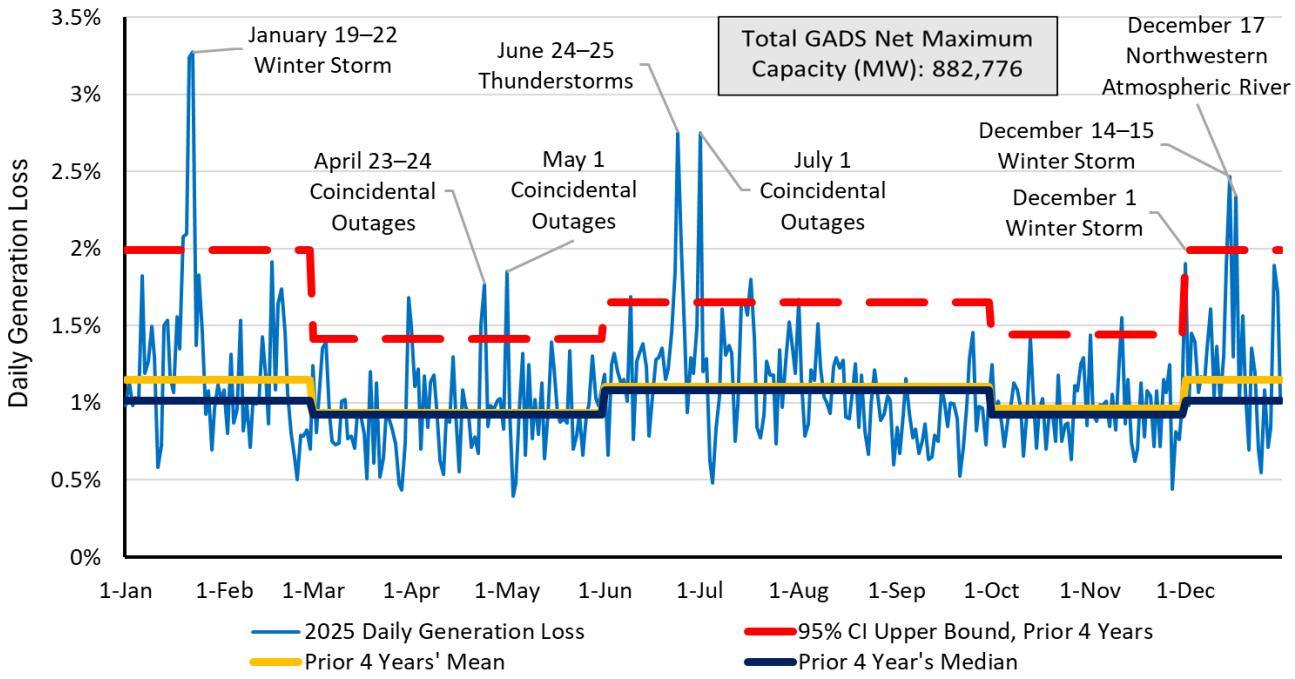


Figure 2.4: 2025 Generation Impacted During Extreme Days

The top causes reported for outages that occurred on extreme days are shown in ranked order by Interconnection (**Table 2.5**). Causes for Interconnections are based on those Interconnections' extreme days, shown in **Appendix A.**

Table 2.5: Top Generation Outage Causes on Extreme Days Ranked by Unavailable Net Maximum Capacity

Area	Cause #1	Cause #2	Cause #3	Cause #4	Cause #5
All NERC Regional Entities	Fuel, Ignition, and Combustion Systems (32,263)	Electrical (25,877)	Boiler Tube Leaks (21,524)	Controls (20,850)	Auxiliary Systems (20,596)
Eastern–Québec Interconnections	Fuel, Ignition, and Combustion Systems (29,278)	Electrical (22,638)	Boiler Tube Leaks (19,109)	Auxiliary Systems (17,338)	Miscellaneous (Gas Turbine) (14,908)
Texas Interconnection	Electrical (11,433)	Controls (9,391)	Boiler Control System (9,094)	Boiler Tube Leaks (7,432)	Feedwater System (5,504)
Western Interconnection	Controls (6,951)	Electrical (6,565)	Auxiliary Systems (5,941)	Turbine (5,740)	Miscellaneous (External) (5,529)

Analysis of Transmission System Resilience

The analysis of large transmission events evaluates transmission outages related to severe weather events that involve 20 or more automatic outages. Outage and restoration processes for transmission elements are analyzed, not the disruption and restoration of distribution customer load. Restoration of the transmission system to serve customer load is always the priority.

The analysis of the 2025 transmission outages identified 13 large transmission events, 12 of which were caused by weather and one non-weather event (**Wyoming System Event**) and quantified the resilience and restoration statistics for them. The resilience statistics enable the measurement and tracking of some abilities of the transmission system to withstand, adapt, protect against, and recover during and after major weather events.[20]

This section provides a detailed description of the December 17 Atmospheric River Event as the largest outage event on the transmission system in 2025. Multiyear statistics by associated weather type and changes in the severity and duration of these events as measured by the number of transmission outages reported for each cause are compared for two five-year periods: 2020–2024 and 2021–2025.

TADS Outage Grouping and 2025 Large Weather Events

The outage grouping algorithm[21] considers automatic outages reported in TADS based on Interconnection and associated start and end times. The resulting transmission outage events are determined to be weather-related if at least one outage in the event is initiated or sustained by one of the following TADS cause codes: Weather (Excluding Lighting), Lightning, Fire, or Environmental. The procedure produces groupings of outages that are further reviewed and compared with the weather information from external sources to confirm or refine the events. The TADS data was supplemented by Velocity Suite as a source to identify utility company footprints, and weather sources like the National Oceanic and Atmospheric Administration (NOAA) and Ventusky were used to visualize the weather events. Matching the data from these sources provides a much clearer picture of outages within the event. This combination of automatic and manual procedures results in a set of transmission events that can cross boundaries of different utilities and Regional Entities to capture significant events caused by major weather occurrences, such as hurricanes and severe winter storms.

In 2025, the grouping algorithm identified 13 large events; 12 of the 13 were weather-related events, in addition to the **Wyoming System Event** that started on November 13. **Table 2.6** lists these events in chronological order and shows the severe weather/event type for each event with statistics that quantify the impact of the event on the transmission system.

In 2025, the largest event was the December 17 Atmospheric River in the WI with 137 outages, affecting 5,343 miles and 48,418 MVA of capacity, making it the highest-impact storm of the year on the transmission system (shown in **blue** in **Table 2.6)**.

The second largest event, as identified by the grouping algorithm, was the March 14 severe storm event, which saw everything from blizzards in the north to tornadoes in the south (with 124 transmission outages reported) and occurred in the EI (shown in **red** in **Table 2.6**). Though it was the second largest event in terms of the number of outages, it had the largest amount of transmission capacity affected (MVA) and the highest number of element-days lost of any event in 2025 with 52,678 MVA affected and 359 element-days lost.

[20] *Resilience Framework, Methods, and Metrics for the Electricity Sector* | IEEE Power & Energy Society Resource Center (ieee-pes.org)

[21] *Impact of Extreme Weather on North American Transmission System Outages* | IEEE Conference Publication | IEEE Xplore

It is also worth noting that the **Wyoming System Event**, though not weather-related, had enough outages to be considered a large transmission event. This event (shown in **purple** in **Table 2.6**) had the quickest recovery of all large transmission events in 2025, with a time to 95% element restoration of just 0.1 days and a final restoration duration of 1 day.

Table 2.6: 2025 Large Transmission Outage Events

Event Start	Event Outage Count			Interconnection	Extreme/Severe Weather Event	Transmission Capacity Affected (MVA)	Miles Affected	Final Restoration Duration (Days)	Time to 95% Restoration, Elements (Days)	Element-Days[22] Lost	Most Simultaneous Unavailable Capacity (MVA)
	All Automatic	Sustained Automatic	Momentary Auto.								
21-Jan	22	19	3	ERCOT	Blizzard	11,714	581	.8	.6	5	5,899
16-Feb	31	23	8	Eastern	Thunderstorms	13,391	1,023	2.9	1.8	13	5,855
25-Feb	29	24	5	Western	Winter Storm	13,931	940	6.1	6.	30	5,541
4-Mar	31	23	8	Eastern	Blizzard	8,745	867	3.3	2.9	18	4,934
14-Mar	**124**	**104**	**20**	**Eastern**	**Tornadoes, Blizzard**	**52,678**	**4,510**	**54.2**	**12.3**	**359**	**27,011**
19-Mar	79	70	9	Eastern	Tornadoes, Blizzard	30,617	1,899	13.5	7.5	92	18,915
24-Mar	28	15	13	Eastern	Blizzard	9,487	507	44.5	3.7	52	4,741
2-Apr	39	29	10	Eastern	Thunderstorms Tornadoes	15,361	1,550	58.1	9.2	96	7,424
5-Apr	35	32	3	Eastern	Thunderstorms	11,545	1,332	6.5	4.9	37	5,835
29-Apr	51	47	4	Eastern	Thunderstorms	16,352	1,056	5.5	4.4	53	8,567
21-Jun	22	17	5	Eastern	Derecho	7,948	2,098	68.7	17.7	118	6,429
13-Nov	**46**	**46**	**0**	**Western**	**Wyoming System Event**	**25,357**	**1,924**	**1.0**	**0.1**	**2**	**12,320**
17-Dec	**137**	**129**	**8**	**Western**	**Northwestern Atmospheric River**	**48,418**	**5,343**	**36.7**	**6.1**	**235**	**27,190**

[22]The definition for element-days is provided in Appendix B of the NERC *2022 SOR*.

Outage, Restore, and Performance Curves

Table 2.6 illustrates the variability in event sizes and duration. However, these statistics do not completely explain what happened during the events; the outage, restore, and performance curves of the events provide more details on how the events unfolded.[23] **Figure 2.5** serves as an example to describe transmission outages during an event. These curves track the number of elements out or the MVA transmission capacity impact on the vertical axis versus time on the horizontal axis.

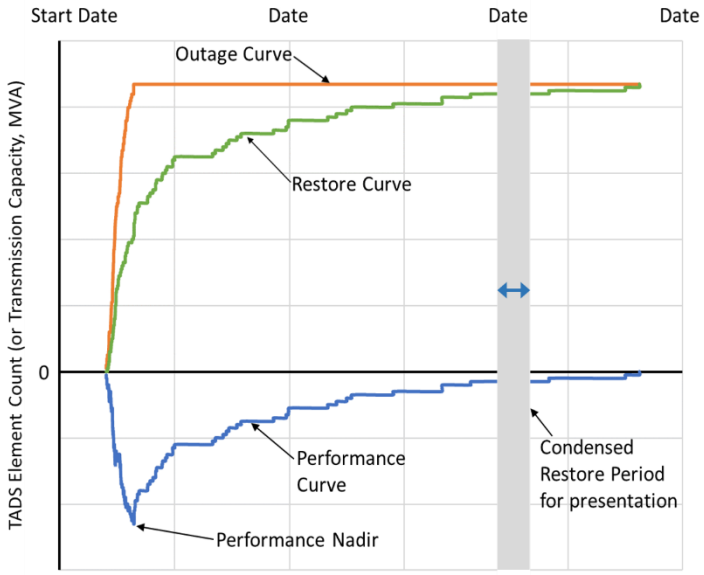


Figure 2.5: Example of Outage, Restore, and Performance Curves for a Large Transmission Outage Event

The outage curve is the cumulative number of elements or cumulative equivalent MVA capacity impact at the time shown on the horizontal axis.

The restore curve is the cumulative number of elements restored or cumulative equivalent MVA restored at the time shown on the horizontal axis.

The performance curve is the number of elements or equivalent MVA capacity impact out simultaneously at the time shown on the horizontal axis. The value is equal to elements or MVA capacity restored minus the elements or MVA capacity (i.e., the performance curve is the restore curve minus the outage curve). The performance curve combines information on degradation and recovery during the event.

The curves enable the calculation of several resilience metrics.[24] These metrics help quantify the abilities of a resilient power system to effectively absorb, withstand, adapt, protect against major weather events (event size, outage process duration and outage rate, time to first restore, the most degraded state in the event, the total element-days and MVA capacity days lost), and recover from and reduce the durations and impacts of major weather events (i.e., event duration, time to first restore, time to substantial restoration, instantaneous restore rate).

[23] S. Ekisheva, I. Dobson, R. Rieder, and J. Norris, "Assessing transmission resilience during extreme weather with outage and restore processes," 2022 17th International Conference on Probabilistic Methods Applied to Power Systems

[24] Resilience statistics are defined in Appendix B in the *2022 SOR*.

Resilience Curves and Statistics for the WI Atmospheric River, the Largest Transmission Outage Event in 2025

The atmospheric river that made landfall along the U.S. Pacific Northwest coastline on December 17, 2025, brought heavy snow and rain as well as high winds in the area before moving into British Columbia and the northern Midwestern United States. At the storm's peak, there were about 950,000 customer outages across British Columbia, Washington, Oregon, Colorado, and Montana.[25]

The atmospheric river also caused a large transmission outage event in the WI that impacted 18 Transmission Owners. With 137 automatic outages, this event was the largest transmission event in 2025 but less impactful than top historic hurricane events, such as the 2024 Hurricane Helene (431 outages) and the 2017 Hurricane Irma (352 outages).

Out of the 137 automatic outages caused by extreme weather, 133 were ac circuit outages (8 momentary and 125 sustained), two were transformer outages (both sustained), and two were ac/dc back-to-back converter outages (both sustained). The total affected mileage was 5,343 ac circuit-miles, and the total transmission capacity affected was 48,418 MVA. The reported event duration was 36.7 days, with a single 230 kV ac circuit outage continuing until January 22, 2026. The element- and MVA-based curves for the atmospheric river event are shown in **Figure 2.6** and **Figure 2.7**, respectively. The curves are truncated at 01/01/2026 0:00 UTC with one ac circuit outage still unrestored.

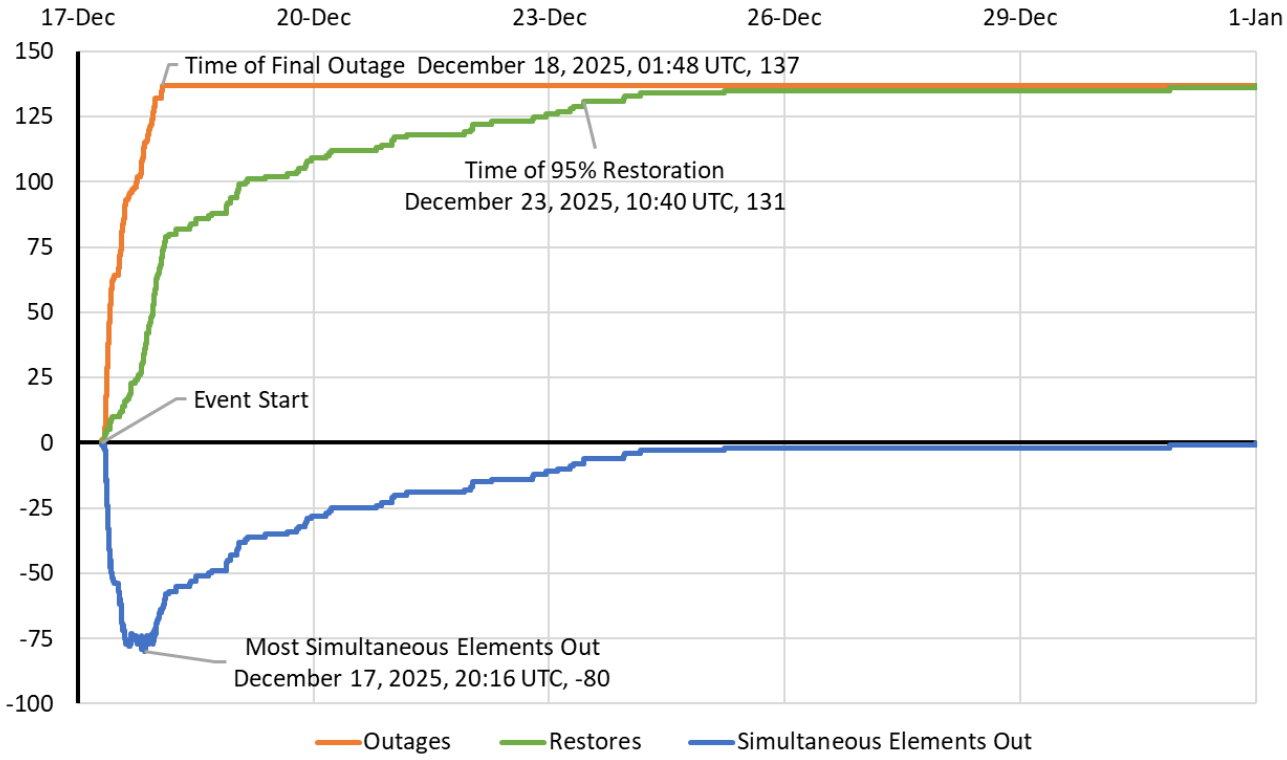


Figure 2.6: Transmission Element Outage, Restore, and Performance Curves for Atmospheric River Event in the Western Interconnection, December 17, 2025–January 22, 2026

[25] Customer outage data sourced from Eagle-I.

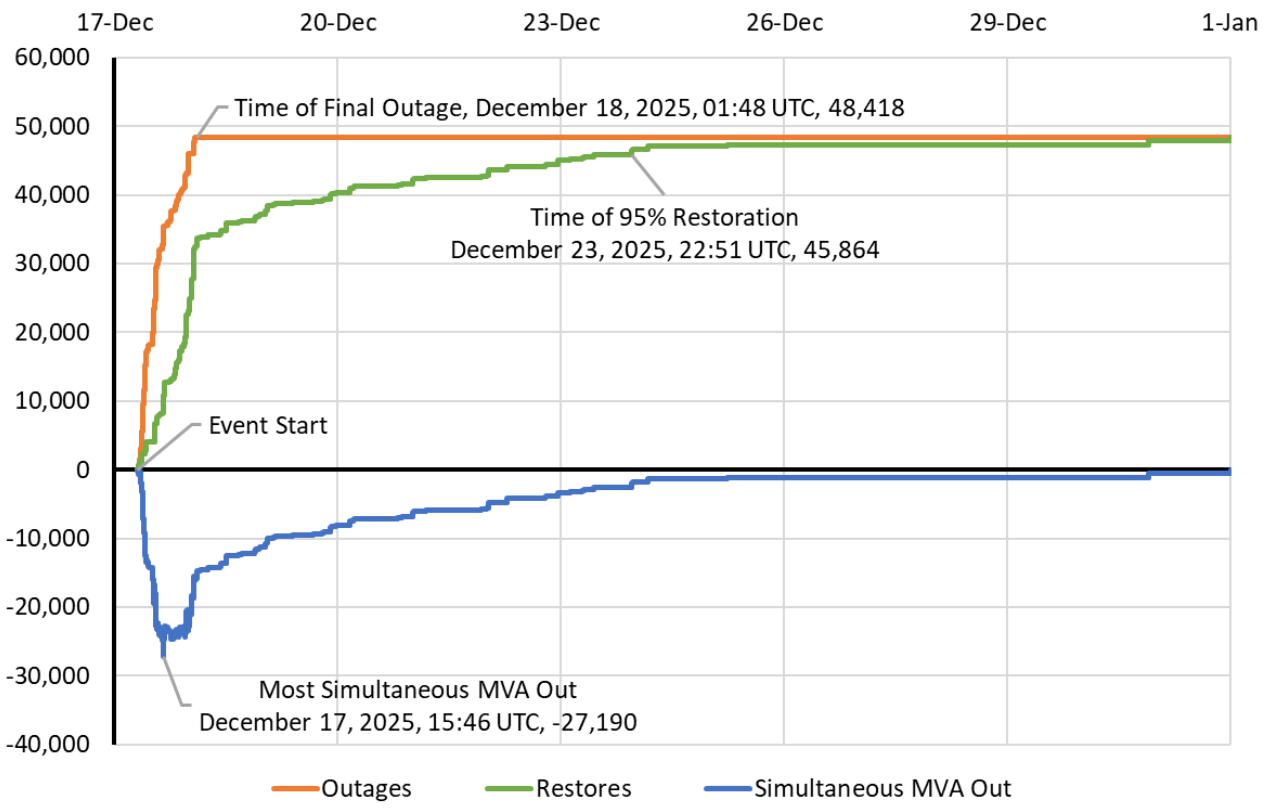


Figure 2.7: Transmission Capacity (MVA-Based) Outage, Restore, and Performance Curves for Atmospheric River Event in the Western Interconnection, December 17, 2025–January 22, 2026

The outage process shown in **Figure 2.6** and **Figure 2.7** by **orange** curves started as a cluster of quickly accumulating outages and continued for 18 hours with an average outage rate of 7.4 outages per hour (2,631 MVA per hour). Due to multiple outages of the same ac circuit, a total of 137 outages occurred on 123 distinct ac circuits.

The restoration process shown in **Figure 2.6** and **Figure 2.7** by **green** curves started with a momentary restoration 28 minutes after the first outage began, with the first sustained outage restoration 50 minutes after the event started. As is typical for large events, the restoration process progressed rapidly;[26] however, restoration times slowed with a larger percentage of equipment still out than usual. By applying a fitted curve for the restore process[27] to **Figure 2.6** it can be estimated that the maximum instantaneous restore rate of 4.3 restores per hour was reached 4 hours and 16 minutes into the event. The restoration rate was 2.4 elements per hour at the time half of the outages were restored (about 19 hours into the event), and only 0.1 elements per hour at the 95% element restoration level. The maximum number of transmission elements simultaneously out was 80 and was observed twice: a momentary nadir occurred about 13 hours after the event started, followed by another 13 minutes later, which lasted 2 minutes. The maximum amount of transmission capacity simultaneously out (27,190 MVA), represented by the nadir of the MVA-based performance curve in **Figure 2.7**, was observed only once and more than 4 hours earlier than the element-based nadirs. It occurred when a 500 kV ac circuit went out and ended 4 minutes later, when a different 500 kV ac circuit was restored. When the 80 elements were out simultaneously for the element-based nadirs,

[26] S. Ekisheva, I. Dobson, R. Rieder, and J. Norris, "Assessing transmission resilience during extreme weather with outage and restore processes," 2022 17th International Conference on Probabilistic Methods Applied to Power Systems.
[27] S. Ekisheva, D. K. Pratt, M. Kachadurian, W. G. Martin, J. Norris, and I. Dobson, "Grid Restoration after Extreme Weather Events", 2023 IEEE PES Innovative Smart Grid Technologies Europe (ISGT) Conference.

the total value of transmission capacity unavailable was about 24,000 MVA—notably lower than the MVA out at the MVA-based nadir.

A substantial 95% restoration was reached after 147 hours (17% of the event duration). The substantial 95% restoration for transmission capacity (MVA) took longer, 159 hours or 18% of the event duration. The total loss for the event, calculated as the area between a **blue** performance curve and the time axis, was 235 element-days lost (**Figure 2.6**) and 77,097 MVA-days lost (**Figure 2.7**).

The longest outage was 36.6 days on a 230 kV ac circuit that sustained tower damage. A small number of disproportionately long outages is common in large transmission events. These very large outage durations are often caused by inaccessibility of a portion of the line, damaged structure or equipment or, in some cases, a utility postponing the restoration of a single remaining element because this element is considered not critical for reliability of the grid.[28]

Transmission System Resilience Statistics by Associated Weather Type: 2021–2025

Weather Types

The outage grouping procedure identified 59 large transmission events in the years 2021–2025, two of which were not weather-related (a 2023 contamination event and a 2025 frequency event).[29,30] The 57 large weather-related events were caused by the weather types listed in **Figure 2.8**. If several weather factors were observed together (e.g., hurricane, tornado, and wind), the dominant cause of transmission outages was determined to be the weather type. Multiple sources (i.e., NERC's daily BPS awareness reports, Velocity Suite, NOAA, Ventusky, public media reports) were used in conjunction with cause codes to determine if a weather event was associated with each large transmission event.

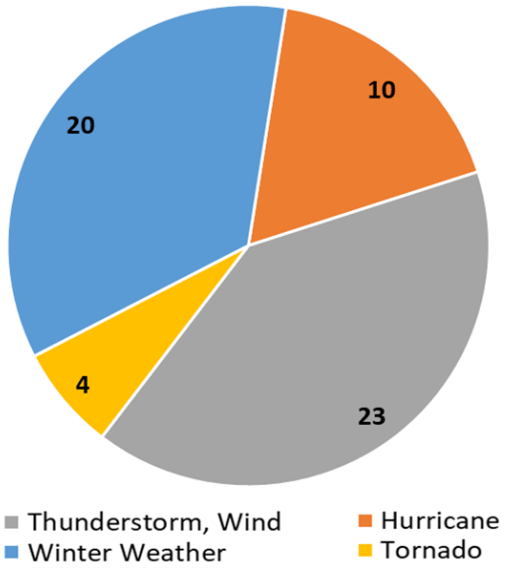


Figure 2.8: Weather Types of Large Transmission Events, 2021–2025

[28] S. Ekisheva, I. Dobson, R. Rieder, and J. Norris, "Assessing transmission resilience during extreme weather with outage and restore processes," 2022 17th International Conference on Probabilistic Methods Applied to Power Systems.
[29] A 2023 large event in SERC with 30 outages caused by Bird Contamination; the event duration was 2.5 days.
[30] A 2025 large event in WECC with 46 outages caused by Power System Condition; the event duration was a day.

Figure 2.9 shows selected resilience statistics for the 2021–2025 events by weather type. Hurricanes caused the largest transmission events, with the average one having 123 outages, while other groups had average outage counts that ranged from 43–64 outages. The maximum number of elements simultaneously out (the most degraded state in an event as indicated by the nadir of the performance curve) fell between 51–67% of the event size on average.

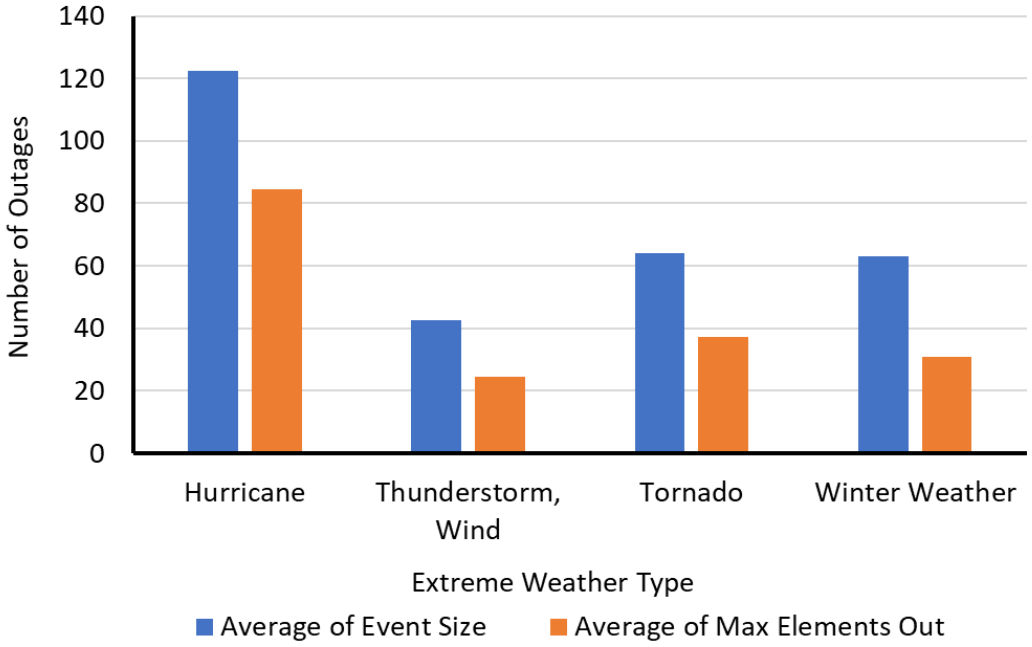


Figure 2.9: Resilience Statistics for 2021–2025 Large Weather-Related Events

Figure 2.10 compares the average event duration with the average substantial restoration duration (the time to restore 95% of outages and 95% of MVA capacity) and shows the time to first restore.

Hurricanes were the highest in average event duration, second for 95% outage restoration duration, and lowest for 95% MVA restoration duration. Tornadoes were the second highest in event duration with the highest average 95% restoration duration for both outages and MVA capacity. While some value can be extracted from evaluating the average event duration, the time to 95% restoration is typically more indicative of overall performance.[31]

[31] *How Long is a Resilience Event in a Transmission System?: Metrics and Models Driven by Utility Data* | IEEE Journals & Magazine | IEEE Xplore

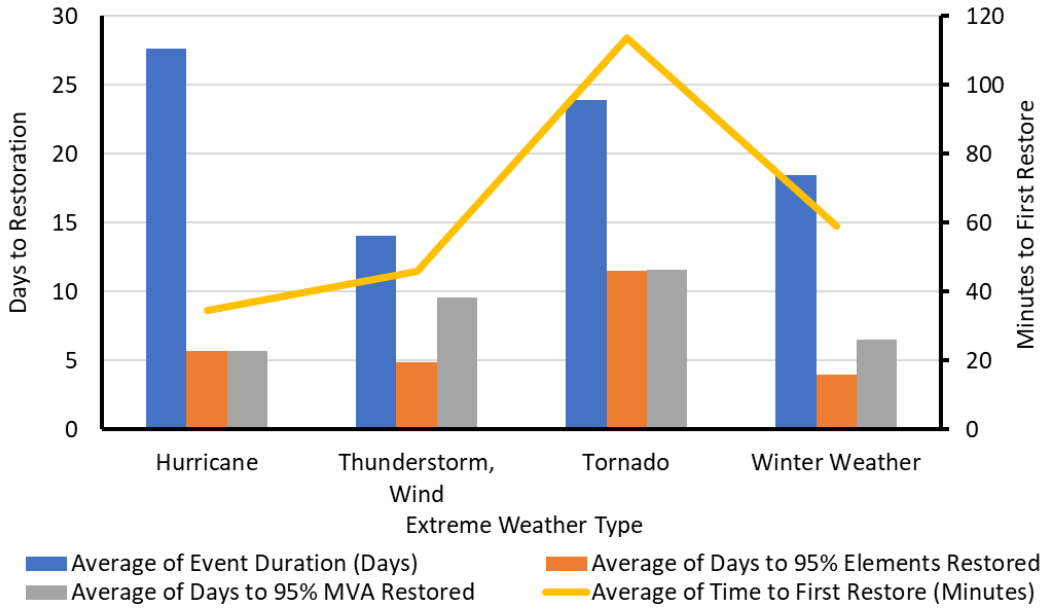


Figure 2.10: Average Event Duration vs. Average Sustained Restoration Duration

Changes in Resilience Statistics: 2021–2025 Events vs. 2020–2024 Events

To draw conclusions about improving, stable, or declining transmission resilience against weather, the analysis focuses on capturing changes in the several metrics that quantify resilience over years. The resilience statistics are calculated for large weather-related events for the years 2020–2024 and 2021–2025, and changes in the metrics by weather types were analyzed. The five-year period is selected due to the small annual number of events in some groups.

The bubble chart in **Figure 2.11** shows the groups of large weather-related transmission events by weather type; the five patterned bubbles correspond to the groups for combined 2020–2024 data, and the five solid-colored bubbles show the same groups for combined 2021–2025 data. The size of a bubble represents the average time (in days) to restore 95% of outages for the events in this group (displayed in the center of each bubble). The X-axis of a bubble shows the number of events, and the Y-axis shows the average event size. The bubble color indicates the average MVA-day loss for each group: Below 30,000 MVA-days is shown in **blue**, between 30,000 and 100,000 MVA-days is shown in **yellow**, and above 100,000 MVA-days is shown in **red**.

Change in size or position of a bubble for the same weather type in **Figure 2.11** indicates changes in the impact of that weather resulting from a combination of the weather frequency and severity and improved or declined resilience performance. There was a decrease in the number of events in all categories except for winter weather as reflected by the bubble position change along the X-axis in **Figure 2.11**.

Comparing 2020–2024 vs. 2021–2025, the number of Hurricane; Tornado; and Thunderstorm, Wind events decreased while Winter Weather increased. No weather type changed category for MVA-days lost as reflected by the color of the bubbles (shaded for previous range and solid for new). A comparison of the values for the average number of days to 95% element restoration between the year ranges indicates that the average increased by about one day. Tornado is an exception, which increased by 4.2 days because of some smaller tornadoes dropping out of the year range. Most categories had a similar average event size, except for Hurricanes. This decrease was because 2020, which is outside the most recent five-year window, had record-setting hurricanes and no hurricanes made landfall in 2025.

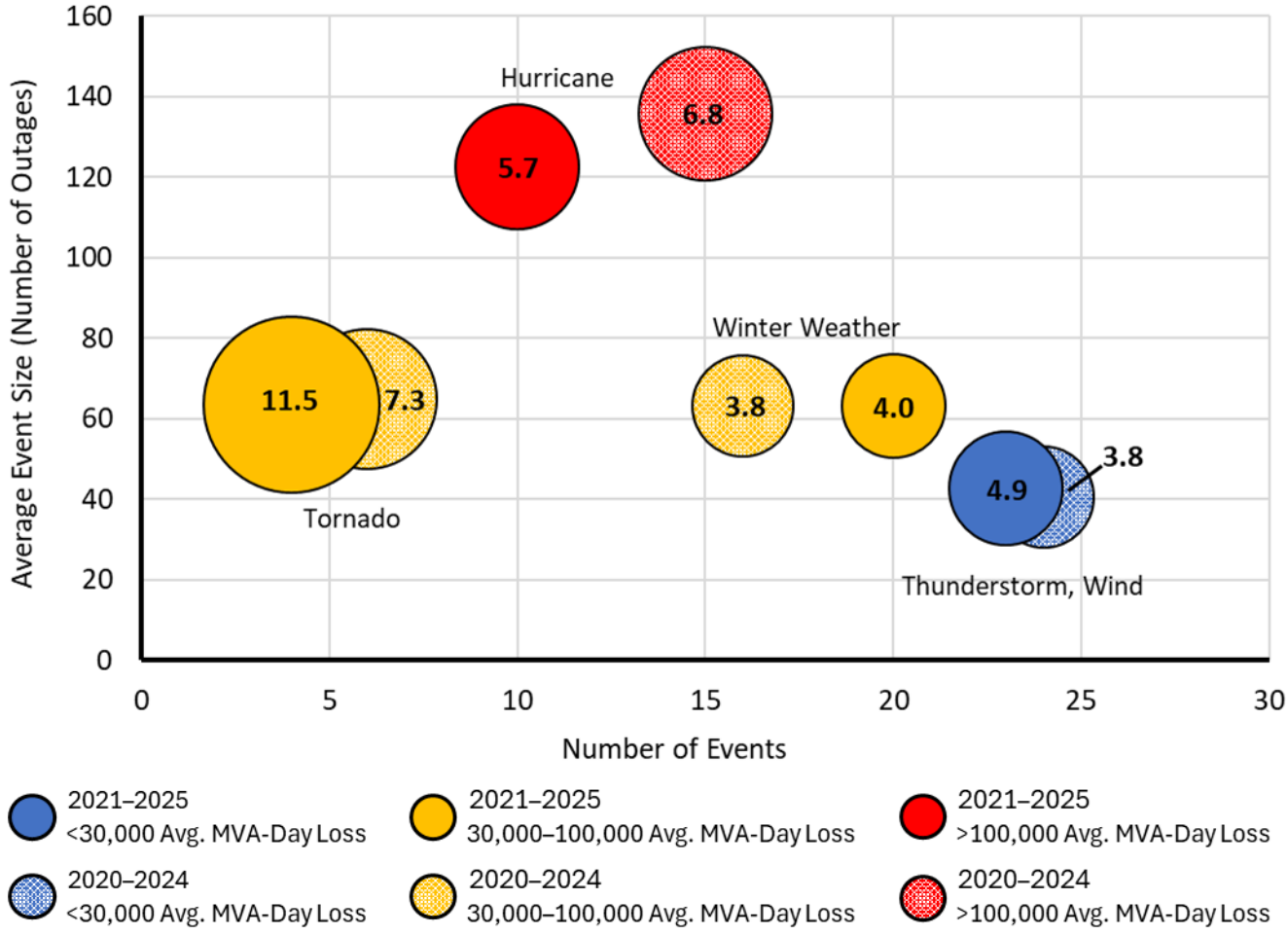


Figure 2.11: Statistics for Large Transmission Events by Weather Type for 2020–2024 vs. 2021–2025

Chapter 3: Grid Transformation

Resource Adequacy

Highlights

- In comparison to five years prior, 2025 saw tightening reserve margins across most notably Manitoba, New England and PJM with MISO, SaskPower and especially ERCOT seeing improvements in the level of anticipated reserve margins heading into last year's peak season.
- In 2025, anticipated resources exceeded Reference Margin Levels (RML) across all assessment areas.
- Improved performance of the thermal generation fleet and delivery of natural gas supplies to generators during arctic events of Winter 2024–2025 compared to prior extreme cold events.
- As of the 2025 LTRA, solar photovoltaic (PV) is no longer the sole, predominant generation type planned over the next 10 years as new battery resource projects have grown to match solar projections.

2025 Planning Reserve Margins

Planning Reserve Margins are a long-term resource adequacy indicator. Anticipated Reserve Margin (ARM) expresses the level of additional resource capacity that an area has above its peak summer (June–September) and winter (December–February) seasonal demand. It is calculated as the difference in anticipated resources and net internal demand divided by net internal demand and shown as a percentage. Each assessment area's ARM is compared against its RML—the threshold margin established by the state, provincial authority, Independent System Operator/Regional Transmission Organization (ISO/RTO), or other regulatory body to provide the level of resources needed to meet reliability criteria (e.g., maintain loss-of-load expectation below 1-day-in-10 years).

Figure 3.1 shows the ARM percent difference from the area-specific RML as calculated using data from the 2021 and 2025 seasonal assessments for each area's peak season. In 2025, all assessment areas except for NPCC-Maritimes had ARMs in excess of the area RML. Assessment areas with improved reserve margins relative to 2021 include MISO, SaskPower, New York, Québec, the eastern and southeastern SERC regions, British Columbia, and—most notably—ERCOT. A realignment of the WECC United States assessment areas in 2025 precludes comparison with 2021 values.[32]

The notable improvement in ERCOT is attributable to a 29% (7,010 MW) increase in solar capacity, continuing a trend of robust solar penetration, and a 94% (7,414 MW) increase in energy storage installed capacity. The large increase in available capacity reflects (1) new rules for managing state of charge (SoC), including a requirement to maintain a certain SoC to participate in ancillary services, (2) installation of systems with longer durations, and (3) improvements in battery operational practices.

The five-year comparisons also reveal tighter reserve margins across Manitoba, Ontario, SPP, Florida, and SERC-Central relative to 2021. In addition to having the most precipitous drops in reserve levels relative to 2021, NPCC-Maritimes, NPCC-New England, and PJM, where generator retirements and significant load growth continue to present challenges, also display discernible year-over-year trends of tightening reserve levels across the 2021–2025 period.

[32] 2025 Western Assessment, 2025–2026 Winter Reliability Assessment Western Overview

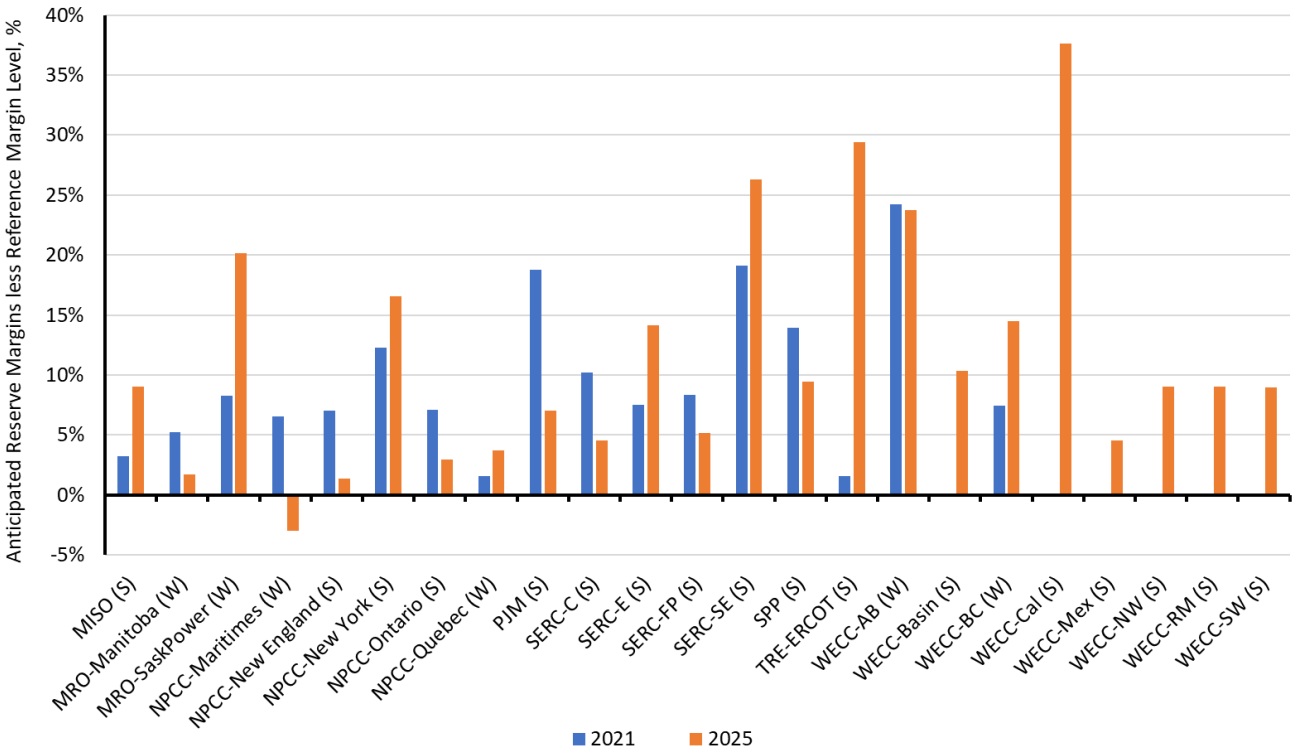


Figure 3.1: 2021 and 2025 Peak Season Planning Reserve Margins Less Reference Margin Levels[33]

Energy Emergency Alerts (EEA)[34]

The purpose of an EEA is to provide a real-time indication of potential and actual energy emergencies within an Interconnection. An EEA 3 is reported when firm load interruption is imminent or in progress. EEA trends may provide an indication of BPS capacity, energy, and transmission insufficiency.

Figure 3.2 shows that 10 EEA 3s were declared in 2025, a reduction of 11 EEA 3 declarations over 2024. None of the EEA 3 declarations in 2025 included load shed, versus 0.108 GWh of firm load shed in 2024.

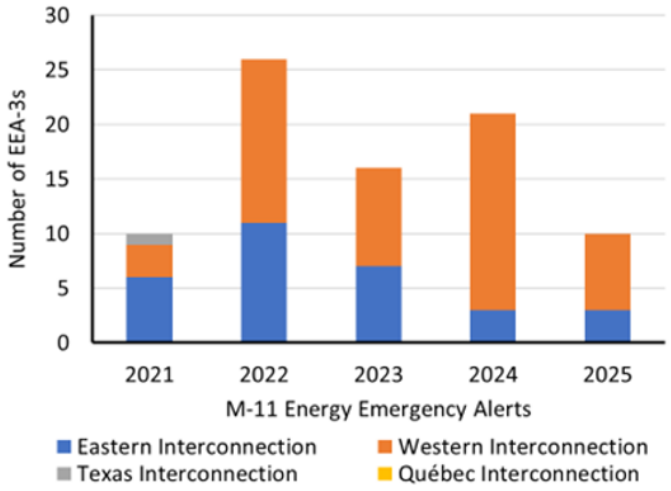


Figure 3.2: EEA 3 by Year and Interconnection

[33] M-1, Reserve Margin displayed as the difference between ARM and area's RML.
[34] M-11, Energy Emergency Alerts

All 10 of the EEA declarations in 2025 were associated with periods of reduced generation or import capability combined with heavy load days. Seven EEA 3s were associated with two non-U.S. entities, both of which have weak connections to their neighbors. Of these seven, six are associated with a balancing area that has processes requiring the declaration of an EEA 3 prior to requesting assistance from neighbors. **Table 3.1** shows the number of hours when operator-initiated firm load shed was deployed during each of the past five years.

Table 3.1: Hours with Operator-Initiated Firm Load Shed (Hours/Year)

Year	Event	Event Hours	Total Annual Hours
2021	Winter Storm Uri	70.5	70.5
2022	June Heatwave	21.0	56.5
	Winter Storm Elliot	35.5	
2023	N/A	0.0	0.0
2024	WI: Generator Trip, Subsequent Failure of Dispatched Units	0.43	0.43
2025	N/A	0.0	0.0

2025 Seasonal Energy and Capacity Risk Analysis

The ERO assesses the risk of electricity supply shortfall in seasonal reliability assessments by considering Planning Reserve Margins, seasonal risk scenarios, and probability-based risk assessments. The expected impact of generator outages and extreme operating conditions on electricity supply and demand are also considered in NERC's seasonal reliability assessments. NERC evaluates the availability of supplies to meet normal seasonal peak demand as well as higher demand that may occur only once per decade, referred to as an extreme or 90/10 demand scenario. In the case of Texas RE-ERCOT and WECC CA/MX in the summer, the highest risk hour period is analyzed. The highest risk hour typically occurs after the peak demand hour when the sun has set, and solar PV resources are not contributing. Increased demand, which can be caused by extreme temperatures, higher-than-anticipated generator forced outages, and derates, can create conditions that lead system operators to take emergency operating actions. The maps in **Figure 3.3** and **Figure 3.4** highlight the assessment areas that NERC identified ahead of the Winter 2024–2025[35] and Summer 2025[36] seasons as at risk for resource deficiencies.

[35] NERC 2024-2025 Winter Reliability Assessment
[36] NERC 2025 Summer Reliability Assessment

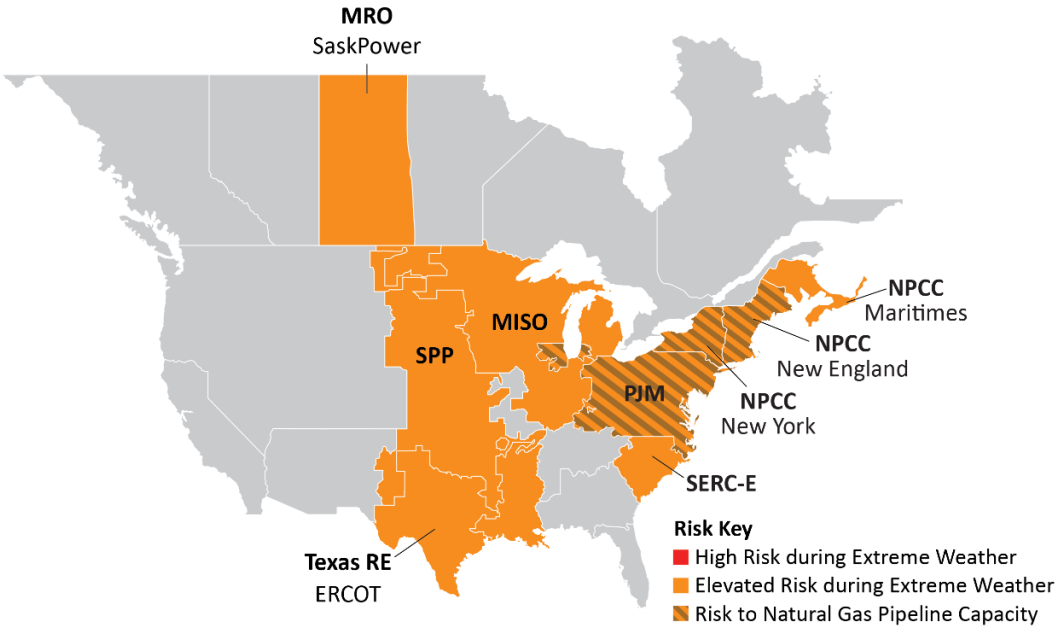


Figure 3.3: 2024–2025 Winter Reliability Assessment Risk Area Map

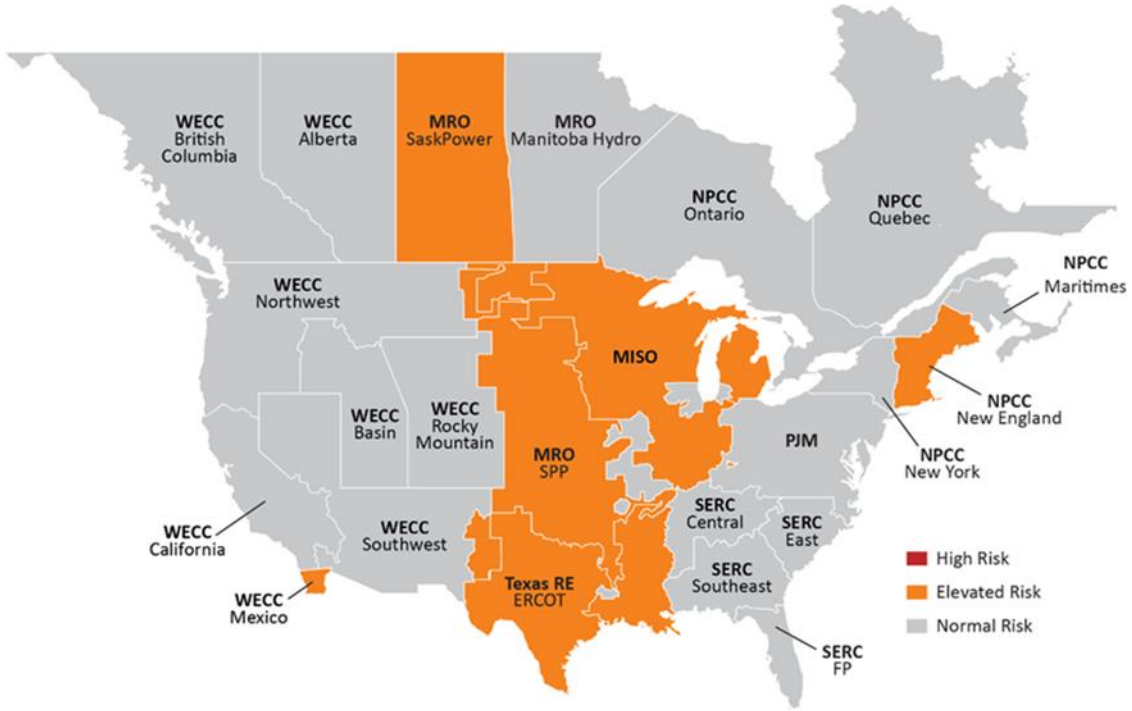


Figure 3.4: 2025 Summer Reliability Assessment Risk Area Map

Review of 2025 Capacity and Energy Performance

Periods of extreme temperatures in the summer and winter of 2025 challenged grid operators to maintain sufficient electricity supplies for demand in many parts of North America. Electricity demand is closely linked to temperature as electric load for space and equipment cooling varies with temperature. Seasonal weather extremes also affect electricity supply because generators of all types have weather-related limitations in some form. **Table 3.2** and **Table 3.3** provide demand and resource performance information for the peak demand hour of the summer and winter seasons in each assessment area. The tables include observed peak demand and resource output along with expected values from risk scenarios used in NERC's summer and

winter reliability assessments. Most assessment areas experienced peak demand that exceeded their normal 50/50 demand forecasts, and several areas exceeded their 90/10 (extreme) demand forecasts. As discussed below, winter arctic air events and summer heat domes contributed to generally high peak demand in North America.

Winter Operating Conditions

Meteorological winter (December 2024–February 2025) temperatures averaged 34.1 degrees Fahrenheit across the contiguous United States, 1.9 degrees above average, placing it in the warmest third of winters tracked by the National Oceanic and Atmospheric Administration. Total winter precipitation in the United States was nearly an inch below average, putting it in the driest third of recorded winters.[37] Canada experienced its fifth-warmest winter on record, with temperatures averaging 3.7 degrees Celsius above average.[38] Although the 2024–2025 Winter was warmer than average overall, a series of arctic events in January 2025 produced an extended deep freeze and harsh winter conditions over much of North America. As in past extreme winter storms, electricity demand surged while generator outages rose from freezing equipment and fuel supply issues. Nevertheless, during the January 2025 arctic events, operators did not require the use of manual load shedding and were able to maintain system balance using conservative operations, resource advisories, and other operational mitigations without resorting to EEA 3s.[39] A report of system performance prepared by the Federal Energy Regulatory Commission (FERC), NERC, and the NERC Regional Entities found that generators performed better during the January 2025 arctic events than in prior winter storms and attributed some improvements to additional generator commitments, improved preparedness, increased situational awareness, and the implementation of lessons learned from previous extreme cold weather events and prior report recommendations.[40] During the Winter 2024–2025 period, the highest amount of capacity in a forced outage state for all reasons occurred on January 20, 2025, with 68,519 MW across all regions. The natural gas system also performed better overall, delivering record levels of natural gas and experiencing only minor production declines and short-duration force majeure events.

A comparison of projected and actual Winter 2024–2025 peak/risk hour is provided in **Table 3.2**.

[37] Despite Arctic air outbreaks, U.S. had warm, dry winter on average | National Oceanic and Atmospheric Administration

[38] Climate Trends and Variations Bulletin – Winter 2024/2025 - Canada.ca

[39] See NERC's *2025–2026 Winter Reliability Assessment* for capacity and energy performance and operating narratives for each Interconnection (p. 51–52).

[40] *January 2025 Arctic Events | A System Performance Review by FERC, NERC, and its Regional Entities*, April 2025

Table 3.2: 2024–2025 Winter Demand and Generation Summary at Peak Demand

Assessment Area	2025 Values Winter Reliability Assessment Scenarios										
	Peak Demand			Generation[1] (MWh)	Transfers[1] (MW)	Wind Actual[1] (MWh)	Solar Actual[1] (MWh)	Forced Outages Summary[4] (MW)	Peak Demand[2] (MW)	Wind Expected[3] (MW)	Solar Expected[3] (MW)
	Date	Time	MW								
MISO	Jan. 21	18:00	108,888*	101,655	-977	18,468	0	17,010	96,134 100,395	16,761	519
MRO-Manitoba Hydro	Jan. 20	8:00	5,132	5,292	-277	142	N/A	146	4,814 5,060	52	0
MRO-SaskPower	Dec. 18	18:00	3,785	3,641	-231	664	0	0	3,802 3,897	368	3
MRO-SPP	Feb. 20	8:00	47,981	40,898	-1,424	4,886	255	9,272	45,926 47,054	4,783	36
NPCC-Maritimes	Jan. 22	7:00	5,810	4,266	-1,174	368	3	*	5,907 6,498	261	5
NPCC-New England	Jan. 21	18:00	19,607	17,686	-1,896	285	4	624	20,308 21,814	329	23
NPCC-New York	Jan. 22	19:00	23,521	18,932	-4,589	654	0	4,835	22,998 24,023	728	0
NPCC-Ontario	Jan. 22	18:00	21,940	24,250	2,990	3,693	0	*	20,951 22,179	1,914	0
NPCC-Québec	Jan. 22	8:00	37,178	39,514	-766	1,463	0	*	36,061 39,545	1,449	0
PJM	Jan. 22	9:00	144,420	152,142	7,731	3,704	3,076	8,663	130,712 144,939	3,620	1
SERC-C	Jan. 22	8:00	47,815	40,898	-6,921	563	214	1,538	41,397 47,062	176	455
SERC-E	Jan. 23	8:00	47,130	41,810	-5,323	0	145	1,830	44,023 47,662	0	2,526
SERC-FP	Jan. 25	8:00	43,974	41,702	-557	0	362	2,824	45,714 54,239	0	1,684
SERC-SE	Jan. 22	8:00	46,490	48,227	1,741	0	592	2,210	43,670 45,116	0	3,861
TRE-ERCOT	Feb. 20	8:00	80,560	79,960	-191	9,397	1,586	5,742	731,935 904,055	15,697	15
WECC-AB	Dec. 18	17:00	12,241	12,711	-470	3,175	4	*	12,280 12,635	1,867	0

Table 3.2: 2024–2025 Winter Demand and Generation Summary at Peak Demand

Assessment Area	2025 Values Winter Reliability Assessment Scenarios										
	Peak Demand			Generation[1] (MWh)	Transfers[1] (MW)	Wind Actual[1] (MWh)	Solar Actual[1] (MWh)	Forced Outages Summary[4] (MW)	Peak Demand[2] (MW)	Wind Expected[3] (MW)	Solar Expected[3] (MW)
	Date	Time	MW								
WECC-BC	Feb. 3	18:00	11,359	11,415	44	70	0	839	11,996 12,749	279	0
WECC-CA/MX	Dec. 12	15:00	35,555	31,925	-4,669	4,021	11,547	1,627	35,359 36,823	569	0
WECC-NW	Feb. 12	8:00	54,278	48,437	-920	2,607	1,494	3,281	58,001 62,230	7,876	2,198
WECC-SW	Feb. 13	16:00	22,969	25,087	2,117	2,741	1,599	1,496	16,177 17,777	1,065	182

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 2024–2025 WRA demand scenarios for each assessment area. Values are the normal winter peak demand forecast and an extreme peak demand forecast that represents a 90/10, or once-per-decade, peak demand. Some areas use other basis for extreme peak demand.

3 Expected values of wind and solar resources from the 2024–2025 WRA for the projected peak hour; actual peak hour can impact solar contribution

4 Values from NERC GADS for the 2024–2025 winter hour of peak demand in each assessment area. Highlighted areas had actual forced outages that were more than twice the value for typical forced outage rates used in the 2024–2025 winter risk period scenarios in the 2024–2025 WRA.

5 Texas RE-ERCOT peak demand scenarios are obtained by adding expected demand response (5.4 GW for winter 2024-2025) to the demand

scenarios found on p. 29 of the 2024–2025 WRA.

*Canadian assessment areas report to GADS on a voluntary basis, which can contribute to the absence of some values in certain assessment areas.

Summer Operating Conditions

The summer of 2025 was the 12th-hottest on record for the contiguous United States[41] during the meteorological summer period (June–August) and the 11th-warmest summer in Canada.[42] Actual peak demand exceeded normal demand forecasts across most assessment areas and exceeded extreme demand projections from the *2025 SRA* in three assessment areas. A summer heat wave developed in early June for most of the eastern half of the continent, triggering system operators to issue resource advisories and other operating mitigations. The east experienced only brief periods of relief from high temperatures through the end of July. Twenty energy emergency alerts were declared during the June and July heat events, but operators were able to manage high loading without resorting to load shedding.[43]

Summer conditions were generally less severe in other parts of the North American BPS. Peak demand in the Western Interconnection was 168,206 MW, slightly below Summer 2024. Western Canada experienced a heat wave from late August and through early September, exacerbating the ongoing drought in western Canada and triggering some energy shortfall events that were managed without shedding load. Wildfire activity also increased due to heat and dry conditions. The western United States overall navigated last summer with the BPS experiencing relatively few emergency events. Demand in WECC U.S. assessment areas never reached or exceeded the projections for extreme demand from the *2025 SRA.* Texas experienced a relatively mild summer in 2025, yet, due to significant load growth, the Summer 2025 load levels were comparable to the far hotter 2023 summer load levels.[44]

A comparison of projected and actual Summer 2025 peak/risk hour is provided in **Table 3.3**.

Table 3.3: 2025 Summer Demand and Generation Summary at Peak Demand

Assessment Area	Actual Peak Demand[1]			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)
	Date	Time	GW						
MISO	Jul. 29	17:00	121.6	116.3 121.6	1,105	6,039	12,323	9,123	8,779
MRO-Manitoba Hydro	Aug. 29	17:00	3.5	3.4 3.6	0	48	0	0	252
MRO-SaskPower	Sep. 7	17:30	3.6	3.6 3.8	232	310	26	9	0
MRO-SPP	Jul. 29	16:00	54.5	54.8 57.5	8,130	5,556	810	492	4,370
NPCC-Maritimes	Aug. 11	17:00	3.6	3.3 3.5	151	314	69	0	33
NPCC-New England	Jun. 24	19:00	26.6	24.7 26.4	566	142	180	1,412	1,963
NPCC-New York	Jun. 24	19:00	32	30.0 31.7	1,256	446	164	243	1,372
NPCC-Ontario	Jun. 24	19:00	24.9	21.0 24.5	607	742	39	66	1,532
NPCC-Québec	Aug. 11	18:00	22.7	22.3 23.3	790	885	0	0	5,029
PJM	Jun. 23	18:00	160.7	146.2 158.7	4,515	1,855	7,730	6,244	15,945

[41] Assessing the U.S. Temperature and Precipitation Analysis in August 2025 | News | National Centers for Environmental Information (NCEI)

[42] Rapid Extreme Weather Attribution system: Top heat events of summer 2025 – ClimateData.ca

[43] See NERC Bulk Power Systems Awareness update to the Reliability and Security Technical Committee on September 10, 2025.

[44] See NERC's *2026 Summer Reliability Assessment* for capacity and energy performance and operating narratives for each Interconnection (p. 52–56).

Table 3.3: 2025 Summer Demand and Generation Summary at Peak Demand

Assessment Area	Actual Peak Demand[1]			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)
	Date	Time	GW						
SERC-C	Jul. 28	18:00	43.2	41.9 45.7	84	370	714	1,053	701
SERC-E	Jun. 24	17:00	44.8	42.5 45.7	0	0	3,200	5,022	2,407
SERC-FP	Jul, 28	17:00	54.6	49.8 50.8	0	0	8,035	5,749	1,599
SERC-SE	Jul. 28	16:00	46.4	45.7 55.9	0	0	3,366	7,728	1,380
TRE-ERCOT	Aug. 8	18:00	83.7	81.9 88.1	14,509	9,396	16,961	22,962	11,095
WECC-AB	Aug. 27	0:00 UTC	12.0	12.2 12.7	2,870	796	32	1,480	N/A
WECC-BC	Aug. 13	01:00 UTC	9.8	9.3 10.0	293	149	4.8	0	N/A
WECC-CA	Aug. 22	02:00 UTC	54	54.1 64.3	1,744	1,207	5,064	14,756	1,063
WECC-MX	Aug. 7	0:00 UTC	3.5	3.8 4.1	2.5	50	296	227	N/A
WECC-NW	Aug. 13	01:00 UTC	29.8	29.1 32.7	1,054	3,107	1,398	666	1,825
WECC-RM	Jul. 9	00:00 UTC	13.4	13.8 15.0	2,313	1,359	1,571	1,669	1,954
WECC-Basin	Jul. 9	01:00 UTC	13.8	13.6 15.0	931	911	2,660	2,231	0
WECC-SW	Aug. 8	01:00 UTC	36.9	35.1 39.0	1,230	1,091	4,472	4,293	2,323

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 the assessment areas.

[2] See NERC *2025 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 *2025 SRA* for the projected peak hour, actual peak hour can impact solar contribution[4] Values from NERC GADS for the 2025 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 *2025 SRA*.

*Values include both maintenance and forced outages.

**Canadian assessment areas report to GADS on a voluntary basis, which can contribute to the absence of some values in certain assessment areas.

Changes in the Peak Resource Mix Over the Past 10 Years

The generation resource mix is changing as older nuclear and fossil-fired generators retire and natural-gas-fired generators and wind and solar PV resources are built (**Table 3.4**). Over the past 10 years, the BPS has reduced its on-peak[45] capacity of coal-fired generation by almost 118 GW and reduced its capacity of nuclear generation by 6.6 GW. During this time, the BPS added on-peak generation capacity: 57.6 GW of natural gas, 20.5 GW of wind, and 65 GW of solar PV.[46] **Table 3.4** shows the resource contribution to meeting the seasonal peaks for years 2015 and 2025. The lower solar contribution to meeting the Winter 2025 peak is offset by increased gas generation and lower peak demand.

Table 3.4: Generation Resource Capacity by Fuel Type

Generation Fuel Type	Summer				Winter			
	2015 On-Peak		2025 On-Peak		2015 On-Peak		2025 On-Peak	
	GW	Percent	GW	Percent	GW	Percent	GW	Percent
Coal	289.2	28.0%	172.1	15.8%	286.6	27.4%	172.7	16.2%
Natural Gas	418.1	40.5%	489.0	44.9%	437.2	41.8%	512.9	48.2%
Hydro	128.9	12.5%	135.3	12.4%	128.9	12.3%	137.9	13.0%
Nuclear	112.2	10.9%	105.4	9.7%	112.2	10.7%	107.1	10.1%
Oil	48.1	4.7%	28.2	2.6%	51.2	4.9%	30.2	2.8%
Wind	13.0	1.3%	37.4	3.4%	13.6	1.3%	44.0	4.1%
Solar PV	3.9	0.4%	77.8	7.1%	0.6	0.1%	13.5	1.3%
Other	19.8	1.9%	44.2	4.1%	16.8	1.6%	45.3	4.3%
Total:	**1,033.3**	**100.0%**	**1,089.4**	**100.0%**	**1,047.0**	**100.0%**	**1,063.7**	**100.0%**

The resource mix and the pace at which it is changing varies considerably across different parts of the North American BPS. **Figure 3.5** provides an Interconnection-level view of the generation resource mix since 2015.

[45] Individual assessment areas may peak in either the Winter or Summer season and thus on-peak in this context is the sum of the individual areas' non-coincident seasonal peak.

[46] Data obtained from NERC long-term reliability assessments

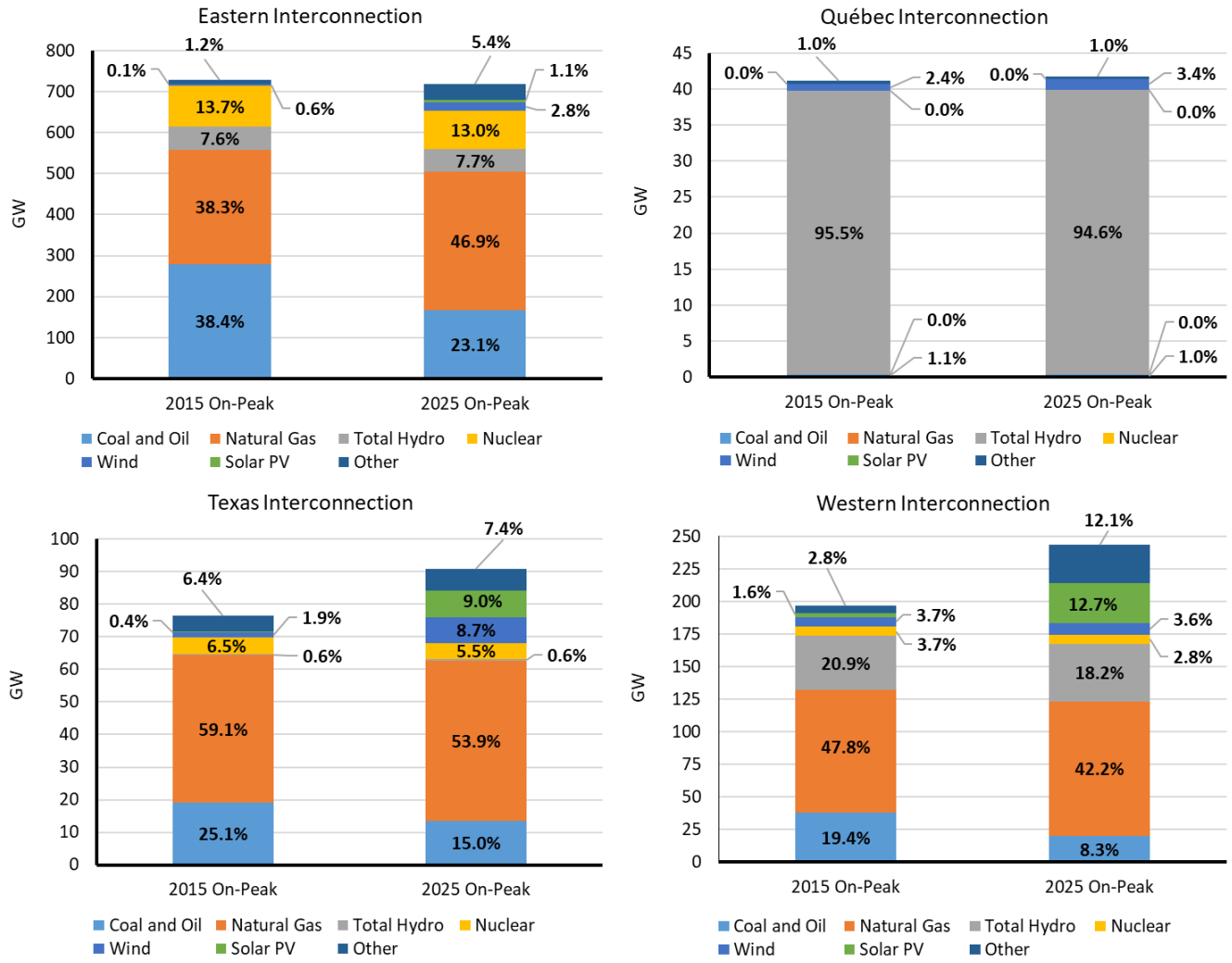


Figure 3.5: 2015 and 2025 Capacity Resource Mix by Interconnection

The growth of battery energy storage systems (BESS) arrived at an inflection point in 2025. **Figure 3.6** below shows the recent growth in both nameplate and on-peak capacity for battery storage across all Interconnections. NERC's LTRA reports on both the current generation resource mix and projections for the next 10 years for each of the 20 assessment areas within the four Interconnections that encompass the North American BPS. As the *2025 LTRA*[47] notes, the shift toward a more variable resource mix continues. One key insight from the *2025 LTRA* is that solar PV is no longer the sole, predominant generation type planned over the next 10 years. New battery resource projects have grown to match solar projections, and, together, solar and battery capacity additions represent two-thirds of the Tier 1 and Tier 2 resources over the 10-year LTRA study period.

[47] *Long-Term Reliability Assessment*, 2025

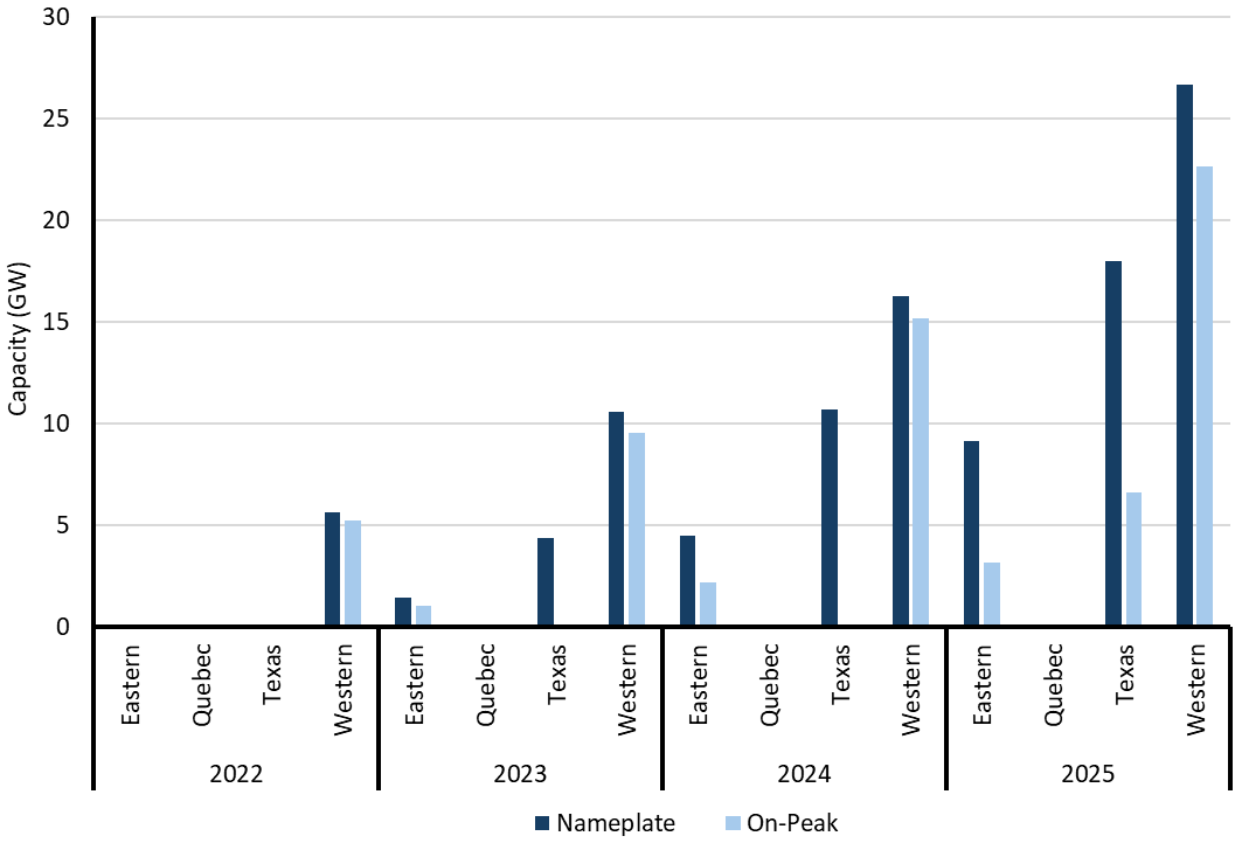
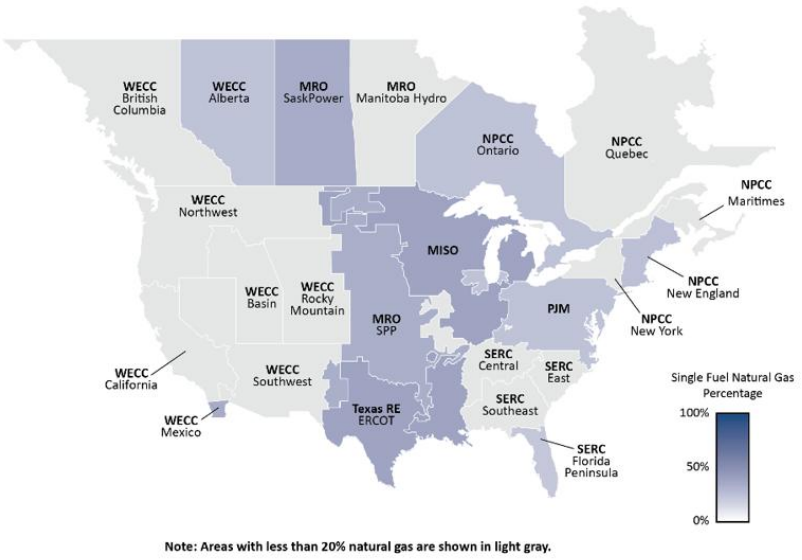


Figure 3.6: 2022–2025 Battery and Hybrid Capacity by Interconnection[48]

Critical Infrastructure Interdependencies

The natural gas and electric systems are constituent parts of an interconnected energy delivery system in North America. While natural-gas-fired generation is important in all seasons, it is especially vital to meet electricity demand in winter when solar and battery resources have less capability than in other seasons. Natural gas-fired generators can be exposed to risk of fuel supply curtailments in winter for a variety of reasons. One mitigation strategy used by generators in some areas is to have dual-fuel capability and maintain supplies of backup fuels. Single-fueled generators currently make up a large portion of the winter peak generating capacity in many parts of the BPS (**Figure 3.7**). These generators are at risk of outages or derates when fuel supplies are limited.

[48] Includes hybrid generation



Single-Fuel Natural-Gas-Fired Generation

	Winter Capacity (GW)	Contribution to Total Winter Resource Mix
MISO	63.9	38%
TRE-ERCOT	53.0	38%
WECC-MX	2.2	34%
MRO-SaskPower	2.5	34%
SPP	33.4	32%
NPCC-New England	12.1	24%
PJM	60.9	23%
WECC-AB	13.9	23%
NPCC-Ontario	8.0	23%
SERC-FP	45.6	21%
WECC-CA	35.9	18%
WECC-SW	21.5	17%
WECC-Basin	4.9	16%
WECC-RM	6.2	14%
SERC-C	17.0	13%
SERC-SE	21.5	13%
WECC-NW	8.7	12%
SERC-E	11.3	9%
NPCC-New York	5.0	8%
NPCC-Maritimes	0.5	7%
MRO-Manitoba	0.3	4%
WECC-BC	0.1	1%
NPCC-Quebec	0.0	0%

Figure 3.7: Single-Fuel Natural-Gas-Fired Generation Capacity Contribution to the Winter Generation Mix in 2025[49]

January 2025 Gas-Electric System Performance

The arctic events in January 2025 presented challenging conditions for the natural gas and electric systems, requiring close coordination between operators. A review of BPS and natural gas system performance following the January winter storms found notable improvement in the delivery of natural gas to BPS generators since winter storms Elliott and Uri with overall less natural gas production decline during cold weather and fewer natural gas infrastructure force majeures.[50] BPS generator outages climbed during the extreme cold due to equipment freezing issues and some gas supply issues.[51] The January 2025 arctic events demonstrated again how closely linked the reliability of the BPS is to natural gas supplies and infrastructure. Because natural gas infrastructure freeze protection mitigations are voluntary for the natural gas industry in most of North America, protections can be unevenly applied, resulting in continued supply risks during extreme conditions. Furthermore, timing misalignments between the natural gas and electric markets continue to challenge generator fuel procurement in advance of severe winter conditions that occur over winter holiday weekends.

Call to Action

NERC developed an Electricity-Natural Gas Strategy[52] to identify, assess, and facilitate ongoing and future treatment of the risks that arise from the growing reliance on natural gas for electricity generation. More information on NERC's response to the risks associated with gas-electric interdependence is provided on the NERC Reliability Initiatives[53] page.

Increasing Complexity of Protection and Control Systems

Together with the progression of interconnected power generation, transmission, and distribution assets, the landscape of automated tools and systems has transformed. This evolution spans an array of digital information platforms and microprocessor-driven devices, fostering a technologically diverse environment wherein operators can wield unprecedented control from virtually any location at a fraction of the historical

[49] *2025–2026 Winter Reliability Assessment*
[50] See *January 2025 Arctic Events | A System Performance Review*, April 2025
[51] PJM January 2025 Cold Weather Operations Presentation
[52] Electricity-Natural Gas Strategy
[53] Reliability Initiatives

cost. When meticulously designed and executed, these automated tools offer a means to enhance the reliable and secure use of the technologies and concepts in the BPS. However, the proliferation of these systems introduces an increasing web of rules, algorithms, and interdependencies that amplify the intricacy of operation. The swift decision-making capabilities of modern relays, tripping circuits, or initiating alternative actions within milliseconds epitomize the accelerated pace at which these systems must navigate intricate operational scenarios. The increasing integration of inverter-based resources (IBR) also expands this complexity, requiring the deployment of additional automated tools and systems. Navigating this expanding labyrinth demands not only vigilant maintenance, prudent asset replacement, and strategic upgrades but also a nuanced understanding of the dynamic interplay between diverse system components. As the scope and scale of these challenges continue to increase, it is imperative to cultivate agile, adaptive solutions.

Protection System Misoperation Trends

Figure 3.8 presents the annual misoperation rates across all Regional Entities and separately for each Regional Entity over the last five years. The comparison of the misoperation rate of the first four years to the most recent year shows a statistically significant decreasing trend for MRO. There is no statistically significant trend for other Regional Entities nor for the ERO as a whole. The overall count of misoperations in 2025 was the lowest over the past five years (**Table 3.4**).

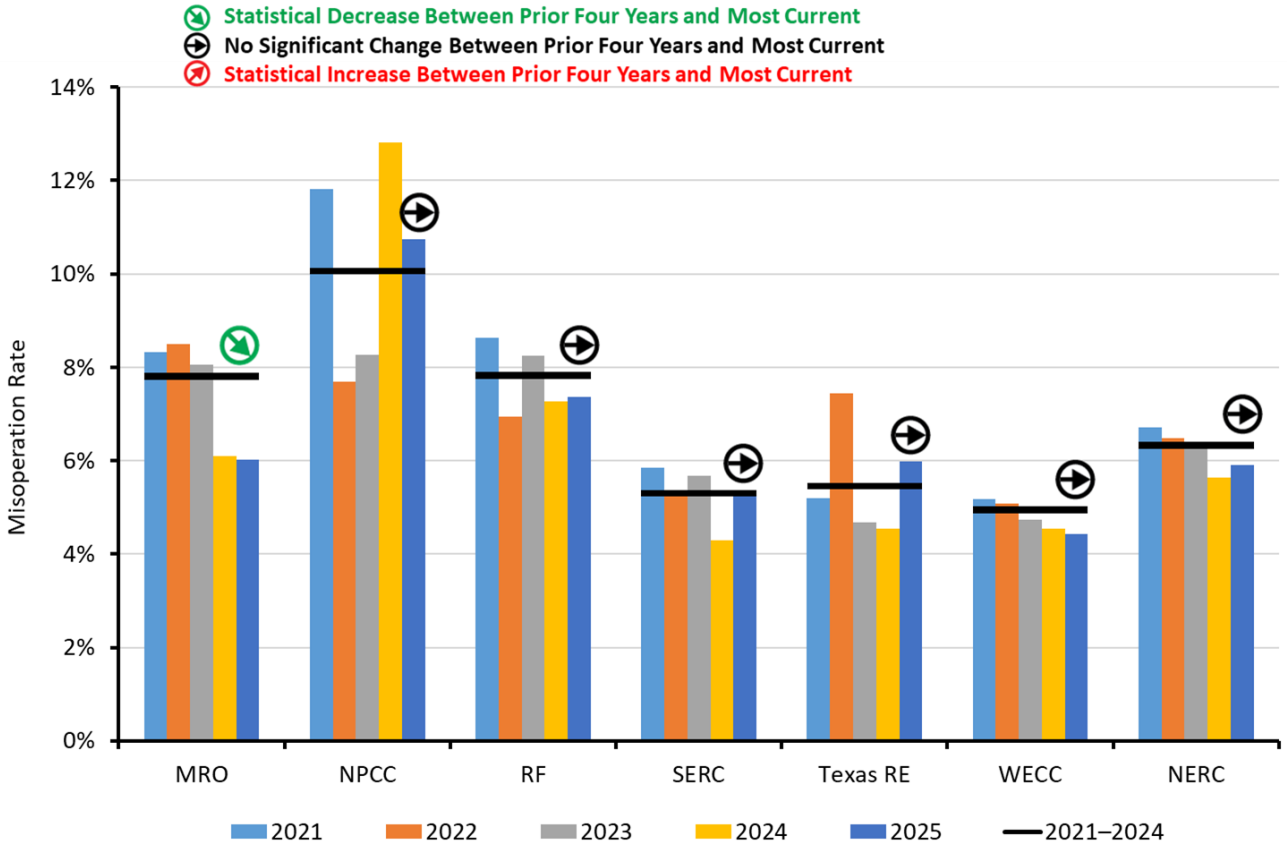


Figure 3.8: Changes and Trends in the Annual Misoperations Rate by Regional Entity[54]

[54] M-9, Protection System Misoperations Rate

Table 3.5: Five-Year Protection System Operations and Misoperations 2021–2025										
Area	Protection System Operations					Misoperations				
	2021	2022	2023	2024	2025	2021	2022	2023	2024	2025
All Regional Entities	17,454	17,804	17,871	19,325	18,397	1,172	1,153	1,118	1,089	1,087
MRO	2,618	3,238	2,977	3,097	3,267	218	275	240	189	197
NPCC	1,362	1,664	1,752	1,521	1,275	161	128	145	195	137
RF	1,867	2,061	1,867	1,843	2,010	161	143	154	134	148
SERC	4,617	4,775	4,954	5,701	5,058	270	252	281	245	265
Texas RE	2,599	1,991	2,183	2,461	2,542	135	148	102	112	152
WECC	4,391	4,075	4,138	4,702	4,245	227	207	196	214	188

Leading Causes of Misoperations

Figure 3.9 shows the distribution of misoperation causes over the past five years. Incorrect settings and relay failures/malfunctions remain the most common causes of misoperations. While a relative increase in Unknown/Unexplainable occurred from 2024 to 2025, historically the misoperation rate for this cause code decreases as ongoing investigations reveal additional information and corrective action plans (CAP) remedy the situations causing the misoperations. There were minimal changes in the relative frequency of other causes from 2024 to 2025.

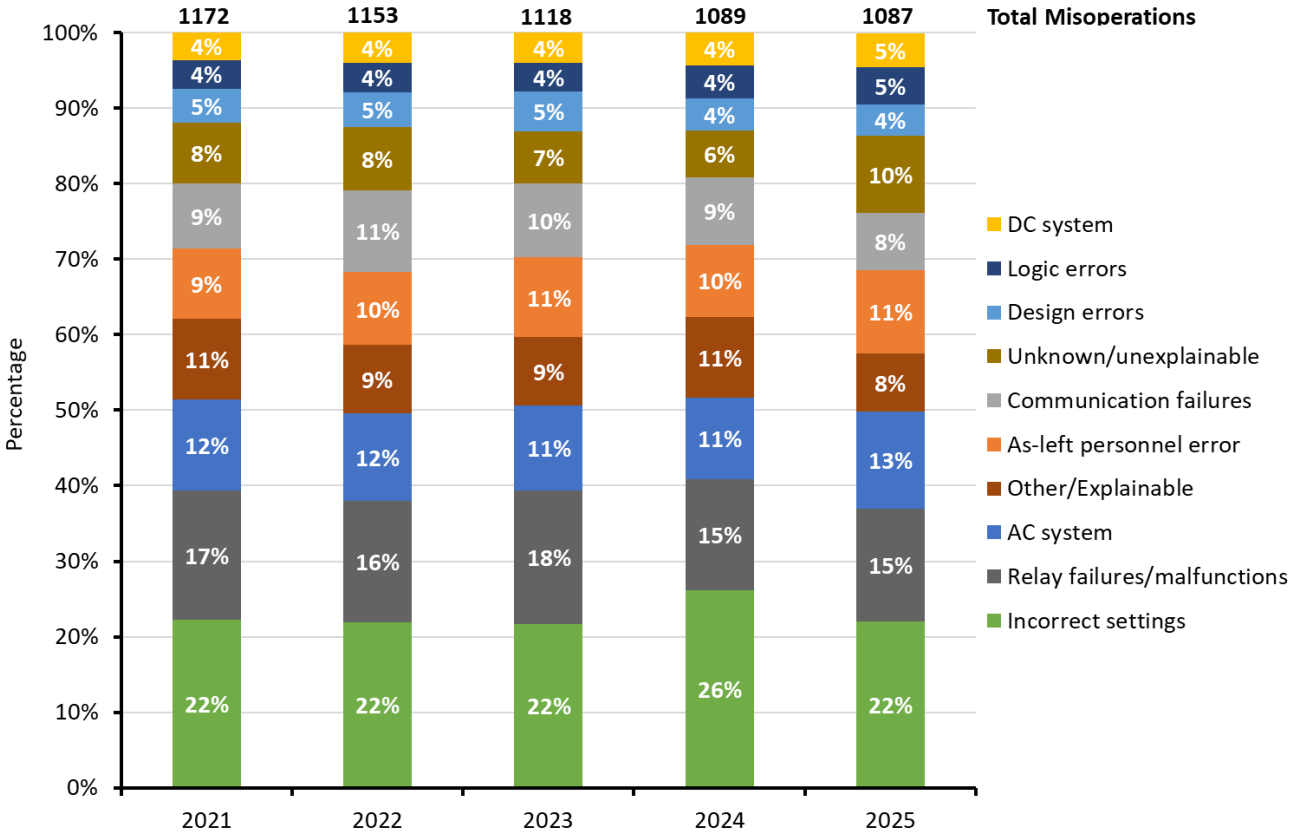


Figure 3.9: Percentage of Misoperations by Cause Code (2021–2025)

Misoperation Impact Score

The misoperation impact score measures the estimated impact of each misoperation on the BES, which is then aggregated to assess overall performance. This is done by summing weighted values for the facility voltage class, equipment type, cause, and category to determine the event's impact to BES reliability.[55] The maximum score of 1.0 implies the worst impact an event is projected to have on the BES, while a minimum score of 0.3034 reflects the least impact an event is projected to have on the BES.

In 2025, there was a statistically significant increase in the average misoperation impact score compared to the prior four years for Texas RE and NERC-wide (**Figure 3.10**). No statistically significant change occurred for any other Regional Entity. Further analysis identified that the Texas RE increase was primarily driven by an increase in misoperations reported by new Generator Owners (GO), increasing misoperations on 345 kV equipment (the highest voltage in the region) and the use of the "unknown" cause code.

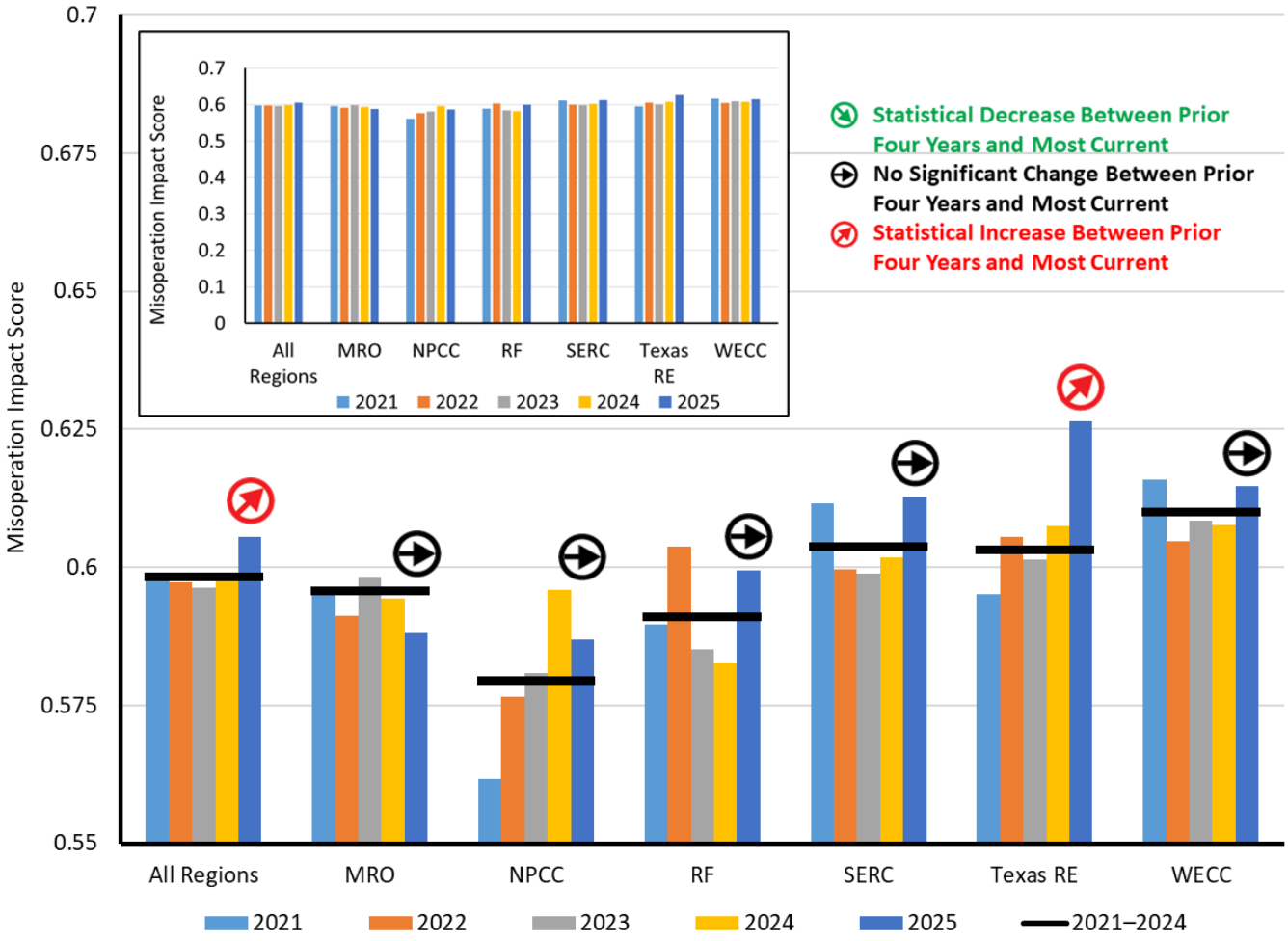


Figure 3.10: Misoperation Impact Score

Protection System Failures Leading to Transmission Outages

Protection system failures may result from or be the cause of transmission circuit outages, unnecessarily removing equipment from service. AC circuits saw a slight decrease in the number of outages due to protection system failures in 2025, but this decrease was not statistically significant. Transformers saw a statistically significant decrease in the number of outages for 2025 (**Figure 3.11**).

[55] Misoperations Impact Score

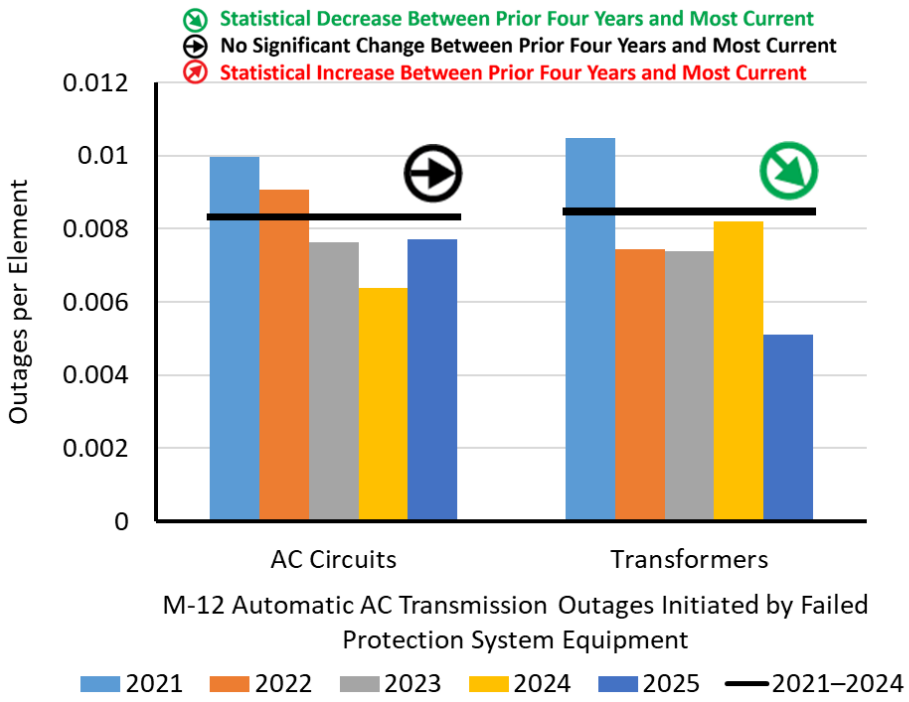


Figure 3.11: Failed Protection System Equipment Outages[56]

Event-Related Misoperations[57]

An analysis of events meeting published criteria[58] reported through the ERO Event Analysis Process (EAP) found that there were 51 transmission-related events in 2025, 32 of which (63%) involved misoperations (**Figure 3.12**). In comparison, 2024 saw 60 transmission-related events, of which 34 (57%) had associated misoperations. While the percentage of events with misoperations increased, the overall numbers for events and misoperations continue to decrease. This reduction is likely attributable in part to the ERO Enterprise and industry stakeholder efforts to reduce protection system misoperations through initiatives such as various task forces, workshops, and analytical efforts.

[56] M-12, Automatic AC Transmission Outages Initiated by Failed Protection System Equipment

[57] When reviewing ERO Event Analysis misoperations data, it is important to differentiate between it and analysis of MIDAS. These are different datasets and processes. This results in datasets that both relate to protection system misoperations and have overlap but often have significantly different sources, intents, and results.

[58] ERO Event Analysis Process - Version 5.0 (Effective January 1, 2024)

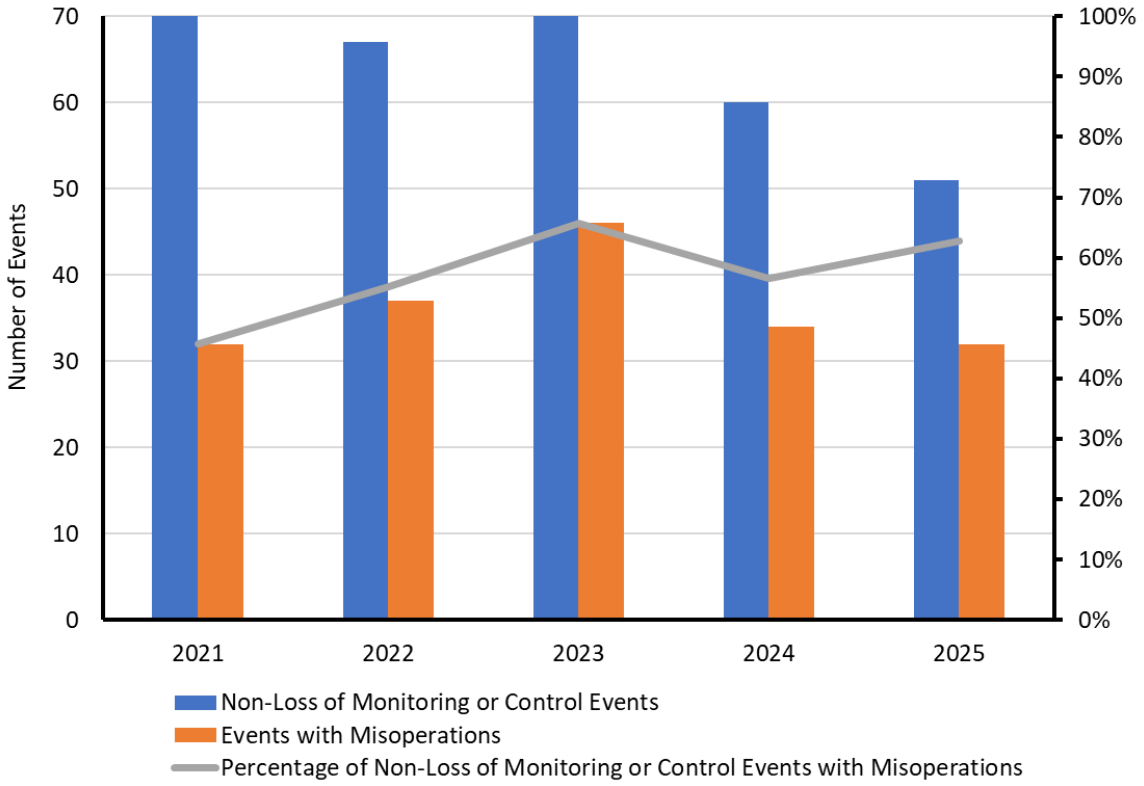


Figure 3.12: Events with Misoperations

Loss of Situational Awareness

The BPS operates in a dynamic environment where physical properties are constantly changing. To ensure reliability, it is essential to maintain situational awareness to anticipate events and respond effectively before or as they occur. Various tools are employed to support situational awareness and uphold BPS reliability. These tools include energy management systems (EMS), transmission outage planning, load forecasting, forecasting for geomagnetic disturbances and weather, data sharing with neighboring entities, and effective communication both within organizations and with adjacent systems.

Without the appropriate tools and up-to-date data, system operators may experience degraded situational awareness, which can affect their ability to make informed decisions about BPS reliability. Unexpected outages of communication systems or monitoring and control equipment, along with planned outages that lack proper coordination or oversight, can result in diminished visibility for operators. For system operators, the EMS is essential for maintaining situational awareness.

Impacts from the Loss of EMS

An EMS is a computer-based set of tools that system operators use to monitor, control, and optimize the performance of both the generation and transmission systems. The EMS enables operators to oversee and manage various factors, including frequency, the status (open or closed) of switching devices, and the real and reactive power flows on BES tie-lines and transmission facilities within their control area. Additionally, it provides oversight of critical EMS applications, such as state estimation (SE), RTCA, automatic generation control, and alarm management.

There were 36 categorized[59] events associated with an EMS in 2025; there were no categorized EMS-related events that caused loss of generation, transmission lines, or customer load. **Figure 3.13** illustrates a trend of the categorized EMS events by loss of EMS functions over the 2021–2025 period.

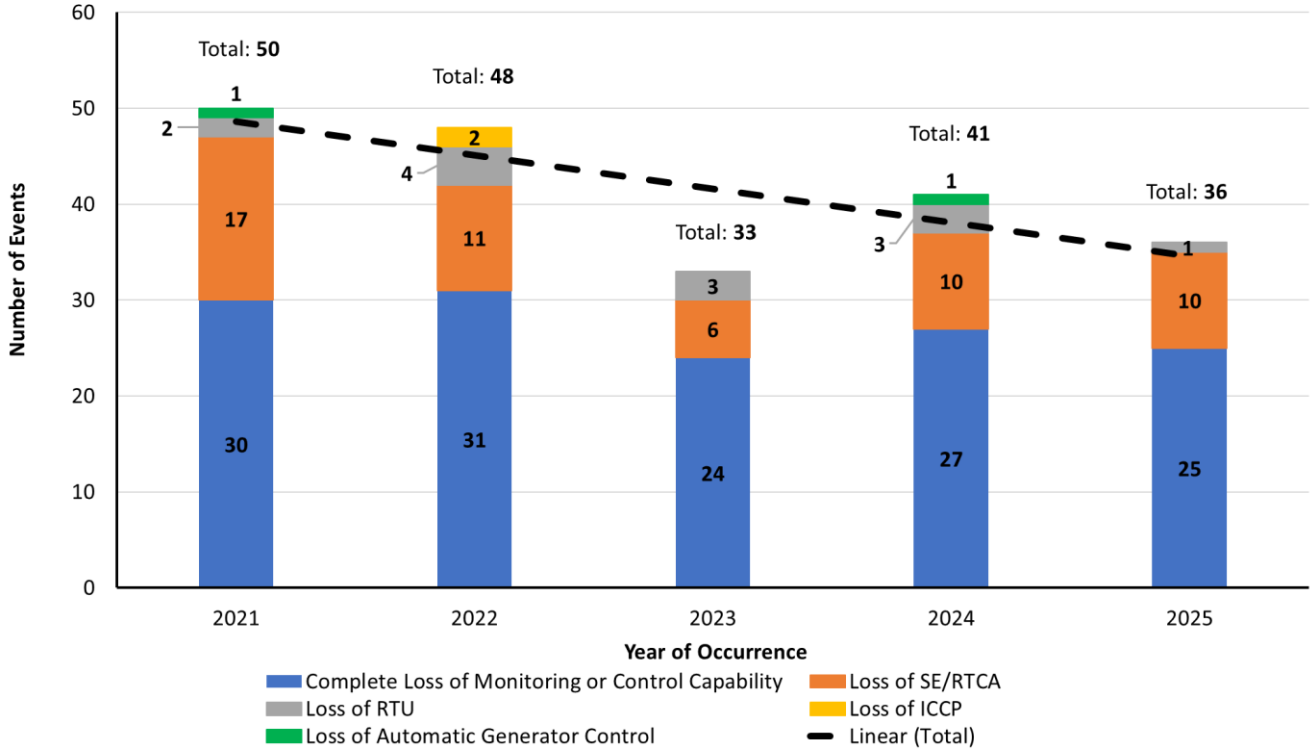


Figure 3.13: Number of EMS-Related Events (2021–2025)

In 2025, there were 25 categorized events involving a complete loss of monitoring[60] or control[61] capability. Two new themes to these events were identified:

- **Lack of effective communication between working departments**

  Maintenance typically involves the collaboration of various working departments, each playing a vital role in ensuring the efficiency and reliability of systems. Effective communication between these teams is crucial, especially when they handle the same equipment or systems that are interdependent. Prioritizing the clear exchange of work and maintenance schedules among departments will significantly reduce the likelihood of overlapping tasks that could negatively affect the utility's equipment and overall operations.

  To address the issues that have arisen from insufficient communication between working groups, a series of recommendations were developed during the analysis of the EMS events. These recommendations aim to foster a more cohesive approach to maintenance and ensure that all teams are informed and coordinated, ultimately enhancing operational safety and efficiency:

  - **Pre-Maintenance:** Planning and risk mitigation before the work starts.

[59] Category 1h. See Electric Reliability Organization Event Analysis Process Version 5.0
[60] The ability to accurately receive relevant information about the BPS in real time and evaluate system conditions using real-time data to assess existing (pre-contingency) and potential (post-contingency) operating conditions to maintain reliability of the BPS.
[61] The ability to take and/or direct actions to maintain the reliability of the BPS in real time via entity actions or by issuing operating instructions.

- Establish Communication Channels: Set up a bridge call with all stakeholders during the work to enable quick communication and coordination between groups.
- Move Active Server to Hot Standby: Move the active server to the hot standby site before work begins to reduce potential impact.
- Transfer Operational Activities: Shift all operational activities to an alternate location until the telecom work is finished.
- Verify Equipment Status: Perform a status check on all equipment prior to beginning any work.

- **During Maintenance:** Real-time monitoring and active communication
  - Monitor Progress: Supervision should actively monitor scheduled work to ensure no conflicts occur between groups.
  - Ensure Real-Time Status Updates: Communicate work status continuously between shifts and work groups, especially when multiple groups share the same equipment.
  - Implement Immediate Escalation: If schedules cannot be met, the group performing the work must immediately notify supervision and other scheduled teams.
- **Post-Maintenance:** Post-activity verification and closure
  - Ensure Final Status Handoff: Ensure the final equipment status is communicated to the next shift or work group before closing the bridge.
  - Verify System Reversion: Verify the system before moving traffic back to the primary servers.

- **Inadequate monitoring of operational support system resource usage**

  Operational support systems are vital for ensuring situational awareness and facilitating real-time decision-making across various operations. Unfortunately, several EMS events have arisen due to overwhelming demands for computer resources and the depletion of disk space. A recurring issue revealed through these incidents is the lack of a proactive framework for managing resource margins. This framework is essential for maintaining operating reserves akin to those established for ensuring BES reliability.

  To enhance the effectiveness of infrastructure monitoring, it is important to:

  - Incorporate a multi-tiered system of alert thresholds,
    - Perform a thorough trend analysis and detection of rate-of-change.
    - Enable early interventions to address issues before they escalate into emergencies.
  - Manage temporary file lifecycles and govern system logs as they are integral components of reliability controls.
    - Validate mechanism for cleanup in both normal operating conditions and potential failure scenarios.
    - Avoid unnecessary buildup of digital artifacts that could compromise system performance and reliability.

The loss of the categorized SE/RTCA was stable in 2025 (10 in both 2024 and 2025). External modeling was still the primary contributor to these events in 2025. Many entities have expanded their EMS models to monitor the impact of events and outages that occur beyond their own footprint. This expansion has raised

the risk of encountering inaccurate data points, faulty topology modeling, and communication issues that could lead to EMS events. Entities were encouraged to communicate changes to the BES, including the addition of new substations and new facilities and the removal of existing facilities, to neighboring entities well in advance. This proactive communication will allow neighboring entities to update their external EMS models promptly, ensuring that the data received through integrated communications control panel (ICCP) links is accurately aligned with the corresponding data points in their models.

Over the five-year period (2021–2025), the average partial or full function categorized EMS outage time (**Figure 3.14**) was 78 minutes, making the calculated EMS availability 99.994% during the term.

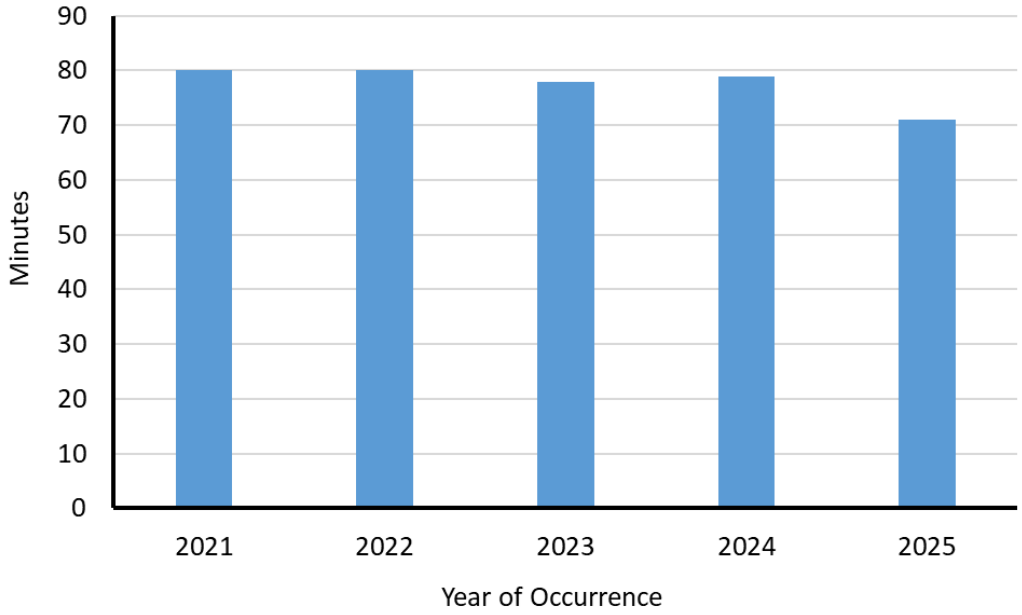


Figure 3.14: Average EMS Outage Time (2021–2025)

Largest Contributor to Loss of EMS

Reported EMS events can be grouped by the following attributes:

- **Software:** Software defects, modeling issues, database corruption, memory issues, etc.
- **Communications:** Device issues, less-than-adequate system interactions, etc.
- **Facility:** Loss of power to the control center or data center, fire alarm, ac failure, etc.
- **Maintenance:** System upgrades, job scoping, change management, software configuration, settings failure, etc.

Figure 3.15 illustrates that software was the primary contributor to EMS outages during the evaluation period from 2021 to 2025. This was followed by communication and maintenance challenges.

Figure 3.16 shows a trend in reported EMS events by the contributors of EMS function loss throughout the same period. In 2025, the main contributors were software and communications challenges, indicating a consistent overall trend from 2021 to 2025.

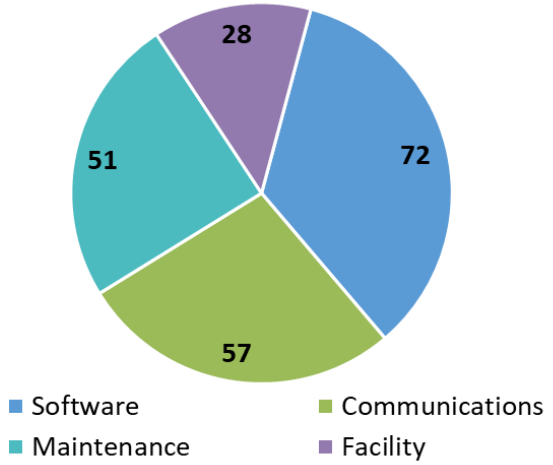


Figure 3.15: Overview of Contributors to Loss of EMS Functions (2021–2025)

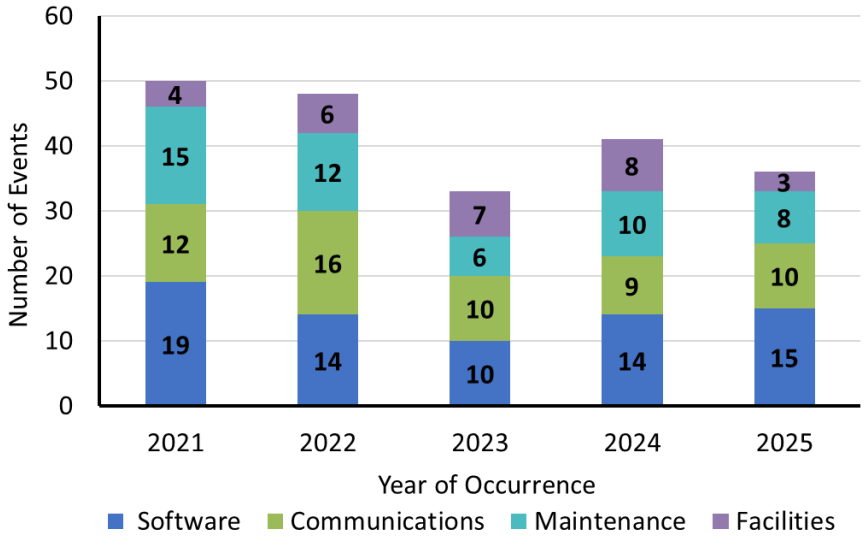


Figure 3.16: Trend of Contributors to Loss of EMS Functions (2021–2025)

Bugs often cause software failures, whether in vendor applications or in-house implementations. A software testing process should be in place to ensure that requirements are met. For effective systems and software assurance, a formal testing process model should be based on the development framework used to create the software. The testing scope should provide an assurance case for the software's operation under both known and unknown conditions and should include a data integrity check of the module. It is important to develop a team of dedicated and skilled in-house personnel who can troubleshoot and resolve issues. Providing in-house staff with real-time tools and training will enhance their knowledge and facilitate better knowledge transfer from software vendors.

Communications failure was typically related to device issues or less-than-adequate system interactions. The failure indicates that data exchange was degraded between substations and control rooms or between the entity and its RC/neighboring entities. An example is a spanning-tree protocol implementation in a network switch, causing a loop that generated an exceptionally high volume of traffic. The result was to shut down the communication network supporting the EMS. Another example is that the entity lost remote terminal unit (RTU) data from major substations as the telecom company's staff cut the fiber between the substations and the data center. Entities should maintain network devices on a schedule in accordance with

the latest vendor information, security bulletins, technical bulletins, and other recommended updates. Entities must also consider redesigning communications systems such that the most critical BES substations communicate simultaneously over entirely separate physical paths (and possibly separate vendors) to both control centers, eliminating the need for telecom company communication structure.

An analysis of the ERO EAP data reveals that 4.8% (or 10 out of 208) of the reportable EMS events lasting more than 30 minutes from 2021 to 2025 were linked to issues with external communication providers. This indicates that external communication provider-related problems are not a significant cause of EMS outages.

Human Causes

As human error can adversely impact the performance of the BPS and BES equipment, it is important to establish and adhere to robust processes to minimize the risks. In-depth analysis often identifies that primary human error causal factors are a result of latent errors as well as organizational and programmatic weaknesses. As the 2025 ERO *Reliability Risk Priorities Report*[62] states, "The BPS continues to evolve in complexity. The industry faces significant risk in staffing skilled workers due to new complexities, advanced technologies, the convergence of engineering and IT skillsets, and competition from other industries."

Transmission Outages

NERC's TADS collects transmission outage data, including on human error; human error as a cause of transmission outage is defined in the *TADS Data Reporting Instructions*.[63]

Statistical significance testing for automatic outages compared the event frequency of 2025 to the average event frequency of the prior four years. Statistical significance testing for operational outages was performed by outage frequency because they are not grouped into events. Automatic outage events involving human error improved a statistically significant amount, while operational outages did not change a significant amount for either ac circuits (**Figure 3.17**) or transformers (**Figure 3.18**).

[62] 2025 ERO Reliability Risk Priorities Report

[63] Human Error: relative human factor performance including any incorrect action traceable to employees and/or contractors of companies operating, maintaining, and/or assisting the Transmission Owner.

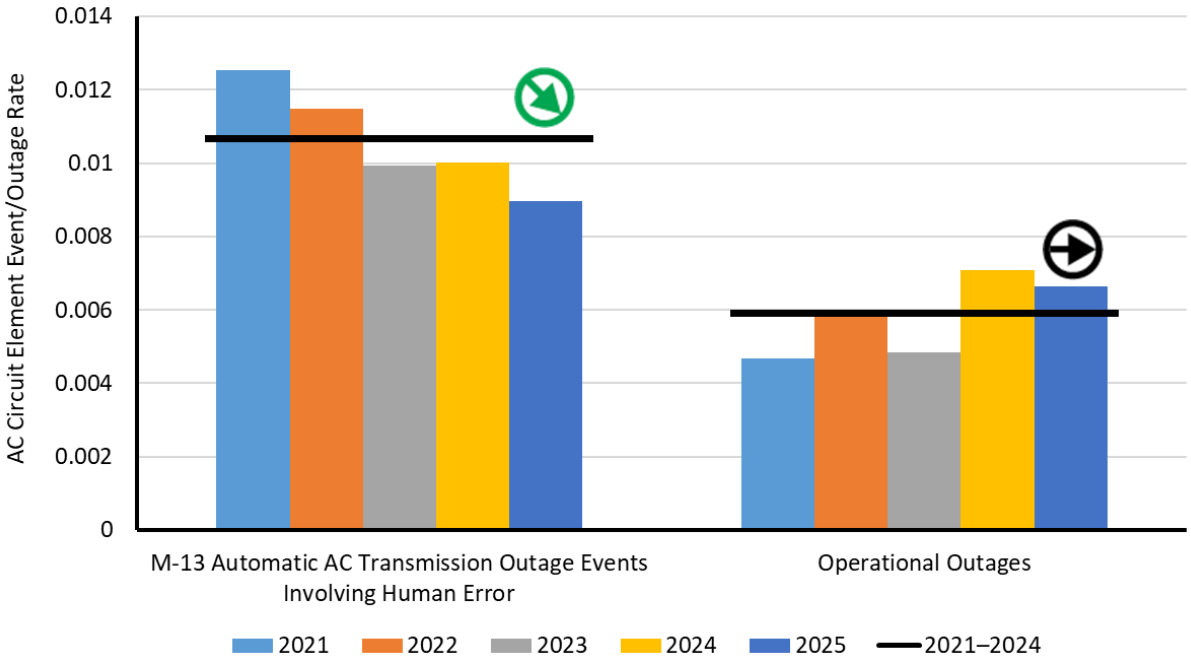


Figure 3.17: Automatic AC Transmission Outage Events and Operational Outages Involving Human Error[64]

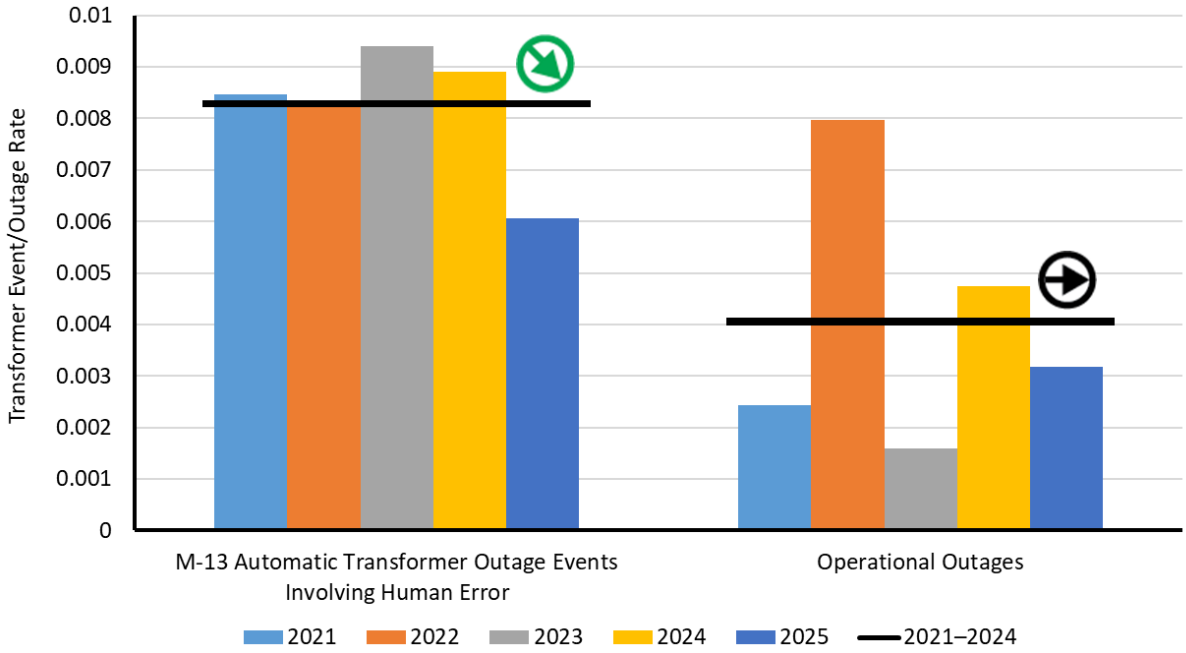


Figure 3.18: Automatic Transformer Outage Events and Operational Outages Involving Human Error[65]

Generation Outages

NERC's GADS collects generation availability data, including on outages associated with human error. While NERC continues tracking these outages, they historically represent approximately 1% of all forced outage

[64] M-13, Automatic AC Transmission Outage Events Involving Human Error
[65] Ibid.

events. Though there was a slight increase observed in 2025, it was not significant enough of a variance to warrant presentation.

Trends of Human and Organizational Root Causes[66,67]

In the ERO EAP, the cause sets of individual human performance and management/organization identify events or conditions that caused or contributed to the reported event. In 2025, organization/human performance was identified as the root cause for 41 processed events (**Figure 3.19**). This does not fully project the final 2025 number, as 66% of the 2025 events have been assigned a final root cause. The top five human and organizational performance root causes for the 2021–2025 period are listed in order of frequency below. These include the individual human error category, the management and organization performance category, and/or the design and engineering category:

- Design output scope less than adequate
- Job scoping did not identify special circumstances and/or conditions
- Management policy guidance or expectations are not well-defined, understood, or enforced
- Corrective action responses to a known or repetitive problem were untimely
- System interactions not considered or identified

Events from 2021 to 2025[68] saw the same top five human and organizational performance root cause identified events from 2020 to 2024.

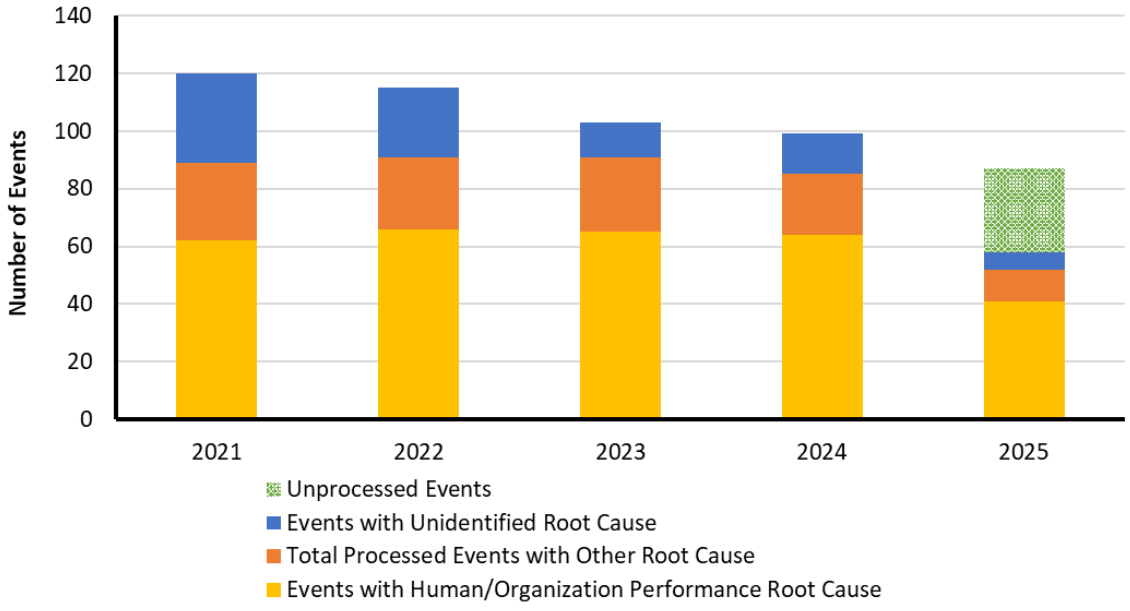


Figure 3.19: ERO EAP Organization/Human Performance Root Cause Identification by Year

Improvement opportunities exist for industry to increase BPS reliability through increased focus in the areas of management and organization performance and engineering and design. Management and organization

[66] Cause Code Assignment Process (Updated January 2026)

[67] When reviewing ERO Event Analysis Human and Organization Performance data, it is important to differentiate between it and GADS and TADS values. These are different datasets and processes. GADS and TADS are primarily focused on wholistic equipment availability and often not analyzed through the same methods nor depth used for the ERO event analysis (EA) process.

[68] Only includes 2025 events that have been processed as of data pull.

performance includes subcategories in which methods, actions, and/or practices are less than adequate. The engineering and design category includes ensuring that the engineering group employs a robust peer-review process to identify procedural errors and all considerations a design needs to be accountable. Some ways to improve human and organization performance would be to establish robust internal control mechanisms to ensure that processes and procedures such as peer reviews are in place to assist project leaders when considering the potential impacts and dependencies that may exist elsewhere on the system and to implement causal analysis when appropriate.

Protection System Misoperations

Human performance-related misoperations remain common, representing 42% of misoperations in 2025 and consisting of 11% As-Left Personnel Error, 4% Design Errors, 22% Incorrect Settings, and 5% Logic Errors (**Figure 3.9**). **Figure 3.20** additionally shows the number of misoperations related to human error by Regional Entity for the past five years.

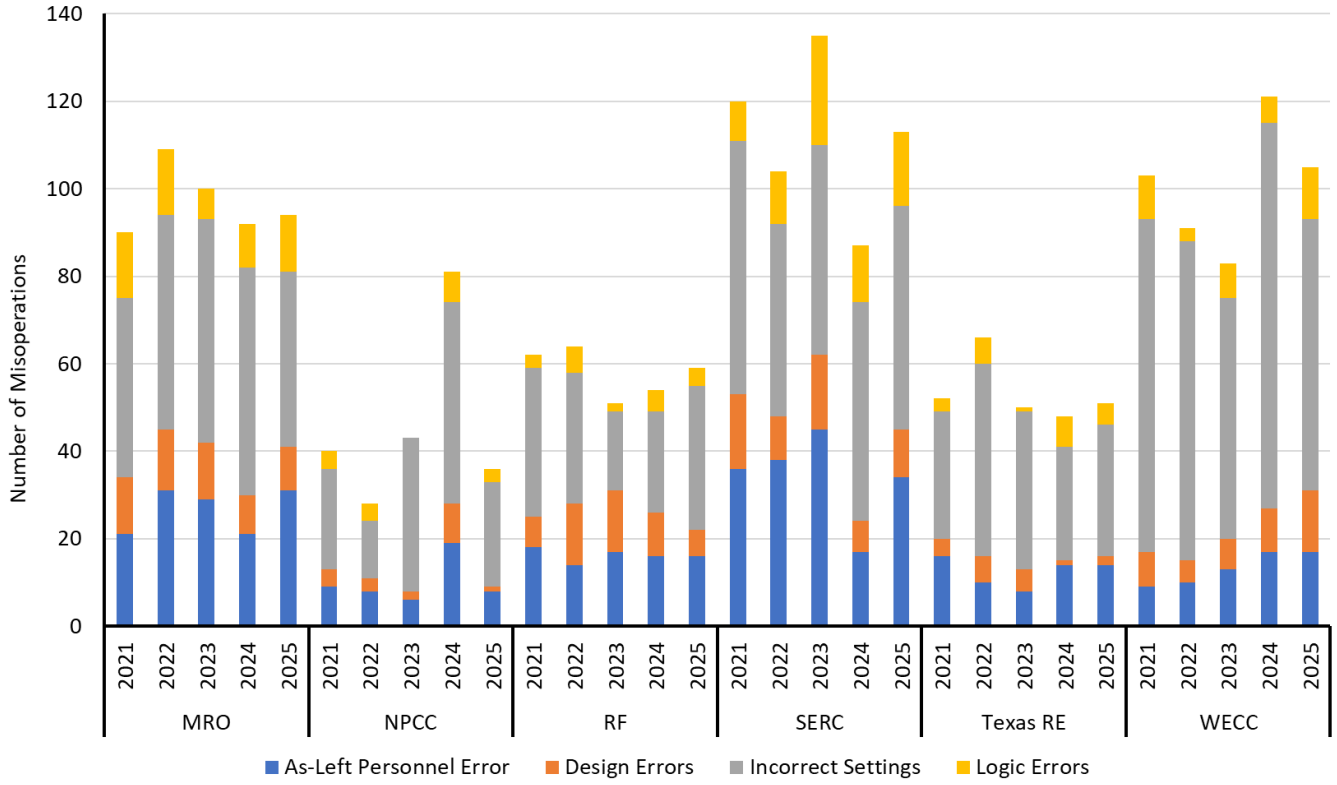


Figure 3.20: MIDAS Protection System Misoperations Due to Human Error by Regional Entity

Chapter 4: Grid Performance

Grid performance is evaluated through established reliability metrics and more in-depth analysis of specific aspects of the BPS:

- Reliability Metrics
- Frequency Response Performance
- Generation Performance and Availability
- Transmission Performance and Unavailability

Reliability Metrics

By calculating 2025 reliability metrics[69] and comparing the results to the previous years as well as the five-year average values, the reliability metrics discussed in this report can be categorized as either Improving, Stable, Monitor, or Actionable. Measuring and trending the relative state of the BPS and BES in this manner supports NERC's obligation to assess the capability of the BPS. **Table 4.1** shows the status of the reliability metrics and includes a reference to the specific metric.

Table 4.1: Reliability Indicators

Metric Name		Metric Performance Status
M-1: Reserve Margin		**Monitor: NPCC-Maritimes (Winter)**
M-2: Transmission-Related Events Resulting in Loss of Load (Excluding Weather)		**Monitor[70]**
M-3: System Voltage Performance		**Retired**
M-4: Interconnection Frequency Response	Eastern	**Improving**
	Texas	**Improving**
	Western	**Improving**
	Québec	**Stable**
M-4.1: Inertia and Rate-of-Change-of-Frequency	Eastern	**Improving**
	Texas	**Improving**
	Western	**Improving**
	Québec	**Actionable[71]**
M-5: Activation of Under Frequency Load Shedding		**Retired**
M-6: Disturbance Control Standard Failures		**Proposed Retirement**
M-7: Disturbance Control Events Greater than Most Severe Single Contingency		**Proposed Retirement**
M-8: Interconnection Reliability Operating Limit (IROL) Exceedance		**Monitor**
M-9: Protection System Misoperations Rate		**Stable**
M-10: Transmission Constraint Mitigation		**Retired**
M-11: Energy Emergency Alerts		**Improving**
M-12: Automatic AC Transmission Outages Initiated by Failed Protection System Equipment	AC Circuits	**Stable**

[69] Current Approved Reliability Metrics; Metrics M-3, M-5, and M-10 are retired.
[70] Average lost load increased, but number of events decreased.
[71] See 2025 Interconnection Frequency Response section for details.

Table 4.1: Reliability Indicators		
Metric Name		**Metric Performance Status**
	Transformers	**Improving**
M-13 Automatic AC Transmission Events Involving Human Error[72]	AC Circuits	**Improving**
	Transformers	**Improving**
M-14: Automatic AC Transmission Outages Initiated by Failed AC Substation Equipment	AC Circuits	**Stable**
	Transformers	**Monitor**
M-15: Automatic AC Transmission Outages Initiated by Failed AC Circuit Equipment (Number of Outages per 100 miles)		**Improving**
M-16: Transmission Element Availability Percentage and Unavailability Percentage	AC Circuits	**Stable**
	Transformers	**Monitor**
M-17: Transmission Outage Severity		**Stable**
M-18: TADS Physical Security Metric		**Stable**

Frequency Response Performance

2025 Interconnection Frequency Response

2025 analysis of frequency response performance and trends below indicates an adequate level of reliability. Further analysis is provided in NERC's *Frequency Response Annual Analysis* (FRAA).[73]

- For the stabilizing period (M4 metric), the EI, WI, and Texas Interconnection (TI) showed statistically significant improvements from 2021 through 2025, while the QI showed no statistically significant changes for the stabilizing period.
- For the arresting period (M4.1 metric), the EI, WI, and TI showed statistically significant improvements from 2021 through 2025, while the QI showed a statistically significant decline. It was noted in the 2024 SOR report that the decreasing trend in the arresting period metric for the QI was due to an overrepresentation of events in Summer 2023 (months that typically have lower inertia) compared to other years, in part due to the wildfire events in the region. A large number of events were also recorded in Summer 2025, which contributed to the declining trend. The QI has been experiencing low hydraulicity conditions since 2023. In 2025, this resulted in reduced energy exports and increased energy imports. Therefore, fewer hydro generating units were synchronized within the QI, particularly under summer light-load conditions, leading to lower system inertia during this period.
- For the underfrequency load shedding (UFLS) margin metric, the EI showed a statistically significant decline from 2021 through 2025. Although the decline is statistically significant, the magnitude of the decline, while measurable, is a very small magnitude. The year-over-year reduction in the mean and median UFLS margin values was only .003 Hz. During the five-year period, there have been changes to both the interconnection frequency response obligations (IFRO) and the minimum frequency bias settings, which will all have an impact on the UFLS margin metric. With UFLS starting

[72] Metric was revised in 2025 to evaluate the number of TADS events instead of outages. The change was made because a small number of events had resulted in a large number of outages. By tracking the frequency of human error events, the metric now tracks how often human error occurs instead of how many outages each instance happens to cause.

[73] 2025 FRAA Report

at .5 Hz off of nominal, the reduction is de minimis to reliability when the remaining margin to UFLS is taken into account.

- The number of valid events for the TI continues to decline. This was also noted in the 2024 SOR report. It was also noted in the 2024 SOR report that there was a declining trend for the number of events in the WI; however, the number of events measured in 2025 was back to within historical norms. This trend in the reduction of valid M4 events is suspected to be due to the retirement of large conventional generation as well as the ongoing integration of battery energy storage facilities in both Interconnections and is considered to be a positive indicator when considering impacts to Interconnection reliability.
- In both 2024 and 2025, there were multiple outlier events in the WI. The WI outlier events were reviewed and were not considered to be anomalous. This was also noted in the 2024 SOR report. These events represent the frequency response performance of the WI when a BA with a large battery energy storage system (BESS) fleet experiences a large resource loss. These events are becoming common place in both the WI and TI.

During the five-year period (**Table 4.2**), the WI had two events within the five-year period where the measured frequency response was less than the IFRO for the Interconnection. This was noted in the *2024 SOR*. Both events occurred in 2023 and had a starting frequency well above 60.00Hz and had a confirmed MW loss under 500 MW. These two factors combined eliminate any concerns that the WI frequency response is insufficient. The EI, TI, and QI did not have any events within the five-year period where the measured frequency response was less than the IFRO for the respective Interconnection.

Table 4.2: Five-Year Statistical Time Trend

Interconnection	M4 Stabilizing Period	M4.1 Arresting Period	Margin-C-UFLS	Comment
Eastern	Increasing	Increasing	Decreasing	No M4 events with FRM below IFRO
Texas	Increasing	Increasing	Increasing	No M4 events with FRM below IFRO
Western	Increasing	Increasing	Neither Increasing nor Decreasing	Two M4 events with FRM below IFRO in 2023
Québec	Neither Increasing nor Decreasing	Decreasing	Neither Increasing nor Decreasing	No M4 events with FRM below IFRO

Frequency response for all Interconnections indicates stable and improving performance for the stabilizing period as shown in **Table 4.3** below.

Table 4.3: 2025 Frequency Response Performance Statistics for Stabilizing Period										
2025 Operating Year Stabilizing Period Performance										
	Number of Events					Mean Frequency Response	Median	Minimum	Maximum	Number of events with FRM below the IFRO
	2021	2022	2023	2024	2025	MW per 0.1 Hz				
Eastern	29	46	47	44	37	2,824	2,443	1,107	6,784	0
Texas	44	33	39	23	22	1,634	1,376	961	3,509	0
Québec	42	22	65	61[74]	63	1,319	644	225	23,800	0
Western	43	30	28	15	29	2,953	2,600	1,256	7,650	0

During the arresting period, the goal is to arrest the frequency decline for credible contingencies before the activation of UFLS. The calculation for IFRO under BAL-003 is based on arresting the point C nadir before the first step of UFLS for resource contingencies at or above the resource loss protection criteria (RLPC)[75] for the Interconnection. Measuring and tracking the margin between the first step UFLS setpoint and the Point C nadir is an important indicator of risk for each Interconnection. **Figure 4.1** indicates the measurement periods used for analysis of the arresting period of events by looking at the frequency response between Value A and Point C as well as at the margin between Point C and the first step UFLS setpoint.

During the stabilizing period, the goal is to stabilize system frequency following a disturbance primarily due to generator governor action. **Figure 4.1** indicates the measurement periods used for analysis of the stabilizing period of events by looking at the frequency response between Value A and Value B.

Frequency response for the EI, WI, and TI indicates stable and improving performance for the arresting period for 2025. Frequency response for the QI indicates a declining trend for the arresting period for 2025 as shown in **Table 4.4** below.

Table 4.4: 2025 Frequency Response Performance Statistics for Arresting Period												
2025 Operating Year Arresting Performance												
	Number of Events					Mean Frequency Response	Median	Min	Max	Mean UFLS Margin	Median UFLS Margin	Min. UFLS Margin
	2021	2022	2023	2024	2025					For Loss of Generation M4 Events Only		
						MW per 0.1 Hz				Hz		
Eastern	29	46	47	44	37	2,104	1,980	1,036	3,400	0.452	0.451	0.439
Texas	44	33	39	23	22	786	764	504	1,382	0.608	0.610	0.544
Québec	42	22	65	63	63	119	123	51	196	1.078	1.149	0.649
Western	43	30	28	15	29	979	918	755	1,506	0.416	0.425	0.334

[74] GADS Events for 2024 has been updated

[75] BAL-003-2 specifies that the RLPC be based on the two largest potential resource losses in an Interconnection or the largest resource loss due to an N-2 RAS. This value is updated annually through the BAL-003-2 data collection process.

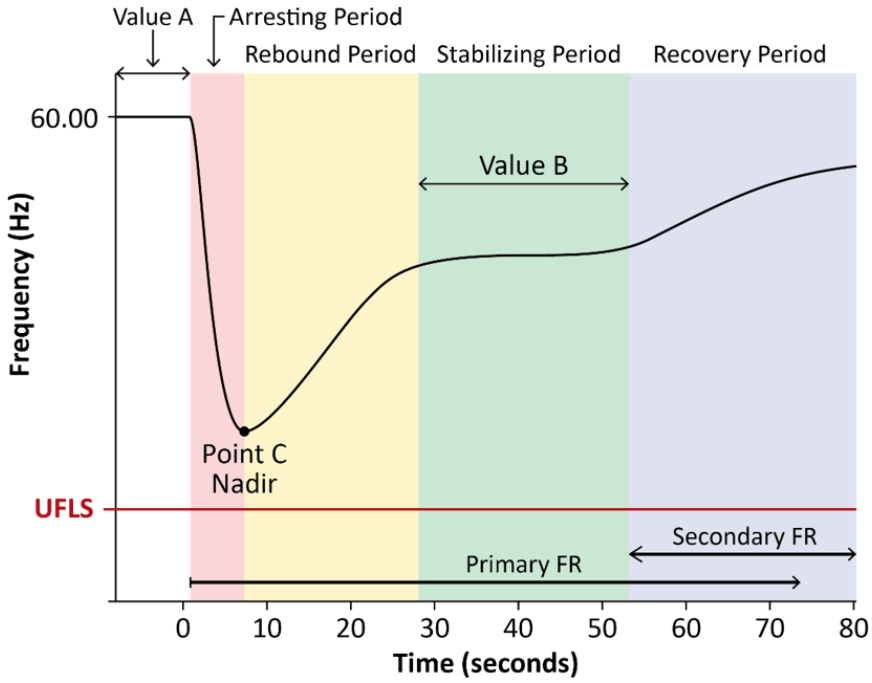


Figure 4.1: Frequency Response Methodology

Figure 4.2 represents an analysis of the arresting period of frequency response events. The Y-axis shows the percent UFLS margin from 100% (60 Hz) to 0% (first UFLS set point for the Interconnection). The X-axis represents the MW loss for the event, expressed as a percentage of the RLPC for the Interconnection. There were no events within the five-year period larger than the RLPC for any of the Interconnections. The largest events for the EI and TI were 50% as measured by percentage of RLPC. The largest events for the WI and QI were 88% and 96%, respectively, as measured by percentage of RLPC.

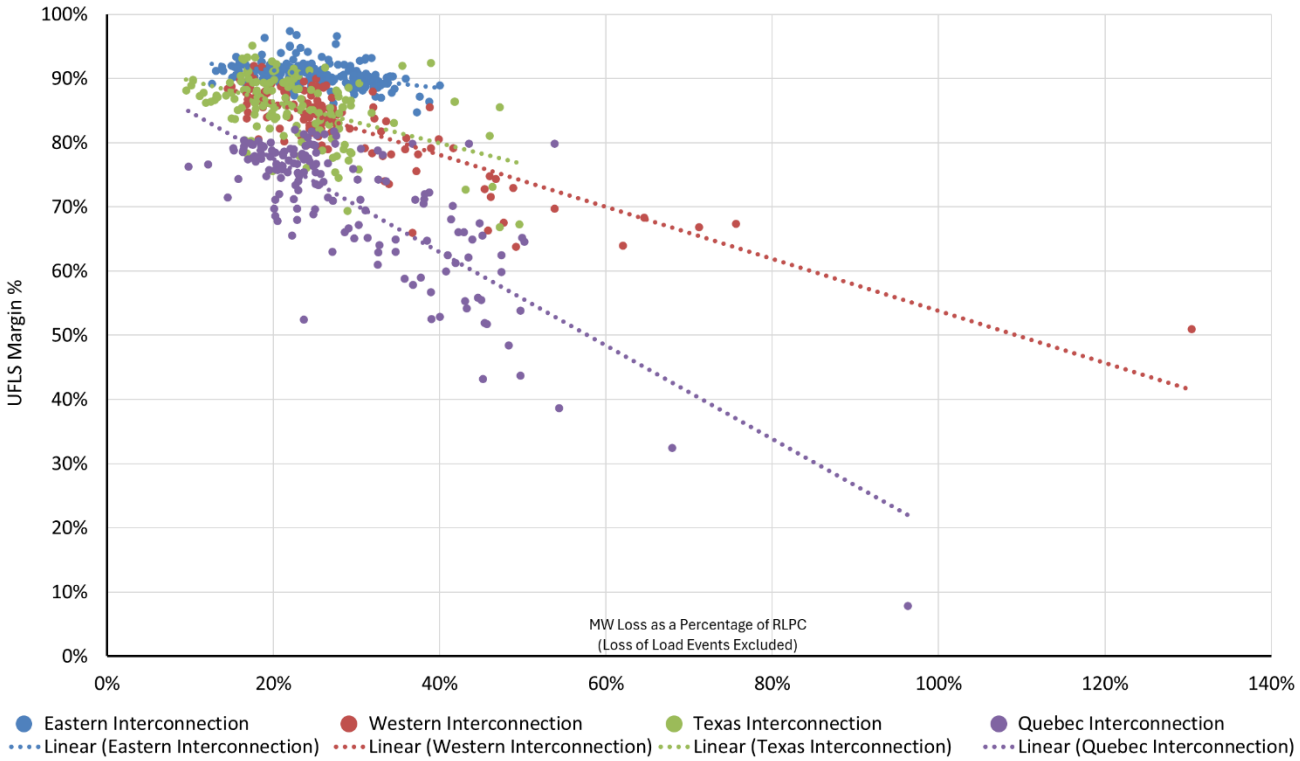


Figure 4.2: Operating Year 2021–2025 Qualified Frequency Disturbances and Remaining UFLS Margin

Interconnection Reliability Operating Limit Exceedances

2025 Performance and Trends

An IROL[76] is an SOL that, if exceeded, could lead to system instability, uncontrolled separation, or cascading that may adversely impact the reliability of the BES. The maximum time that an IROL can be exceeded is the IROL Tv. The IROL Tv must be less than or equal to 30 minutes. Each RC has a different methodology for determining IROLs based on the makeup of their area and what constitutes an operating condition that is less than desirable.

IROLs are established to ensure that corrective actions are taken to prevent and mitigate the exceedance of limits to either return to the Normal state or stay within the Alert state for certain conditions and contingencies that could otherwise cause the BPS to enter the extreme state, being at high risk of system instability, cascading, and uncontrolled separation.

The Texas and Western Interconnections both maintained stable trends with no IROL exceedances reported in 2025. In the Eastern–Québec Interconnections, there were 19 exceedances that lasted more than 10 minutes in 2025, more than the five-year rolling average of 11.8 exceedances as shown in **Figure 4.3**. The 10- to 20-minute range increased from a single exceedance in 2024 to 18 exceedances in 2025, while one exceedance lasted more than 20 minutes. The five-year average still declined slightly as year 2020 rolled off with 20 total exceedances.

[76] M-8, IROL Exceedance

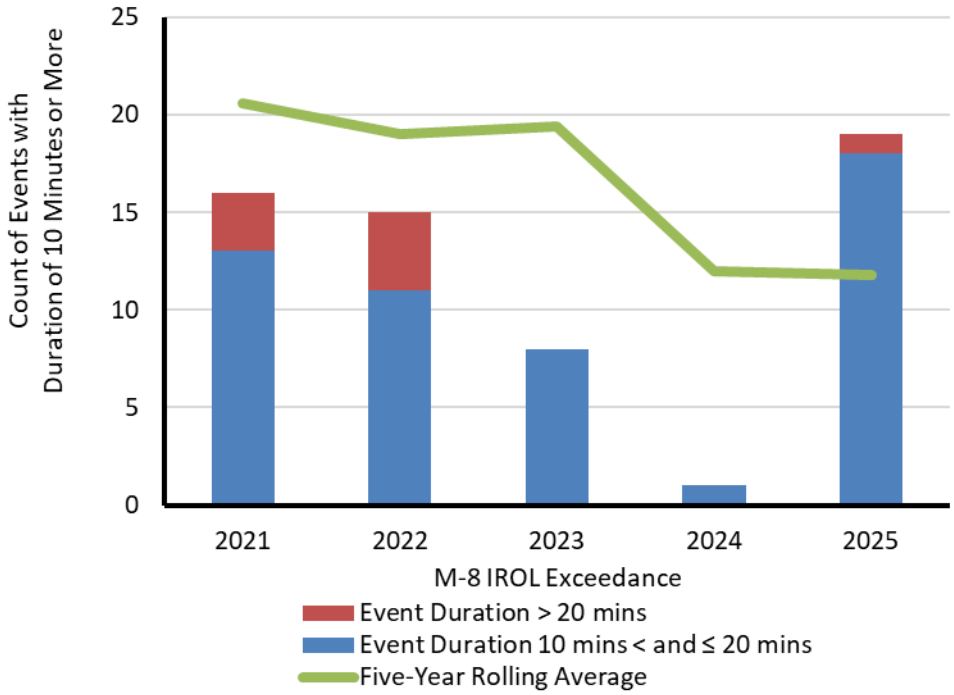


Figure 4.3: IROL Exceedance Counts

Generation Performance and Availability

GADS contains information that can be used to compute reliability measures, such as the weighted equivalent forced outage rate (WEFOR). GADS collects and stores unit operating information by pooling individual unit information, generating unit availability, performance, and calculated metrics.

Conventional Generation WEFOR

The horizontal lines in **Figure 4.4** show the annual WEFOR compared to the monthly WEFOR columns; the solid horizontal bar shows the WEFOR for all years in the analysis period of 8.1%. The 2025 WEFOR rate of 9.2% is a notable increase over 2024 (7.6%) and above recent historical norms in the 7–8% range.

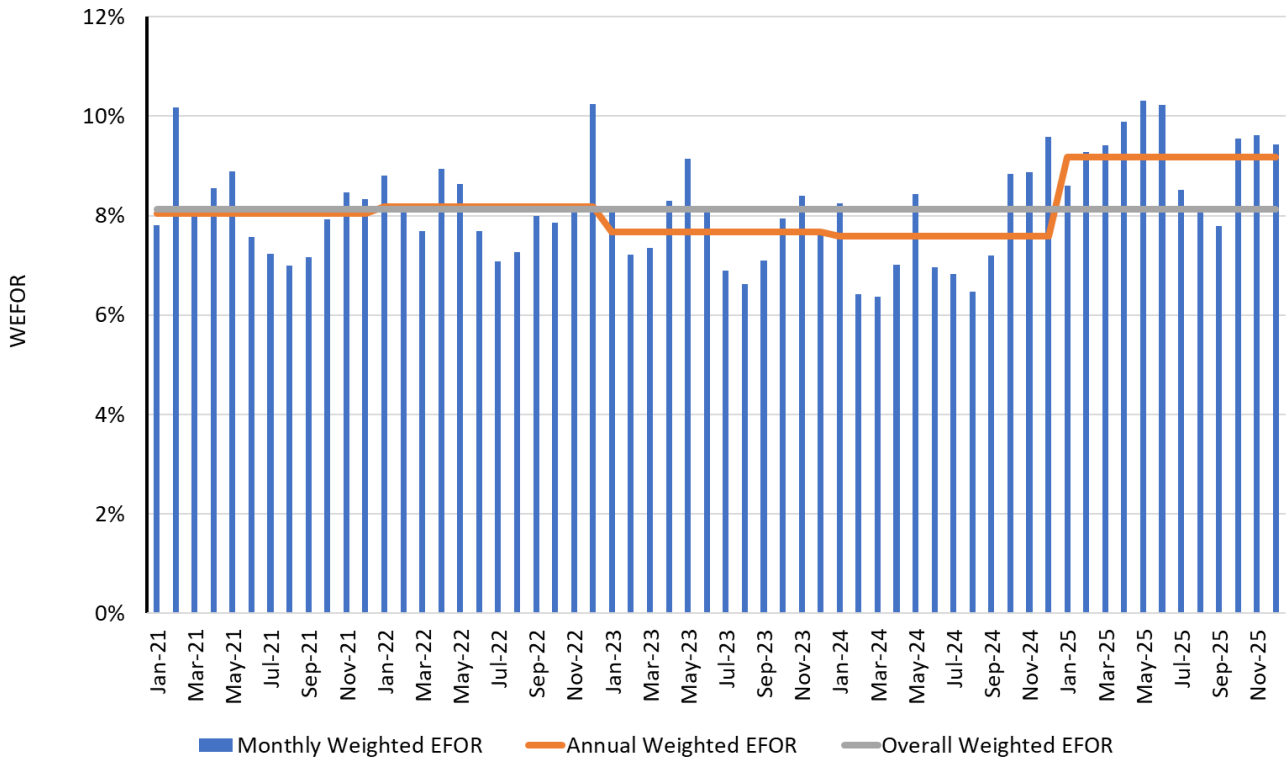


Figure 4.4: Monthly, Annual, and Five-Year WEFOR

Additional analysis identified that the increase is driven by combustion-based generators as shown in **Table 4.5**; further details are provided in the *2026 SOR Overview* report.

Table 4.5: Primary Fuel Type Year-Over-Year Change in MWh

Primary Fuel Type	2024 vs 2025 Year-Over-Year Change in GWh[77]	2024 WEFOR	2025 WEFOR
Gas - Steam Turbine	8,772	19.2%	22.4%
Gas - Simple Cycle Combustion Turbine	5,938	20.7%	22.8%
Gas – Simple Cycle w/Heat Recovery Steam Generator (HRSG)	-203	7.7%	7.0%
Combined Cycle	19,154	4.2%	5.7%
Coal	39,835	11.2%	14.1%
Oil - Steam Turbine	1,857	24.6%	25.6%
Oil - Combustion Turbine	2,427	48.2%	69.4%
Hydro	-3,171	8.4%	7.7%
Nuclear	-3,862	2.7%	2.2%
Other	-2,308	11.1%	8.4%
Total	68,440	7.6%	9.2%

[77] Measured by WEFOR numerator:
$\sum(([Forced\ Outage\ Hours] + [Equivalent\ Forced\ Derate\ Hours]) * [Net\ Maximum\ Capacity])$

The monthly WEFOR for major contributing fuel types is shown as a layered area chart with a relative capacity breakdown pie chart in **Figure 4.5**. The dashed line shows the monthly WEFOR of all fuel types reported to NERC, and the red line shows the mean outage rate of all fuel types reported to NERC over the five years in the analysis period. As stated above, in 2025, the annual WEFOR increased to 9.2%. Observing individual fuel types, coal experienced a fairly consistent increase in WEFOR throughout the year, simple cycle gas turbines experienced normal peak outage rates but with prolonged recovery, and combined cycle experienced both a baseline increase as well as two abnormal peak outage periods in early summer and early winter. These trends can be further contextualized by comparing the change in MWh of lost production due to forced unavailability from 2024 to 2025 in **Table 4.5**, examining each fuel's capacity percentage (**Figure 4.5**), and annual net actual generation (**Figure 4.6**).

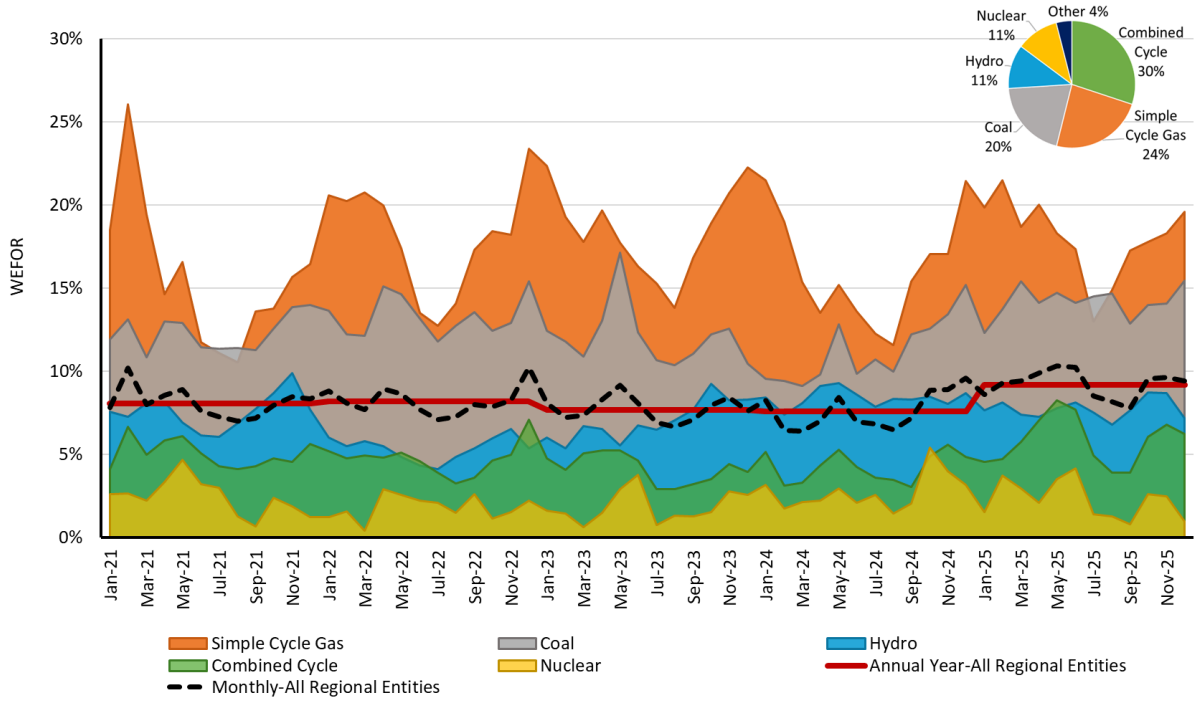


Figure 4.5: Five-Year WEFOR by Fuel Type and 2025 Resource Mix by Net Maximum Capacity

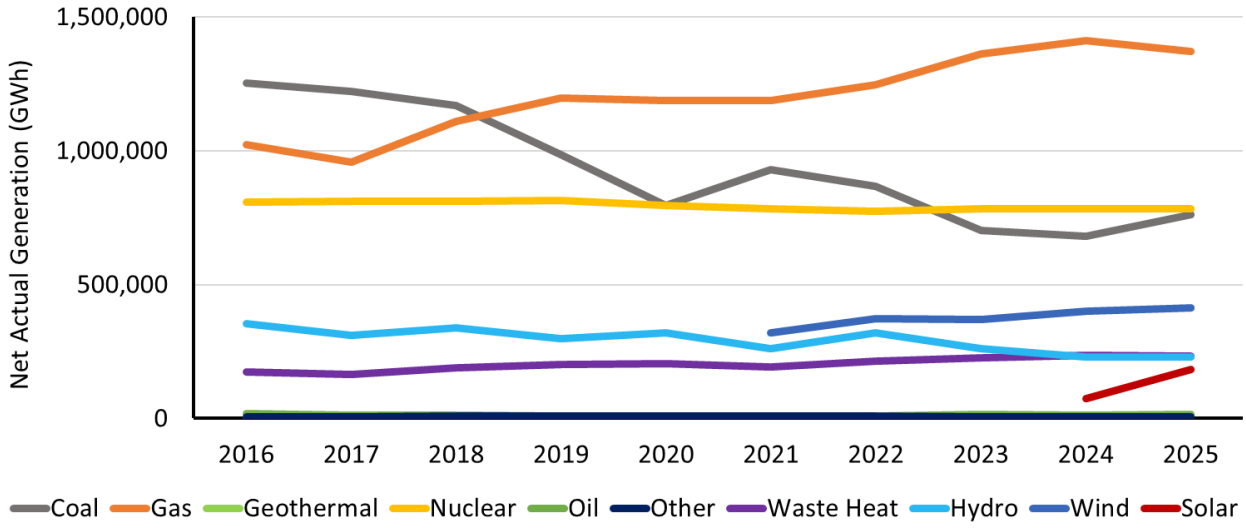


Figure 4.6: 10-Year Annual Net Actual Generation (GWh) by Fuel Type

Wind and Solar[78] Generation Weighted Factors

Figure 4.7–**Figure 4.9** present various weighted factors for wind[79] plant data collected in GADS. Because no exact analog to conventional generation's WEFOR calculation exists, the data is broken down into different factors representing what percentage of the month the plants were in each state and presented as a stacked area chart representing the entire duration of the month. For the purposes of this report, the following calculation and data modifications have been made:

- Resource forced outage factor has been separated into resource forced outage factor (representing forced equipment outages) and resource unavailable outage factor (representing forced outages due to a lack of generating resource).
- Resource reserve shutdown factor is calculated the same way as other factors, with reserve shutdown as the numerator.
- Generation losses due to sub-optimal resource conditions are calculated by subtracting the resource net capacity factor from the resource generating factor. The value represents the portion of the month in which the plant was producing at less than full capacity. For example, if a wind plant has 100 MW of installed capacity but due to wind speed is only producing 60 MW and has no other constraints, this value would be 40%.

Wind data is presented in **Figure 4.7**–**Figure 4.9**, with each figure showing a different stage of data collection: plants >200 MW, 100–199 MW, and 75–99 MW.

NERC is continuing to develop unbiased, representative analysis for wind and solar analysis to best understand trends in the data and draw comparisons to more conventional resources. In 2025, equipment performances across all wind plant sizes were comparable to one another and would not be considered problematic compared to conventional generation, with a resource forced outage factor (RFOF) most like hydro generation's WEFOR. Energy generation at plants >200 MW declined in 2025, warranting further investigation.

[78] During this year's data analysis, NERC identified significant GADS solar data reporting errors and numerous missing plants compared to EIA 860 data. NERC will be coordinating with Regional Entity staff to perform industry outreach and resolve these errors in 2026.

[79] 2025_GADS_Wind_DRI

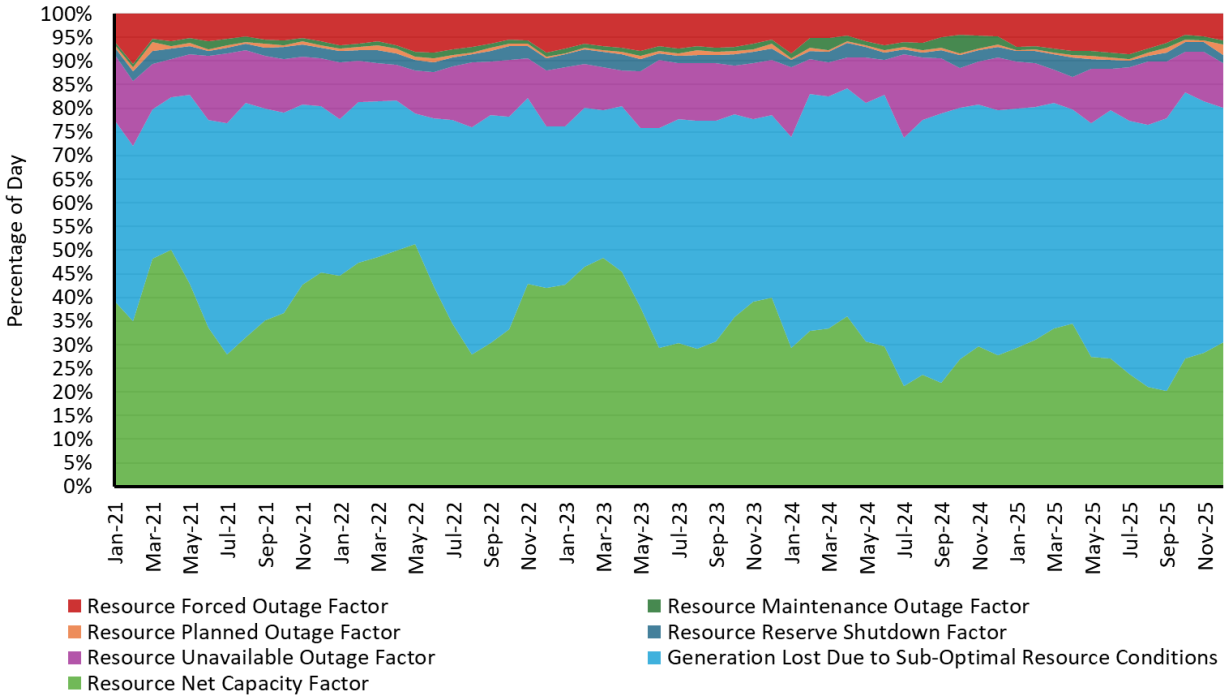


Figure 4.7: Monthly Net Output Factor and Weighted Resource Forced Outage Rate (WRFOR) Wind Plant Reporting Group 200 MW+

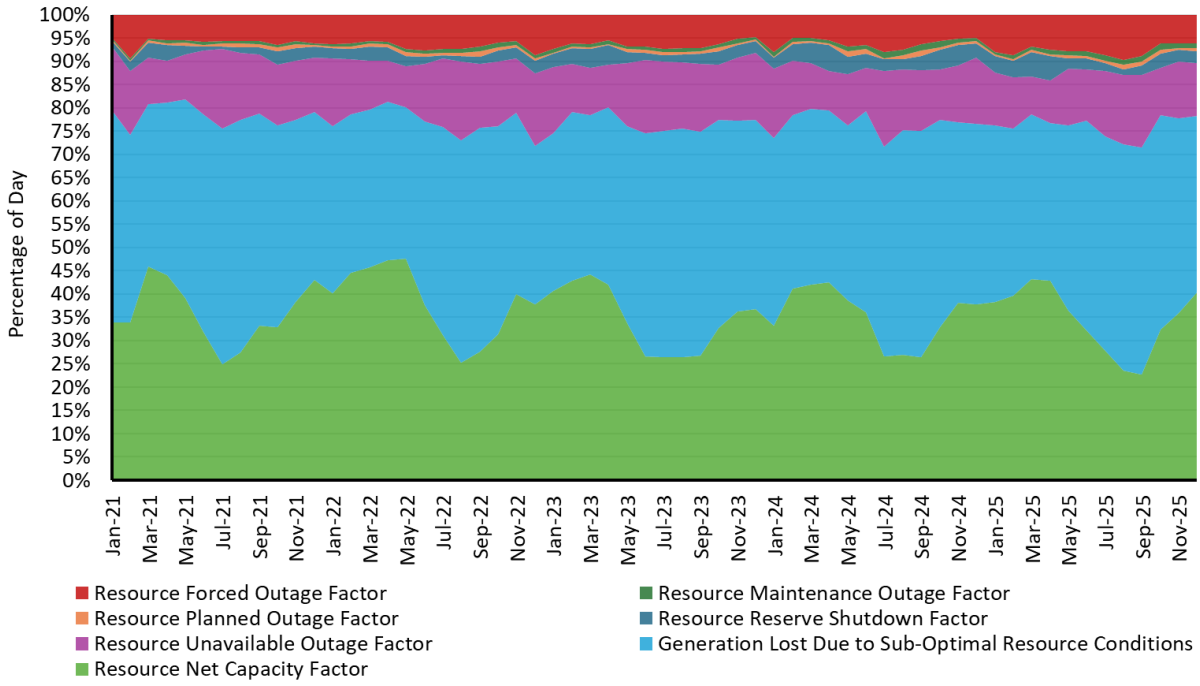


Figure 4.8: Monthly Net Output Factor and WRFOR Wind Plant Reporting Group 100–199 MW

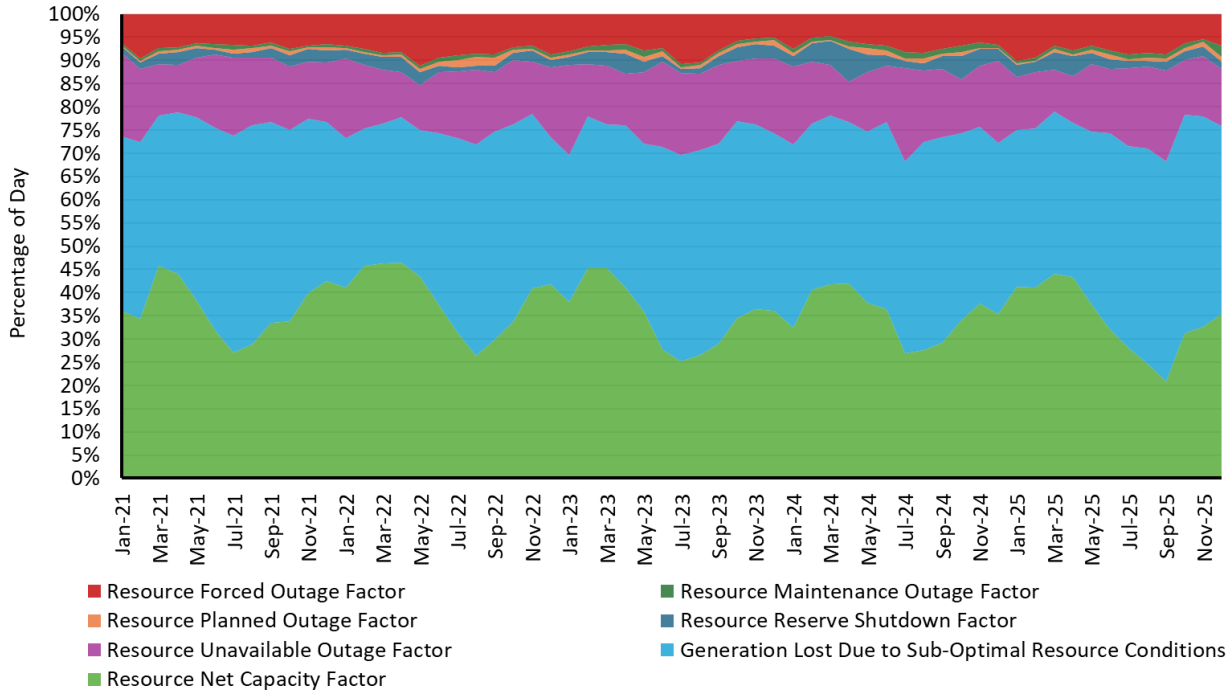


Figure 4.9: Monthly Net Output Factor and WRFOR Wind Plant Reporting Group 75–99 MW

Transmission Performance and Unavailability

When evaluating transmission reliability, an important concept is that transmission line outages have different impacts on BPS reliability. Some impacts can be very severe, such as those that affect other transmission lines and load loss. Additionally, some outages are longer than others, leaving the transmission system at risk for extended periods of time. Reliability indicators for the transmission system are measured by using qualified event analysis reporting not related to weather and outages reported to TADS.

Transmission-Related Events Resulting in Loss of Load

In 2025, a total of six distinct non-weather-related transmission events resulted in a loss of firm load that met the ERO EAP reporting criteria (**Figure 4.10**). The median firm load loss over the past five years was 88.0 MW, which is a decrease from 2020–2024's 90 MW. In 2024 the median load loss was 85.5 MW or 47.0 MW below the 2020–2023 median, and 2025 saw the median increase to 132.5 MW, which is 44.5 MW above the 2021–2024 median.

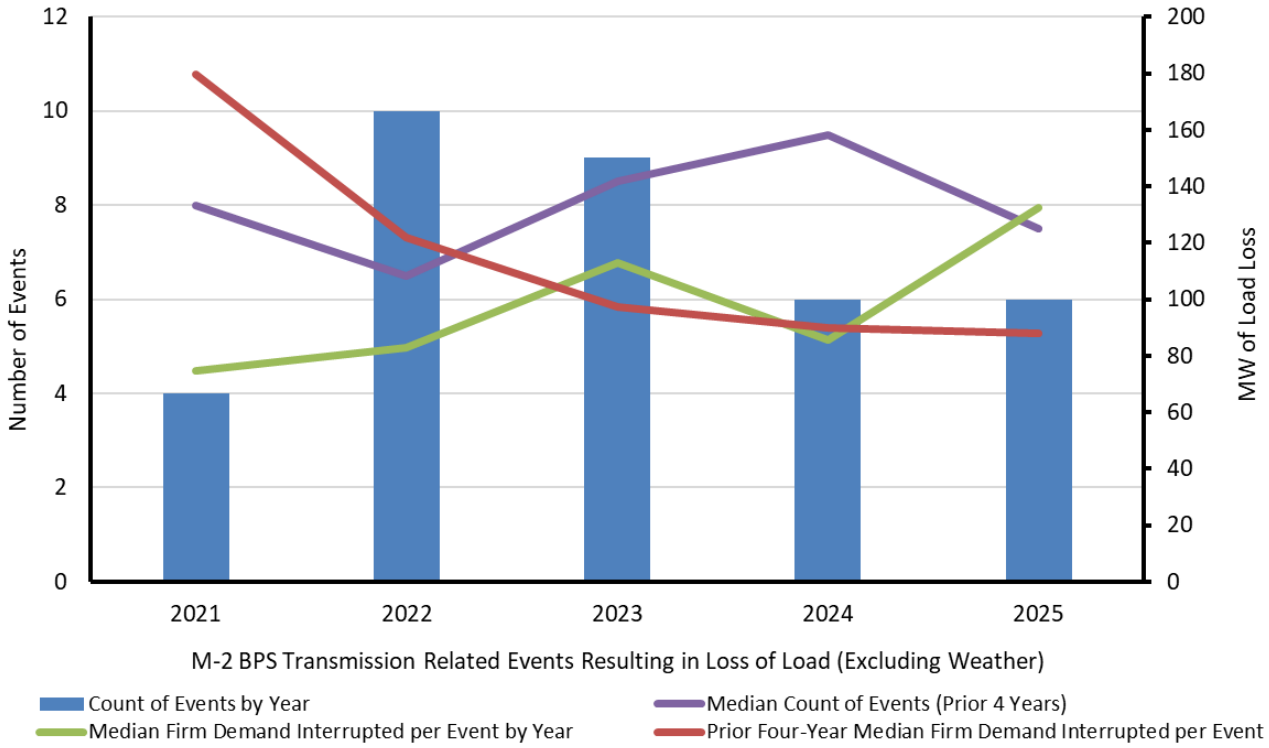


Figure 4.10: Transmission-Related Events Resulting in Loss of Firm Load and Median Amount of Firm Load Loss Excluding Weather-Related Events[80]

TADS Reliability Indicators

A TADS event is an unplanned transmission incident that results in the automatic outage (sustained or momentary) of one or more elements. TADS event information was analyzed for the following indicators in this section:

- **Transmission Outage Severity**
- **Automatic AC Transmission Outages**
- **Transmission Element Unavailability**

Transmission Outage Severity

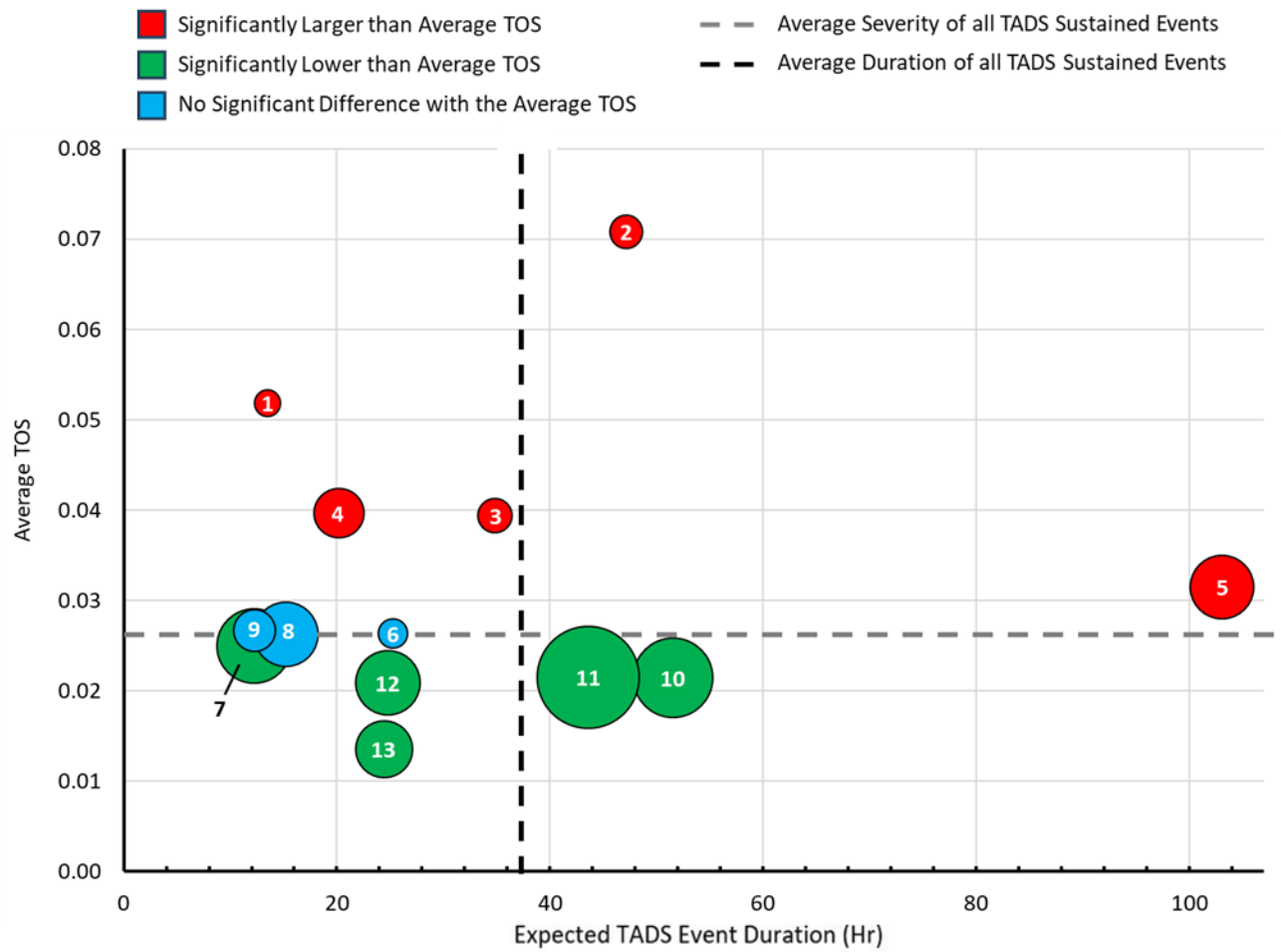
The impact of a TADS event on BPS reliability is called the transmission outage severity (TOS) of the event, which is defined by the number of sustained outages in the event and by the type and voltage class of transmission elements involved in the event. TADS events are categorized by initiating cause codes (ICC). These ICCs facilitate the study of cause-effect relationships between each event's ICC and event severity.

The number of events per hour, average event duration, and average TOS for each ICC group are shown in **Table 4.6**.

[80] M-2, BPS Transmission Related Events Resulting in Loss of Load (Excluding Weather)

Table 4.6: TOS vs. Expected TADS Event Duration				
TADS Event	Events per Hour	TOS		Average Event Duration (Hours)
		Average	Maximum	
Combined Smaller ICC Groups	0.018	0.039	0.318	34.9
Failed AC Circuit Equipment	0.099	0.021	0.249	51.5
Failed AC Substation Equipment	0.063	0.032	0.414	103.1
Fire	0.017	0.071	0.652	47.2
Foreign Interference	0.064	0.021	0.196	24.8
Human Error	0.027	0.027	0.377	12.3
Lightning	0.064	0.026	0.519	15.2
Misoperation	0.038	0.040	0.732	20.2
Other	0.013	0.026	0.327	25.2
Power System Condition	0.011	0.052	0.998	13.5
Unknown	0.086	0.025	0.365	12.2
Vegetation	0.050	0.014	0.494	24.4
Weather, Excluding Lightning	0.163	0.022	0.654	43.6

By examining the average TOS, duration, and frequency of occurrence for events with different ICCs (**Figure 4.11**) it is possible to determine which ICCs contribute most to reliability performance for the period under consideration. The average TOS for events with a specific ICC is displayed on the Y-axis. A higher TOS for an ICC indicates that more sustained outages or higher voltage elements were involved in an event. The average duration for events with a specific ICC is displayed on the X-axis; generally, events with a longer duration pose a greater risk to the BPS. The number of ICC occurrences is represented by the bubble size; larger bubbles indicate that an ICC occurs more often. Lastly, the bubble colors indicate a statistical significance of a difference in the average TOS of this group and the events from other groups.



1. Power System Condition
2. Fire
3. Combined Smaller ICC Groups
4. Misoperation
5. Failed AC Substation Equipment
6. Other
7. Unknown
8. Lightning
9. Human Error
10. Failed AC Circuit Equipment
11. Weather, Excluding Lightning
12. Foreign Interference
13. Vegetation

Figure 4.11: TOS vs. Expected TADS Event Duration

An analysis of the total TOS by year indicates that 2025 shows an improving trend compared to 2024, with the Unknown category improving to the point that it went from the No Significant Difference category (blue) in 2024 to the Significantly Lower than Average TOS category (green) in 2025. All other categories remained the same. **Figure 4.12** shows the annual TOS, which is the lowest since TADS data collection began.

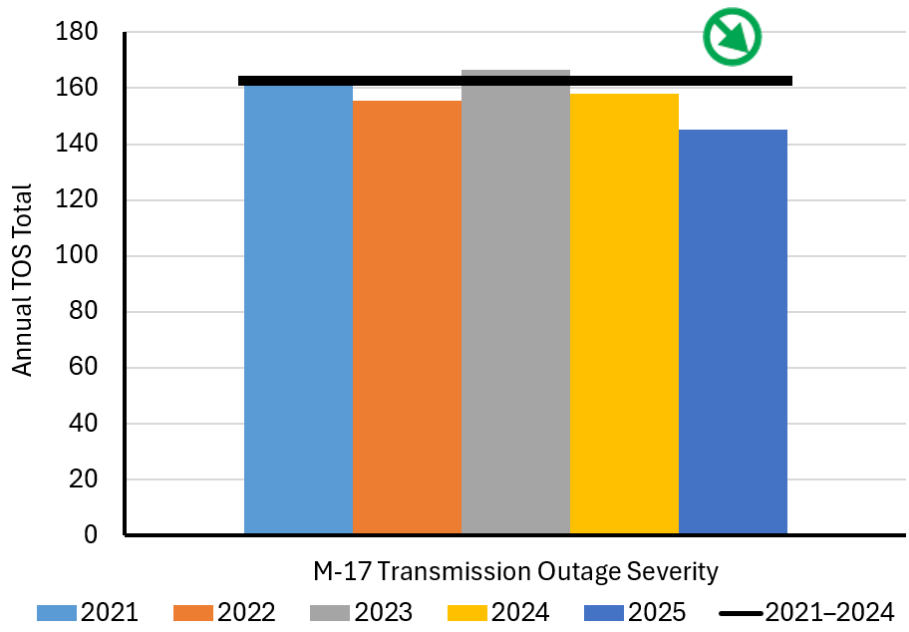


Figure 4.12: TOS of TADS Sustained Events of 100 kV+ AC Circuits and Transformers by Year[81]

Automatic AC Transmission Outages

The average number of outages per circuit due to failed ac substation equipment slightly decreased from 2024 to 2025 and is effectively equal to the previous four-year average (**Figure 4.13**). The number of sustained outages due to failed ac circuit equipment per 100 miles decreased in 2025 to the lowest of the past five years (**Figure 4.14**).

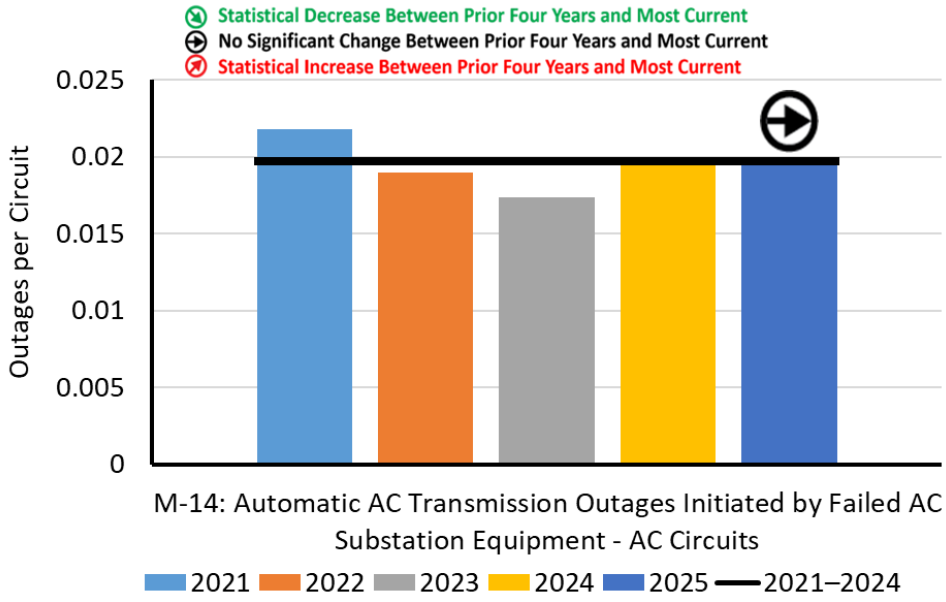


Figure 4.13: Number of Outages Per AC Circuit Due to Failed AC Substation Equipment[82]

[81] M-17, Transmission Outage Severity
[82] M-14, Automatic AC Transmission Outages Initiated by Failed AC Substation Equipment

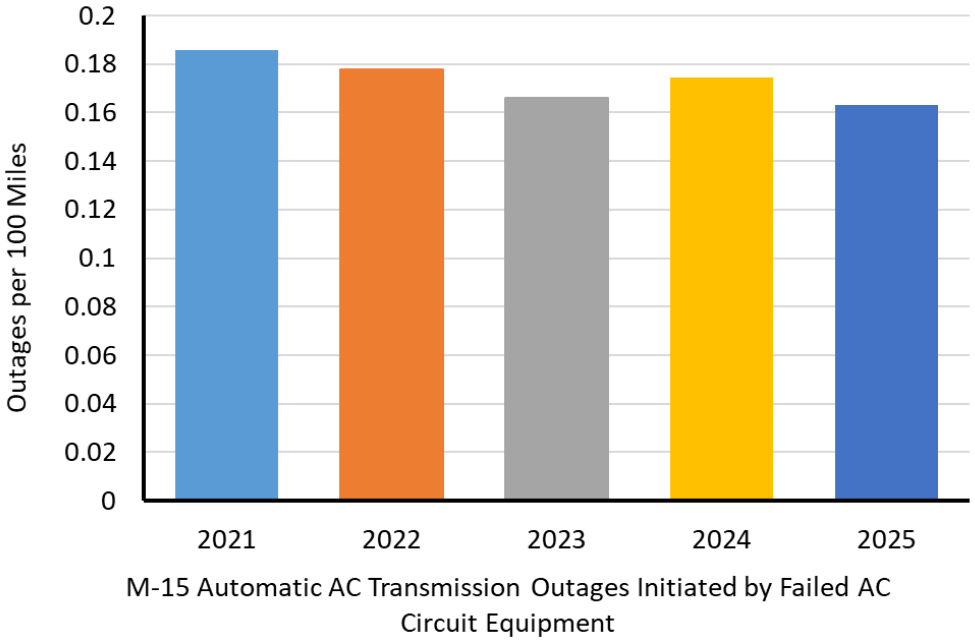


Figure 4.14: Number of Outages Per 100 Miles Due to Failed AC Circuit Equipment[83]

Automatic AC Transformer Outages

In 2025, there was a slight decrease in the number of automatic ac transformer outages per element caused by failed ac substation equipment, but there was no significant change compared to the prior four years. Though the decrease in outages is not statistically significant, as can be seen in **Figure 4.15**, this number remains the second highest over the past five years.

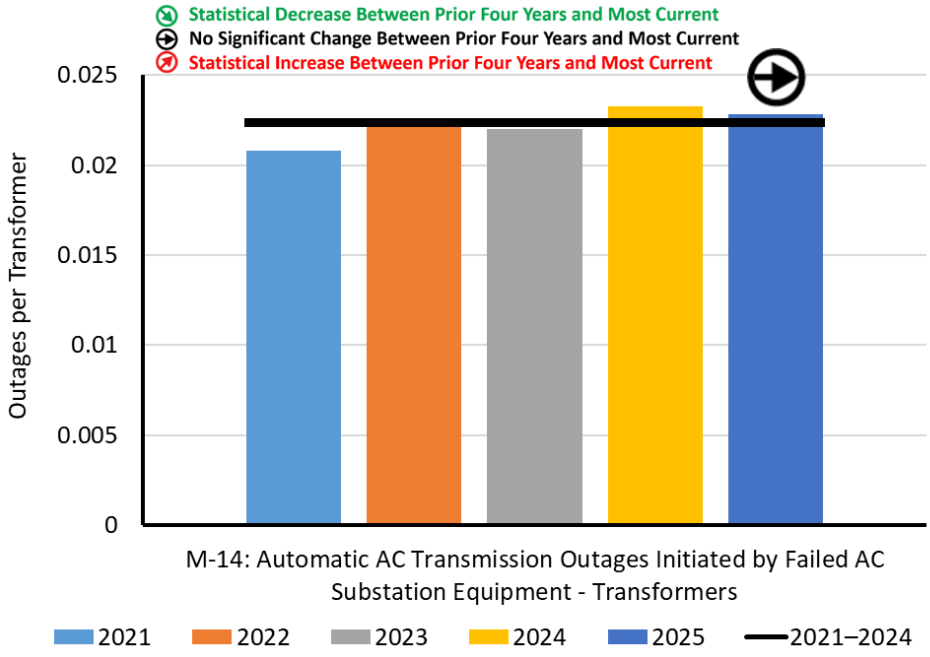


Figure 4.15: Number of Outages Per Transformer Due to Failed AC Substation Equipment[84]

[83] M-15, Automatic AC Transmission Outages Initiated by Failed AC Circuit Equipment
[84] M-14, Automatic AC Transmission Outages Initiated by Failed AC Substation Equipment

Transmission Element Unavailability

In 2025, ac circuits over 200 kV across North America had an unavailability rate of 0.22%, representing the chance that a specific transmission circuit is unavailable due to sustained automatic and operational outages at any given time. Transformers also had an unavailability rate of 0.35% in 2025. **Figure 4.16** shows that while there was a decrease in ac circuit availability in 2025, it was not statistically significant when compared to the prior four years.

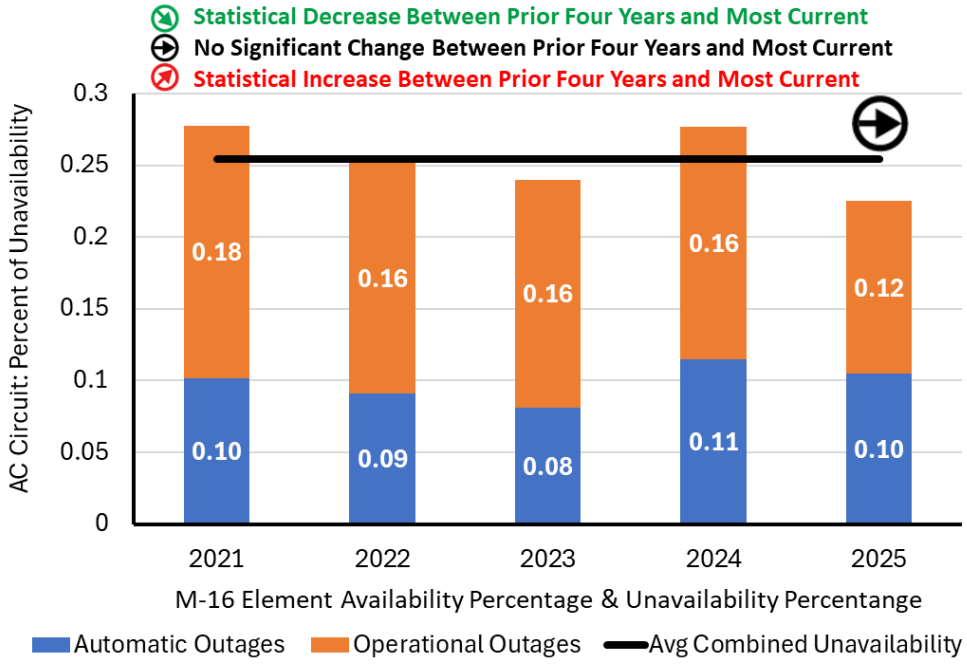


Figure 4.16: AC Circuit Unavailability >200 kV[85]

Figure 4.17 shows that 2025 is the highest year for transformer unavailability of the five-year analysis period, in large part due to an increase in the number of operational outages. Responses from voluntary outreach to utilities with the longest operational transformer outages in 2025 aligned with historically provided reasons for prolonged outages and did not indicate the need for immediate action. In addition to several one-off scenarios, common themes included removing transformers temporarily multiple times to maintain system reliability, system redundancy reducing restoration urgency, and two instances where supply chain constraints in the form of known long lead times prolonged outages.

[85] M-16, Element Availability Percentage (APC) & Unavailability Percentage

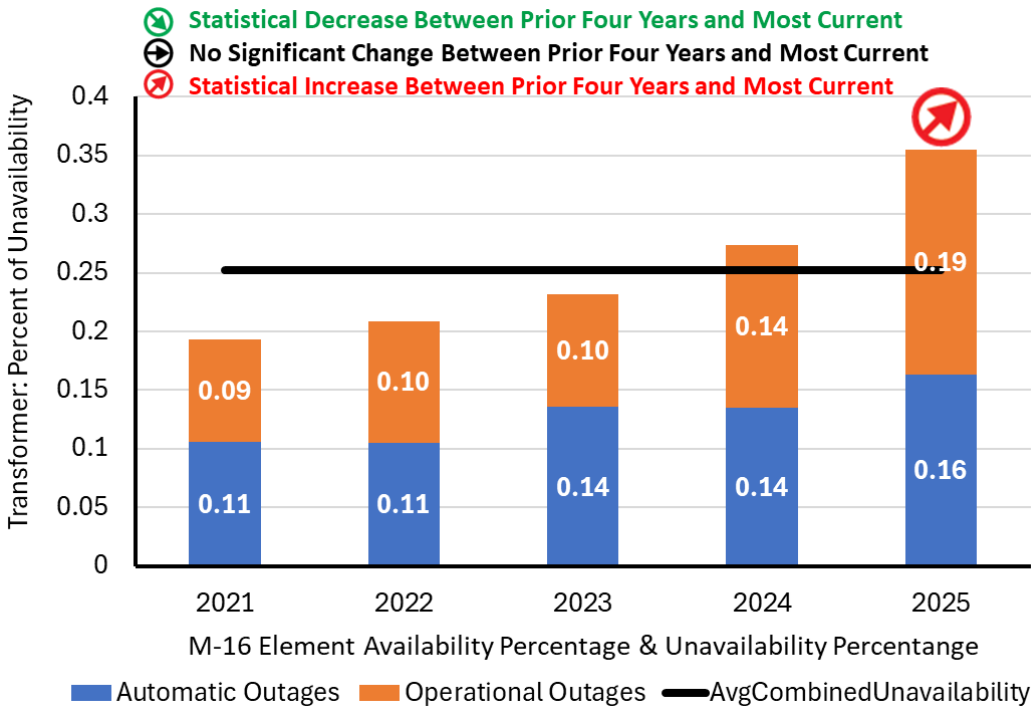


Figure 4.17: Transformer Unavailability >200 kV [86]

TADS Physical Security Metric

Over the past several years, there has been an increase in physical attacks on the BPS. To help measure the impact of these transmission physical security events on the BES and identify trends, a new metric was introduced, the TADS Physical Security Metric (M18), described as follows.

- The TADS Physical Security metric uses the data from TADS sustained physical security-related outages for transmission elements reportable in TADS with a voltage of 100 kV and above. Prior to 2024, these outages were reported using the initiating or sustained cause code labeled Vandalism, Terrorism, or Malicious Acts. Since 2024, these outages have been reported using the initiating or sustained cause code labeled Physical Security Incident. The metric is calculated by adding the number of outages, their average equivalent MVA, and their average duration, for a rolling five-year period that is then statistically compared to identify trends.
- The bubble chart in **Figure 4.18** shows a rolling comparison of the TADS Physical Security metric of 2021–2025 to 2020–2024. The size of a bubble represents the total number of physical security outages (displayed in the center of each bubble). The X-axis of a bubble shows the average duration of the outages (in hours), and the Y-axis shows the average MVA capacity impacted for those outages.

[86] M-16, Element Availability Percentage (APC) & Unavailability Percentage

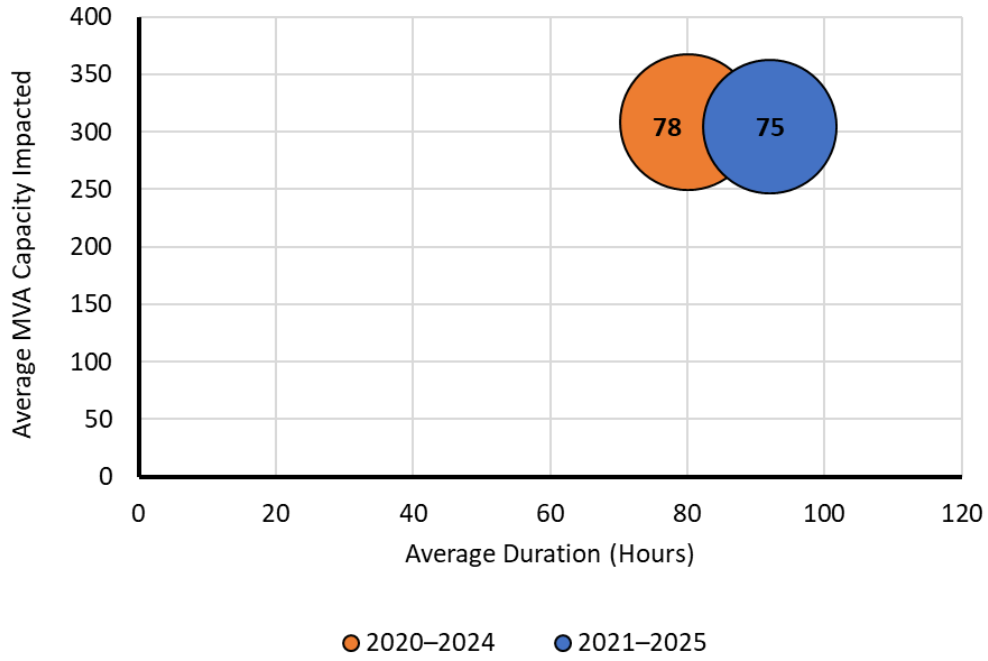


Figure 4.18: Comparison of TADS Physical Security Metric for 2020–2024 vs. 2021–2025[87]

Figure 4.18 shows a decreasing trend in both the total number of physical security outages (from 78 to 75) and average MVA capacity (from 308.5 MVA to 304.6 MVA) and an increase in the average duration for those outages (from 80 hours to 92 hours). Based on the rating criteria for this metric, the assessment rating for this metric is Stable.

Table 4.7: 2025 M-18 TADS Physical Security Metric		
	2020–2024	2021–2025
Outage Count	78	75
Average MVA	308.5	304.57
Average Duration (Hours)	80.15	92.03

Incident Tracking Context/Background

The E-ISAC tracks physical security incidents shared by asset owners across North America to reduce physical security risks to the sector by monitoring and reporting on relevant trends such as the criminal threat environment and the tactics, techniques, and procedures that result in operational impacts to the North American grid. In addition to physical security incidents reported to the ERO through mandatory mechanisms such as the DOE-417 and EOP-004 forms, the E-ISAC tracks incidents shared voluntarily by members on the E-ISAC Portal or shared directly with the E-ISAC through the Bulk Data Program. Approximately 91% of incidents tracked by the E-ISAC since 2021 were received through voluntary methods. Since 2021, the E-ISAC has tracked over 17,000 physical security incidents within the following categories: Assault, Ballistic Damage, Intrusion, Theft, Threat, Surveillance, Suspicious Activity, and Other. Of these 17,000, less than 3% have resulted in operational impacts since 2021 (**Table 4.8**), though the proportion typically fluctuates within shorter time periods between 2% and 4%.

[87] M-18, TADS Physical Security

Table 4.8: E-ISAC Severity Level Definitions and Data Summary (2021–2025)[88]		
Severity Level	**Definition**	**% of incidents**
Level 0	Non-criminal, potential security nexus	11%
Level 1	Likely criminal activity with no operational impacts; only monetary.	86%
Level 2	Some operational impacts; including limited customer outages, generation unavailability, or partial loss of control and monitoring.	2%
Level 3	Significant operational impacts; including extensive customer outages, generation unavailability or loss of control and monitoring.	<1%

Operational Impacts Increasing

Since 2021, Level 2 and Level 3 incidents shared with the E-ISAC have increased (**Figure 4.19**). While 2023 saw an increase in Ballistic Damage incidents resulting in operational impacts, the primary tactics that increased throughout 2024 and 2025 involved Theft or Vandalism. The change in tactics reflects the changing risk environment and can be attributed to copper market spikes and supply chain constraints, leading to increased targeting of copper through Theft and Vandalism. In 2025, the E-ISAC observed sustained levels of Vandalism and Ballistic Damage compared to historic norms, paired with an increase in operational impacts from Theft and continued targeting of fiber infrastructure.

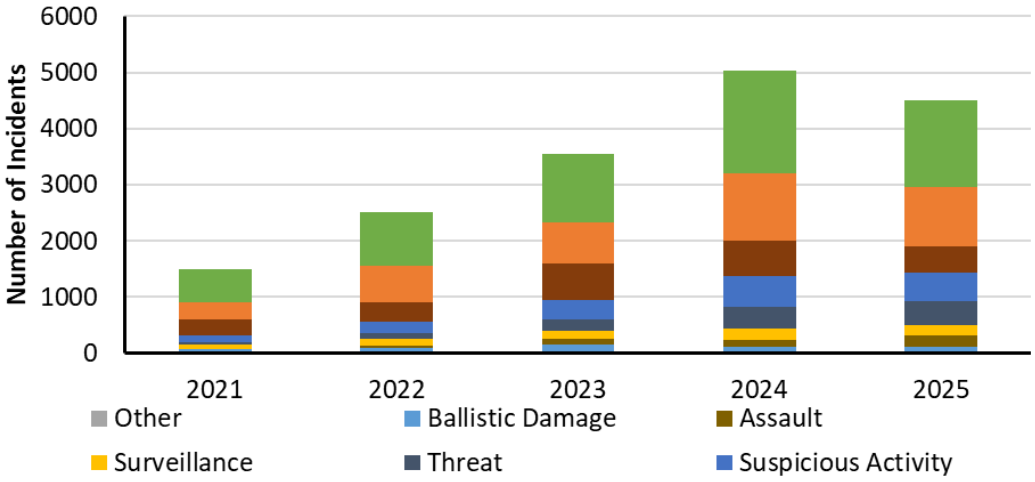


Figure 4.19: Incidents Resulting in Operational Impacts (Severity Level 2 and Level 3) by Tactic (2021–2025)

Unlike Operational Impacts, Overall Incidents Decreased

In 2025, overall incidents shared with the E-ISAC decreased by 11% compared with 2024 (**Figure 4.19**); this decline was relatively consistent between mandatory/voluntarily shared incidents for all severity levels. This is in contrast to incidents discussed above resulting in operational impacts. The differing volume trend observed between all incidents versus those resulting in operational impacts can be attributed to a shifting tactical focus by adversaries, with copper thefts increasingly affecting energized distribution (non-substation) assets, resulting in customer outages.

For more insight into the risks to industry related to physical security incidents that result in operational impacts, see the E-ISAC's annual Grid-Impacting Report (available to E-ISAC members on the Portal).

[88] https://www.eisac.com/portal/article/124886-Physical-Security-Incident-Severity-Level-Categorization

Appendix A: Supplemental Analysis at Interconnection Level

Severity Risk Index by Interconnection

Eastern and Québec Interconnections

The cumulative SRI for the EI and QI in **Table A.1** shows a 3% increase compared to the average of the four-year period of 2021–2024. The 2025 cumulative SRI was the second highest among the five years analyzed.

Table A.1: Annual Cumulative SRI, Eastern and Québec Interconnections

Year	Cumulative Weighted Generation	Cumulative Weighted Transmission	Cumulative Weighted Load Loss	Annual Cumulative SRI	Average Daily SRI
2021	346.3	53.7	65.8	465.9	1.28
2022	385.1	52.3	53.0	490.4	1.34
2023	324.5	64.4	47.2	436.1	1.19
2024	358.7	59.5	52.0	470.2	1.28
2025	**367.5**	**52.7**	**46.8**	**467.0**	**1.28**

The top 10 SRI days of the EI and QI were distributed throughout the year as shown in **Figure A.1** (numbered circles). A total of 7 of the top 10 days that occurred in the EI and QI aligned with the top 10 SRI days reported for North America.

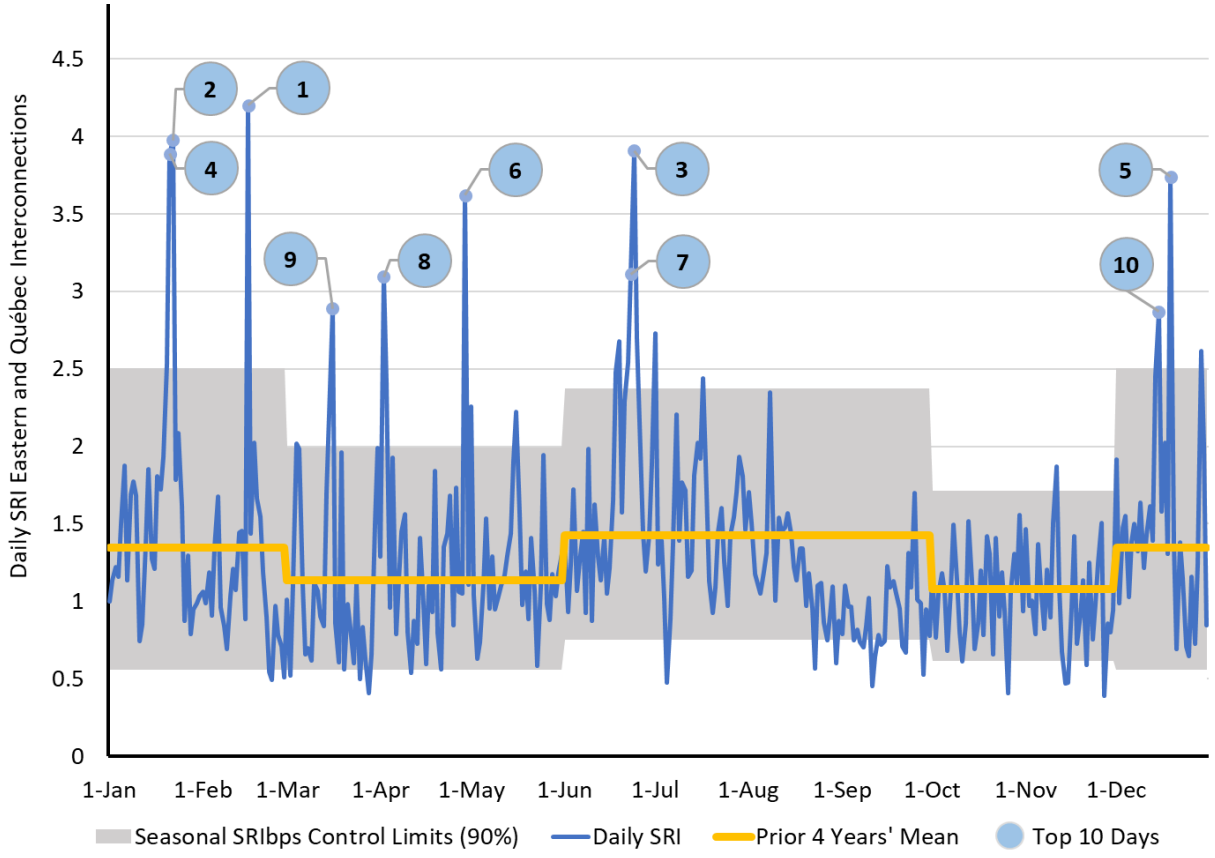


Figure A.1: 2025 Eastern and Québec Interconnections Daily SRI with Top 10 Days Labeled, 90% Confidence Interval

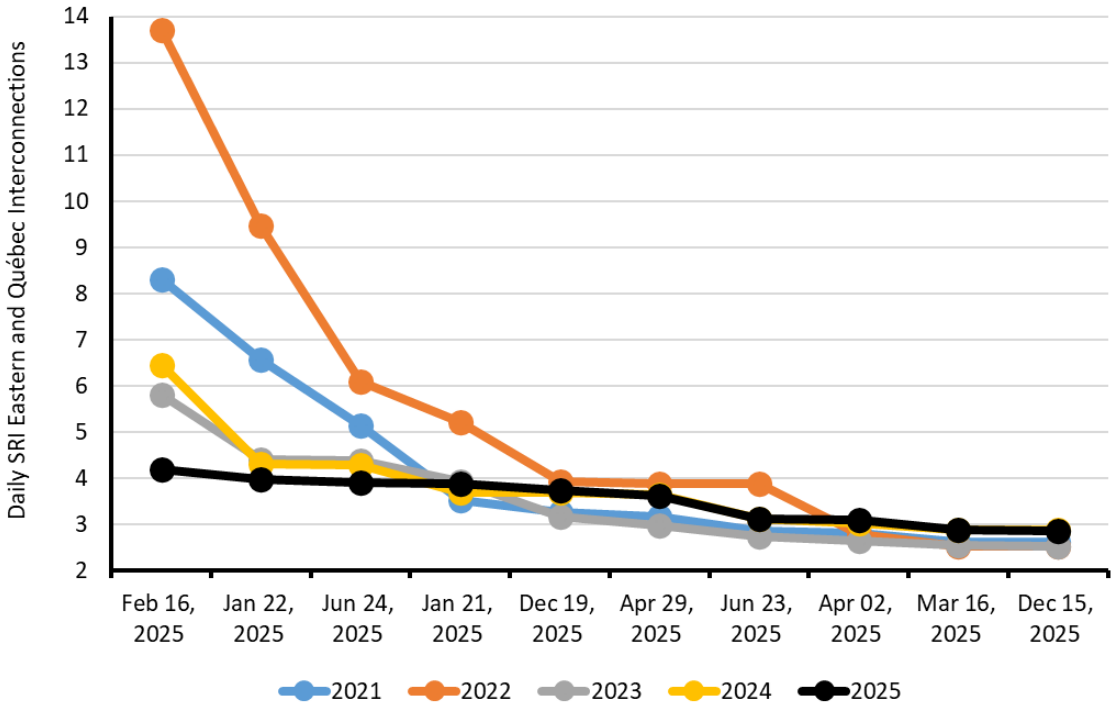


Figure A.2: Eastern and Québec Interconnections Top Annual Daily SRI Days, Sorted Descending

Figure A.2 shows the EI and QI's top 10 SRI days in 2025 relative to the four prior years, while **Table A.2** provides details on each component's contribution to the top 10 SRI days. Out of the top 10 SRI days for the EI and QI, three were driven by load loss, one was driven by a combination of generation and load loss, none were driven by transmission, and the rest were predominantly driven by generation.

Table A.2: 2025 Top 10 SRI Days, Eastern and Québec Interconnections

Rank	Date	SRI and Weighted Components 2025				Atypical Weather Conditions	Regional Entities
		SRI	Weighted Generation	Weighted Transmission	Weighted Load Loss		
1	February 16, 2025	4.20	2.20	0.31	1.68	Northwestern Atmospheric River	WECC
2	January 22, 2025	3.98	3.74	0.15	0.08	Winter Storm Enzo	RF, SERC
3	June 24, 2025	3.91	3.09	0.26	0.55	Thunderstorms	NPCC, RF, SERC
4	January 21, 2025	3.89	3.71	0.10	0.07	Winter Storm Enzo	RF, SERC
5	December 19, 2025	3.74	1.70	0.29	1.76	Northwestern Atmospheric River	WECC
6	April 29, 2025	3.62	1.06	0.37	2.19	Thunderstorms	MRO, NPCC, RF
7	June 23, 2025	3.11	2.13	0.16	0.82	Thunderstorms	NPCC, RF, SERC
8	April 2, 2025	3.09	0.99	0.55	1.56	Tornadoes & Severe Storms	MRO, RF, SERC
9	March 16, 2025	2.89	0.50	0.34	2.05	Tornadoes	MRO, RF, SERC
10	December 15, 2025	2.87	2.51	0.07	0.29	Winter Storm	RF, SERC, Texas RE

Table A.3 shows the top 10 SRI days for the EI and QI over the last five years with no dates in 2025.

Table A.3: 2021–2025 Top 10 SRI Days, Eastern and Québec Interconnections

Rank	Date	SRI and Weighted Components 2025				Atypical Weather Conditions	Regional Entities
		SRI	Weighted Generation	Weighted Transmission	Weighted Load Loss		
1	December 23, 2022	13.70	8.88	0.90	3.92	Winter Storm Elliott	All
2	December 24, 2022	9.46	8.12	1.27	0.07	Winter Storm Elliott	All
3	February 16, 2021	8.31	4.10	0.58	3.63	Cold Weather Event	MRO, RF, SERC
4	December 11, 2021	6.57	0.92	0.92	4.73	Severe Storms	NPCC, RF, SERC
5	September 27, 2024	6.45	1.62	3.61	1.23	Hurricane Helene	SERC
6	June 14, 2022	6.09	1.70	0.49	3.90	High Temperatures and Derecho	All
7	April 1, 2023	5.80	0.74	0.63	4.43	Widespread Storms and Tornadoes	MRO, RF, SERC
8	June 15, 2022	5.22	1.63	0.24	3.36	Hurricane Isaias	NPCC, RF, SERC
9	February 15, 2021	5.15	3.62	0.54	0.99	Unnamed Tropical Storm	RF, SERC
10	June 22, 2023	4.42	1.34	2.95	0.13	High Temperatures and Derecho	All

Western Interconnection

The 2025 cumulative SRI for the WI shows an 9% decrease over the prior four-year period of 2021–2024. The 2025 cumulative SRI was the lowest among the five years analyzed (**Table A.4**).

Table A.4: Annual Cumulative SRI, Western Interconnection

Year	Cumulative Weighted Generation	Cumulative Weighted Transmission	Cumulative Weighted Load Loss	Annual Cumulative SRI	Average Daily SRI
2021	426.8	98.2	97.8	622.7	1.71
2022	423.8	87.3	60.1	571.2	1.57
2023	423.1	68.6	59.6	551.3	1.51
2024	418.0	74.3	50.1	542.4	1.48
2025	**402.5**	**76.2**	**42.2**	**521.0**	**1.43**

The top 10 SRI days of the WI for 2024 were distributed throughout the year as shown in **Figure A.3**. A total of 2 of the top 10 days that occurred in the WI aligned with the top 10 SRI days reported for North America.

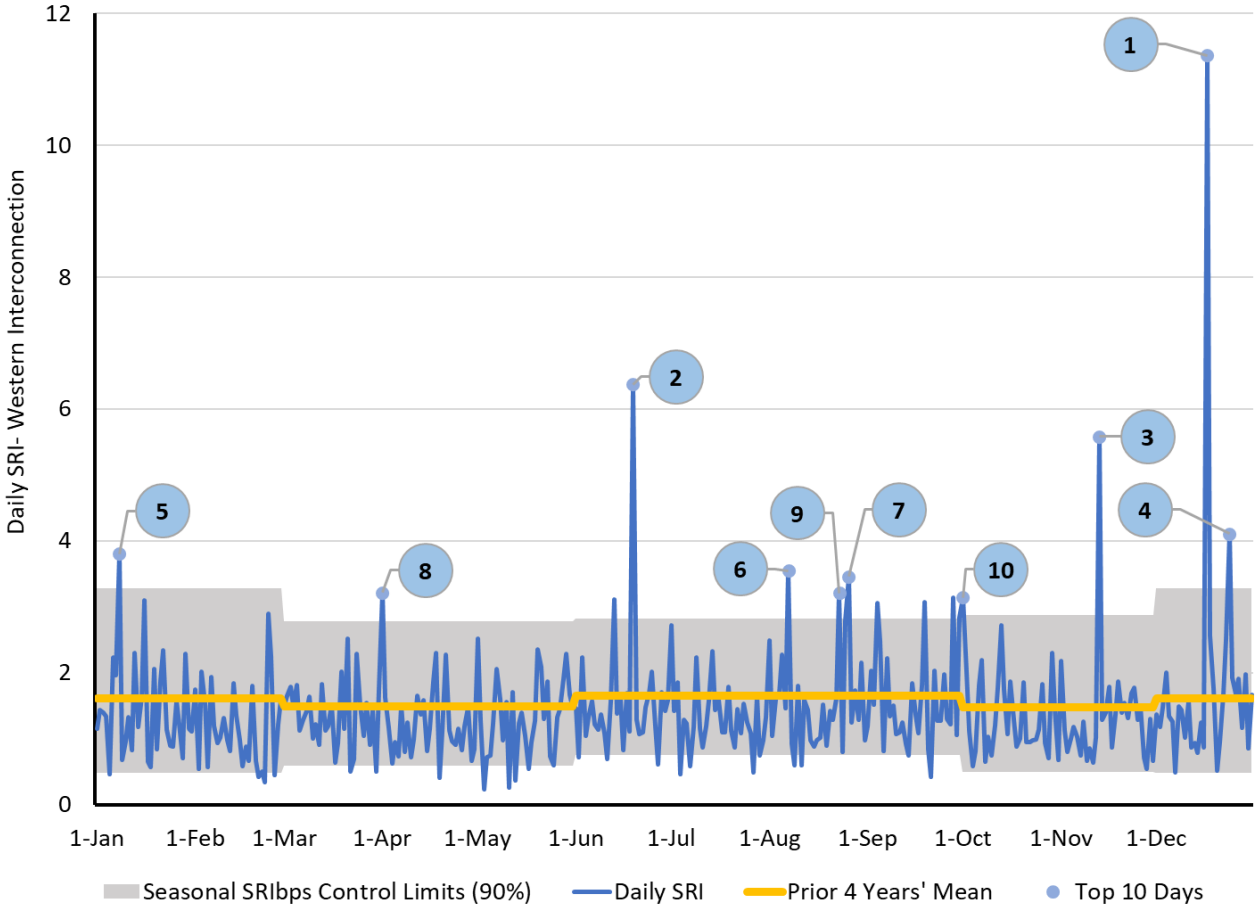


Figure A.3: 2025 Western Interconnection Daily SRI with Top 10 Days Labeled, 90% Confidence Interval

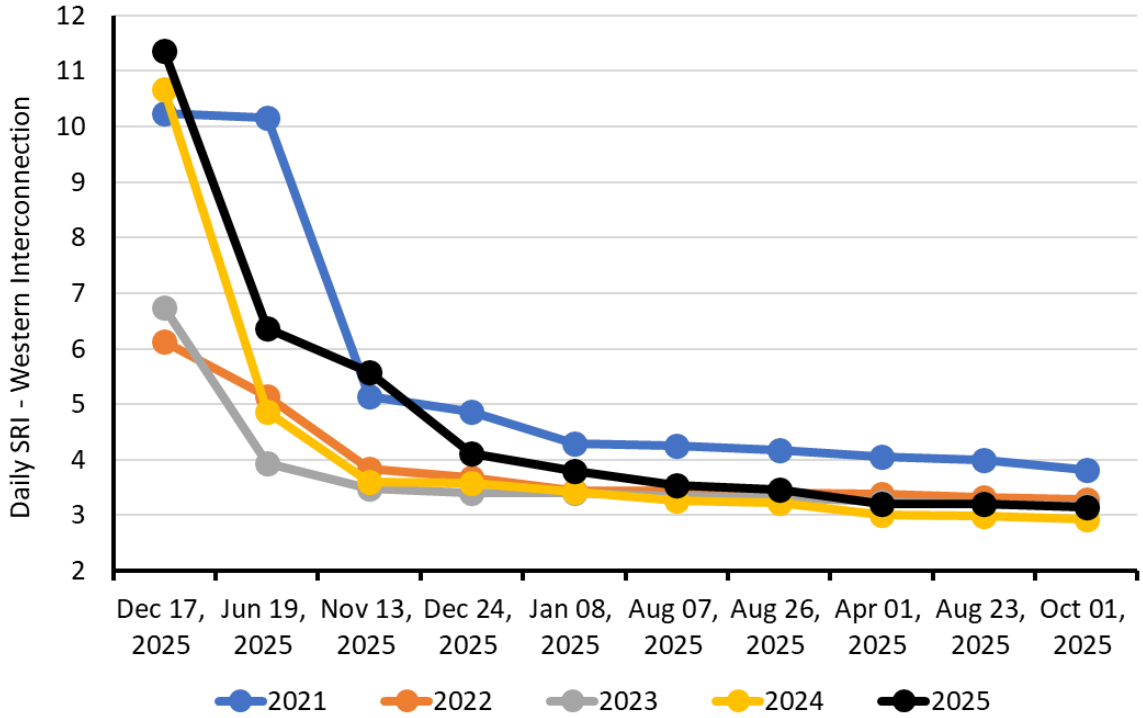


Figure A.4: Western Interconnection Top Annual Daily SRI Days Sorted Descending

Table A.5 details each component's contribution to the top 10 SRI days for the WI; WECC is the only Regional Entity in the WI. Out of the top 10 SRI days for the WI, one was driven by load loss, two were driven by a combination of transmission and generation, and the rest were predominantly driven by generation.

Table A.5: 2025 Top 10 SRI Days, Western Interconnection

Rank	Date	SRI and Weighted Components 2025				Atypical Weather Conditions Regional Entities
		SRI	Weighted Generation	Weighted Transmission	Weighted Load Loss	
1	December 17, 2025	11.36	4.54	4.02	2.80	Northwestern Atmospheric River
2	June 19, 2025	6.38	0.87	0.44	5.07	Thunderstorms, Tornadoes
3	November 13, 2025	5.58	3.23	2.35	0.00	Wyoming System Event
4	December 24, 2025	4.11	1.07	0.87	2.16	Winter Storm
5	January 8, 2025	3.81	1.54	1.73	0.53	High Wind Conditions
6	August 7, 2025	3.55	2.73	0.67	0.14	Extreme Heat
7	August 26, 2025	3.46	1.99	0.57	0.90	Extreme Heat
8	April 1, 2025	3.21	2.80	0.18	0.23	Thunderstorms, Tornadoes
9	August 23, 2025	3.21	1.26	0.80	1.15	Extreme Heat
10	October 1, 2025	3.14	2.76	0.38	0.00	Thunderstorms

Table A.6 shows the top 10 SRI days for the WI over the last five years, with three days in 2025 highlighted in red.

Table A.6: 2021–2025 Top 10 SRI Days, Western Interconnection

Rank	Date	SRI and Weighted Components 2025				Atypical Weather Conditions
		SRI	Weighted Generation	Weighted Transmission	Weighted Load Loss	
1	December 17, 2025	11.36	4.54	4.02	2.80	Northwestern Atmospheric River
2	February 4, 2024	10.67	0.34	0.31	10.02	Atmospheric River
3	November 15, 2021	10.23	1.42	0.40	8.41	Atmospheric River
4	January 13, 2021	10.16	1.86	3.83	4.48	Northwest Winter Weather
5	February 24, 2023	6.75	2.61	0.88	3.26	Winter Storm
6	June 19, 2025	6.38	0.87	0.44	5.07	Tornadoes, High Winds
7	November 5, 2022	6.13	1.75	1.77	2.61	Severe Weather

Table A.6: 2021–2025 Top 10 SRI Days, Western Interconnection						
Rank	Date	SRI and Weighted Components 2025				Atypical Weather Conditions
		SRI	Weighted Generation	Weighted Transmission	Weighted Load Loss	
8	November 13, 2025	5.58	3.23	2.35	0.00	Wyoming System Event
9	December 20, 2022	5.14	1.05	0.15	3.93	Winter Storm
10	February 13, 2021	5.14	1.14	1.30	2.70	Winter Storm Uri

Extreme-Day Analysis by Interconnection

The extreme-day analyses for transmission and generation for 2025 are presented by Interconnection. The maximum TADS reported MVA capacity or GADS reported net maximum capacity for 2025 is shown in the upper right or left corners of **Figure A.5**–**Figure A.10**. The largest outliers and extreme days correlating with NERC-wide extreme days have been labeled with any atypical weather conditions during those days. Interconnection extreme days that do not align with NERC-wide extreme days are dated, but the underlying conditions are not identified. The number of customers interrupted (CI) due to transmission or generation sources for the day is obtained from the IEEE PES Distribution Reliability Working Group (DRWG) benchmark data. All dates are shown in UTC.

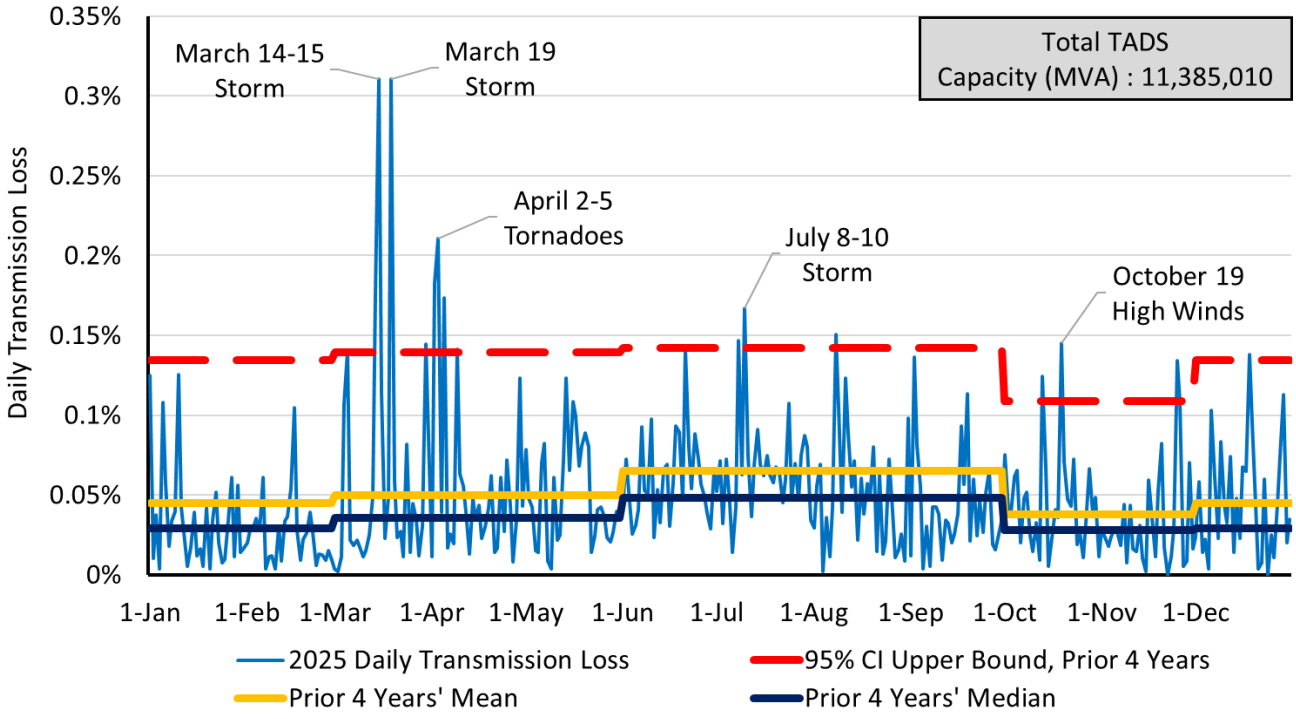


Figure A.5: Eastern and Québec Interconnections—Transmission Impacts During Extreme Days of 2025

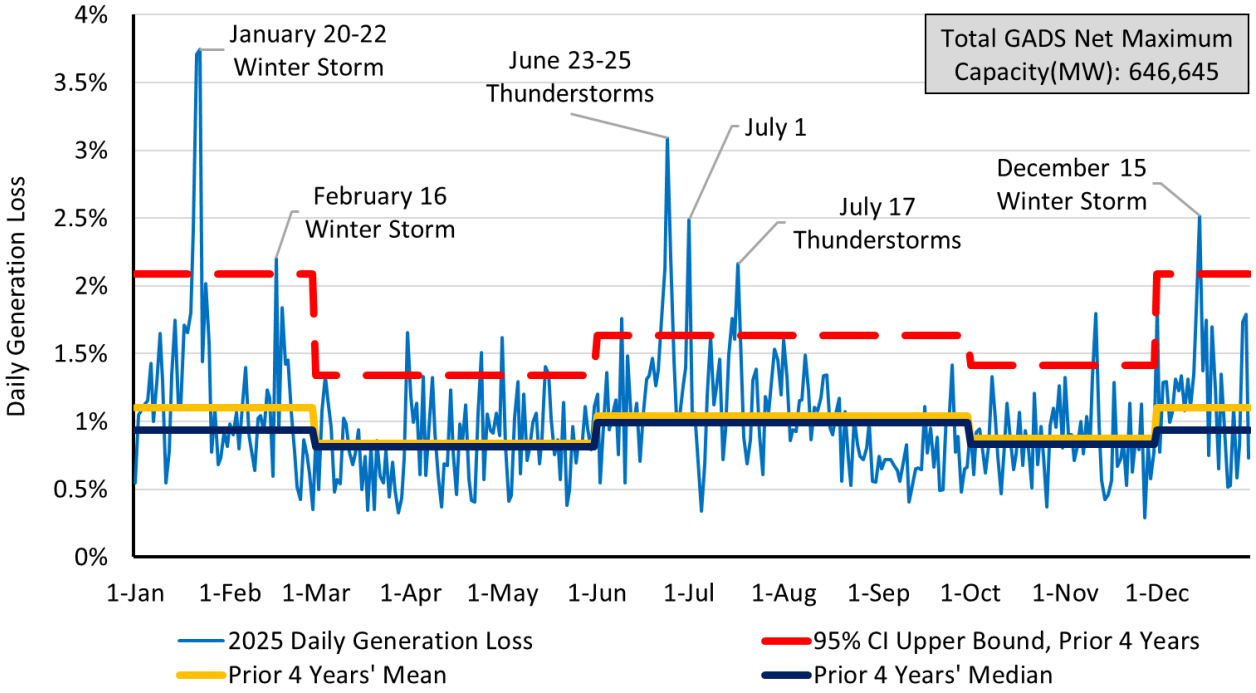


Figure A.6: Eastern and Québec Interconnections—Generation Impacts During Extreme Days of 2025

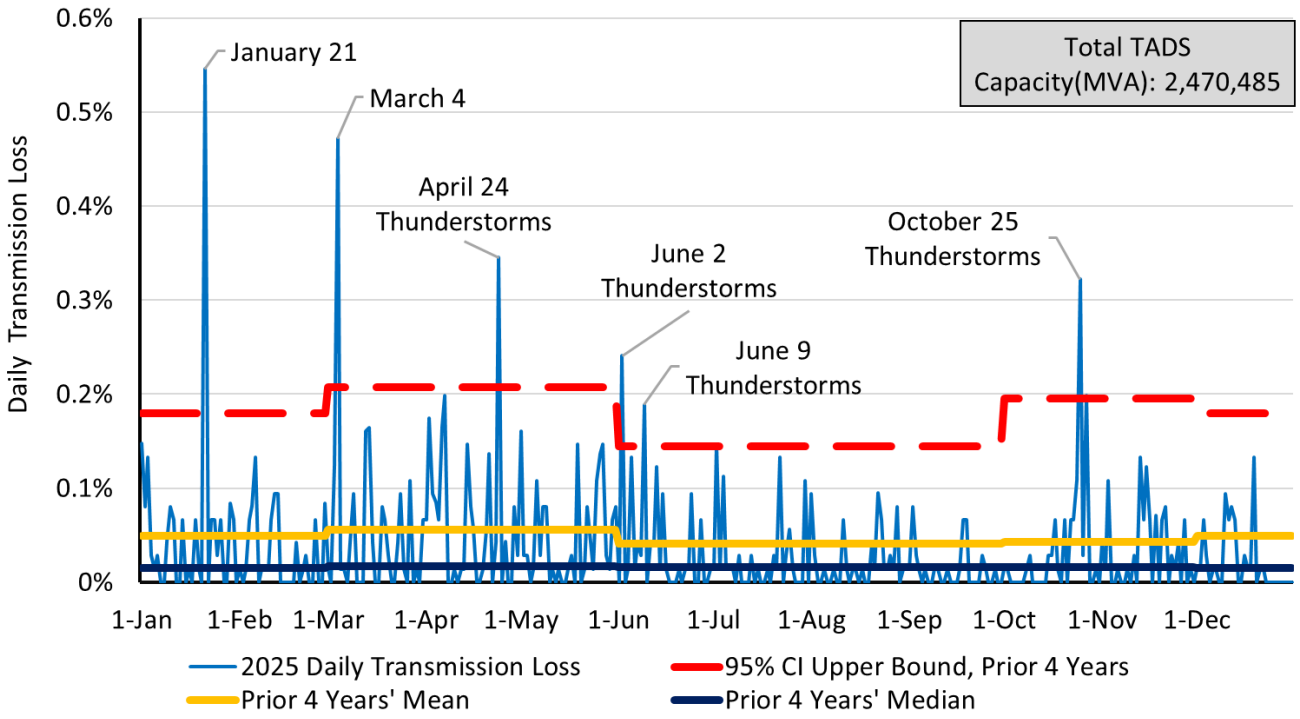


Figure A.7: Texas Interconnection—Transmission Impacts During Extreme Days of 2025

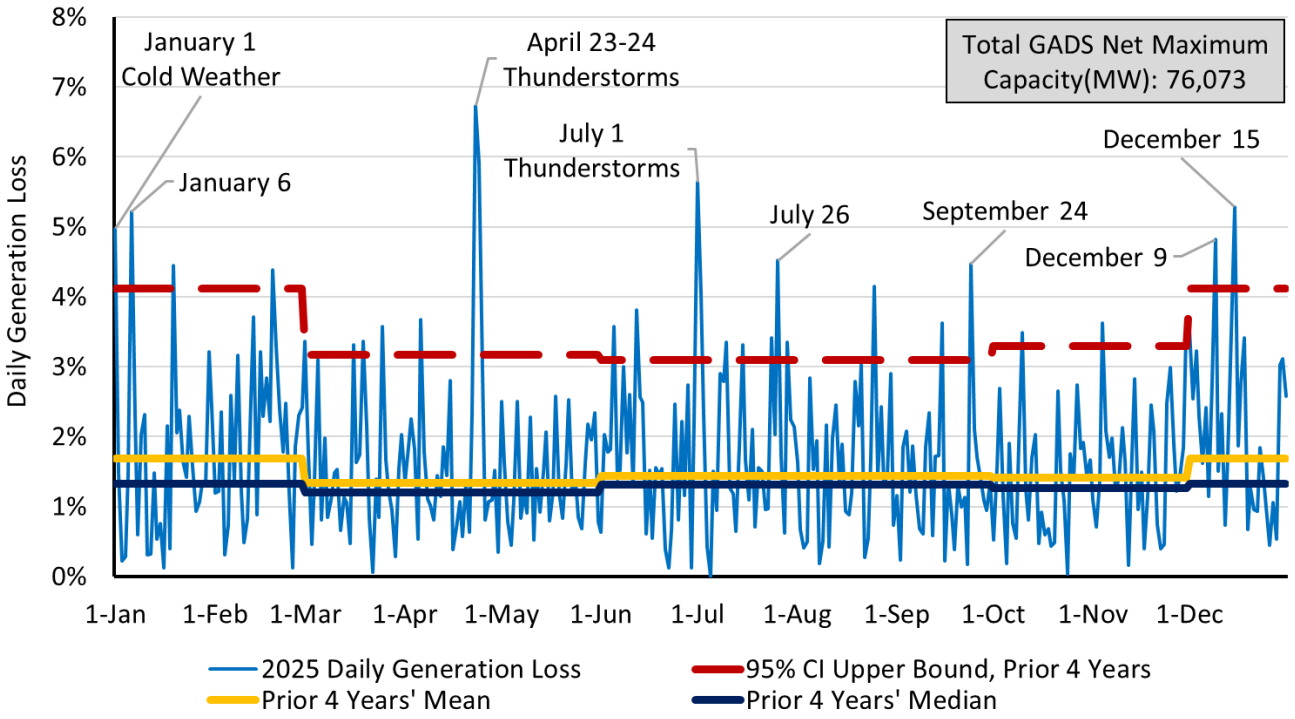


Figure A.8: Texas Interconnection—Generation Impacts During Extreme Days of 2025

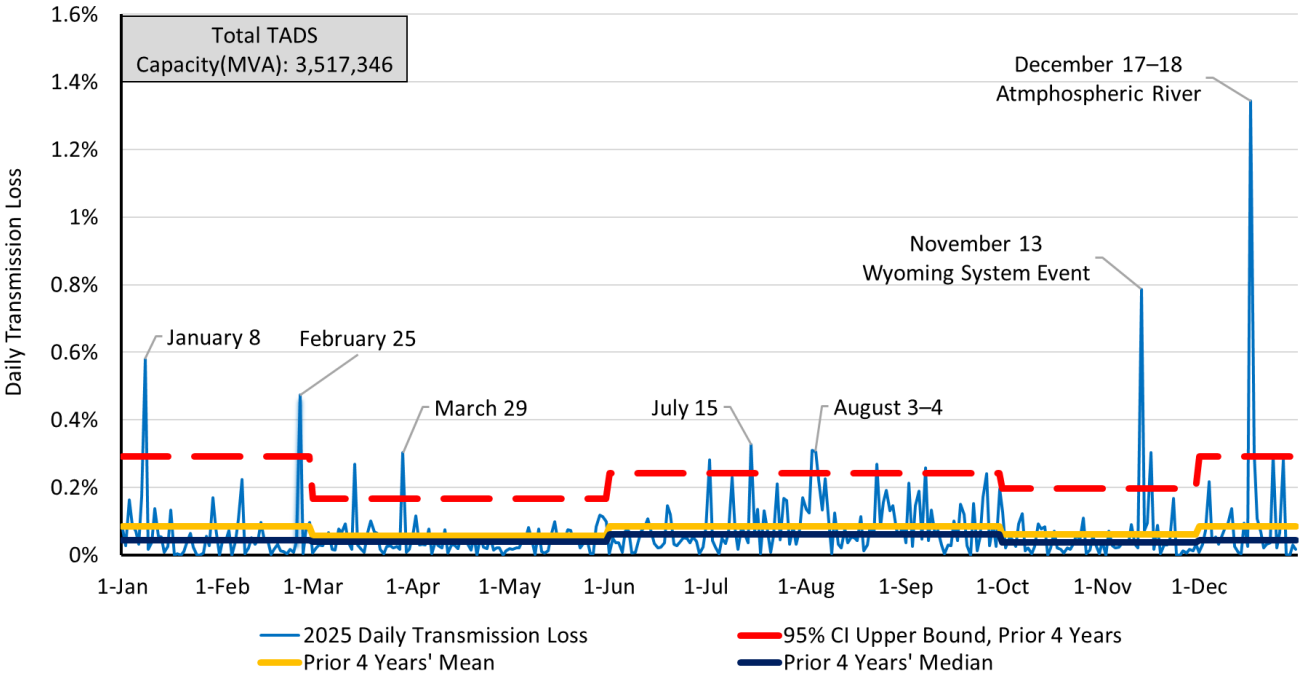


Figure A.9: Western Interconnection—Transmission Impacts During Extreme Days of 2025

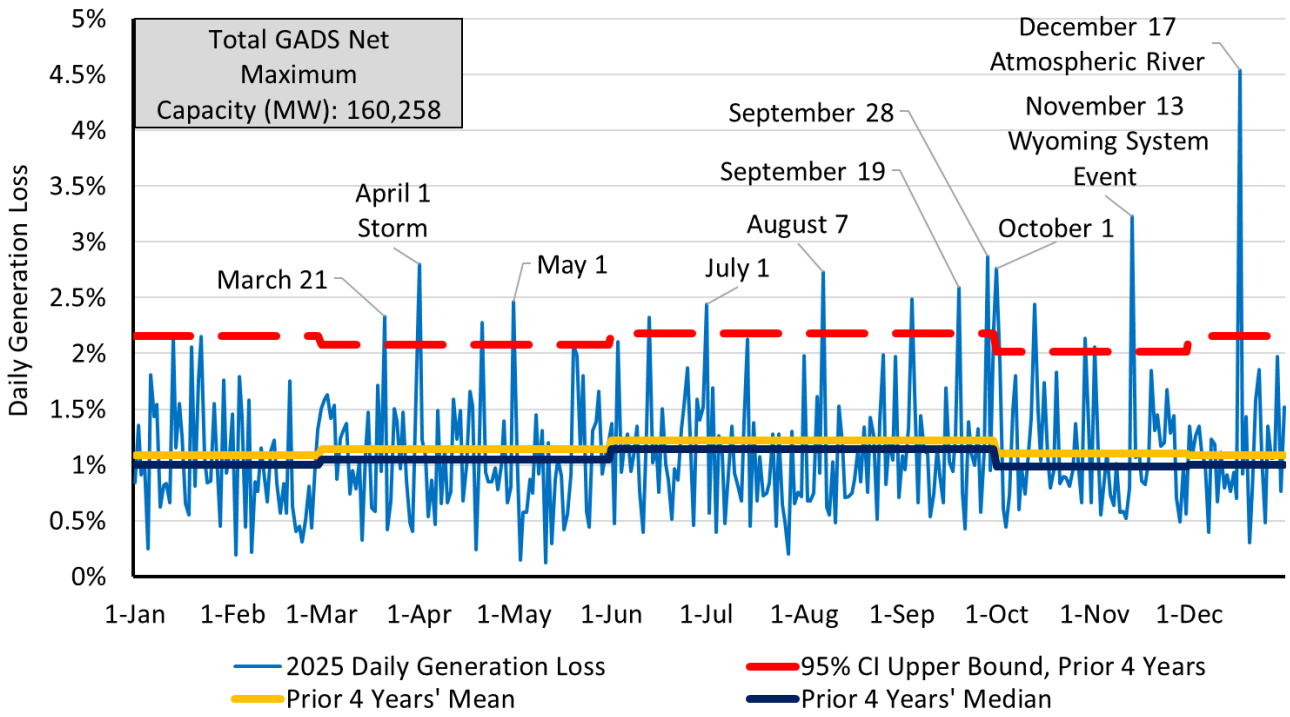


Figure A.10: Western Interconnection—Generation Impacts During Extreme Weather Days

Appendix B: Acknowledgements

NERC Industry Group Acknowledgements	
Group	**Officers**
Reliability and Security Technical Committee	Chair: John Stephens, City Utilities of Springfield Vice Chair: Srinivas Kappagantula, Arevon Energy
Performance Analysis Subcommittee	RSTC Sponsor: Brett Kruse, Calpine Corporation Chair: Heide Caswell, Oregon Public Utilities Commission Vice Chair: Peter Ashcroft, WECC
Transmission Availability Data System User Group	Chair: Nick DePompei, SERC Vice Chair: Rodolfo Lozano, ITC Transmission
Generation Availability Data System User Group	Chair: Danny Small, Missouri Public Utility Alliance Vice Chair: Ken Sabourin, Sunflower Energy
Events Analysis Subcommittee	Chair: James Hanson, WECC Vice Chair: Cindy Robert, Hydro- Québec
Reliability Assessment Subcommittee	Chair: Amanda Sargent, WECC Vice Chair: Evan Shuvo, Texas RE
Resources Subcommittee	Chair: Daniel Baker, Southwest Power Pool Vice Chair: Jose Luis Hinojosa, ERCOT
Electromagnetic Transient Modeling Working Group	Co-Chair: Adam Sparacino, Mitsubishi Electric Power Products, Inc. Co-Chair: Miguel Angel Cova Acosta, Vestas Americas
Frequency Working Group	Chair: Joseph Marcrum, Southern Company
Inverter-Based Resources Performance Subcommittee	Chair: Julia Matevosyan, Entergy Vice Chair: Rajat Majumder, Invenergy
Large Loads Working Group	Chair: Eric Meier, ERCOT Vice Chair: Sudip Manandhar, Southern Company
Real-Time Operating Subcommittee	Chair: Derek Hawkins, Southwest Power Pool Vice Chair: Raja Thappetaobula, CAISO
System Planning Impacts from Distributed Energy Resources Working Group	Chair: Shayan Rizvi, NPCC Vice Chair: John Schmall, ERCOT
System Protection and Control Working Group	Chair: Lynn Schroeder, Sunflower Vice Chair: Manish Patel, Silicon Ranch Corporation

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Tony Burt	Physical Security Analyst, Situational Awareness
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UNITED STATES OF AMERICA
BEFORE THE
UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Craig Unit 1	))))	Order No. 202-26-49

The State Of Colorado's Request for Rehearing,
Motion To Intervene, And Stay Request

Exhibit KKKK: Letter from Michelle Bloodworth, President and CEO of America's Power to Chris Wright, Secretary of the U.S. Department of Energy (Mar. 11, 2025)

AMERICA'S POWER
Reliable • Secure • Resilient • Affordable

March 11, 2025

The Honorable Chris Wright
Secretary
U.S. Department of Energy
1000 Independence Ave., SW
Washington, DC 20585

Dear Secretary Wright:

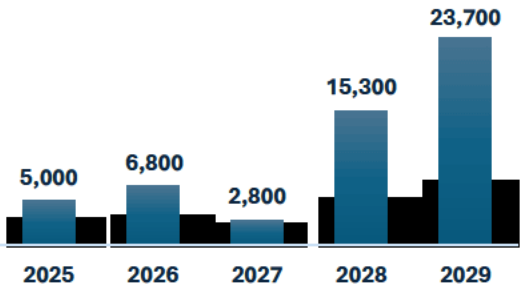
I am writing on behalf of America's Power to seek assistance from the Department of Energy (DOE) in preventing the retirement of more coal-fired electric generating units. America's Power is the only national trade association whose sole mission is to advocate for the nation's coal fleet, which totals 370 electric generating units that represent approximately 175,000 megawatts (MW) of generating capacity. Our membership is comprised of electricity generators, coal producers, equipment manufacturers, and companies that transport coal (collectively, the coal supply chain).

As you know, the nation's coal fleet and a healthy supply chain are essential to maintaining a reliable, affordable, and resilient electricity supply. The coal fleet provides essential reliability services, helps stabilize electricity prices, provides energy security, possesses a high capacity value, has demonstrated its resilience during extreme weather, and is capable of providing substantial amounts of electricity to meet exploding electricity demand.

We commend President Trump for issuing the Executive Order "Declaring a National Energy Emergency" (EO) that calls attention to our nation's "inadequate energy supply," an "increasingly unreliable grid," and the need for "swift and decisive action" to remedy these problems. Premature coal retirements are one of the major reasons for this energy emergency. The following facts show the gravity of the situation:

- Forty (40) percent of the nation's coal fleet (769 generating units totaling 141,000 MW) has retired since 2010. Of this total, 43,300 MW (137 units) retired during 2020-2024.
- Electricity generators have announced plans to retire an additional 53,600 MW of coal (118 generating units) during 2025-2029. Retirements increase dramatically in 2028 and 2029 (chart).

Nationwide Announced Coal Retirements (MW)
During the Next 5 Years



- This is the same 5-year period during which the North American Electric Reliability Corporation's (NERC) Long-Term Reliability Assessment (December 2024) projects that half the U.S. will be at either "high" or "elevated" risk of electricity shortages.
- The bulk of announced coal retirements – 52 generating units totaling more than 31,000 MW – will occur over the next 5 years in three regions: MISO ("high" risk of shortages), PJM ("elevated" risk of shortages), and SPP ("elevated" risk of shortages).
- Recognizing their urgent need for coal-fired generation, utilities have announced plans to delay 26,000 MW of coal retirements primarily because of load growth and reliability concerns. (These are excluded from the retirement numbers above.) These delayed retirements are necessary but obviously not sufficient to prevent a national energy emergency from continuing.

Repealing or rewriting a number of EPA regulations could reverse some of these announced retirements. However, these regulations must be repealed as quickly as possible to prevent electricity generators from being forced to make irreversible compliance decisions that could lead to even more premature coal retirements.

Besides regulatory reforms, some form of economic support is also essential to preserve coal-fired generation. For example, the General Services Administration entered into a contract in January 2025 to purchase 10 million megawatt-hours of nuclear power over a period of 10 years. A similar arrangement to purchase coal-fired electricity would provide much needed support to the coal fleet and would be consistent with the mandate in the EO to remedy the vulnerabilities resulting from inadequate energy and electricity.

In addition, a DOE order pursuant to Section 202(c) of the Federal Power Act (FPA) could prevent the premature retirement of certain coal units. Section 202(c) provides that:

> [W]henever the [Secretary 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 … the [Secretary of Energy] shall have authority … to require by order such temporary connections of facilities and generation, delivery, interchange, or transmission of electric energy as in [the Secretary's] judgment will best meet the emergency and serve the public interest.

DOE has issued Section 202(c) orders and extensions of orders more than 20 times since 2000. While most of these orders were issued for only a few days due to extreme weather, Section 202(c) allows the Secretary of Energy to direct the continued operation of specific coal units for longer periods of time as well as to mandate payments to ensure their availability because of national security risks or the resource adequacy risks identified in NERC's annual Long-Term Reliability Assessments such as the one mentioned above.

In addition, DOE could act pursuant to Section 101(a) and (c) of the Defense Production Act (DPA) because of the need for adequate power supplies to promote the national defense. Contracts that preserve the coal supply chain for national defense purposes are justified under the DPA as well.

The EO directs agencies and departments and agencies to "identify and exercise any lawful emergency authorities available to them …." We believe that use of the authorities above is consistent with this directive. We would welcome the opportunity to discuss these and other potential solutions with you.

In the meantime, please contact me at [redacted] or Paul Bailey at [redacted] if you or your staff have any questions.

Sincerely,



Michelle Bloodworth
President and CEO

Copy to:

The Honorable Steve Winberg
Under Secretary for Infrastructure

UNITED STATES OF AMERICA
BEFORE THE
UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Craig Unit 1	)	Order No. 202-26-49

The State Of Colorado's Request for Rehearing,
Motion To Intervene, And Stay Request

Exhibit LLLL: Plaintiffs' Reply in Support of Response to Defendants' First Status Report, *Renewable Northwest, et al., v. Peter B. Hegseth, et al.*, No. 26-CV-01092 (D. Or. Sep. 29, 2026)

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IN THE UNITED STATES DISTRICT COURT
FOR THE DISTRICT OF OREGON
PORTLAND DIVISION

RENEWABLE NORTHWEST, *et al.*, *Plaintiffs*, v. PETER B. HEGSETH, *et al.*, *Defendants.*	Case No.: 3:26-cv-01092-IM **PLAINTIFFS' REPLY IN SUPPORT OF RESPONSE TO DEFENDANTS' FIRST STATUS REPORT**

Pursuant to this Court's order, Plaintiffs respectfully submit this reply in support of their response to Defendants' First Status Report ("Report").

I. Defendants Do Not Demonstrate Compliance with the Court's Order.

The Court required 30-day status reports for a specific purpose: "[t]o ensure compliance with the stay" by determining whether review had resumed at each stage of the Clearinghouse process. Dkt. 125 at 35–36. Instead of meeting that requirement, Defendants' Report and response principally point to DoD's purported development and adoption of a new methodology and form of mitigation agreement. But a new methodology or form is a potential tool for carrying out the process, not a substitute for compliance with its requirements. Pursuant to 10 U.S.C. § 183a and its implementing regulations in 32 C.F.R. Part 211, DoD is required to take concrete, project-specific action within specified time periods, including: preliminary review of individual applications and communication of preliminary determinations within 30 days, commencement of the prescribed mitigation process where a project presents a presumed risk to be completed within 90 days absent written extension, and issuance and communication of its determination following of conclusion of the process.

DoD may not use its development of new internal policies to replace the project-specific actions required within the timeframes prescribed by law. By doing so, Defendants have essentially perpetuated their review freeze with a new justification. As the Court previously found, DoD "cannot pick and choose which parts of this legal regime to follow" but rather "must adhere to the entire regime," including its deadlines "from start to finish." Dkt. 125 at 25.

Defendants' own account reflects the gap between their new review process and the framework prescribed by law. Defendants identify: (1) no countersigned mitigation agreements; (2) no new draft agreements beyond a single model agreement provided to non-Plaintiff developer; (3) no resumed developer engagement for the projects already in the mitigation response team process; (4) no initiation of new mitigation response team discussions; and (5) no non-objection transmittals to the Federal Aviation Administration. In other words, Defendants identify no project that has advanced through any of those stages to the next prescribed step. Nor do Defendants identify a single project that completed the Clearinghouse review since this Court entered its order. Plaintiffs do not contend that completion is the sole measure of compliance. But a report that principally describes methodology development while identifying little movement through the prescribed project-specific steps does not demonstrate that review has resumed at each stage of the Clearinghouse process. Nor does the limited activity Defendants identify necessarily show meaningful advancement. For example, an extension of the period in which mitigation review may occur is not itself mitigation review or advancement of a project through that process.

Nor can Defendants credibly reduce this issue to a disagreement about the "pace of progress." Dkt. 149 at 3. The Court already held that the statutory and regulatory timeframes are binding: preliminary review is governed by mandatory deadlines; mitigation discussions may not extend beyond 90 days absent the prescribed written extension; and for Categories 1 and 2 the

Court separately found "no basis in statute or in regulation for DoD to withhold action." Dkt. 125 at 36 n.13. That conclusion is particularly significant as to Category 1 projects. More than 30 days after that Order, Defendants still identify no Category 1 mitigation agreement that has been countersigned and offer no explanation why that action remains withheld. Neither Defendants' status report nor their response explains how that continuing inaction complies with the Court's Order.

Defendants' reliance on a historical 491-day average to process Clearinghouse projects does not help: the Court already rejected the Government's materially identical reliance on a 512-day historical average to process those applications, holding that "practical constraints cannot justify an agency's failure to comply with federal law." Dkt. 125 at 27–28; Dkt. 149 at 3. Historical noncompliance does not excuse present noncompliance. Nor does it address the issue that review of most projects remains paused indefinitely while DoD performs initial "analysis" and negotiates a mitigation agreement with a single non-Plaintiff developer.

Defendants' reliance on Plaintiffs' statement at the preliminary-injunction hearing likewise confirms, rather than undermines, Plaintiffs' position. Defendants quote Plaintiffs as saying they were "not asking for any particular action to be taken by the Government," Dkt. 149 at 3, but omit the immediately following qualification: "except for that which is required by the statute and the regulations." Dkt. 149–1, 58:8–10. Plaintiffs then explained that the relevant status quo was "the status quo that is required by the statute." *Id.* at 58:11–12. That remains Plaintiffs' position: DoD retains its capability to exercise substantive national-security judgment, but it must exercise that judgment through the timely, project-specific process Congress prescribed.

II. Recent Reporting About the Administration's Willingness to Approve Wind Energy Projects Raises Questions That Warrant Clarification at the Status Conference.

Recent public reporting indicates that the Administration is considering directing DoD to begin clearing its queue of long-delayed onshore wind projects as part of ongoing negotiations over federal permitting legislation.[1] For example, according to the reporting, the Administration has promised to approve approximately 30 projects that "have a mitigation agreement executed and are just awaiting a countersignature." *Id.* Plaintiffs do not ask this Court to adjudicate, supervise, or interfere with those negotiations, or to treat the reporting as an independent basis for relief. The reporting is nevertheless relevant to a discrete issue already before the Court. Defendants contend that pending projects require reassessment because prior mitigation work was conducted under a "former, outdated analytical framework," and that the steps DoD has taken since the injunction are "necessary" components of resumed review. Dkt. 149 at 4. If DoD can quickly approve the projects with mitigation agreements awaiting countersignature in a deal on permitting reform legislation, it's unclear why they can't quickly approve the projects to comply with the Court's order staying the freeze.

Plaintiffs respectfully submit that Defendants should be prepared at the October 1 status conference to address whether the public reporting concerns projects within the categories identified by the Court, and if so, how the reported proposal relates to the explanations Defendants

[1] *See* Josh Siegel, *Trump will green-light wind energy projects to strike permitting deal*, Politico Pro (Sept. 22, 2026); Josh Siegel, *Permitting talks on the brink as frustrations grow*, Politico Pro (Sept. 24, 2026). The Court may take judicial notice of these publications to "indicate what was in the public realm at the time." *Von Saher v. Norton Simon Museum of Art at Pasadena*, 592 F.3d 954, 960 (9th Cir. 2010). Copies of both articles are included in the State Intervenors' supplemental notice, Dkt. 150.

have offered for withholding further project-specific action pursuant to the already well-established and robust Clearinghouse process.

Dated: September 29, 2026

Respectfully submitted,

s/ Michael Giaquinto

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CERTIFICATE OF SERVICE

The undersigned certifies that, on September 29, 2026, a copy of the foregoing was uploaded to the Court's CM/ECF system, which will effectuate service on all registered counsel in this case.

s/ Michael Giaquinto

Michael Giaquinto

UNITED STATES OF AMERICA
BEFORE THE
UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Craig Unit 1	)	Order No. 202-26-49

The State Of Colorado's Request for Rehearing,
Motion To Intervene, And Stay Request

Exhibit MMMM: Partial Repeal of the Carbon Pollution Standards for Fossil Fuel-Fired Electric Generating Units, 91 Fed. Reg. 58954 (Sep. 17, 2026)

ENVIRONMENTAL PROTECTION AGENCY

40 CFR Part 60

[EPA–HQ–OAR–2025–0124; FRL–12674–02–OAR]

RIN 2060–AW55

Partial Repeal of the Carbon Pollution Standards for Fossil Fuel-Fired Electric Generating Units

AGENCY: Environmental Protection Agency (EPA).

ACTION: Final rule.

SUMMARY: In this final rule, the U.S. Environmental Protection Agency (EPA) is repealing most provisions of the 2024 Carbon Pollution Standards for greenhouse gas (GHG) emissions from fossil fuel-fired electric generating units (EGUs) based on a reevaluation of the best system of emission reduction for the relevant subcategories. Specifically, the EPA is repealing the emission guidelines for existing fossil fuel-fired steam generating units, the carbon capture and sequestration/storage (CCS)-based standards for coal-fired steam generating units undertaking a large modification, and the CCS-based standards for new base load stationary combustion turbines (*i.e.,* Phase 2 standards). In a separate action published concurrently with this final rule, the EPA is issuing a supplemental proposal soliciting comment on additional reasons to rescind all GHG emission requirements for fossil fuel-fired EGUs to effectuate the best reading of Clean Air Act (CAA) section 111 and ensure consistency with applicable principles of administrative law beyond those reasons on which the EPA solicited comment in the June 2025 notice of proposed rulemaking.

DATES: This final rule is effective on November 16, 2026. The approval of the Director of the Federal Register (FR) for incorporation by reference (IBR) of certain material listed in this rule expires as of November 16, 2026.

ADDRESSES: The EPA established a docket for this rulemaking under Docket ID No. EPA–HQ–OAR–2025–0124. All documents in the docket are listed on the *https://www.regulations.gov* website. Although listed, some information is not publicly available, *e.g.,* Confidential Business Information (CBI) or other information whose disclosure statute restricts. The EPA does not place certain other material, such as copyrighted material, on the internet; this material is publicly available only as portable document format (PDF) versions on the EPA computers in the docket office reading room. The public cannot download certain databases and physical items from the docket but may request these items by contacting the docket office at (202) 566–1744. The docket office has 10 business days to respond to these requests. With the exception of such material, publicly available docket materials are available electronically at *https://www.regulations.gov.*

FOR FURTHER INFORMATION CONTACT: For information about this final rule, contact U.S. EPA, Attn: Dr. Gregory Honda, Mail Drop: Industrial Processing and Power Division, 109 T.W. Alexander Drive, P.O. Box 12055, Research Triangle Park, North Carolina 27711; telephone number: (919) 541–2034; and email address: *honda.gregory@epa.gov.*

SUPPLEMENTARY INFORMATION:

Preamble acronyms and abbreviations. Throughout this notice the use of ''we,'' ''us,'' or ''our'' refers to the EPA. The EPA uses multiple acronyms and terms in this preamble. While this list may not be exhaustive, to ease the reading of this preamble and for reference purposes, the EPA defines the following terms and acronyms here:

ACE Affordable Clean Energy [rule]
AI artificial intelligence
BSER best system of emission reduction
Btu British thermal units
Btu/kWh British thermal units per kilowatt-hour
CAA Clean Air Act
CAAA Clean Air Act Amendments
CCS carbon capture and sequestration/storage
CCUS carbon capture, utilization, and storage
CFR Code of Federal Regulations
CO_2 carbon dioxide
CPS Carbon Pollution Standards
CPP Clean Power Plan
CRA Congressional Review Act
DOE Department of Energy
EAV equivalent annualized value
EGU electric generating unit
EIA Energy Information Administration
E.O. Executive Order
EOR enhanced oil recovery
EPA Environmental Protection Agency
EPAct05 Energy Policy Act of 2005
FEED Front-End Engineering Design
FR *Federal Register*
GHG greenhouse gas
GW gigawatt
ICR information collection request
IGCC integrated gasification combined cycle
IRC Internal Revenue Code
lb pound
MMBtu million British thermal units
MMBtu/h million British thermal units per hour
MW megawatt
MWh megawatt-hour
MWe megawatt-equivalent
NAAQS National Ambient Air Quality Standards
NAICS North American Industry Classification System
NERC North American Electric Reliability Corporation
NETL National Energy Technology Laboratory
NGCC natural gas combined cycle
NPRM notice of proposed rulemaking
NSPS new source performance standards
NTTAA National Technology Transfer and Advancement Act
OBBBA One Big Beautiful Bill Act of 2025
OMB Office of Management and Budget
PRA Paperwork Reduction Act
PV Present Value
RFA Regulatory Flexibility Act
RIA regulatory impact analysis
SO_2 sulfur dioxide
UIC Underground Injection Control
UMRA Unfunded Mandates Reform Act
U.S.C. United States Code

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I. Executive Summary

In this final rule, the EPA is finalizing the repeal of most of the GHG standards promulgated in the 2024 Carbon Pollution Standards (''2024 CPS'') for fossil fuel-fired power plants.[1] Specifically, the EPA is finalizing the repeal of the emission guidelines for existing fossil fuel-fired steam generating units, the CCS-based standards for coal-fired steam generating units undertaking a large modification, and the 2024 CCS-based standards for new base load stationary combustion turbines.

With this final action, the EPA addresses much of the regulatory uncertainty brought by the Agency's novel attempts to regulate GHG emissions from fossil fuel-fired power plants under CAA section 111. The EPA attempted to restrict GHG emissions from power plants for the first time in 2015, when the Agency issued both new source performance standards (NSPS) for new power plants (''2015 NSPS'') [2] and emission guidelines for existing power plants (the Clean Power Plan (''2015 CPP'')).[3]

In *West Virginia* v. *EPA,* the U.S. Supreme Court struck down [4] these efforts in large part, ruling that CAA section 111 does not authorize the EPA to adopt a regulatory scheme that ''cap[s] carbon dioxide emissions at a level that will force a nationwide transition away from the use of coal to generate electricity.'' [5] Rather than change course, however, the EPA in 2024 promulgated a new rule that embraced the goals of the 2015 NSPS and 2015 CPP by expanding restrictions on certain new sources and regulating existing sources in a similar manner.

The EPA's most recent effort to regulate GHG emissions from the power sector, the 2024 CPS, includes standards of performance for new and reconstructed fossil fuel-fired combustion turbines and for certain modified fossil fuel-fired steam generating power plants, as well as rules directing States to set standards of performance for existing fossil fuel-fired steam generating power plants. During the rulemaking and subsequent litigation over the 2024 CPS, numerous States, regulated entities, and other stakeholders warned that these requirements are based on technologies that have not been adequately demonstrated, are unachievable, threaten to impose massive costs on the power sector, and do not adequately ensure the national interest in affordable, reliable electricity.

On January 20, 2025, President Trump issued Executive Order (E.O.) 14154, ''Unleashing American Energy,'' which directs Federal agencies, including the EPA, to review existing regulations ''to identify those agency actions that impose an undue burden on the identification, development, or use of domestic energy resources—with particular attention to oil, natural gas, coal, hydropower, biofuels, critical mineral, and nuclear energy resources.'' [6] The E.O. further affirms that it is ''the policy of the United States to ensure that all regulatory requirements related to energy are grounded in clearly applicable law.'' [7] During the course of this review, the EPA has identified GHG emissions standards for power plants as one such action, including the 2024 CPS requirements that are the subject of this final rule.[8]

On February 19, 2025, President Trump issued E.O. 14219, ''Ensuring Lawful Governance and Implementing the President's 'Department of Government Efficiency' Deregulatory Initiative,'' which directs Federal agencies, including the EPA, to identify and consider taking action to repeal ''regulations that are based on anything other than the best reading of the underlying statutory authority or prohibition'' and ''regulations that implicate matters of social, political, or economic significance that are not authorized by clear statutory authority.'' [9] The EPA identified GHG emissions standards for power plants during the course of this review, including the 2024 CPS requirements that are the subject of this final rule.

On April 8, 2025, President Trump issued E.O. 14261, ''Reinvigorating America's Beautiful Clean Coal Industry and Amending Executive Order 14241,'' which determined that ''coal is essential to our national and economic security'' and established ''a national priority to support the domestic coal industry by removing Federal regulatory barriers that undermine coal production.'' [10] E.O. 14261 specifically found that ''coal resources will be critical to meeting the rise in electricity demand due to the resurgence of domestic manufacturing and the construction of artificial intelligence data processing centers'' and to increasing ''energy supply,'' lowering ''electricity costs,'' stabilizing the power grid, creating ''high paying jobs,'' supporting ''burgeoning industries,'' and assisting allies abroad.[11] Accordingly, E.O. 14261 directed the EPA, among other Federal agencies, to ''identify any guidance, regulations, programs, and policies within their respective executive department or agency that seek to transition the Nation away from coal production and electricity generation'' and ''consider revising or rescinding Federal actions identified in subsection (a) of this section consistent with applicable law.'' [12] The EPA identified GHG emissions standards for power plants during the course of this review as well, including the 2024 CPS requirements that are the subject of this final rule and are estimated to result in mass closures of coal-fired power plants.

The EPA reviewed the GHG emissions standards for the power sector, as directed by E.O. 14154, E.O. 14219, and E.O. 14261, and has substantial concerns about the legal and technical underpinnings of the Agency's efforts to regulate GHG emissions from fossil fuel-fired power plants. Based on a reassessment of the legal and technical conclusions in the 2015 NSPS and 2024 CPS, the EPA issued a notice of proposed rulemaking in June 2025 (''June 2025 NPRM'') that included both a primary proposal and an alternative proposal. The primary proposal would have repealed all GHG emissions

[1] 89 FR 39798 (May 9, 2024).

[2] 80 FR 64510 (October 23, 2015).

[3] 80 FR 64662 (October 23, 2015).

[4] The Supreme Court stayed the 2015 CPP after the U.S. Court of Appeals for the D.C. Circuit declined to do so prior to merits briefing. *West Virginia* v. *EPA*, 577 U.S. 1126 (2016).

[5] 597 U.S. 697, 735 (2022).

[6] 90 FR 8353 (January 20, 2025).

[7] *Id.*

[8] References to ''GHG standards'' here and elsewhere include NSPS promulgated under CAA section 111(b) and emission guidelines for existing sources promulgated under CAA section 111(d). *See* 42 U.S.C. 7411(b), (d).

[9] 90 FR 10583 (February 25, 2025).

[10] 90 FR 15517 (April 14, 2025).

[11] *Id.*

[12] *Id.*

standards for new and existing sources in the fossil fuel-fired EGU source category.[13] Specifically, the EPA proposed to determine that CAA section 111 requires the Agency to make a finding that GHG emissions from fossil fuel-fired power plants ''cause[ ], or contribute significantly'' to ''air pollution which may reasonably be anticipated to endanger public health or welfare'' (which we shorthand as ''dangerous air pollution'') as a predicate to regulating GHG emissions from those plants. The EPA further proposed to find that GHG emissions from fossil fuel-fired power plants do not contribute significantly to dangerous air pollution. The EPA is not acting on those proposed determinations at this time and is instead concurrently issuing a supplemental proposal soliciting additional public comment on the underlying question raised in the primary basis of the June 2025 NPRM: Whether the EPA lacks statutory authority to regulate GHG emissions from fossil fuel-fired power plants under CAA section 111. Whereas the primary proposal in the June 2025 NPRM sought public comment on whether fossil fuel-fired EGUs ''contribute significantly'' to air pollution, the supplemental notice seeks public comment on the distinct question whether global climate change concerns satisfy the threshold requirement in CAA section 111(b)(1)(A) that fossil fuel-fired power plant emissions contribute significantly to ''air pollution which may reasonably be anticipated to endanger public health or welfare.''

The EPA's alternative proposal was based on the Agency's reexamination of the best system of emission reduction (BSER) determinations and associated requirements for fossil fuel-fired power plants in the 2024 CPS, which it undertook to ensure that all regulatory requirements are grounded in applicable law. Under CAA section 111(a)(1), the EPA determines the BSER which, taking into account cost and any nonair quality and environmental impacts and energy requirements, has been adequately demonstrated. Based on the review of the BSER and associated requirement, the EPA proposed, in the alternative, to repeal parts of the 2024 CPS including the emission guidelines and other CCS-based requirements. As discussed below, the EPA is finalizing the alternative proposal repealing parts of the 2024 CPS and revising the associated BSER determinations as follows.

The EPA is finalizing the repeal of the emission guidelines for existing fossil fuel-fired steam generating units in their entirety. Specifically, the EPA is finalizing the determination that 90 percent CCS is not the BSER for existing long-term coal-fired steam generating units because 90 percent CCS has not been adequately demonstrated, the costs of 90 percent CCS are not reasonable, and the associated degree of emission limitation is not achievable. In a change from the 2024 CPS, the EPA concludes that previous projects that failed to achieve 90 percent CCS were not a sufficient basis to conclude the technology has been adequately demonstrated. Additionally, the carbon dioxide (CO_2) capture, pipeline, and sequestration infrastructure necessary to implement 90 percent CCS for the fleet of existing coal-fired steam generating units does not currently exist and would need to be broadly deployed. Because it is significantly unlikely that the necessary infrastructure for CCS can be deployed by the January 1, 2032 compliance date, the EPA is finalizing the determination that the degree of emission limitation in the 2024 CPS for long-term coal-fired steam generating units is not achievable.

The EPA is finalizing the determination that 40 percent natural gas co-firing is not the BSER for existing medium-term coal-fired steam generating units because 40 percent natural gas co-firing constitutes impermissible generation shifting under *West Virginia* and because the Agency erred in the 2024 CPS by construing *West Virginia* too narrowly in this respect. Additionally, a thorough consideration of the ''energy requirements'' BSER factor in CAA section 111(a)(1) shows that natural gas co-firing in a steam generating unit is an inefficient use of natural gas. Moreover, because it is unlikely that the necessary pipeline infrastructure can be deployed by the January 1, 2030 compliance date, the EPA is finalizing the determination that the degree of emission limitation is not achievable. Based on these conclusions, the EPA is repealing the requirements in the emission guidelines related to existing long-term and medium-term coal-fired steam generating units.

The EPA is also repealing the requirements in the emission guidelines related to natural gas- and oil-fired steam generating units. The EPA believes that requiring States to develop, submit, and implement plans solely for natural gas- and oil-fired steam generating units would be an inefficient use of State resources, as these sources comprise a relatively small part of the source category and the requirements under the 2024 emission guidelines for these sources would result in few or no emission reductions.

Furthermore, because the EPA is finalizing that 90 percent CCS has not been adequately demonstrated, the costs are not reasonable, and the degree of emission limitation is not achievable, the EPA is finalizing the repeal of the CCS-based requirements for coal-fired steam generating units undertaking a large modification.

The EPA is also finalizing that 90 percent CCS has not been adequately demonstrated and that the costs are not reasonable for new base load stationary combustion turbines. Furthermore, because it is unlikely that the infrastructure necessary for CCS can be deployed by the January 1, 2032 compliance date, the EPA has determined that the phase 2 standards of performance in the 2024 CPS for new base load combustion turbines are not achievable. The contrary determinations in the 2024 CPS appear to be in error for many of the same reasons that apply to existing coal-fired steam generating units. Consequently, the EPA is finalizing repeal of the phase 2 CCS-based requirements for new base load stationary combustion turbines.

The EPA solicited comment in general on the other GHG requirements for fossil fuel-fired EGUs and received comments suggesting that the 2024 efficiency-based standards (*i.e.,* the phase 1 standards) for new stationary combustion turbines are not achievable. However, the EPA is not revising or repealing those requirements in this final rule. The EPA acknowledges commenters' meritorious concerns regarding the 2024 efficiency-based standards for new stationary combustion turbines. While the EPA is not repealing or otherwise revising the 2024 efficiency-based standards in this final action, the Agency notes that it is concurrently issuing a supplemental proposal that, if finalized, would repeal all GHG standards for the fossil fuel-fired EGU source category under CAA section 111, including the 2024 efficiency-based standards in question. That action, if finalized as proposed, would resolve commenters' concerns.

A. Cost Savings

Over the 2026 to 2047 period, the present value (PV) of the estimated compliance cost savings for the power sector in 2024 dollars, discounted to 2025, is $160 billion using a three percent discount rate and $95 billion using a seven percent discount rate. Over this same period, the PV of the estimated real resource cost savings, which is the full avoided expenditure on physical and labor inputs used in the

[13] 90 FR 25752 (June 17, 2025).

power sector for compliance, is $280 billion using a three percent discount rate and $180 billion using a seven percent discount rate discounted to 2025.[14] The cost savings do not account for benefits such as ensuring electric grid reliability and other secondary and tertiary benefits that cannot be monetized.

II. General Information

A. Where To Get a Copy of This Document and Other Related Information

In addition to the docket, an electronic copy of this final action will be on the internet. Following signature by the Administrator, the EPA will post a copy of this final action at *https://www.epa.gov/stationary-sources-air-pollution/greenhouse-gas-standards-and-guidelines-fossil-fuel-fired-power.* Following publication in the **Federal Register** (FR), the EPA will post the FR version at this same website.

B. Action Applicability

Fossil fuel-fired electric utility steam generating units and stationary combustion turbine EGUs that provide electricity to the electric grid (a utility power distribution system) comprise the source category that is subject to this action. The 2022 North American Industry Classification System (NAICS) code for the source category is 221112. The EPA does not intend this identification to be exhaustive but rather to provide a guide for readers regarding the entities that this final action is likely to affect.

The final repeal of 40 Code of Federal Regulations (CFR) part 60, subpart UUUUb, is applicable to States that, under the existing regulations, must develop and submit state plans pursuant to CAA section 111(d). The final repeal of 90 percent CCS-based requirements of 40 CFR part 60, subpart TTTTa, is applicable to affected facilities that began construction, reconstruction, or modification after May 23, 2023. This final action also affects Federal, State, local, and Tribal government entities that own and/or operate EGUs subject to 40 CFR part 60, subpart TTTTa, as affected facilities are no longer subject to requirements based on 90 percent CCS.

[14] The real resource cost savings account for the costs that society avoids paying as an outcome of the CPS requirements the EPA is repealing in this final rule. *See* Regulatory Impact Analysis for the Final Partial Repeal of the Carbon Pollution Standards for Fossil Fuel-Fired Electric Generating Units, available in the docket for this rulemaking (Document ID No. EPA–HQ–OAR–2025–0124).

C. Statutory Authority

CAA section 111 authorizes the EPA to list and regulate a category of stationary sources if the Administrator, ''in his judgment,'' finds that the source category ''causes, or contributes significantly to, air pollution which may reasonably be anticipated to endanger public health or welfare.'' [15] The listing of a source category triggers the EPA's authority to promulgate ''standards of performance'' for new sources and, under limited circumstances, to prescribe regulations under which States submit plans that establish standards of performance for existing sources.[16] CAA section 111, along with agencies' authority to reconsider prior regulations, provides the statutory authority for this final action.[17]

1. Regulation of Emissions From New Sources

CAA section 111(b)(1)(A) authorizes the Administrator to publish, and from time-to-time revise, a list of categories of stationary sources that the Administrator, ''in his judgment,'' finds ''causes, or contributes significantly to, air pollution which may reasonably be anticipated to endanger public health or welfare.'' Once the EPA lists a source category under CAA section 111(b)(1)(A), the EPA must, under CAA section 111(b)(1)(B), establish ''standards of performance'' for ''new sources'' in the source category. These standards are referred to as new source performance standards, or NSPS. The NSPS are national requirements that apply directly to new sources within the relevant source category.

CAA section 111(a)(2) defines a ''new source'' as ''any stationary source, the construction or modification of which is commenced after the publication of regulations (or, if earlier, proposed regulations) prescribing a standard of performance under this section, which will be applicable to such source.'' CAA section 111(a)(4) defines ''modification'' as ''any physical change in, or change in the method of operation of, a stationary source which increases the amount of any air pollutant emitted by such source or which results in the emission of any air pollutant not previously emitted.'' While this provision treats modified sources as new sources, the EPA's regulations also treat a source that undergoes ''reconstruction,'' by substantially replacing its components, as a new source.[18]

CAA section 111(a)(1) defines ''standard of performance'' as ''a standard for emissions of air pollutants'' that must be promulgated or revised in a specified manner. When the EPA establishes or revises a performance standard, CAA section 111(a)(1) provides that such a standard must ''reflect[ ] the degree of emission limitation achievable through the application of the best system of emission reduction which (taking into account the cost of achieving such reduction and any nonair quality health and environmental impact and energy requirements) the Administrator determines has been adequately demonstrated.'' Thus, the term ''standard of performance,'' as used in CAA section 111, makes clear that the EPA must determine both the ''best system of emission reduction . . . adequately demonstrated'' for emissions of the relevant air pollutants by regulated sources in the source category and the ''degree of emission limitation achievable through the application of the [BSER].'' [19] As explained elsewhere in this preamble, to determine the BSER, the EPA first identifies the ''system[s] of emission reduction'' that are ''adequately demonstrated'' and then determines the ''best'' of those adequately demonstrated systems, ''taking into account'' factors including ''cost,'' ''nonair quality health and environmental impact,'' and ''energy requirements.'' The EPA has discretion in determining the BSER, and has historically followed a ''technology-based approach'' that focuses on ''measures that improve the pollution performance of individual sources,'' such as ''add-on controls.'' [20] (If no system of emission reduction can be deemed adequately demonstrated in light of the EPA's consideration of these factors, then it may be the case that EPA cannot identify BSER).

After determining the BSER, the EPA derives the ''degree of emission limitation achievable'' through ''application'' of the BSER. A standard of performance is ''achievable'' if a technology can reasonably be projected to be available to an individual source at the time it is constructed so as to allow it to meet the standard.[21] The EPA must then, under CAA section

[15] 42 U.S.C. 7411(b)(1)(A).

[16] 42 U.S.C. 7411(b), (d).

[17] *See FDA* v. *Wages & White Lion Invs., LLC,* 604 U.S. 542, 568 (2025); FCC v. *Fox TV Stations, Inc.,* 556 U.S. 502, 517–18 (2009); *Motor Vehicle Mfrs. Ass'n* v. *State Farm Mut. Auto. Ins. Co.,* 463 U.S. 29, 41–42 (1983); see also *Clean Air Council* v. *Pruitt,* 862 F.3d 1, 8 (D.C. Cir. 2017) (''Agencies obviously have broad discretion to reconsider a regulation at any time.'')

[18] 40 CFR 60.15.

[19] *West Virginia,* 597 U.S. at 709.

[20] *See id.* at 727 (quoting the 2015 CPP).

[21] *Portland Cement Ass'n* v. *Ruckelshaus,* 486 F.2d 375, 391 (D.C. Cir. 1973).

111(b)(1)(B), promulgate ''standard[s] for emissions''—the NSPS—that reflect that level of stringency. The EPA may determine that different sets of sources have different characteristics relevant for determining the BSER for emissions of the relevant air pollutants and may subcategorize sources accordingly pursuant to CAA section 111(b)(2).[22]

2. Regulation of Emissions From Existing Sources

The EPA has generally used CAA section 111 to establish standards for emissions of air pollutants from new sources within a category. In the rare instances where new stationary source standards concern air pollutant emissions that are not regulated under the National Ambient Air Quality Standards (NAAQS) program pursuant to CAA sections 108–110 or under the National Emission Standards for Hazardous Air Pollutants (NESHAP) program pursuant to CAA section 112, the statute provides a separate authority for addressing emissions of such air pollutants from existing sources in the source category.[23] In these limited circumstances, the promulgation of standards for new stationary sources triggers the EPA's authority to promulgate regulations for emissions of that pollutant from existing sources within the same category under CAA section 111(d).[24]

In contrast to the national regime for new sources under CAA section 111(b), CAA section 111(d) establishes a framework of ''cooperative federalism for the regulation of existing sources.'' [25] CAA section 111(a)(6) defines an ''existing source'' as ''any stationary source other than a new source.'' CAA section 111(d)(1) provides that when air pollutants covered by an NSPS for a source category are not already encompassed within the NAAQS program or NESHAP program, the EPA ''shall prescribe regulations which shall establish a procedure similar to that provided by'' CAA section 110 ''under which each State shall submit to the Administrator'' a plan for addressing emissions of such air pollutants by existing sources within such source category.[26] Reference to CAA section 110 incorporates the statute's provision for State submission and EPA review of state implementation plans (SIPs) that provide for the implementation, maintenance, and enforcement of the NAAQS for the areas within such State.[27] In a comparable manner, State plans required by the regulations authorized in CAA section 111(d) must ''establis[h] standards of performance for any existing stationary source'' for the air pollutant at issue and ''provid[e] for the implementation and enforcement of such standards of performance.''

In the relatively few instances in which the EPA applies CAA section 111(d), the Agency generally promulgates regulations, termed ''emission guidelines,'' that identify the BSER and the degree of emission limitation achievable through the application of the BSER. These regulations then require States to establish standards of performance for emissions of the air pollutant at issue by covered sources that reflect that level of stringency.[28] States need not compel regulated sources to adopt the particular components of the BSER itself. Rather, States have discretion in designing the policies and rules their sources will use to achieve the degree of emission limitation required by the emission guidelines. The statute also requires the EPA's regulations to permit a State ''in applying a standard of performance to any particular source'' to ''take into consideration, among other factors, the remaining useful life of the existing source to which such standard applies.'' [29] Once the EPA approves a State's plan, its provisions become federally enforceable against the source in the same manner as the provisions of an approved SIP under the CAA.[30] If a State elects not to submit a plan or submits a plan that the EPA does not find ''satisfactory,'' the CAA authorizes the Agency to promulgate a plan that establishes Federal standards of performance for the State's existing sources.[31]

3. Key Elements of Determining a Standard of Performance

Congress first defined the term ''standard of performance'' when enacting CAA section 111 in the 1970 CAA, amended the definition in the 1977 CAA Amendments, and amended the definition again in the 1990 CAA Amendments to largely restore the definition as in the 1970 CAA. The D.C. Circuit has reviewed CAA section 111 rulemakings on numerous occasions since the early 1970s and developed a body of case law that interprets the term.[32]

Whether promulgated by the EPA under CAA section 111(b) or established by the States under CAA section 111(d) in response to emission guidelines promulgated by the Agency, the basis for standards of performance is the ''degree of emission limitation'' that is ''achievable'' by sources in the source category by application of the ''best system of emission reduction'' that the EPA determines is ''adequately demonstrated.'' As explained in this section, systems are not ''adequately demonstrated'' if they are ''purely theoretical or experimental.'' [33] The D.C. Circuit has stated that in determining the ''best'' adequately demonstrated system for the pollutants at issue, the EPA must also take into account ''the amount of air pollution'' reduced.[34] The D.C. Circuit has also stated that the EPA may weigh the various factors identified in the statute and case law to determine the ''best'' system and has emphasized that the EPA has significant discretion in weighing the factors.[35]

After determining the BSER, the EPA sets an achievable emission limit based on application of the BSER.[36] For a CAA section 111(b) rule, the EPA determines the standard of performance that reflects that achievable emission limit. For a CAA section 111(d) rule, the States establish the standards of performance that reflect the degree of emission limitation that the EPA has included in

[22] 42 U.S.C. 7411(b)(2).

[23] 42 U.S.C. 7411(d)(1)(A)(i)–(ii).

[24] *See West Virginia,* 597 U.S. at 710 (''Section 111(d) thus 'operates as a gap-filler,' empowering EPA to regulate harmful emissions not already controlled under the Agency's other authorities. . . . Reflecting the ancillary nature of Section 111(d), EPA has used it only a handful of times since the enactment of the statute in 1970.'').

[25] *Am. Lung Ass'n* v. *EPA,* 985 F.3d 914, 931 (D.C. Cir. 2021), *rev'd in part sub nom. West Virginia,* 597 U.S. 697.

[26] 42 U.S.C. 7411(d)(1). CAA section 111(a)(6) defines an ''existing source'' as ''any stationary source other than a new source.'' 42 U.S.C. 7411(a)(6).

[27] 42 U.S.C. 7410.

[28] As discussed below, CAA section 111(d)(1)(B) provides that, in certain circumstances, States may apply standards of performance that are less stringent than the degree of emission limitation that the EPA determines in the emission guidelines. *See* 42 U.S.C. 7411(d)(1)(B).

[29] 42 U.S.C. 7411(d)(1).

[30] 42 U.S.C. 7411(d)(2)(B).

[31] 42 U.S.C. 7411(d)(2)(A).

[32] *Am. Lung Ass'n,* 985 F.3d at 914; *Delaware* v. *EPA,* No. 13–1093 (D.C. Cir. May 1, 2015); *Portland Cement Ass'n* v. *EPA,* 665 F.3d 177 (D.C. Cir. 2011); *Lignite Energy Council* v. *EPA,* 198 F.3d 930 (D.C. Cir. 1999); *Sierra Club* v. *Costle,* 657 F.2d 298 (D.C. Cir. 1981); *Essex Chem. Corp.* v. *Ruckelshaus,* 486 F.2d 427 (D.C. Cir. 1973); *Portland Cement Ass'n,* 486 F.2d at 375.

[33] *Essex Chem. Corp.,* 486 F.2d at 433–34.

[34] *Sierra Club,* 657 F.2d at 326; *see id.* at 347 (stating that the EPA must take ''technological innovation'' into account).

[35] *Lignite Energy Council,* 198 F.3d at 933 (''Because section 111 does not set forth the weight that should be assigned to each of these factors, we have granted the agency a great degree of discretion in balancing them.'').

[36] *See, e.g.,* 77 FR 49490, 49494 (August 16, 2012) (describing the three-step analysis in setting a standard of performance).

an emission guideline. In applying these standards to existing sources, States are permitted to consider a source's remaining useful life and other factors.[37]

In identifying ''system[s] of emission reduction,'' the EPA historically has followed a ''technology-based approach'' that focuses on ''measures that improve the pollution performance of individual sources,'' such as ''add-on controls.'' [38] In the 2015 CPP, the EPA significantly departed from its historical approach to standard setting under CAA section 111(b) by setting a BSER in which the ''system'' of emission reduction involved shifting electricity generation from one type of fuel to another. In *West Virginia,* the U.S. Supreme Court applied the major questions doctrine to hold that neither the term ''system'' nor any other provision of the CAA provided the requisite clear authorization to support the 2015 CPP's BSER, which the Court described as ''carbon emissions caps based on a generation shifting approach'' [39] that capped GHG ''emissions at a level that will force a nationwide transition away from the use of coal to generate electricity[.]'' [40] The Court explained that the EPA's BSER ''forc[es] a shift throughout the power grid from one type of energy source to another,'' which constituted ''unprecedented power over American industry'' and was different in kind from the type of ''system'' of emission reduction envisioned by CAA section 111(d).[41]

To qualify as the BSER, the system of emission reduction must be ''adequately demonstrated'' as ''the Administrator determines.'' [42] The plain text of CAA section 111(a)(1), and in particular the terms ''adequately'' and ''the Administrator determines,'' confers upon the EPA the discretion to identify the appropriate system, including making scientific and technological determinations and considering a broad range of policy considerations.[43] However, the terms ''adequately'' and ''demonstrated,'' as well as applicable case law, make clear that the EPA may not determine that a ''purely theoretical or experimental'' system is ''adequately demonstrated.'' [44] Moreover, applicable case law and the text and structure of CAA section 111, including the requirement that the resulting emission limitation be ''achievable'' and the eight-year review requirement in CAA section 111(b)(1)(B), place an outer bound on the EPA's discretion to project technological development into the future.

In addition, CAA section 111(a)(1) requires the EPA to account for ''the cost of achieving [the emission] reduction'' in determining the adequately demonstrated BSER. Although the CAA does not describe how the EPA should account for costs to affected sources, the D.C. Circuit has formulated the cost standard in various ways, including by stating on the upper bound that the EPA may not adopt a standard the cost of which would be ''excessive'' or ''unreasonable.'' [45] The EPA has discretion in considering cost under CAA section 111(a), both in determining the appropriate level of costs and in balancing costs with other BSER factors.[46] The D.C. Circuit has repeatedly upheld the EPA's consideration of cost in reviewing standards of performance.[47]

Under CAA section 111(a)(1), the EPA must take into account ''any nonair quality health and environmental impact and energy requirements'' in determining the BSER. Nonair quality health and environmental impacts may include the impacts of the disposal of byproducts of the air pollution controls or requirements of the air pollution control equipment for water.[48] Energy requirements may include the impact, if any, of the air pollution controls on the source's own energy needs.[49] In addition, based on the D.C. Circuit's interpretations of CAA section 111, energy requirements may also include the impact, if any, of the air pollution controls on the energy supply for a particular area or nationwide.[50] Furthermore, the EPA has considered under this statutory factor whether possible controls would create risks to the reliability of the national electricity system.[51]

The D.C. Circuit has also held that the term ''best'' authorizes the EPA to consider factors that further the purpose of the statute in addition to the ones enumerated in CAA section 111(a)(1). In particular, consistent with the plain language and the purpose of CAA section 111(a)(1), which requires the EPA to determine the ''best system of *emission reduction*'' (emphasis added), the D.C. Circuit has previously held that the Agency must consider the quantity of emissions at issue.[52] The EPA has broad discretion in determining which adequately demonstrated system of emission reduction is the ''best.'' In *Sierra Club,* the D.C. Circuit explained that ''section 111(a) explicitly instructs the EPA to balance multiple concerns when promulgating a NSPS'' and emphasized that ''[t]he text gives the EPA broad discretion to weigh different factors in setting the standard,'' including the amount of emission reductions, the cost of the controls, and the nonair quality environmental impacts and energy requirements.[53]

A standard of performance is ''achievable'' if a technology can reasonably be projected to be available to an individual source at the time it is constructed so as to allow the source to meet the standard.[54] The courts have established this approach for achievability in cases concerning CAA section 111(b) NSPS. A generally comparable approach applies to CAA section 111(d), although the BSER may differ in some cases between new and existing sources due to, for example, higher costs and feasibility of retrofit.[55] For existing sources, CAA section 111(d)(1) requires the EPA to establish regulations for State plans that, in turn, must include ''standards of performance.'' As the Supreme Court has recognized, the EPA generally carries out this provision by promulgating emission guidelines that determine the BSER for a source category and then identify the degree of

[37] 42 U.S.C. 7411(d)(1).

[38] *See West Virginia,* 597 U.S. at 727 (quoting 80 FR 64662, 64784 (October 23, 2015)).

[39] *Id.* at 732.

[40] *Id.* at 734.

[41] *Id.* at 728 (citation omitted).

[42] 42 U.S.C. 7411(a)(1).

[43] *Nat'l Asphalt Pavement Ass'n* v. *Train,* 539 F.2d 775, 786 (D.C. Cir. 1976); *Essex Chem. Corp.,* 486 F.2d at 434.

[44] *Essex Chem. Corp.,* 486 F.2d at 433–34; *see Portland Cement Ass'n,* 486 F.2d at 391–92 (the EPA may not base an ''adequately demonstrated'' determination on a '' 'crystal ball' inquiry'') (citation omitted).

[45] *Sierra Club,* 657 F.2d at 343; *see* 79 FR 1430, 1464 (January 8, 2014); *Lignite Energy Council,* 198 F.3d at 933 (costs may not be ''exorbitant''); *Portland Cement Ass'n* v. *Train,* 513 F.2d 506, 508 (D.C. Cir. 1975) (costs may not be ''greater than the industry could bear and survive'').

[46] *Sierra Club,* 657 F.2d at 343.

[47] *See Essex Chem. Corp.,* 486 F.2d at 440; *Portland Cement Ass'n,* 486 F.2d at 387–88; *Sierra Club,* 657 F.2d at 313.

[48] *Portland Cement Ass'n,* 486 F.2d at 387–88.

[49] For details on the modeled energy requirements associated with CCS, please see section 6.4 of the RIA for this final rule.

[50] *See Sierra Club,* 657 F.2d at 327–28 (quoting 44 FR 33580, 33583–84 (June 11, 1979)); 79 FR 1430, 1465 (January 8, 2014) (citing *Sierra Club,* 657 F.2d at 351).

[51] *See, e.g.,* 89 FR 39886 (May 9, 2024).

[52] *Sierra Club,* 657 F.2d at 326. The D.C. Circuit has also held that Congress intended for CAA section 111 to create incentives for new technology, and therefore that the EPA is to consider technological innovation as one of the factors in determining the ''best system of emission reduction.'' *See id.* at 346–47.

[53] *Sierra Club,* 657 F.2d at 319, 321; *see also New York* v. *Reilly,* 969 F.2d 1147, 1150 (D.C. Cir. 1992).

[54] *See Portland Cement Ass'n,* 486 F.2d at 391.

[55] *See, e.g.,* 40 FR 53340 (November 17, 1975).

emission limitation achievable by application of the BSER.[56]

D. Severability

In this final rule, the EPA is repealing (1) the emission guidelines for existing fossil fuel-fired steam generating EGUs in 40 CFR part 60, subpart UUUUb; (2) the 90 percent CCS-based standards of performance for coal-fired steam generating units undertaking a large modification in 40 CFR part 60, subpart TTTT; and (3) the 90 percent CCS-based standards of performance for new base load stationary combustion turbines in 40 CFR part 60, subpart TTTTa. Although the record evidence supporting each of these separate actions may overlap, particularly pertaining to 90 percent CCS, the repeal of each is supported by its own, standalone rationale and is severable from the others. That is, the repeal of the emission guidelines for existing sources in subpart UUUUb does not impact the 90 percent CCS-based standards of performance for coal-fired steam generating units undertaking a large modification and new base load stationary combustion turbines, as these rules apply to different sets of sources. Similarly, the repeal of the 90 percent CCS-based standards of performance either for modified sources or for new sources does not impact either of the two other rules. Again, while the records supporting each of these separate actions may overlap, application of the record evidence to each of the separate sets of regulated sources may yield different outcomes. If a court were to invalidate one or more of those actions, the EPA would still be able to implement the repeal of the remaining action or actions.

Additionally, within the group of existing fossil fuel-fired steam generating units (the sources regulated by 40 CFR subpart 60 subpart UUUUb), each of the following actions is severable: repeal of the BSER determination and associated requirements for the subcategory of long-term coal-fired steam generating EGUs, repeal of the BSER determination and associated requirements for the subcategory of medium-term coal-fired steam generating EGUs, and repeal of the requirements for the subcategory of oil- and natural gas-fired steam generating EGUs. That is, the repeal of the requirements for each separate subcategory of existing fossil fuel-fired steam generating units is based on an independent rationale and is severable from the repeal of the requirements for each other subcategory of existing units. If a court were to invalidate the EPA's action with regard to one or more subcategories of existing units, the Agency would still be able to implement the repeal of the requirements for the remaining subcategories or subcategory. This is because the requirements for each subcategory are self-contained in the regulations and, due to the design of the emission guidelines in subpart UUUUb, it would have been relatively difficult for sources to shift between subcategories. Thus, the repeal of the requirements for each subcategory of existing fossil fuel-fired steam generating units is severable.

E. Reliance Interests

The EPA requested comment on reliance interests on the 2015 NSPS and the 2024 CPS in the June 2025 NPRM that commenters believed the Agency should consider in formulating a final action.[57] Potentially significant and legitimate reliance interests may arise, for example, when regulated parties or other stakeholders expend resources to comply with existing standards, including by pricing compliance into costs for consumers. Significant and legitimate reliance interests may also arise when stakeholders reasonably factored the existence of standards into concrete plans that cannot be readily modified. Under relevant case law, these and other reliance interests may be a relevant consideration to weigh against competing rationales when deciding whether to change the Agency's position.[58] However, the EPA notes that general interests in retaining the at-issue 2024 CPS requirements for the sake of regulating GHG emissions from fossil fuel-fired power plants do not justify such retention in the absence of statutory authority and a reasoned basis for particular control requirements. To the extent the EPA is repealing aspects of the 2024 CPS based on applicable statutory requirements, the unlawful nature of those aspects necessitates repeal; the change-in-position doctrine does not expand an agency's statutory authority for the purpose of addressing reliance interests. Where possible and appropriate, the Agency considered whether any asserted reliance interests are significant and legitimate and, if so, whether different or additional regulatory actions could address such concerns, consistent with the requirements of the statute.[59]

The EPA carefully reviewed public comments to assess whether any aspects of this final action should be adjusted to account for reliance interests. The Agency received no comments on reliance interests arising from the 2024 CPS from regulated entities. To our knowledge, no expenditures on projects involving fossil fuel-fired power plants have been made exclusively in response to the 2024 CPS requirements that the EPA is repealing. The EPA notes that under the compliance dates and assumed project schedules for the two control strategies that served as the basis for requirements in the 2024 CPS concerning coal-fired power plants—90 percent CCS and 40 percent natural gas co-firing—affected sources would not yet have incurred significant expenditures. The compliance dates for these requirements, as well as the alternative compliance option of ceasing operations, were not scheduled to begin until 2032. Although, as discussed elsewhere in this preamble, the requirements involved a long implementation timeline and many fossil fuel-fired EGUs are subject to long planning horizons, much of the required buildout was anticipated to be on the part of third parties (pipeline infrastructure and injection wells, for example), and this rulemaking occurred far enough in advance to forestall the vast majority of sunk costs that would otherwise have been incurred. Based on information available to the Agency, such costs would have begun to accrue in earnest around the time of this final rule, making the action both timely and supporting reliance on the cost- and achievability-based rationales discussed herein.

Similarly, the EPA did not receive any comments from States on any resource expenditures they may have made to develop State plans in response to the emission guidelines for existing sources under 40 CFR part 60, subpart UUUUb. The EPA has not received any State plan submissions to date, and such plans were subject to extension opportunities and review that may have involved different timelines and further efforts in any event. Nor has the EPA promulgated a Federal plan in the absence of approved State plans, meaning air agencies have not expended resources participating in such a rulemaking or assisting regulated sources with compliance.

[56] *See West Virginia,* 597 U.S. at 710; 40 CFR 60.21(e), 60.21a(e) (definition of ''emission guideline'' includes provision of the degree of emission limitation achievable through the application of the BSER as determined by the Administrator).

[57] 90 FR 25752, 25777 (June 17, 2025).

[58] *See, e.g., DHS* v. *Regents of Univ. of Cal.,* 591 U.S. 1, 30 (2020).

[59] The Agency also notes that because this final rule addresses certain requirements of the 2024 CPS only, we are not addressing any potential reliance interests on the 2015 NSPS at this time.

The EPA received one comment asserting State-related reliance interests, summarized below. However, upon careful examination, the EPA determined that this comment asserted general interests that are not properly understood as significant and serious reliance on the 2024 CPS that would warrant a different or additional regulatory outcome as to the 2024 CPS requirements at issue in this rulemaking. Therefore, the Agency is not aware of any substantial reliance interests that would have informed its decision making for purposes of this final action.

Comment: One commenter asserted that State and local air agencies are relying on potential non-GHG emission reduction co-benefits from the 2024 CPS to reach NAAQS attainment for criteria pollutants. The commenter asserted that State and local agencies have invested significant staff hours and funds in planning, outreach, modeling, and rule development to implement SIPs for NAAQS attainment. The commenter stated that the proposed repeal potentially required States to develop planning scenarios with and without the 2024 CPS. The commenter stated that State and local agencies must develop new attainment strategies and incur additional expenditures.

EPA Response: The EPA disagrees that State and local air agencies have reasonably relied on the at-issue 2024 CPS requirements to the extent that the impact of repeal on planning activities would amount to serious and irreversible harms. While the EPA acknowledges there may be overlaps between NAAQS attainment planning and the GHG control strategies that States would have had to develop under the 2024 CPS, these programs are governed by separate statutory provisions and address different pollutants on different timelines and under different regulatory paradigms. That is, while GHG control strategies States may have been developing pursuant to the 2024 CPS may have had co-benefits in terms of reductions of criteria air pollutants, we disagree that such co-benefits engender serious reliance interests relevant to this rulemaking because they do not justify retaining a GHG regulatory program that is not consistent with the relevant statutory requirements. This final action does not impact any of the EPA's criteria pollutant standards of performance for power plants regulated under and listed in various pre-2015 source categories pursuant to CAA section 111, which are more directly relevant to NAAQS attainment.

Moreover, the absence of comments raising resource expenditures related to State and local air agency implementation of the 2024 CPS emission guidelines suggests that air agencies have not, in fact, expended significant resources developing GHG control strategies because of the 2024 CPS. NAAQS attainment efforts are ongoing, and the projected criteria emission co-benefits in the 2024 CPS for the at-issue requirements are small in absolute terms. That is not surprising given the relatively long time horizon involved in developing such submissions and the short period of time that elapsed between finalization of the 2024 CPS and the announcement of reconsideration. To the extent the commenter asserts that State and local air agencies worked to develop options with and without the 2024 CPS, the Agency notes that such considerations are expected when analyzing the many options available to States in exercising their considerable discretion in developing strategies to attain and maintain the NAAQS and that requirements, particularly at the proposal stage, are necessarily subject to change.

While it is reasonable for States to consider the different control strategies they will be applying to their sources in a coordinated manner, the 2024 CPS requirements at issue could not have engendered serious reliance interests under the circumstances sufficient to warrant different or additional regulatory actions in this rulemaking. The Agency finalized the CPS in May 2024 and announced its intention to reconsider the rule in March 2025.[60] At the same time, NAAQS attainment planning has been ongoing, in many cases, for decades. It is therefore not likely that States could have relied on the existence of and obligations under the 2024 CPS for NAAQS attainment planning purposes. And, in all likelihood, State and local air agencies would necessarily have to take into consideration other developments in the electric power sector due to changes in, *e.g.,* electricity demand, such that they would be considering the adequacy of their NAAQS attainment planning even absent the repeal of the 2024 CPS requirements being finalized in this action. Moreover, it is a normal course of action for State and local air agencies to re-evaluate their planning in response to changes in Federal air regulations.

Considering these factors, the EPA believes that the commenter's concerns do not constitute a serious reliance interest warranting a different outcome. Such co-benefit considerations would not be an adequate basis to retain the at-issue 2024 CPS requirements, which must be justified under and consistent with statutory requirements with respect to the subject of the regulations (*i.e.,* GHG emissions). The 2024 CPS regulates GHG emissions in the form of CO_2 for the fossil fuel-fired EGU source category and the Agency did not, in the 2024 CPS, analyze or promulgate the at-issue requirements as multi-pollutant standards.

III. Background

A. EPA Regulation of GHG Emissions Under CAA Section 111

This section discusses the EPA's efforts to regulate GHG emissions under CAA section 111 since 2015, including the regulation of fossil fuel-fired EGUs, associated case law that is relevant to this action, and the EPA's asserted legal basis for regulating GHG emissions under CAA section 111.

The EPA has regulated air pollutants from power plants under CAA section 111 since 1971, when the Agency listed ''fossil fuel-fired steam generators of more than 250 million British thermal units per hour (MMBtu/h) heat input'' as a source category under CAA section 111(b)(1)(A)[61] and subsequently promulgated NSPS for certain air pollutants.[62] In 1977, the EPA listed fossil fuel-fired ''stationary gas turbines'' in a category under CAA section 111(b)(1)(A)[63] and subsequently promulgated NSPS for certain air pollutants.[64] However, the EPA did not invoke CAA section 111 to regulate GHG emissions from power plants until 2015, when the Agency promulgated the 2015 NSPS, which addressed GHG emissions as measured by the equivalent of CO_2 emissions, from new fossil fuel-fired EGUs under CAA section 111(b);[65] and the 2015 CPP, which set emission guidelines directing States to regulate GHG emissions as measured by the equivalent of CO_2 emissions from existing EGUs under CAA section 111(d).[66]

[60] ''Trump EPA Announces Reconsideration of Biden-Harris Rule, 'Clean Power Plan 2.0,' '' That Prioritized Shutting Down Power Plants While Raising Costs on American Families'' (March 12, 2025). Available at: *https://www.epa.gov/newsreleases/trump-epa-announces-reconsideration-biden-harris-rule-clean-power-plan-20-prioritized.*

[61] 36 FR 5931 (March 31, 1971).

[62] *See, e.g.,* 36 FR 24876 (December 23, 1971); 40 CFR 60, subpart Da.

[63] *See* 42 FR 53657 (October 3, 1977).

[64] *See, e.g.,* 44 FR 62792 (September 10, 1979); 40 CFR 60, subpart KKKK.

[65] 80 FR 64510 (October 23, 2015).

[66] 80 FR 64662 (October 23, 2015).

In the 2015 NSPS, the EPA laid out a novel legal basis for regulating GHG emissions based on global climate change concerns under CAA section 111. Additionally, in that rule, the EPA asserted that the Agency was not required to make a finding of significant contribution under CAA section 111 before regulating GHG emissions. The EPA explained that CAA section 111(b)(1)(A) requires the Administrator to list any source category that ''causes, or contributes significantly to, air pollution which may reasonably be anticipated to endanger public health or welfare.'' The EPA posited that, unlike other CAA provisions, CAA section 111(b)(1)(A) does not require the EPA to make endangerment and significant contribution findings for individual pollutants. Rather, the EPA asserted that once such findings are made for *any* pollutant emitted by a source category, the Agency has discretion to regulate *all* pollutants emitted by the source category subject only to rational basis constraints.[67]

Using this framework, the EPA created a new source category (*i.e.,* all fossil fuel-fired EGUs) consisting of the type of power plants previously listed in the 1970s under separate source categories. Specifically, the EPA took the step of ''combining the steam generator and combustion turbine categories into a single category of fossil fuel-fired electricity generating units for purposes of promulgating standards of performance for GHG emissions.'' [68] The EPA explained that ''[c]ombining the two categories is reasonable because they both provide the same product: Electricity services,'' and that combining the source categories in the 2015 NSPS was consistent with the Agency's decision to combine the categories ''in the CAA section 111(d) rule for existing sources that accompanies [the 2015 NSPS],'' *i.e.,* in the 2015 CPP.[69] The Agency maintained, however, that it was not listing a new source category and therefore was not required to make any endangerment or significant contribution finding for the fossil fuel-fired EGU source category to promulgate NSPS.

The EPA determined that it had a rational basis for concluding that emissions of CO_2 from fossil fuel-fired power plants merit regulation under CAA section 111. In reaching that conclusion, the Agency stated that it had determined in the 2009 Endangerment Finding that GHG emissions may reasonably be anticipated to endanger public health or welfare and that more recent information confirmed this determination. The EPA explained that the approach it was taking with regard to endangerment and GHG emissions from the fossil fuel-fired EGU source category was ''substantially similar to that reflected in the 2009 Endangerment Finding and the 2010 denial of petitions to reconsider.'' [70] The EPA added that ''the high level of GHG emissions from fossil fuel-fired EGUs makes clear that it is rational for the EPA to regulate GHG emissions from this sector.'' [71]

The EPA explained the legal basis for its interpretation of CAA section 111(b)(1)(A) as follows: The Agency noted that the EPA had listed fossil fuel-fired steam generators as a source category in 1971 and combustion turbines as a source category in 1979, in each case on the basis of the sources' emissions of non-GHG air pollutants, and the EPA acknowledged that the Agency had not considered GHG emissions at the time of those listings. Even so, in the 2015 NSPS, the EPA stated that the Agency interpreted CAA section 111 to provide that after the EPA listed a source category once, the CAA authorized the Agency to promulgate NSPS for any air pollutant from a source listed in that source category, so long as the EPA had a rational basis for doing so.[72]

The EPA received comments on the 2015 NSPS stating that CAA section 111 did not authorize regulation of GHGs from fossil fuel-fired EGUs until the Agency first makes a finding that emission of GHGs from these power plants contributes significantly to air pollution which may reasonably be anticipated to endanger public health or welfare. The EPA disagreed with those comments. The EPA took the position that CAA section 111(b)(1)(A), 111(b)(1)(B), and 111(a)(1), read together, authorize the Agency to regulate an air pollutant from a listed source category, subject to the standards of rationality under CAA section 307(d)(9)(A), and do not require the EPA to make an additional determination, as a predicate for regulation, that the air pollutant contributes significantly to dangerous air pollution.[73]

Notwithstanding the EPA's position in the 2015 NSPS that CAA section 111 does not require a pollutant-specific significant contribution finding for GHG emissions, the Agency purported to make, in the alternative, separate endangerment and significant contribution findings pursuant to CAA section 111(b)(1)(A) for GHG emissions from fossil fuel-fired EGUs. In doing so, the EPA asserted that the information and conclusions in the preamble to the 2015 NSPS provided a sufficient basis for such findings.[74] That is, the EPA took the position that regardless whether the Agency needed only a rational basis to regulate CO_2 emissions from fossil fuel-fired EGUs or was instead required to make new endangerment and significant contribution findings, we had made the requisite determinations based on the 2009 Endangerment Finding and the additional information presented in the preamble to the 2015 NSPS.

The 2015 NSPS promulgated standards of performance to limit emissions of GHGs, manifested as CO_2, from newly constructed, modified, and reconstructed fossil fuel-fired electric utility steam generating units (*i.e.,* utility boilers and integrated gasification combined cycle (IGCC) combustion turbines) and newly constructed and reconstructed stationary combustion turbines. These final standards are codified in 40 CFR part 60, subpart TTTT. In promulgating the 2015 NSPS for newly constructed fossil fuel-fired steam generating units, the EPA determined the BSER to be a new, highly efficient, supercritical pulverized coal (SCPC) EGU that implements post-combustion partial CCS technology.

The 2015 NSPS also included standards of performance for steam generating units that undergo a ''reconstruction'' as well as units that implement ''large modifications'' (*i.e.,* modifications resulting in an increase in hourly CO_2 emissions of more than 10 percent). The 2015 NSPS did not establish standards of performance for steam generating units that undertake ''small modifications'' (*i.e.,* modifications resulting in an increase in hourly CO_2 emissions of less than or equal to 10 percent), due to the limited information available to inform the analysis of a BSER and corresponding standard of performance.

The 2015 NSPS also finalized standards of performance for newly constructed and reconstructed natural gas-fired stationary combustion turbines that operate at base load and non-base load, based on efficient natural gas

[67] 80 FR 64510, 64529–30 (October 23, 2015).

[68] *See id.* at 64531.

[69] *Id.*

[70] *Id.* at 64531; *see* 75 FR 49556 (August 13, 2010) (denying petitions for reconsideration of the 2009 Endangerment Finding).

[71] 80 FR 64510, 64530 (October 23, 2015).

[72] *Id.* at 64529–31.

[73] Promulgation of NSPS under CAA section 111(b)(1)(B) is subject to the requirements of CAA section 307(d), under CAA section 307(d)(1)(C). *See* 42 U.S.C. 7607(d)(1)(C).

[74] 80 FR 64510, 64530–31 (October 23, 2015).

combined cycle (NGCC) technology or the use of lower-emitting fuels (referred to as clean fuels in the 2015 NSPS) as the BSER. The EPA did not promulgate final standards of performance for modified stationary combustion turbines under CAA section 111(d) due to lack of information.

Petitioners challenged the 2015 NSPS in the D.C. Circuit, and the case has been held in abeyance over the years since in light of the EPA's subsequent rulemakings.

In the 2015 CPP—promulgated at the same time as the 2015 NSPS—the EPA interpreted CAA section 111(d) to require the Agency to regulate GHG emissions from existing sources in the newly combined source category because we had promulgated the 2015 NSPS for GHG emissions from new sources in that source category under CAA section 111(b).[75] The Agency noted that GHGs, and CO_2 in particular, are not separately regulated under the NAAQS program under CAA sections 107–110 or the NESHAP program under CAA section 112. The EPA determined that the BSER for existing fossil fuel-fired EGUs consisted primarily of generation shifting measures, as described in section II.C of this preamble.[76] The Supreme Court stayed the 2015 CPP pending review in February 2016,[77] and the D.C. Circuit held the litigation in abeyance and ultimately dismissed the challenges to the 2015 CPP in light of subsequent developments.[78]

In 2018, following a change in administration, the EPA proposed to revise the NSPS for new, modified, and reconstructed fossil fuel-fired steam generating units and IGCC units (2018 NSPS Proposal).[79] The EPA proposed to revise the NSPS for newly constructed units based on a revised BSER of a highly efficient EGU without partial CCS. The EPA also proposed to revise the NSPS for modified and reconstructed units. The EPA never finalized the 2018 NSPS Proposal, and the Agency rescinded the proposal as part of the 2024 CPS.

In 2019, the EPA repealed the 2015 CPP and replaced that rulemaking with the Affordable Clean Energy (ACE) Rule.[80] In the ACE Rule, the Agency determined that the statutory ''text and reasonable inferences from it'' indicate that the best ''system'' of emission reduction as defined in CAA section 111(a)(1) ''is limited to measures that can be applied to and at the level of the individual source,'' meaning the BSER must be control measures for reducing emissions at individual sources.[81] The Agency concluded that generation shifting is not such a control measure.[82] In addition, the EPA further concluded that the 2015 CPP was a ''major rule'' subject to the major questions doctrine and therefore must be supported by ''a clear statement from Congress.'' Because the statutory phrase ''best system of emission reduction'' does not clearly speak to generation shifting, the Agency reasoned that CAA section 111 should not be read to encompass generation-shifting measures.[83] To replace the 2015 CPP, the EPA promulgated as part of the ACE Rule a new set of emission guidelines for existing coal-fired steam-generating EGUs.[84] In these new emission guidelines, the EPA determined the BSER for existing coal-fired EGUs to be heat rate improvements alone. Specifically, the EPA listed various technologies that could improve heat rate and identified the ''degree of emission limitation achievable'' by providing ranges of expected emission reductions associated with each of the technologies.[85] The EPA also explained that we were not determining CCS as the BSER in part because of unreasonable expense and was not determining natural gas co-firing as the BSER because co-firing was an inefficient use of natural gas.[86]

In 2021, a divided panel of the D.C. Circuit vacated the ACE Rule, including the repeal of the 2015 CPP.[87] The panel majority held, among other things, that CAA section 111 did not limit the EPA, in determining the BSER, to measures applied at and to an individual source and that CAA section 111 authorized the Agency to determine generation shifting is the BSER. The panel majority also rejected in the argument that generation-shifting implicated ''the so-called 'major questions' doctrine'' based on its interpretation of the Supreme Court's decisions in *Massachusetts* and *AEP*.[88] As a result, the D.C. Circuit vacated both the repeal of the 2015 CPP and the ACE Rule.[89] The court did not address most other challenges to the ACE Rule, including the arguments concerning the heat rate improvement BSER.

Several petitioners argued that the ACE Rule was invalid on the grounds that the EPA had predicated regulation of GHG emissions from existing EGUs on the new source GHG emissions standards in the 2015 NSPS. In addition, petitioners argued that those standards were flawed because CAA section 111 required them to be predicated on a pollutant-specific significant contribution finding with identified standards or criteria for determining significance. The D.C. Circuit held that it did not need to decide whether CAA section 111 requires a pollutant-specific significant contribution finding for GHG emissions from EGUs as a predicate for CAA section 111 regulation because the EPA had made such a finding in the alternative. The court rejected the petitioners' argument that the significant contribution finding was flawed due to lack of identified criteria for significance and explained that the magnitude of GHG emissions from EGUs supported the significance finding without identified criteria for significance.[90]

In 2022, the U.S. Supreme Court in *West Virginia* reversed the D.C. Circuit's decision to vacate the ACE Rule's embedded repeal of the 2015 CPP.[91] As noted in section II.C of this preamble, the Supreme Court concluded that the 2015 CPP's BSER of ''generation shifting'' implicated the major questions doctrine and exceeded the EPA's statutory authority because CAA section 111 does not clearly authorize the Agency to regulate GHG emissions in a manner that forces a nationwide transition away from using coal to generate electricity.[92]

Following the U.S. Supreme Court's decision in *West Virginia,* the EPA informed the D.C. Circuit that the Agency intended to replace the ACE Rule.[93] On October 27, 2022, the D.C. Circuit took the necessary steps to, among other things, respond to the Supreme Court's decision by ensuring that the 2015 CPP remained repealed and stay further proceedings with respect to the challenges to the ACE Rule given the EPA's plans to replace that rule.[94]

[75] 80 FR 64662, 64702 (October 23, 2015).

[76] *Id.* at 64728–29.

[77] *West Virginia* v. *EPA,* 577 U.S. 1126 (2016).

[78] *Am. Lung Ass'n,* 985 F.3d at 937.

[79] 83 FR 65424 (December 20, 2018).

[80] 84 FR 32520 (July 8, 2019).

[81] *See id.* at 32523–24.

[82] *See id.* at 32546.

[83] *See id.* at 32529.

[84] *See id.* at 32532.

[85] *Id.* at 32535–38.

[86] *Id.* at 32545.

[87] *Am. Lung Ass'n,* 985 F.3d at 914.

[88] *Id.* at 959.

[89] *Id.* at 995. In a partial dissent, Judge Walker argued that the 2015 CPP (and aspects retained in the 2019 ACE Rule) violated the major questions doctrine because CAA section 111 does not include a clear statement of authority to regulate GHG emissions from power plants. *Id.* at 995–1003.

[90] *Id.* at 974–77.

[91] *West Virginia,* 597 U.S. 697.

[92] *Id.* at 734–35.

[93] *Am. Lung Ass'n* v. *EPA,* D.C. Cir. No. 19–1140, Motion to Govern, Doc. #196782 (October 3, 2022).

[94] *Am. Lung Ass'n* v. *EPA,* D.C. Cir. No. 19–1140, Order, Doc. #1970895 (October 27, 2022).

B. Carbon Pollution Standards

On May 9, 2024, the EPA promulgated the CPS, which consisted of several separate actions.[95] The first action was the repeal of the ACE Rule. The EPA explained, among other things, that the suite of heat rate improvements that was identified in the ACE Rule as the BSER is not an appropriate BSER for existing coal-fired EGUs.[96]

In addition, the 2024 CPS included emission guidelines for GHG emissions from existing fossil fuel-fired steam generating units, which include the separate subcategories of coal-fired units, oil-fired units, and gas-fired units.[97] For long-term coal-fired units, the EPA finalized 90 percent CCS as the BSER, with a presumptive standard of an 88.4 percent reduction in annual emission rate and a compliance deadline of January 1, 2032. The EPA asserted that 90 percent CCS is an adequately demonstrated technology that achieves significant emissions reduction and that costs are reasonable, considering the supposedly declining costs of the technology and the Internal Revenue Code (IRC) section 45Q tax credit available for a certain number of years to generating sources that use CCS technology. In recognition of the significant capital expenditures involved in deploying CCS and previously announced retirement dates for several coal-fired steam generating units, the EPA finalized a separate subcategory for existing coal-fired units that demonstrate that they plan to permanently cease operation before January 1, 2039. For this subcategory, the BSER is co-firing with natural gas at a level of 40 percent of the unit's annual heat input, the presumptive standard is a 16 percent reduction in annual emission rate, and the compliance deadline is January 1, 2030. In addition, the EPA exempted existing coal-fired units that demonstrate that they plan to permanently cease operation prior to January 1, 2032. The EPA determined that these controls were cost-effective primarily by reference to two metrics used in prior rulemakings. The first metric determines the annualized cost in dollars for each ton, or other quantity, of the regulated air pollutant removed through the system of emission reduction. The second metric, which the EPA particularly relied on in rules for the electric power sector, determines the annualized cost of controls relative to the electricity generated by the EGU in dollars per megawatt-hour ($/MWh) of generation.[98]

For existing natural gas- and oil-fired steam generating units, the EPA further subcategorized them into base load (units with annual capacity factors greater than or equal to 45 percent), intermediate load (units with annual capacity factors greater than or equal to eight percent and less than 45 percent), and low load (units with annual capacity factors less than eight percent) subcategories. The EPA finalized routine methods of operation and maintenance as the BSER for base load and intermediate load units, with presumptive standards for base load units of 1,400 pounds (lb) CO_2/MWh-gross, and for intermediate load units of 1,600 lb CO_2/MWh-gross.[99] For low load units, the EPA finalized a uniform fuels BSER and a presumptive input-based standard of 170 lb CO_2/MMBtu for oil-fired sources and a presumptive standard of 130 lb CO_2/MMBtu for natural gas-fired sources.

The 2024 CPS also included standards of performance for new and reconstructed combustion turbines organized into three subcategories: base load, intermediate load, and low load. For base load turbines, the standard consisted of two components in two phases. The first component is based on a BSER of highly efficient generation (which was determined based on the emission rates achieved by the best performing units), and the EPA required compliance with this first component upon the effective date of the 2024 CPS. The second component is based on a BSER of 90 percent CCS, and the EPA required compliance with this second component on January 1, 2032. For intermediate load turbines, the EPA determined that highly efficient simple-cycle generation is the BSER. For low load combustion turbines, the EPA determined that the use of lower-emitting fuels is the BSER.

In addition, the EPA revised the standards of performance for coal-fired steam generating units that undertake a large modification (*i.e.,* a modification that increases the hourly emission rate of the source by more than 10 percent) to be based on the BSER of 90 percent CCS. Finally, the EPA withdrew the 2018 NSPS Proposal for GHG emissions from coal-fired EGUs.[100]

Following promulgation of the 2024 CPS, many States and industry groups filed petitions for review in the D.C. Circuit, and many subsequently filed motions to stay the rule. The D.C. Circuit denied the stay motions on July 19, 2024,[101] and the Supreme Court denied these motions on October 16, 2024.[102] Justice Thomas would have granted a stay, and Justice Kavanaugh, joined by Justice Gorsuch, wrote that ''the applicants have shown a strong likelihood of success on the merits as to at least some of their challenges to the [EPA's] rule.'' [103] The parties briefed the merits, and the D.C. Circuit held oral argument on December 6, 2024. Following a change in administration, the D.C. Circuit agreed to hold the case in abeyance pending further actions by the Agency.

C. Changes in Trends in Fossil Fuel-Fired EGUs

In the 2024 CPS, the historical data that supported the analysis that the EPA conducted and relied on to assess the rule's projected impacts showed only incremental increases in electricity demand: a 13 percent increase between 2000 and 2022, with demand remaining relatively flat from 2007 to 2022. At the same time, the share of coal-fired electricity decreased in both relative and absolute terms, declining 58 percent and going from delivering 52 percent of total net generation in 2000 to 19 percent in 2022. Natural gas-fired net generation increased by 181 percent over this period, delivering 39 percent of net generation in 2022. The combination of wind and solar net generation grew 172 percent over this period, delivering 15 percent of total net generation in 2022. Natural gas surpassed the total net generation from coal on an absolute basis in 2016, and renewables surpassed the total net generation from coal on an absolute basis in 2022.[104] The information that the EPA analyzed for purposes of the 2024 CPS indicated that the sector trend of moving away from coal-fired generation was likely to continue, the

[95] 89 FR 39798 (May 9, 2024).

[96] In the CPS, the EPA also withdrew the separate proposed revisions to the New Source Review (NSR) regulations that were included the ACE Rule proposal. *See* 83 FR 44746, 44773–83 (August 31, 2018).

[97] Although the EPA also proposed emission guidelines for GHG emissions from existing fossil fuel-fired combustion turbines in the proposed CPS, the Agency did not finalize those emission guidelines.

[98] 89 FR 39798, 39882 (May 9, 2024).

[99] ''Gross'' refers to the electricity generated by the EGU, as opposed to ''net,'' which is equivalent to the electricity delivered to the grid and accounts for the loss due to the electricity used by auxiliary equipment at the facility.

[100] 83 FR 65424 (December 20, 2018).

[101] *West Virginia* v. *EPA,* D.C. Cir. No. 24–1120, Order, Doc. #2065493 (July 19, 2024).

[102] *West Virginia* v. *EPA,* 145 S. Ct. 2 (2024).

[103] *Id.*

[104] Power Sector Trends Technical Support Document for the New Source Performance Standards for Greenhouse Gas Emissions from New, Modified, and Reconstructed Fossil Fuel-Fired Electric Generating Units; Emission Guidelines for Greenhouse Gas Emissions from Existing Fossil Fuel-Fired Electric Generating Units; and Repeal of the Affordable Clean Energy Rule at 5–6, Document ID No. EPA–HQ–OAR–2023–0072–8920.

share of electricity generation from natural gas-fired sources would likely decline, and the share of generation from non-emitting technologies would likely continue to increase. In the 2024 CPS, the EPA anticipated that the recent trend of retirements of coal-fired capacity (at an average annual rate of 10 gigawatt (GW) from 2015 to 2023) would continue due to the economics of coal-fired generation. At the time of the 2024 CPS final rule, more than half of the coal-fired steam generating units in operation had announced that they would retire or convert to natural gas by 2039.[105]

In contrast, updated information and analysis of power sector trends indicates a significantly different landscape moving forward. As noted in the June 2025 NPRM, the EPA believes that coal-fired steam generating unit capacity and generation will continue to comprise a substantial portion of the nation's electricity supply due to increasing electricity demand.[106] Several key factors play major roles in reshaping projections of electricity markets over the coming decades. Demand growth across the U.S. is significantly higher than prior estimates. According to the 2024 North American Electric Reliability Corporation (NERC) Long Term Reliability Assessment, peak demand remained static nationwide over the ten-year period from 2013 through 2022.[107] In 2022, NERC projected a 0.65 percent compound annual growth rate for summer peak demand based on the ten-year period of 2022 through 2031.[108] In contrast, in late 2024, NERC projected a 1.67 percent compound annual growth rate for summer peak demand based on the ten-year period of 2025 through 2034.[109] Increasing amounts of large commercial and industrial loads, particularly those related to data center demand for artificial intelligence (AI) applications, are primarily driving this nearly 2.6-fold increase in projected growth rates. Sub-nationally, these impacts are even more striking. The Electric Reliability Council of Texas' (ERCOT) 2025 long-term load forecast projects summer peak demand rising at an 8.9 percent annual growth rate based on the six-year period of 2025 to 2031.[110] The 2025 long-term load forecast for PJM, a regional transmission organization serving large parts of the eastern US, projects a 3.1 percent annual growth rate in summer peak demand based on the ten-year period of 2025 to 2035.[111] NERC concludes that critical reliability challenges face the sector when considering the need to meet this higher level of demand, manage ongoing thermal retirements, and develop additional transmission and support resources.[112] A recent Department of Energy (DOE) report, which examines reliability implications of ongoing thermal retirements in the face of projected increases in electricity demand, echoes these findings and further states that the risk of power outages may increase by a hundred fold in some instances if firm resources continue to retire in the face of projected load growth.[113]

The passage of the One Big Beautiful Bill Act of 2025 (OBBBA) will also have important impacts on the power sector. The phaseout of tax subsidies to wind and solar resources will likely reduce incremental builds of these technologies, particularly after 2028. This, in turn, will further increase the need for retaining existing thermal resources (including coal-fired steam generating units) and building new thermal (including new combustion turbines) resources to help meet increasing electricity demand. Considering these changes, the EPA expects the OBBBA to produce a net effect of reducing factors that boosted the economic competitiveness of wind and solar resources and improving the economic competitiveness of thermal generation (including coal and natural gas-fired generation).

Moreover, higher levels of electricity demand result in greater demand for around-the-clock power, which results in a higher utilization of coal- and gas-fired resources in the EPA's current analysis than in the EPA's 2024 analysis underpinning the 2024 CPS.[114] The trends the EPA has incorporated into the updated analysis result in projections that show total electricity generation will increase by approximately 15 percent by 2030 and 25 percent by 2035,[115] significantly higher than projections in the 2024 analysis for the 2024 CPS.[116]

This recent change in demand for around-the-clock power already is effecting changes in the current market, as shown by a number of coal-fired steam generating units that are delaying or canceling their scheduled retirements due to increased electricity demand.[117] Using the latest available data from the Energy Information Administration (EIA), in 2024, the U.S. power sector had approximately 174 GW of coal-fired EGUs that collectively consumed approximately 7.0 quadrillion British thermal units (Btus) of energy. According to data reported by the owners and operators of coal-fired capacity, the EIA expects 146 GW of this capacity to remain in service through 2032. In addition, the EIA now expects 24.5 GW of combined cycle additions and 11.5 GW of combustion turbine additions over the next five years,[118] demonstrating a sharp increase from the August 2023 EIA data underlying the analysis of the 2024 CPS, which cited roughly 9.6 GW of combined cycle and 1.9 GW of combustion turbine additions planned for construction between 2025 and 2030.[119]

The EPA's updated projections reflect these changes.[120] As a specific example, at the end of 2024, 174 GW of coal-fired EGUs were active in the power sector

[105] 89 FR 39798, 39816–18 (May 9, 2024).

[106] *See* 90 FR 25752, 25772, 25774 (June 17, 2025).

[107] NERC 2023 Long-Term Reliability Assessment (December 2024). Available at: *https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_Long%20Term%20Reliability%20Assessment_2024.pdf.*

[108] NERC 2021 Long-Term Reliability Assessment (December 2022). Available at: *https://www.nerc.com/our-work/assessments/past-reliability-assessments.*

[109] NERC 2023 Long-Term Reliability Assessment (December 2024). Available at: *https://www.nerc.com/our-work/assessments/past-reliability-assessments.*

[110] ERCOT. 2025 System Planning Long-term Hourly Peak Demand and Energy Forecast. Available at: *https://www.ercot.com/files/docs/2025/04/08/2025_LTLF_Report.docx.*

[111] PJM. 2025 Long-Term Load Forecast Report. Available at: *https://www.pjm.com/-/media/DotCom/library/reports-notices/load-forecast/2025-load-report.pdf.*

[112] NERC 2023 Long-Term Reliability Assessment (December 2024). Available at: *https://www.nerc.com/our-work/assessments/past-reliability-assessments.*

[113] U.S. Department of Energy, Resource Adequacy Report Evaluating the Reliability and Security of the United States Electric Grid (2025). Available at: *https://www.energy.gov/sites/default/files/2025-07/DOE%20Final%20EO%20Report%20%28FINAL%20JULY%207%29.pdf.*

[114] See memorandum entitled *Trends Relating to Fossil Fuel-fired Electric Generating Units* in the docket for this rulemaking (Docket ID No. EPA–HQ–OAR–2025–0124).

[115] *Id.*

[116] U.S. EPA. Regulatory Impact Analysis for the New Source Performance Standards for Greenhouse Gas Emissions from New, Modified, and Reconstructed Fossil Fuel-Fired Electric Generating Units; Emission Guidelines for Greenhouse Gas Emissions from Existing Fossil Fuel-Fired Electric Generating Units; and Repeal of the Affordable Clean Energy Rule (May 2024). Document ID No. EPA–HQ–OAR–2023–0072–8913.

[117] Power. U.S. Coal Plants Get Reprieve as Market and Policies Change. Available at: *https://www.powermag.com/u-s-coal-plants-get-reprieve-as-market-and-policies-change.*

[118] U.S. Energy Information Administration. EIA Power Monthly (October 2025). Available at: *https://www.eia.gov/electricity/data/eia860m/xls/october_generator2025.xlsx.*

[119] U.S. Energy Information Administration. EIA Power Monthly (August 2023). Available at: *https://www.eia.gov/electricity/data/eia860m/xls/august_generator2023.xlsx.*

[120] See memorandum entitled *Trends Relating to Fossil Fuel-fired Electric Generating Units* in the docket for this rulemaking (Docket ID No. EPA–HQ–OAR–2025–0124).

nationwide.[121] In the 2024 CPS, the EPA projected that, in the baseline absent requirements, approximately 40 GW of existing coal capacity would still be active by 2040.[122] However, the EPA has revisited the 2024 baseline in light of the information above. The EPA now projects that, absent the requirements of the 2024 CPS, approximately 100 GW of coal capacity would be active in 2040,[123] more than twice the capacity EPA previously projected. Similarly, in the 2024 CPS, the EPA projected approximately 26 GW of incremental NGCC capacity additions by 2035.[124] The EPA now projects, absent the requirements of the 2024 CPS, approximately 155 GW of new NGCC capacity by 2035. Based on the EPA's updated projections, informed by the recent and consequential changes in the electricity market, a much larger number of EGUs would be subject to the requirements of the 2024 CPS than previously estimated for the purposes of that rulemaking.

D. June 2025 NPRM

In June 2025, the EPA issued a NPRM that included two proposals: a primary proposal and an alternative proposal. The primary proposal would have repealed all GHG regulations for fossil fuel-fired EGUs under CAA section 111 on the basis that the source category does not significantly contribute to dangerous GHG air pollution. Specifically, the EPA proposed to conclude that CAA section 111 is best read to require, or at least authorize the EPA to require, the Administrator's determination that an air pollutant emitted by a source category causes, or contributes significantly to, air pollution which may reasonably be anticipated to endanger public health or welfare as a predicate to establishing emission standards for that pollutant. The EPA further proposed to determine, in a change from the 2015 NSPS and the 2024 CPS, that GHG emissions from fossil fuel-fired power plants do not contribute significantly to dangerous air pollution as required for the promulgation of new and existing source standards. The EPA proposed to find that the contribution of this source category is not significant because GHG emissions from those sources are a small and decreasing part of global emissions, cost-effective control measures are not reasonably available, and this Administration's priority is to protect the environment, public health, and welfare through energy dominance and independence secured through the use of fossil fuels to generate power. On the basis of the proposed finding that GHG emissions from fossil fuel-fired power plants do not contribute significantly to dangerous air pollution, the EPA proposed to repeal all GHG emissions standards for the power sector under CAA section 111, specifically the 2015 NSPS (codified in 40 CFR part 60, subpart TTTT) and the 2024 CPS (codified in 40 CFR part 60, subparts TTTTa and UUUUb).

In the alternative, based largely on a review of the BSER determinations in the 2024 CPS, the EPA proposed to repeal the emission guidelines for existing steam generating units in 40 CFR part 60, subpart UUUUb, the CCS-based requirements for coal-fired steam generating units undergoing a large modification in 40 CFR part 60, subpart TTTTa, and the CCS-based phase 2 requirements for new base load combustion turbines in 40 CFR part 60, subpart TTTTa. The EPA also solicited comment, in general, on the other standards (*e.g.,* phase 1 standards for new combustion turbines).

IV. Repeal of Sections of the Carbon Pollution Standards

The EPA is finalizing the repeal of the emission guidelines in the 2024 CPS for existing fossil fuel-fired steam generating units in 40 CFR part 60, subpart UUUUb. The EPA also is finalizing the repeal of the requirements for coal-fired steam generating units undertaking a large modification in 40 CFR part 60, subpart TTTTa and the phase 2 CCS-based requirements for new base load combustion turbine EGUs in 40 CFR part 60, subpart TTTTa. As discussed in more detail in this section of the preamble, the EPA is finalizing those repeals on the bases that (1) 90 percent CCS is not the BSER for existing long-term coal-fired steam generating units and the degree of emission limitation in the 2024 CPS is not achievable, (2) 40 percent natural gas co-firing is not the BSER for medium-term coal-fired steam generating units and the degree of emission limitation is not achievable, (3) it would be imprudent to require States to submit plans for oil- and natural gas-fired steam generating units, and (4) 90 percent CCS is not the BSER for new base load combustion turbines and the associated standards of performance are not achievable.

The EPA acknowledges the uncertainty created by the 2024 CPS, particularly given the consequential changes to projected trends in electricity demand and generation.[125] To provide near-term relief to affected sources from the regulatory burdens of the 2024 CPS that are the cause of this uncertainty, the EPA is finalizing, based largely on the unreasonableness of the BSER determinations in the 2024 CPS, the repeal of the emission guidelines for existing steam generating units, the CCS-based requirements for coal-fired steam generating units undergoing a large modification, and the CCS-based phase 2 requirements for new base load combustion turbines.

Specifically, the EPA is finalizing the determination that 90 percent CCS is not the BSER for existing long-term coal-fired steam generating units because it has not been adequately demonstrated and because the costs are not reasonable. Furthermore, because it is unlikely the infrastructure for CCS can be deployed by the January 1, 2032 compliance date, the EPA is finalizing the determination that the degree of emission limitation in the 2024 CPS for long-term coal-fired steam generating units is not achievable. The EPA is also finalizing the determination that 40 percent natural gas co-firing is not the BSER for existing medium-term coal-fired steam generating units for several reasons. First, 40 percent natural gas co-firing cannot be BSER because 40 percent natural gas co-firing is a type of generation-shifting and is precluded by the Supreme Court's decision in *West Virginia.* Additionally, 40 percent natural gas co-firing cannot be BSER because consideration of the energy requirements shows that 40 percent natural gas co-firing has adverse consequences for the energy system. Moreover, because it is unlikely the infrastructure for 40 percent co-firing can practicably be deployed by the January 1, 2030 compliance date, the EPA is finalizing the determination that the degree of emission limitation in the 2024 CPS for medium-term coal-fired steam generating units is not achievable. Therefore, the EPA is repealing the BSER determinations, presumptive standards of performance, and all

[121] U.S. Energy Information Administration. EIA Power Monthly (December 2024). Available at: *https://www.eia.gov/electricity/monthly/archive/december2024.pdf.*

[122] U.S. EPA. RIA for 2024 CPS. Document ID No. EPA–HQ–OAR–2023–0072–8913. Table 3–14.

[123] See memorandum entitled *Trends Relating to Fossil Fuel-fired Electric Generating Units* in the docket for this rulemaking (Docket ID No. EPA–HQ–OAR–2025–0124).

[124] U.S. EPA. RIA for 2024 CPS. Document ID No. EPA–HQ–OAR–2023–0072–8913. Table 3–14.

[125] *See, e.g.,* Comments of the Power Generators Air Coalition on EPA's Proposed Repeal of Greenhouse Gas Emissions Standards for Fossil-Fuel Fired Electric Generating Units at 6, Document ID No. EPA–HQ–OAR–2025–0125–0610; Comments from the Edison Electric Institutes on the Proposed Rule Repeal of Greenhouse Gas Emissions Standards for Fossil Fuel-Fired Electric Generating Units at 6–12, Document ID No. EPA–HQ–OAR–2025–0125–0897.

related requirements in the emission guidelines for existing long-term and medium-term coal-fired steam generating units.

Additionally, the EPA is repealing the requirements for existing natural gas- and oil-fired steam generating units because it would be an inefficient use of State resources to develop, submit, and implement state plans solely for natural gas- and oil-fired steam generating units, which comprise a relatively small part of the source category and would contribute few or no emission reductions under the existing emission guidelines. That is, it would not be reasonable for the EPA to require States to prepare plans for existing natural gas- and oil-fired steam generating units given that the Agency is repealing the requirements for existing coal-fired steam generating units.

The EPA is thus repealing the substantive requirements and, on that basis, is repealing 40 CFR part 60, subpart UUUUb—the emission guidelines for existing fossil fuel-fired steam generating units—in its entirety.

Because the EPA is determining that 90 percent CCS is not the BSER for existing long-term coal-fired steam generating units, the EPA is also repealing the CCS-based requirements for coal-fired steam generating units undertaking a large modification. The EPA is also determining that 90 percent CCS is not the BSER for new base load combustion turbine EGUs because it has not been adequately demonstrated and the costs are not reasonable. Furthermore, because it is unlikely that the infrastructure necessary for CCS can be deployed by the January 1, 2032 compliance date, the EPA is determining that the phase 2 standards of performance in the 2024 CPS for new base load combustion turbines are not achievable. Consequently, the EPA is repealing the phase 2 CCS-based requirements for new base load combustion turbine EGUs.

Although the EPA discusses each relevant repeal and the associated bases below, several observations about the 2024 CPS reinforce the fundamental issues with that prior action—and the 2015 CPP that preceded it—and support the Agency's decision to proceed with these repeals, including the repeal of standards predicated on 90 percent CCS.

First, the 2024 CPS reflected an overly restrained reading of the Supreme Court's assessment of the 2015 CPP in *West Virginia.* The EPA initially viewed that decision as barring only standards that expressly require generation shifting.[126] Upon further consideration, the EPA now accepts that decision as holding that the Agency may not impose standards with the objective or result of generation shifting at the scale the Court found to raise a major question reserved for Congress. Information reviewed since promulgation of the 2024 CPS demonstrates that standards predicated on achieving 90 percent CCS cross that threshold. Regulated sources in the relevant subcategories (*i.e.,* coal plants) were given the choice between complying with the standards by 2032 or ceasing operations by 2032. Because, for the reasons discussed throughout this preamble, emission limitation requirements based on 90 percent CCS are not achievable, the 2024 CPS effectively requires coal plants to shut down by 2032—a form of generation shifting. Under these circumstances, retaining these aspects of the 2024 CPS would be improper.

Second, the 2024 CPS reflected an overbroad reading of CAA section 111 that did not recognize or account for limits on the EPA's ability to identify a BSER requiring the deployment of new infrastructure over a long time horizon. In promulgating the 2024 CPS, the EPA projected—based on, as discussed below, optimistic assumptions—that complex carbon capture, transmission, and injection infrastructure that did not yet exist could be deployed nationwide within seven years, and did not view the inherent uncertainties and long time horizon as a barrier to adopting, or reason not to adopt, 90 percent CCS as the BSER. Upon further consideration, the Agency concludes that the inherent difficulties in accurately projecting such large-scale deployments counsel against selecting BSERs predicated on large-scale national infrastructure buildouts years into the future, particularly given the statute's eight-year cycle for reviewing the effectiveness of promulgated standards.

Third, and relatedly, the 2024 CPS reflected an overbroad reading of CAA section 111 that did not recognize or account for the scale of the infrastructure required for compliance, including the difference between systems that sources can apply to meet the standards that apply to them and systems that require significant investment and performance by third parties. Owners and operators of power plants subject to 90 percent CCS-based requirements are dependent on third parties to develop and operate virtually all the components of CCS. Transport and storage, in particular, differ from the types of equipment the Agency has historically selected as BSER. All relevant third parties would need to timely complete their components of the infrastructure across large geographic areas for the owners and operators to be able to implement the CCS requirements by the compliance date, and thereafter, owners and operators must rely on the continued cooperation and operation of these third parties. Upon further consideration, the EPA concludes that the scale of the necessary infrastructure, including the necessary involvement of third parties nationwide, is different in kind from control measures historically considered under CAA section 111 and counsels against selecting 90 percent CCS as BSER.

The remainder of this section details the rationale for the repeal of the emission guidelines for existing fossil fuel-fired steam generating units, the CCS-based requirements for coal-fired steam generating units undertaking a large modification, and the 2024 CCS-based requirements for new combustion turbine EGUs. The EPA carefully considered the comments received on the June 2025 NPRM in the development of this final rulemaking and the supporting rationale. The EPA discusses some of the overarching comments received on the June 2025 NPRM and provides responses in this section of the preamble.[127]

Comments: The EPA received extensive comments on both the primary and alternative proposals of the June 2025 NPRM. Among the group of commenters generally in favor of the proposals, some supported finalizing the primary proposal, some supported finalizing the alternative proposal, and others supported finalizing both proposals. Among the commenters in favor of finalizing both proposals, some recommended finalizing the alternative proposal first, followed by the primary proposal, while others urged the EPA to finalize both proposals simultaneously. Other commenters opposed both proposals.

EPA Response: Based on consideration of those comments and other factors, in this final rule, the EPA is finalizing only the alternative proposal in the June 2025 NPRM—that is, the proposal to repeal the emission guidelines for existing steam generating

[126] *See, e.g.,* US working on power plant standards for energy transition: US EPA head, July 29, 2023, available at *https://www.world-energy.org/article/34841.html* (''We are working on a proposed power plant standard in the United States that helps us to transition from heavily fossil fuel resources to clean resources. . . .'').

[127] Responses to substantial comments on specific issues are addressed in the relevant sections of this preamble. Responses to additional comments are in the RTC, available in the docket for this rulemaking (Docket ID No. EPA–HQ–OAR–2025–0124).

units and the CCS-based requirements for new base load combustion turbine EGUs and coal-fired steam generating units undertaking a large modification. This final action is based on a record-focused reevaluation of the BSER determinations for the relevant subcategories. As previously explained, the EPA is taking this final action to provide near-term relief from regulatory requirements it now finds are unlawful or otherwise unreasonable. The EPA is not, in this rulemaking, finalizing the primary proposal in the June 2025 NPRM to repeal all GHG regulations for fossil fuel-fired EGUs under CAA section 111 on the basis that the source category does not significantly contribute to qualifying air pollution. The EPA is instead issuing a supplemental proposal soliciting additional public comment on the underlying question raised in the primary basis of the June 2025 NPRM: Whether the EPA lacks statutory authority to regulate GHG emissions from fossil fuel-fired power plants under CAA section 111 under the applicable statutory standard for such regulation. The primary proposal in the June 2025 NPRM sought public comment on whether fossil fuel-fired EGUs ''contribute significantly'' to air pollution, and the supplemental notice seeks public comment on the distinct question whether global climate change concerns satisfy the threshold requirement in CAA section 111(b)(1)(A) that the source category emissions contribute significantly to ''air pollution which may reasonably be anticipated to endanger public health or welfare.'' We will evaluate both proposed approaches and rationales in taking final action, as both issues—contribution and endangerment—were the subject of significant interpretive and policy changes in the 2009 Endangerment Finding and the 2015 NSPS (as retained by the 2024 CPS) that extended the Agency's novel approach to power plant stationary sources. The EPA therefore is responding in this final rule only to comments on the alternative proposal that the Agency is finalizing—the proposal to repeal 40 CFR part 60, subpart UUUUb and certain components of 40 CFR part 60, subpart TTTTa. The EPA is not responding at this time to comments that relate solely to the June 2025 primary proposal.

Comments: Some commenters opposed to the proposal to repeal the emission guidelines and other CCS-related requirements asserted that such repeal would be unlawful because the EPA must consider alternatives to the BSER determinations and requirements at issue and/or immediately promulgate different requirements based on alternative BSERs. Commenters asserted that the CAA requires the EPA to set standards of performance under CAA section 111(b) for GHG emissions from fossil fuel-fired power plants because they are listed as a source category under CAA section 111 and that the Agency has previously determined that such emissions contribute significantly to GHG air pollution that endangers public health and welfare. Additionally, these commenters asserted that CAA section 111(d) requires the EPA to promulgate emission guidelines for existing sources that would be subject to the standards under CAA section 111(b) if the sources were new sources. Commenters asserted that the repeal of the 2024 CPS's emission guidelines and standards of performance at issue in this rulemaking would leave these legal mandates unfilled and that repealing these requirements without considering and/or promulgating alternative requirements based on alternative BSERs would be arbitrary and capricious.

EPA Response: The EPA disagrees with these comments. The EPA carefully considered alternatives to repeal of the emission guidelines and standards of performance (*e.g.,* whether to revise the BSER determinations or compliance schedules for the affected sources and whether to promulgate different standards immediately) and is determining that it is not necessary to do so at this time. The EPA remains concerned that it lacks the requisite statutory authority to regulate GHG emissions from power plants in the first instance under the applicable statutory standard for regulation. Indeed, other commenters urged that the EPA must resolve this predicate question before promulgating additional or different standards. Accordingly, the EPA is exercising its discretion to proceed through multiple steps that will address the totality of the problem before it in an orderly fashion.

In a concurrently issued supplemental proposal, the EPA is proposing to find that the Agency lacks the requisite legal basis to regulate GHG emissions from fossil fuel-fired power plants under CAA section 111. These proposed bases are in addition to those presented in the primary proposal in the June 2025 NPRM and will be considered together with the bases previously presented in taking final action. If finalized as proposed, this subsequent action would abrogate any legal requirement and authority to replace the BSER determinations and associated requirements that the EPA is repealing in this final rule. Such action would render it inappropriate and unnecessary to promulgate any alternative BSER determinations, standards of performance, or compliance schedules. Conversely, if the EPA determines that it has the requisite statutory authority, the Agency would conduct additional analyses and propose any necessary and appropriate additional requirements for the fossil fuel-fired EGU source category at that time, having confirmed its statutory basis for doing so.

As a general matter, ''[n]othing prohibits federal agencies from moving in an incremental manner.'' [128] The EPA notes that CAA section 111 contemplates that the Agency need not immediately promulgate standards upon listing a source category and that review of regulations for a previously listed source category occurs on an eight-year cycle. Moreover, CAA section 111(b)(1)(B) does not require the Agency to regulate all types of emissions simultaneously, and CAA section 111(d) does not provide a deadline for promulgating emission guidelines. Even with respect to source categories for which no regulations exist, Congress previously provided a prioritization scheme in CAA section 111(f) under which the EPA was required to promulgate such regulations over the course of a six-year period. The EPA has consistently taken the position that it need not, in any particular CAA section 111 rulemaking, address all potential issues relevant to the at-issue source category. This final action does not repeal all requirements applicable to the fossil-fuel fired EGU source category, and as noted elsewhere in this preamble, nothing in this final action disturbs criteria pollutant emission standards applicable to power plants regulated under pre-2015 listings.

Thus, the EPA need not analyze and promulgate alternative BSERs and associated requirements to address serious issues identified with certain existing standards. In this context, this final rule simply represents a permissible first step in a multi-step process.[129] As noted above, the EPA is

[128] *Fox Television Stations,* 556 U.S. at 522; *see, e.g., Pub. Safety Spectrum All.* v. *FCC,* No. 24–1363, slip op. 20 (D.C. Cir. July 21, 2026) (it was reasonable for the FCC to defer making relevant decisions to a subsequent action).

[129] *See Grand Canyon Air Tour Coal.* v. *FAA,* 154 F.3d 455, 471 (D.C. Cir. 1998) (''ordinarily, agencies have wide latitude to attack a regulatory problem in phases and . . . a phased attack often has substantial benefits''); *Las Vegas* v. *Lujan,* 891 F.2d 927, 935 (D.C. Cir. 1989) (upholding agency action that was a first step toward a ''complete solution,'' stating that ''agencies have great discretion to treat a problem partially''); *Nat'l Ass'n of Broadcasters* v. *FCC,* 740 F.2d 1190, 1210 (D.C. Cir. 1984) (it is

taking this first step to provide near-term relief from 2024 CPS requirements that it is now determining to be unlawful or otherwise unreasonable and which, absent further action, would imminently begin forcing the expenditure of significant resources. Promulgation of alternative BSERs or compliance schedules at this time would require completing multiple additional steps, including resolving questions regarding the Agency's statutory authority and analyzing competing alternative BSERs and requirements, all of which would delay resolution of the distinct issues addressed in this rulemaking and defeat the purpose of resolving these distinct issues before regulated sources are put to the choice between expending significant resources to comply, or planning to close, before the current 2032 compliance deadline (or other upcoming compliance deadlines, as applicable).

The EPA does not believe its repeal of certain 2024 CPS standards and requirements runs afoul of case law such as *Regents of the University of California* and *State Farm.* These cases stand for the proposition that when an agency ''rescinds a prior policy its reasoned analysis must consider the 'alternative[s]' that are 'within the ambit of the existing [policy].'' [130] In concluding that the CAA and general principles of administrative law do not require the EPA to analyze and promulgate alternative, replacement BSER determinations or requirements immediately and as part of this discrete repeal, the Agency again emphasizes that this action is the first step in what is intended to be a multi-step rulemaking process. If the second step of this process is finalized as proposed, the ''existing policy'' will be mooted based on the lack of legal basis for that policy in the first instance. The EPA is thus not promulgating new standards for existing coal-fired steam generating units or for new base load combustion turbines in this final rule, and, accordingly, need not develop alternative BSER determinations to support such new and additional standards.

In analyzing this aspect of the problem, the EPA reviewed the alternatives it considered prior to selecting the BSER and standards finalized in the 2024 CPS to examine the scope and nature of possible regulatory alternatives. The Agency believes that its prior consideration and rejection of other potential BSERs in the 2024 CPS rulemaking demonstrates that further analyzing additional alternative BSERs and requirements would be unnecessary under the circumstances here. In the 2024 CPS, the EPA considered and rejected a range of potential alternatives to the BSERs ultimately selected. For long-term coal-fired steam generating units now subject to standards based on 90 percent CCS, the EPA considered partial CCS at lower capture rates, natural gas co-firing, and heat rate improvements.[131] The EPA rejected partial CCS ''because it achieves substantially fewer unit-level reductions at greater cost, and because CCS at 90 percent is achievable.'' [132] The Agency also noted that ''the IRC section 45Q tax credit may not be available to defray the costs of partial CCS and the emission reductions would be limited.'' [133] As explained in section IV.A.1 of this preamble, the EPA now rejects the conclusion that 90 percent CCS is adequately demonstrated and achievable and further finds that the IRC section 45Q tax credit should not be accounted for when evaluating the reasonableness of the costs of the BSER. The EPA therefore believes the costs of partial CCS would be significantly higher than anticipated in the 2024 CPS and therefore remains an inappropriate alternative. With regard to natural gas co-firing as an alternative to 90 percent CCS, as discussed in section IV.A.2 of this preamble, the EPA is determining in this final rule that this control strategy amounts to impermissible generation shifting, thereby disqualifying it from being the BSER. And the EPA explained in the 2024 CPS that it was not finalizing heat rate improvements as the BSER ''because of the limited reductions and potential rebound effect.'' [134] Similarly, for medium-term coal-fired EGUs, the 2024 CPS considered CCS and heat rate improvements as potential BSERs and rejected each.[135] Thus, based on the EPA's earlier assessments and the further analysis conducted for purposes of this final rule, potential alternatives to 90 percent CCS for long-term coal-fired units and 40 percent natural gas co-firing for medium-term coal-fired units are not obvious and suffer from their own shortcomings. As noted above, fully analyzing and working through these issues is a distinct task that warrants a distinct process that would be most appropriate to undertake after, and pending the results of, the Agency's consideration of the scope of its statutory authority.

For new base load combustion turbines, the 2024 CPS included consideration of potential alternative BSERs including lower-emitting fuels, high efficiency generation, and hydrogen co-firing.[136] In the 2024 CPS, the EPA explained that lower-emitting fuels are not the BSER for new base load combustion turbines because they would achieve few emission reductions.[137] And the EPA further explained that, ''[i]n light of public comments and additional analysis, uncertainties regarding projected costs prevent the EPA from determining that low-GHG hydrogen is a component of the BSER at this time.'' [138] This previous evaluation of potential alternative BSERs in the 2024 CPS corroborates the EPA's conclusion in this rulemaking that it is not necessary for the Agency to consider alternatives to repeal of the 90 percent CCS, phase 2 BSER for new base load combustion turbines.

Comments: Some commenters asserted that the EPA's proposed repeal of the 2024 CPS failed to consider the disbenefits of that proposal, namely, forgone emissions reductions. One commenter noted that the standards the Agency was proposing to repeal would reduce CO_2 emissions by 1.38 billion metric tons over roughly two decades. The commenter further stated that the standards the EPA was proposing to repeal would also secure reductions of tens of thousands of tons of particulate matter, sulfur dioxide, and nitrogen oxide emissions. Commenters argued that the Agency had failed to consider the public health benefits of the 2024 CPS and the corresponding disbenefits of repealing certain requirements of that rule, and that this purported oversight rendered the proposed repeal inconsistent with the Administrative Procedure Act and the CAA.

EPA Response: The EPA disagrees with these comments. The Agency acknowledges that CO_2 emission reductions are a relevant consideration in making BSER determinations under a regulatory framework that addresses GHG emissions from the affected sources. The EPA also recognizes that this action to repeal requirements of the 2024 CPS forgoes the CO_2 emission reductions that were projected to be

reasonable for an agency to ''defer resolution of issues raised in a rulemaking even when those issues are 'related' to the main ones being considered''; the inquiry into when agencies may defer resolution of issues raised in a rulemaking to a subsequent action is ''a pragmatic one'').

[130] *Regents,* 591 U.S. at 30 (quoting *State Farm,* 463 U.S. at 51).

[131] 89 FR 39798, 39846 (May 9, 2024).

[132] *Id.*

[133] *Id.*

[134] *Id.*

[135] *Id.* at 39895–96.

[136] *Id.* at 39924.

[137] *Id.*

[138] *Id.* at 39939.

achieved under the 2024 CPS. However, the EPA emphasizes that the repeal of the 2024 CPS requirements is based on the Agency's technical determinations that 90 percent CCS and 40 percent natural gas co-firing do not satisfy certain threshold legal criteria to be eligible to be the BSER. For 90 percent natural gas co-firing, the EPA is determining, among other things, that CO_2 capture at this rate is not adequately demonstrated; the Agency is also determining that 40 percent natural gas co-firing is impermissible generation shifting. Because each of these determinations disqualifies the emissions control strategy from further consideration, the amount of CO_2 emission reductions available through implementation of these strategies cannot compel a different outcome. Further, as discussed in the relevant subsections of this preamble, many of the selected control strategies underlying the at-issue 2024 CPS requirements are infeasible, and the EPA has significantly revised its projections and analysis in the 2024 CPS with respect to the timeline for implementation. These issues mean that the emissions reductions projected in the 2024 CPS were not likely to come to fruition in any event absent outcomes inconsistent with the CAA (*i.e.,* forced plant closures because compliance by the applicable deadline is not possible).

Separately, the EPA is also determining that the cost of 90 percent CCS is unreasonable and that the energy impacts associated with 40 percent co-firing are unreasonable. The amount of CO_2 emission reductions is relevant to the balancing of the BSER factors, which also include cost and nonair quality health and environmental impacts and energy requirements. As explained in this section of the preamble, the EPA has considered the available emission reductions associated with 90 percent CCS and 40 percent natural gas co-firing and is finding that, on balance, these emission control strategies are unreasonable. Furthermore, as explained in section IV.3 of this preamble, the EPA is repealing the requirements for oil and natural gas-fired steam generating units in part because the BSERs for these units in the 2024 CPS would not have achieved appreciable CO_2 emission reductions. The EPA has thus considered the foregone CO_2 emission reductions and determined that its action is reasonable notwithstanding.

While the EPA acknowledges that the 2024 CPS would have also resulted in reductions of co-pollutants including particulate matter, sulfur dioxide, and nitrogen oxides, reductions of these pollutants in the 2024 CPS, or foregone emission reductions of these pollutants in this action, did not factor into the Agency's BSER determinations for the regulated pollutant—CO_2—emitted from the regulated sources. And even if the EPA were to consider these incidental reductions of co-pollutants, the Agency would determine that the costs and energy impacts of the controls should be weighted more heavily than those forgone reductions.

The EPA's consideration of foregone emission reductions together with costs in relation to projections in the 2024 CPS is consistent with the Supreme Court's statement in *Michigan* v. *EPA,* 576 U.S. 743 (2015), that ''reasonable regulation ordinarily requires paying attention to the advantages *and* the disadvantages of agency decisions.'' [139] That is, the EPA has considered the reductions that the 2024 CPS would have achieved in CO_2 emissions, as well as the reductions in the other pollutants emitted by power plants, including particulate matter, sulfur dioxide, and nitrogen oxides. The EPA has also considered the health impacts of reducing emissions of these pollutants. Those emissions reductions and health impacts are noted in section V.A of this preamble. However, the EPA believes that any benefits from them are outweighed by the costs of the 2024 CPS, including the costs to the industry (and, in many instances, to the ratepayers who will absorb those costs through higher electricity bills) of complying with the requirements, as also noted in section V.A of this preamble, as well as the adverse energy impacts of using natural gas for co-firing, as noted in section IV.A.2.a of this preamble. In the EPA's view, this relative weighting is confirmed by the uncertainty of actually achieving the benefits attributed to the 2024 CPS, in light of the record and legal deficiencies in the 2024 CPS's determination of CCS and co-firing as BSER, as noted in sections IV.A.1 and IV.A.2 of this preamble. Accordingly, the EPA believes that today's action to repeal the 2024 CPS is reasonable and consistent with the *Michigan* statement cited above concerning reasonable regulation.

A. Repeal of the Emission Guidelines for Existing Fossil Fuel-Fired Steam Generating Units

This section details the rationale for the repeal of the emission guidelines for existing fossil fuel-fired steam generating units.

[139] *Michigan,* 576 U.S. at 753 (emphasis in original).

1. CCS-Based Requirements for Long-Term Existing Coal-Fired Steam Generating Units

In the 2024 CPS, the EPA determined the BSER for long-term coal-fired steam generating units to be 90 percent CCS. The EPA premised that BSER specifically on 90 percent CO_2 capture using an amine solvent-based system, CO_2 transport through a pipeline, and geologic sequestration of the CO_2 in a saline reservoir. In the 2024 CPS, the EPA argued that 90 percent CCS, including the 90 percent CO_2 capture component, was adequately demonstrated. The EPA further argued that 90 percent CCS satisfied the other criteria for BSER, including that costs were reasonable based on counting the IRC section 45Q as a reduction in the cost to the affected source of 90 percent CCS. Based on application of the 90 percent CCS BSER to the affected sources, the EPA established a degree of emission limitation and argued this was achievable by the compliance date of January 1, 2032, considering the time necessary to deploy capture equipment, transport, and sequestration.

The EPA proposed to repeal the requirements for long-term coal-fired steam generating units based largely on a reassessment of the record for the 2024 CPS. Specifically, the EPA proposed that 90 percent CO_2 capture, and therefore 90 percent CCS as a whole, have not been adequately demonstrated. The EPA further proposed that the average unit-level costs of 90 percent CCS were unreasonable. In the June 2025 NPRM, the EPA evaluated the average unit level costs assuming a lower capacity factor of the host EGU and operation beyond the 12-year period of availability of the IRC section 45Q tax credit. The reduced amount of CO_2 that would be captured and eligible for the IRC section 45Q tax credit resulted in higher costs than in the 2024 CPS. The EPA further proposed that the IRC section 45Q should not be counted as a reduction in the costs of 90 percent CCS. Finally, the EPA proposed that the degree of emission limitation in the 2024 CPS is not achievable because it is unlikely that the infrastructure (including the capture system, pipelines, and sequestration) for CCS can be deployed by the January 1, 2032 compliance date.

The EPA has reassessed the record underlying the 2024 CPS. The EPA is finalizing the determination that CCS with 90 percent capture is not the BSER for long-term existing coal-fired steam generating units because 90 percent CO_2 capture and, therefore, 90 percent CCS have not been adequately demonstrated

and the costs are unreasonable. Additionally, the capture, pipeline, and sequestration infrastructure necessary for 90 percent CCS for the fleet of existing coal-fired steam generating units does not currently exist and would need to be broadly deployed. It is unlikely the infrastructure necessary for CCS can be deployed by the January 1, 2032 compliance date, and the EPA is therefore finalizing the determination that the degree of emission limitation in the 2024 CPS for long-term coal-fired steam generating units is not achievable. Consequently, for the reasons explained in the June 2025 NPRM [140] and discussed below, the EPA is finalizing the repeal of the requirements in the emission guidelines pertaining to long-term existing coal-fired steam generating units.

a. Adequately Demonstrated

CCS with 90 percent capture involves the capture of 90 percent of the CO_2 emissions from the EGU, compression and transport of the captured CO_2 via pipeline, and sequestration in geologic storage. Due to the relatively low concentration of CO_2 in the flue gas, an amine solvent-based capture system is better suited for application to the post-combustion flue gas of fossil fuel-fired EGUs than other CO_2 removal technologies (*e.g.,* pressure-swing adsorption). CO_2 removal occurs by reactive absorption of the CO_2 from the flue gas into the amine solution in an absorption column. The amine reacts with CO_2 but will also react with impurities in the flue gas, including sulfur dioxide (SO_2). Particulate matter (PM) will also affect the capture system. Adequate removal of SO_2 and PM prior to the CO_2 capture system is therefore necessary. After pretreatment of the flue gas with conventional SO_2 and PM controls, the flue gas goes through a quencher to cool the flue gas and remove further impurities before the CO_2 absorption column. After absorption, the CO_2-rich amine solution passes to the solvent regeneration column, while the treated gas passes through a water and/or acid wash column to limit emission of amines or other byproducts. In the solvent regeneration column, the solution is heated (using steam) to release the absorbed CO_2. The released CO_2 is then compressed and transported to a sequestration site. In an integrated CO_2 capture system, steam and electricity for the capture process are provided by the host-EGU; this avoids the need to capture additional emissions from any auxiliary boilers or cogeneration units.

In the 2024 CPS, the CO_2 capture component of the 90 percent CCS BSER was premised on an integrated amine solvent-based CO_2 capture system with 90 percent removal of CO_2 from the post-combustion flue gas of the host EGU. The EPA previously argued that such a system was adequately demonstrated.

The EPA has reevaluated the record and is determining in this final rulemaking that, critically, 90 percent capture of the CO_2 from flue gas of an EGU has not been adequately demonstrated. As a result, 90 percent CCS has not been adequately demonstrated and cannot be the BSER for long-term coal-fired steam generating units. The EPA is basing this conclusion primarily on a revised evaluation of the record in the 2024 CPS, as detailed in this section of the preamble.[141] The EPA is additionally considering several developments since the EPA promulgated the 2024 CPS (*e.g.,* changes in the plans of certain CCS projects).

In the 2024 CPS, the emission guidelines required States to establish plans that would require long-term existing coal-fired steam generating units to achieve an annual standard of performance based on capturing 90 percent of the unit's total CO_2 emissions. However, the record for 90 percent capture as adequately demonstrated did not include an example of a commercial scale coal-fired steam generating unit that was already capturing 90 percent of its annual CO_2 emissions. Instead, the EPA attempted to argue that 90 percent capture has been adequately demonstrated based on other evidence for the technology at that time. Specifically, the EPA relied primarily on evidence that consisted of the operation of the CO_2 capture system at Boundary Dam Unit 3, fixes applied at Boundary Dam Unit 3, and testing on new solvents from different vendors.[142] Consequently, the EPA extrapolated from that combination of primary evidence to determine that 90 percent capture would perform as anticipated for the affected sources. On that basis, the EPA concluded that 90 percent capture was adequately demonstrated for existing coal-fired steam generating units.

The only datapoint for commercial scale post-combustion CCS on a fossil fuel-fired EGU, with integrated steam and power, is Boundary Dam Unit 3. However, between 2014 and 2022, the capture system at Boundary Dam achieved a total capture efficiency of not more than 63 percent over the course of a calendar year.[143] [144] This total annual capture efficiency is substantially below the 90 percent capture level specified by the BSER. While the EPA had acknowledged the challenges and underperformance of the capture system at Boundary Dam in the 2024 CPS, the Agency asserted that fixes were available or could be made to address those issues. However, many of those fixes were already made, and performance remained below the design capture efficiency.[145] The EPA also previously argued that new solvents were available that could capture CO_2 at higher rates to address these gaps.[146] However, in the 2024 CPS, the EPA failed to reasonably account for potential underperformance of capture systems using new solvents, and the experience at Boundary Dam shows it would be reasonable to anticipate that such capture systems would similarly underperform.[147] Furthermore, the EPA also failed to account for any decrease in operating-availability of capture, even though the annual operating-availability of the capture system at Boundary Dam has been less than 100 percent.[148] In combination, a capture system would achieve much less than 90 percent total capture efficiency. On review, the EPA's

[140] 90 FR 25752, 25769–73 (June 17, 2025).

[141] *See Nat'l Ass'n of Home Builders* v. *EPA,* 682 F.3d 1032, 1038 (D.C. Cir. 2012) (''EPA did not rely on new facts, but rather on a reevaluation of which policy would be better in light of the facts . . . . Fox makes clear that this kind of reevaluation is well within an agency's discretion.'' (citing 556 U.S. at 514–15)).

[142] The EPA also included other, secondary observations (*e.g.,* projects in development) that would be insufficient on their own to conclude 90 percent capture is adequately demonstrated.

[143] Here, total capture efficiency is equivalent to the mass of CO_2 captured relative to (*i.e.,* divided by) the mass of CO_2 that the EGU would otherwise emit (including the mass of CO_2 produced in the combustion chamber of the EGU plus the mass of CO_2 produced by any auxiliary equipment that supports the capture process) over a given period (*e.g.,* annual).

[144] Jacobs, B., *et al.* Reducing the CO_2 Emission Intensity of Boundary Dam Unit 3 Through Optimization of Operating Parameters of the Power Plant and Carbon Capture Facilities. *Proceedings of the 16th International Conference on Greenhouse Gas Control Technologies* (2022). Available at: *https://dx.doi.org/10.2139/ssrn.4286430.*

[145] The most recently reported total capture efficiency when operating was 83 percent on an instantaneous basis. Accounting for periods when the capture system is offline, the total annual capture efficiency would be lower.

[146] 95 percent total capture on an instantaneous basis, not accounting for uncertainty in real-world operation or availability.

[147] As the only commercial scale and long-term application of CO_2 capture on a fossil fuel-fired EGU, Boundary Dam's underperformance is a reasonable quantification of potential underperformance.

[148] Between 2015–2022, the availability of the capture system relative to the EGU was, at best, 94 percent.

prior extrapolation fails to support CCS with 90 percent capture as adequately demonstrated. The EPA's other tangential arguments in the 2024 CPS similarly fail to show that 90 percent capture has been adequately demonstrated (including projects in development, as discussed in section IV.A.1.a.iv of this final rule preamble). Considering these factors, the EPA is finalizing the determination that CCS with 90 percent capture and, consequently, 90 percent CCS are not adequately demonstrated for existing coal-fired steam generating units. The following subsections provide further explanation.

i. Extrapolation From Boundary Dam Unit 3

In the 2024 CPS, the EPA based the determination that 90 percent CO_2 capture was adequately demonstrated on the record for amine-solvent CO_2 capture.[149] Thus, the EPA relied heavily on the operation of carbon capture at the commercial scale 110 megawatt (MW) coal-fired Boundary Dam Unit 3 (Saskatchewan, Canada) to demonstrate 90 percent capture. Boundary Dam has operated CCS since 2014. The unit uses Shell's amine-based CANSOLV® solvent technology to capture CO_2 from the post-combustion flue gas of the coal-fired boiler.[150] Captured CO_2 is then compressed, transported by pipeline, and used for enhanced oil recovery (EOR) or stored in a saline aquifer at the Aquistore site.[151] While Boundary Dam Unit 3 achieved 89.7 percent capture over a 3-day test early in its operation, longer-term capture levels have been lower.[152] Between 2015 and 2022, Boundary Dam achieved a total capture efficiency of not more than 63 percent in a calendar year.[153] This total long term capture efficiency is substantially below the 90 percent capture efficiency of the BSER.

This lower total capture efficiency is due to, among other things, the capture system at Boundary Dam Unit 3 typically processing less than all of the flue gas, in part to ''maintain long-term reliable operation.'' [154] Prior to 2023, the CO_2 capture system at Boundary Dam Unit 3, when operating, processed up to approximately 75 percent of the flue gas with 90 percent CO_2 capture from the processed flue gas.[155] The EPA argued in the 2024 CPS that such capture from the majority of the flue gas supported the determination of 90 percent capture from all of the flue gas as adequately demonstrated; however, this ignores that the total capture efficiency was substantially less than the 90 percent design capture efficiency.

Additionally, Boundary Dam Unit 3 has experienced various technical challenges that have reduced its performance.[156] These include fouling of the CO_2 absorber due to PM (fly ash), buildup of scale on heat exchangers, biological fouling in the wash-water section of the CO_2 absorber, foaming of the amine solvent in the CO_2 absorber, and damage to the CO_2 compressor. Fouling in the CO_2 absorber affects the throughput of the process by increasing the pressure drop (*i.e.,* difference in pressure between the bottom and top of the absorber) such that it cannot be overcome by the draft fans (*i.e.,* more energy is required to move the same volume of flue gas than the fans are designed to provide). Boundary Dam Unit 3 has implemented improvements to its particulate controls (electrostatic precipitator) and added more spray-wash systems to mitigate fouling due to fly ash. Caustic shocking of the wash-water section can reduce the buildup of biological material. Buildup of scale on heat exchangers reduces throughput by increasing pressure drop, while the layer of scale reduces the rate of heat transfer. To address this issue, redundant heat exchangers with isolations were installed in 2017 to allow for removal of scale without shutting down the CO_2 capture system. Finally, damage to the CO_2 compressor caused by a loose bolt, and issues with a leaking intercooler in the compressor, forced the CO_2 capture system to be offline for several months in 2021 and the start of 2022. While the compressor was repaired, the unit lacks a redundant compressor in the event of a similar outage. Importantly, despite these attempts to improve operation, the unit continues to underperform. Furthermore, outages to address these issues have contributed to a lower total capture efficiency.

Comments: Some commenters agreed that Boundary Dam Unit 3 does not support 90 percent capture as adequately demonstrated. Commenters noted the low total capture efficiency achieved by the unit over time and the challenges faced by the unit. Other commenters argued Boundary Dam Unit 3 does support 90 percent capture as adequately demonstrated because of the capture rate from the processed flue gas and the fixes to the unit.

EPA Response: In approximately 2024, SaskPower made additional improvements at Boundary Dam Unit 3 to increase throughputs, and SaskPower noted that the capture system was processing a greater portion of the flue gas (up to 95 percent of the flue gas, with 87 percent capture from the processed flue gas, resulting in 83 percent total capture when operating).[157] SaskPower has not reported whether Boundary Dam Unit 3 has maintained that performance in the long term.[158] Notably, at those higher throughputs, the capture efficiency from the processed flue gas is lower. Moreover, even with those improvements, Boundary Dam continues to operate with capture efficiencies below design specification. Therefore, the fixes applied at Boundary Dam Unit 3 do not support 90 percent capture as adequately demonstrated.

Additionally, the operating-availability of the capture system at Boundary Dam Unit 3 has been less than 100 percent.[159] Between 2015 and 2022, annual operating-availability of the capture plant relative to the EGU varied

[149] 89 FR 39798, 39848 (May 9, 2024).

[150] Giannaris, S., *et al.* SaskPower's Boundary Dam Unit 3 Carbon Capture Facility—The Journey to Achieving Reliability. *Proceedings of the 15th International Conference on Greenhouse Gas Control Technologies* (2021). Available at: *http://dx.doi.org/10.2139/ssrn.3820191.*

[151] Aquistore. Available at: *https://ptrc.ca/aquistore.*

[152] SaskPower Annual Report (2015–16). Available at: *https://www.saskpower.com/-/media/saskpower/about-us/reports/past-reports/report-annualreport-2015-16.pdf.*

[153] Jacobs, B., *et al.* Reducing the CO_2 Emission Intensity of Boundary Dam Unit 3 Through Optimization of Operating Parameters of the Power Plant and Carbon Capture Facilities. *Proceedings of the 16th International Conference on Greenhouse Gas Control Technologies.* (2022). Available at: *https://dx.doi.org/10.2139/ssrn.4286430.*

[154] SaskPower. ''Docket ID No. EPA–HQ–OAR–2023–0072: SaskPower Correction of Reference to Boundary Dam Unit 3 Emissions Performance in Proposed Rule'' (August 4, 2023). Document ID No. EPA–HQ–OAR–2023–0072–0687.

[155] Jacobs, B., *et al.* Reducing the CO_2 Emission Intensity of Boundary Dam Unit 3 Through Optimization of Operating Parameters of the Power Plant and Carbon Capture Facilities. *Proceedings of the 16th International Conference on Greenhouse Gas Control Technologies.* (2022). Available at: *https://dx.doi.org/10.2139/ssrn.4286430.*

[156] Jacobs, B., *et al.* Reducing the CO_2 Emission Intensity of Boundary Dam Unit 3 Through Optimization of Operating Parameters of the Power Plant and Carbon Capture Facilities. *Proceedings of the 16th International Conference on Greenhouse Gas Control Technologies.* (2022). Available at: *https://dx.doi.org/10.2139/ssrn.4286430.*

[157] U.S. EPA, ''Meeting with SaskPower to Discuss CCS at Boundary Dam Unit 3'' (January 18, 2024). Document ID No. EPA–HQ–OAR–2023–0072–8906.

[158] Status updates from Boundary Dam from the second quarter of 2022 onward report average daily capture rates on a metric tons per day basis, capture system availability, and emissions intensity. Capture efficiency is not reported. *See* SaskPower. BD3 Status Update: Q4 2024. Available at: *https://saskpower.com/about-us/our-company/blog/2025/bd3-status-update-q4-2024.*

[159] Here, operating-availability is the percent of time that the capture system is operating relative to the time that the EGU is operating.

between 58 and 94 percent.[160] In 2023, the average quarterly operating-availability of the capture plant was approximately 85 percent.[161] Operating-availability remained at this level in 2024.[162] Lower operating-availabilities further contribute to lower total capture efficiencies.

The total capture efficiency at Boundary Dam Unit 3 has been less than 90 percent because the capture system has not processed all the flue gas. Also, the capture efficiency is still less than 90 percent when the capture system is operating even after applying fixes. Additionally, the operating-availability of the capture system is less than 100 percent. Considering this, the EPA concludes that the experience at Boundary Dam Unit 3 does not support 90 percent CCS as adequately demonstrated. Furthermore, the capacity of Boundary Dam Unit 3 is less than the capacity of the average U.S. coal-fired steam generating unit of approximately 430 MW. Because CCS at Boundary Dam Unit 3 underperformed at 110 MW, the EPA concludes that 90 percent capture would similarly underperform at any units greater than 25 MW, including larger units.

In the 2024 CPS, the EPA argued that new solvents achieving 95 percent capture efficiency were evidence that 90 percent capture was adequately demonstrated. However, the EPA failed to reasonably account for the performance that could be achieved in practice. The only datapoint for commercial scale post-combustion CCS on a fossil fuel-fired EGU, with integrated steam and power, is Boundary Dam Unit 3. As noted in the June 2025 NPRM, it would be reasonable to anticipate that a capture system using a new solvent would underperform to a similar degree as Boundary Dam.[163] A capture system using a new solvent, even in a process designed to achieve 95 percent capture on an instantaneous basis, would achieve just 66 percent total capture efficiency and still fail to achieve 90 percent capture if the capture system using a new solvent performed proportionately to Boundary Dam's best annual performance.[164] Even under more optimistic circumstances, assuming Boundary Dam's best annual operating-availability and that a new solvent capture system performs proportionally to Boundary Dam's recent performance, the resulting total annual capture efficiency would be only 82 percent.[165] In combination, a capture system would achieve much less than 90 percent total capture efficiency. On review, the EPA's prior extrapolation fails to support CCS with 90 percent capture as adequately demonstrated. Considering these factors, the EPA is finalizing the determination that CCS with 90 percent capture is not adequately demonstrated for existing coal-fired steam generating units.

ii. CO_2 Capture at Other Coal-Fired Steam Generating Units

In the 2024 CPS, to support the determination of 90 percent capture as adequately demonstrated, the EPA cited other applications of CCS at coal-fired steam generating units. These included CO_2 capture at the Argus Cogeneration Plant (Trona, California), at AES's Warrior Run (Cumberland, Maryland) and Shady Point (Panama, Oklahoma) plants, and at Plant Barry's (Mobile, Alabama) 25 MWe (megawatt-equivalent) project.[166] These projects were not of an equivalent size to commercial scale or, in the case of the Argus Cogeneration Plant, captured far less than 90 percent of CO_2. These earlier examples would have informed the design of the capture system at Boundary Dam Unit 3. However, the lessons learned from such projects failed to limit the underperformance of the CO_2 capture system at Boundary Dam. Consequently, they do not mitigate the anticipated underperformance in the extrapolation of 90 percent CCS and cannot support 90 percent capture as adequately demonstrated.

In the 2024 CPS, the EPA also cited the Petra Nova project at W.A. Parish Unit 8 (Thompsons, Texas). The Petra Nova project began operation in 2017, and the owner put the facility into reserve shutdown (*i.e.,* idled) in May 2020, citing the poor economics of utilizing captured CO_2 for EOR at that time. On September 13, 2023, the carbon capture facility at Petra Nova restarted.[167] A final report from the National Energy Technology Laboratory (NETL) details the challenges that the project faced over an initial 3-year period, including leaks from heat exchangers, build-up of slurry and solids on the flue gas blower, and build-up of scale on various components.[168] Petra Nova captured on average 92.4 percent of the CO_2 from the 240 MWe flue gas processed over a 3-year period while operating. However, that does not account for emissions during outages of the CO_2 capture system. Maintenance to address outages directly attributable to the CO_2 capture facility was approximately 10 percent of the year on average over that timeframe. Accounting for those outages alone would, approximately, result in a total capture efficiency of 83.2 percent. Furthermore, Petra Nova processes a 240 MWe portion of the flue gas from the 610 MW W.A. Parish Unit 8. At full load, that would equate to a capture efficiency of approximately 36 percent of the emissions from the coal-fired steam generating unit.[169] With 10 percent outages, this would be reduced further to 32.4 percent. Additionally, the 90 percent CCS BSER in the 2024 CPS was premised on the CO_2 capture plant using integrated steam and electricity from the host EGU. However, Petra Nova uses an auxiliary natural gas-fired combustion turbine cogeneration unit to provide steam and electricity to the CO_2 capture process, and the system does not capture the CO_2 emissions from the auxiliary cogeneration unit. This design is inconsistent with the premise of the CCS BSER in the 2024 CPS. A system consistent with the premise of the BSER uses integrated steam and power and would need to meet the electricity and steam load requirements of the capture process. Furthermore, accounting for

[160] Jacobs, B., *et al.* Reducing the CO_2 Emission Intensity of Boundary Dam Unit 3 Through Optimization of Operating Parameters of the Power Plant and Carbon Capture Facilities. *Proceedings of the 16th International Conference on Greenhouse Gas Control Technologies.* (2022). Available at: *https://dx.doi.org/10.2139/ssrn.4286430.*

[161] SaskPower. BD3 Status Update: Q4 2023. Available at: *https://www.saskpower.com/about-us/our-company/blog/2024/bd3-status-update-q4-2023.*

[162] SaskPower. BD3 Status Update: Q4 2024. Available at: *https://saskpower.com/about-us/our-company/blog/2025/bd3-status-update-q4-2024.*

[163] 90 FR 25752, 25769 (June 17, 2025).

[164] 95 percent design capture × (63 percent total annual capture/90 percent design capture) = 66 percent total annual capture efficiency. Between 2015 and 2022, Boundary Dam Unit 3 achieved a total annual capture efficiency of not more than 63 percent. *See* Jacobs, B., *et al.* Reducing the CO_2 Emission Intensity of Boundary Dam Unit 3 Through Optimization of Operating Parameters of the Power Plant and Carbon Capture Facilities. *Proceedings of the 16th International Conference on Greenhouse Gas Control Technologies.* (2022). Available at: *https://dx.doi.org/10.2139/ssrn.4286430.*

[165] 94 percent availability × 95 percent design capture × (83 percent total capture/90 percent design capture) = 82 percent total annual capture efficiency.

[166] Dooley, J.J., et al. ''An Assessment of the Commercial Availability of Carbon Dioxide Capture and Storage Technologies as of June 2009.'' U.S. DOE, Pacific Northwest National Laboratory, under Contract DE–AC05–76RL01830. (2009). Available at: *https://doi.org/10.2172/967229.*

[167] JX Nippon Oil & Gas Exploration Corporation. *Restart of the large-scale Petra Nova Carbon Capture Facility in the U.S.* (September 2023). Available at: *https://www.eneos-xplora.com/english/newsrelease/upload_files/20230913EN.pdf.*

[168] W.A. Parish Post-Combustion CO_2 Capture and Sequestration Demonstration Project, Final Scientific/Technical Report (March 2020). Available at: *https://www.osti.gov/servlets/purl/1608572.*

[169] 90 percent × 240 MWe / 610 MW = 36 percent.

emissions from the auxiliary cogeneration unit would lower the capture efficiency at Petra Nova further. In the 2024 CPS, by ignoring the emissions from the auxiliary cogeneration unit, the EPA failed to reasonably extrapolate the results at Petra Nova to a system using integrated steam and power. Considering these factors, the experience at Petra Nova does not support 90 percent capture as adequately demonstrated.

Comments: Some commenters cited additional examples of CO_2 capture on coal-fired steam generating units in China. Commenters cited the 150,000 metric tons of CO_2 per year Jinjie demonstration project. Commenters also cited the 500,000 metric tons of CO_2 per year Taizhou CCS project, which began operation in June 2023 and captures less than 12.5 percent of the 1,000 MW EGU's total CO_2 emissions. Commenters also referenced the 1.5 million metric tons of CO_2 per year Longdong CCS project at the coal-fired Zhengning Power Plant. Captured CO_2 will be stored in geologic storage and used for EOR. The 270 MWe project has a design capture efficiency of 95 percent from a portion of the flue gas from a 1,000 MW coal-fired EGU.[170]

EPA Response: The Jinjie demonstration project began operation in June 2021 and processes less than five percent of the flue gas from one of the units at the coal-fired power plant.[171] By January 2025, the Taizhou CCS project had captured just 300,000 metric tons of CO_2, far below its design basis. While a report states that this project achieves a capture rate of 90.86 percent, detailed data (*e.g.,* operating-availability, amount of flue gas processed) is limited.[172] According to a press release, the Longdon CCS project completed a 72-hour test on September 25, 2025, but the press release did not contain detailed performance information.[173] Beyond that press release, no reports on the project are available. Because of the limited data available, the EPA has concluded that these projects do not support 90 percent capture as adequately demonstrated.

iii. Variations in Performance of CO_2 Capture

The determinations in the 2024 CPS assumed that the CO_2 capture system is available every hour the EGU is operational and performs at its design capture efficiency (or better) during each of those hours. The EPA finds that the Agency did not adequately account for variations in performance of CO_2 capture that would result in a lower capture efficiency. This further supports the conclusion that 90 percent CO_2 capture is not adequately demonstrated for existing coal-fired steam generating units.

In the 2024 CPS, the EPA did not account for periodic decreases in the performance of the CO_2 capture system due to solvent degradation and fouling of components between maintenance cycles. Boundary Dam Unit 3 experienced challenges with respect to solvent foaming, biological fouling, scaling, and fouling from fly-ash.[174, 175] While units could take actions to address those issues, performance and capture efficiency would necessarily decrease in between treatments or maintenance (*e.g.,* fouling would steadily accumulate after cleaning). On average, the capture efficiency would therefore be less than optimal. SaskPower indicated that even after applying such fixes, Boundary Dam Unit 3 achieved, at best, a total capture efficiency of 83 percent when the capture system was operating.[176]

Furthermore, the EPA did not adequately account for periods of startup on the operation of the capture system.[177] After absorption, thermal energy (heat) in the form of steam is required to release the CO_2 from the CO_2-rich solvent and electricity is required to power the compressor to compress the CO_2 for transport via pipeline. However, prior to substantial production of steam and electricity, major components of the capture process may be offline. Even assuming the capture system could consistently capture 90 percent CO_2 when operating, any CO_2 emitted prior to operation of the capture equipment would necessarily result in an average capture efficiency of less than 90 percent.

To consistently achieve 90 percent capture on average, the source would have to overperform during certain hours. The EPA cited results from Boundary Dam that suggested higher capture efficiencies were achieved at lower throughputs.[178] However, in its justification of the BSER, the EPA relied on an assumption that sources would operate at high capacity throughout the course of the year. If that were the case, the hypothetical higher capture efficiencies a system could potentially achieve at lower throughputs would not occur in practice. To otherwise achieve an annual average capture efficiency of 90 percent, higher instantaneous capture efficiencies likely would need to be achievable. In the 2024 CPS, the EPA cited vendor statements of pilot tests for different commercial amine solvents where operators observed higher capture efficiencies under specific conditions.[179] However, the experience at Boundary Dam shows that it would be reasonable to anticipate that the total capture efficiency a system achieves in practice would be less than design specifications.

iv. Planned Projects

In the 2024 CPS, the EPA also previously cited planned projects and front-end engineering and design (FEED) studies.[180, 181] However, the planned projects are neither operational nor provide measured data. While the equipment for those planned projects may have been designed for 90 or even 95 percent CO_2 capture, simply designing a project for a certain percentage capture does not ensure that the project will achieve that percentage capture in practice. Boundary Dam Unit 3 did not achieve its design percentage capture, as detailed in section IV.A.1.a.i of this preamble. Therefore, because those hypothetical projects have not yet produced any data, they do not mitigate

[170] State of the Art: CCS Technologies 2025. Global CCS Institute (2025). Available at: *https://www.globalccsinstitute.com/wp-content/uploads/2025/08/State-of-the-Art-CCS-Technologies-2025-Global-CCS-Institute.pdf.* 27 percent of the flue gas is treated.

[171] Bongers, N. China's impressive strides towards CCUS. Low Emission Technology Australia. (2025). Available at: *https://letaustralia.com.au/wp-content/uploads/Executative-Summary-Chinas-Impressive-Strides-Towards-Carbon-Capture-Utilisation-and-Storage-CCUS.pdf.*

[172] Gong, H., *et al.* Taizhou 500kt per year post-combustion carbon capture demonstration project. *Clean Energy,* 9 (4). (2025). Available at: *https://doi.org/10.1093/ce/zkaf011.*

[173] China Launches World's Largest Coal-fired Carbon Capture Project (September 29, 2025). Available at: *en.sasac.gov.cn/2025/09/29/c_19886.htm.*

[174] Giannaris, S., *et al.* SaskPower's Boundary Dam Unit 3 Carbon Capture Facility—The Journey to Achieving Reliability. *Proceedings of the 15th International Conference on Greenhouse Gas Control Technologies.* (2021). Available at: *http://dx.doi.org/10.2139/ssrn.3820191.*

[175] Pradoo, P., *et al.* Improving the Operating Availability of the Boundary Dam Unit 3 Carbon Capture Facility. *Proceedings of the 16th International Conference on Greenhouse Gas Control Technologies.* (2022). Available at: *http://dx.doi.org/10.2139/ssrn.4286503.*

[176] U.S. EPA, ''Meeting with SaskPower to Discuss CCS at Boundary Dam Unit 3'' (January 18, 2024). Document ID No. EPA–HQ–OAR–2023–0072–8906.

[177] 89 FR 39798, 39854, 39929 (May 9, 2024).

[178] Jacobs, B., *et al.* Reducing the CO_2 Emission Intensity of Boundary Dam Unit 3 Through Optimization of Operating Parameters of the Power Plant and Carbon Capture Facilities. *Proceedings of the 16th International Conference on Greenhouse Gas Control Technologies.* (2022). Available at: *https://dx.doi.org/10.2139/ssrn.4286430.*

[179] 89 FR 39798, 39852 (May 9, 2024).

[180] 89 FR 39798, 39851 (May 9, 2024).

[181] *See* Chapter 4.4 and Table 13 of *Greenhouse Gas Mitigation Measures for Steam Generating Units.* Document ID No. EPA–HQ–OAR–2023–0072–9095.

the potential underperformance of CO_2 capture, and, therefore, are not sufficient to show that 90 percent CO_2 capture is adequately demonstrated.[182] Moreover, none of the projects (for post-combustion CO_2 capture from fossil fuel-fired EGUs) with feasibility or FEED studies previously cited by the EPA have moved forward to construction.

There are no post-combustion CCS applications on fossil fuel-fired EGUs that have begun operation since the finalization of the 2024 CPS that are sufficient to support 90 percent capture as adequately demonstrated. Rather, some of the planned projects cited in the 2024 CPS either have been abandoned or have faced other challenges. Project Diamond Vault was a planned project to capture up to 95 percent of CO_2 emissions from the 600 MW Madison Unit 3 at Brame Energy Center in Lena, Louisiana.[183] The FEED study and current plans for carbon capture were abandoned in late 2024.[184] Project Tundra is a carbon capture project in North Dakota at the Milton R. Young Station lignite coal-fired power plant that planned for the capture plant to treat the flue gas from the 455 MW Unit 2 and some additional flue gas from the 250 MW Unit 1 (an equivalent capacity of 530 MW in total).[185] TC Energy, a primary sponsor of Project Tundra, has since withdrawn from the project, although the project may continue to move forward depending on various factors.[186] The timeframes for several other CCS projects on coal-fired EGUs are unclear.[187]

[182] This includes projects for CCS on coal-fired steam generating units in West Virginia and Alaska that were recently selected for funding by DOE. *See* Project Selections for Broad Agency Announcement DE–FOA–0003605, Restoring Reliability: Coal Recommissioning and Modernization (Topic 1). Available at: *https://www.energy.gov/hgeo/project-selections-broad-agency-announcement-de-foa-0003605-restoring-reliability-coal-0.*

[183] Project Diamond Vault Overview. Document ID No. EPA–HQ–OAR–2025–0124–0027.

[184] Cleco Corporate Holdings, LLC SEC Form 10Q, at 51 (August 18, 2024). Available at: *https://www.sec.gov/Archives/edgar/data/18672/000108981924000026/cnl-20240630.htm.*

[185] ''An Overview of Minnkota's Carbon Capture Initiative—Project Tundra,'' 2023 LEC Annual Meeting (October 5, 2023).

[186] Power Engineering. Key partner withdraws from large-scale CO_2 capture project. Available at: *https://www.power-eng.com/environmental-emissions/carbon-capture-storage/key-partner-withdraws-from-large-scale-co2-capture-project/.*

[187] D. Gearino, *A Carbon Capture Project Faces a New Delay in a Year of Slow Progress for Coal Power Plants Looking for Retrofits,* Inside Climate News (December 10, 2024). Available at: *https://insideclimatenews.org/news/10122024/north-dakota-coal-plant-carbon-capture-project-faces-new-delay/.*

b. Cost

The EPA has re-evaluated the costs and associated assumptions of 90 percent CCS on existing long-term coal-fired steam generating units and is finalizing the determination that the costs are not reasonable based on the rationale detailed in this section of the preamble.

i. Capacity Factor, Effective Capture Efficiency, and Other Assumptions

In the 2024 CPS, costs for CCS on existing coal-fired steam generating units were determined assuming a best-case scenario. Specifically, the cost assessment assumed sources operated at high annual capacity factors (80 percent) and that the CO_2 capture equipment was available and performing optimally every hour the EGU was operating. However, in 2023, coal-fired EGUs had an average capacity factor of 42 percent.[188] Lower capacity factors typically result in less revenue from electricity generation. Moreover, as detailed in the preceding section of this preamble, even with a design capture efficiency of 90 percent, the actual total capture efficiency over the course of the year is lower, and under some circumstances significantly lower. Consequently, less CO_2 captured (due to lower actual capture efficiency, lower EGU capacity factor, or both) results in higher costs due to reduced revenue from the IRC section 45Q tax credit.[189]

Furthermore, rather than directly considering the costs for any operation after the expiration of availability of the IRC section 45Q tax credit for existing coal-fired steam generating units in the 2024 CPS, the EPA committed to review the requirements of the emission guidelines pertaining to existing coal-fired steam generating units by January 1, 2041, and posited that other mechanisms for potential valuation of EGUs operating with 90 percent CCS could arise in the future.[190] However, those assumptions are no longer reasonable because the EPA believes that coal-fired steam generating units are now more likely to operate longer than they will be able to claim the tax credit. As noted in the June 2025 NPRM, the EPA believes that coal-fired steam generating unit capacity and generation will continue to comprise a substantial portion of the nation's electricity supply.[191] A number of coal-fired steam generating units are delaying or canceling their scheduled retirements in light of increasing electricity demand, among other factors.[192] The EPA's projections further show a substantial capacity of coal-fired steam generating units operating in the long term.[193] Based on a lower capacity factor and operation beyond 12 years, the EPA proposed that, even if the IRC section 45Q tax credit is accounted for as a reduction, the costs are unreasonable and solicited comment on the assumptions in evaluation of the reasonableness of the cost of the BSER.

Comments: Some commenters agreed with the EPA's capacity factor assumptions in the June 2025 NPRM for evaluating the cost of CCS as BSER. Other commenters stated that the 80 percent capacity factor assumed for cost calculations in the 2024 CPS was reasonable and argued that the availability of the IRC section 45Q tax credit would incentivize higher capacity factors. Commenters also argued that the EPA's June 2025 NPRM was internally inconsistent, noting that elsewhere the June 2025 NPRM stated that ''coal-fired steam generating unit capacity and generation will continue to comprise a substantial portion of the nation's electricity supply.'' [194] Some commenters disagreed with the EPA's analysis based on a capture system underperforming (*i.e.,* designed for 90 percent capture, but achieving 75 percent total capture efficiency in practice). Commenters argued that the 75 percent total capture efficiency was unjustified.

EPA Response: As detailed in section IV.A.1.a of this preamble, it is reasonable to anticipate that a capture system designed to achieve a given capture efficiency would underperform. While CCS may achieve emission reductions, evidence shows the CO_2 capture system underperforms. The capture system at Boundary Dam Unit 3 was designed to achieve 90 percent capture but achieved, at best, 63 percent total capture efficiency on an annual basis between 2015 and 2022. Under a set of assumptions that reflect the underperformance of CCS, lower capacity factors, and the limited

[188] U.S. Energy Information Administration. Electric Power Annual. Available at: *https://www.eia.gov/electricity/annual/.*

[189] These tax credits are currently available for a twelve-year period for facilities that commence construction before January 1, 2033, and can be used to offset tax liability. 26 U.S.C. 45Q (2025).

[190] 89 FR 39798, 39902 (May 9, 2024).

[191] *See* 90 FR 25752, 25772, 25774 (June 17, 2025).

[192] D. Proctor, *U.S. Coal Plants Get Reprieve as Market and Policies Change,* Power (February 6, 2025). Available at: *https://www.powermag.com/u-s-coal-plants-get-reprieve-as-market-and-policies-change/.*

[193] See memorandum entitled *Trends Relating to Fossil Fuel-fired Electric Generating Units* in the docket for this rulemaking (Docket ID No. EPA–HQ–OAR–2025–0124).

[194] 90 FR 25774 (June 17, 2025).

availability of the IRC section 45Q tax credit,[195] the costs are substantially higher ($62/MWh, $124/ton of CO_2 reduced) than those determined in the 2024 CPS and more than three times higher on a $/MWh basis than the costs the EPA has previously determined to be reasonable ($18.50/MWh).[196] Even assuming a higher capacity factor that reflects the average capacity factor of coal-fired steam generating units of approximately 70 percent in the updated baseline projection,[197] costs remain high ($50/ton, $25/MWh).[198] Such high costs, particularly on a $/MWh basis, are not reasonable, even considering the potential CO_2 emission reductions, and do not support 90 percent CCS as BSER.

ii. The IRC Section 45Q Tax Credit

The costs for 90 percent CCS are even higher if the IRC section 45Q tax credit is not accounted for as a reduction ($77/MWh and $155/ton).[199] In the 2024 CPS, the costs of 90 percent CCS for existing coal-fired steam generating units accounted for the IRC 45Q tax credit by reducing the direct costs to the source for every ton of CO_2 reduced. The 2024 CPS assessed costs over a period consistent with the 12-year availability of the IRC section 45Q tax credit. The 2024 CPS justified that position on grounds that CAA section 111(a)(1) requires the EPA, in determining the BSER, to account for ''the cost of achieving such [emissions] reduction,'' and asserted that this provision refers to the cost to the source rather than the societal cost. The Inflation Reduction Act (IRA) extended and expanded the IRC section 45Q tax credit and included CAA section 135(a)(6), requiring the EPA to promulgate regulations under the CAA's authorities to ensure reductions in GHG emissions. In the 2024 CPS, the EPA further stated that the IRA included legislative history stating that Congress intended to authorize the Agency to promulgate regulations under CAA section 111 to reduce GHGs from fossil fuel-fired power plants, including regulations based on CCS that assumed lower cost due to the 45Q tax credit.[200] In its proposed repeal of the 2024 CPS, the EPA reevaluated this position and proposed that reducing control costs by the amount of the tax credit is an incorrect accounting for the costs of control, and solicited comment on this position.[201]

(A) Comments and Responses

Comments: Some commenters opposed the June 2025 NPRM and stated that the EPA must account for the IRC section 45Q tax credit as a reduction when evaluating the costs of 90 percent CCS. Commenters argued that the EPA has long understood the ''cost'' in CAA section 111(a)(1) to refer to whether the cost to the regulated source would be too great to implement the technology.[202] Some commenters argued that counting the IRC section 45Q tax credit as a reduction in costs in the evaluation of reasonableness of the costs is the best reading of CAA section 111(a)(1), which directs EPA to ''tak[e] into account the cost of achieving such reduction,'' when determining the BSER, not costs generally. Commenters stated the phrase ''such reduction'' refers to the emission reduction ''achieve[ed] through the application of the best system of emission reduction.'' Because sources are the entities that apply the best system, the phrase ''cost of achieving such reduction'' is best read as focusing on costs borne by those sources, rather than broader economic impacts. Commenters argued the EPA has followed this approach since the beginning of the regulatory program.[203]

Other commenters agreed with the June 2025 NPRM and stated that the EPA should not consider the IRC section 45Q tax credit as a reduction when evaluating the cost of CCS as a potential BSER. One commenter stated that the statute requires consideration of total costs and cited the Supreme Court's decision in *Michigan.*[204] Commenters claimed that the decision held that the EPA must consider all costs, including system and indirect costs, when evaluating the reasonableness of a standard. Some commenters argued that tax credits do not reduce the cost of 90 percent CCS but simply shift those costs to taxpayers. A few commenters further stated that CAA section 111(a)(1) includes consideration of societal costs beyond those to a source's owner or operator. One commenter argued that the inclusion of ''cost'' in the parenthetical of CAA section 111(a)(1), along with other factors that account for societal disbenefits, suggests that the best reading of CAA section 111(a)(1) is that the EPA should not focus solely on the cost to the source when evaluating the BSER and, therefore, should not account for the IRC section 45Q tax credit as reducing costs.

EPA Response: The EPA agrees with the commenters who stated that the 2024 CPS erred in excluding the value of the IRC section 45Q tax credit from the cost of CCS by counting the tax credit as a reduction in the cost of CCS. CAA section 111(a)(1) provides that the EPA must determine ''the best system of emission reduction . . . (taking into account the cost of achieving such reduction and any nonair quality health and environmental impact and energy requirements).'' This provision does not, by its terms, limit the costs to those incurred directly by the source. Under *Loper Bright Enterprises* v. *Raimondo,* 603 U.S. 369 (2024), the best interpretation of this provision is that the costs include the full costs of the controls (*i.e.,* without reduction by the amount of the IRC section 45Q tax credit). Under the justification in the 2024 CPS for considering the IRC section 45Q tax credit, if a cost was passed on to the public through a large tax credit or other similar subsidy, and

[195] These costs include the costs of capital equipment, *etc.,* consistent with 90 percent design capture rate, 63 percent actual capture rate, a fixed 40 percent capacity factor, and 15-year booklife (12 years of 45Q availability, three years without). Costs are expressed in 2019$. See memorandum entitled *Updated Evaluation of Best System of Emission Reduction Costs of Carbon Capture and Sequestration/Storage at Existing Coal-Fired Electric Generating Units* in the docket for this rulemaking.

[196] Costs are expressed in 2019$. In a variety of rulemakings, the EPA has required coal-fired EGUs to install and operate flue gas desulfurization (FGD, or wet scrubbers) to reduce their SO_2 emissions. The annualized cost of installing these controls on a representative 700 to 300 MW coal-fired steam generating unit are $14.80 to $18.50/MWh. Hence control costs that are generally consistent with these values should be considered reasonable. *See* 89 FR 39798, 39882 (May 9, 2024).

[197] See memorandum entitled *Trends Relating to Fossil Fuel-fired Electric Generating Units* in the docket for this rulemaking (Docket ID No. EPA–HQ–OAR–2025–0124).

[198] These costs include the costs of capital equipment, *etc.,* consistent with 90 percent design capture rate, 63 percent actual capture rate, a fixed 70 percent capacity factor, and 15-year booklife (12 years of 45Q availability, three years without). Costs are expressed in 2019$. See memorandum entitled *Updated Evaluation of Best System of Emission Reduction Costs of Carbon Capture and Sequestration/Storage at Existing Coal-Fired Electric Generating Units* in the docket for this rulemaking.

[199] These costs include the costs of capital equipment, *etc.,* consistent with 90 percent design capture rate, 63 percent actual capture rate, a fixed 70 percent capacity factor, and 15-year booklife (no reduction in cost from 45Q). Costs are expressed in 2019$. See memorandum entitled *Updated Evaluation of Best System of Emission Reduction Costs of Carbon Capture and Sequestration/Storage at Existing Coal-Fired Electric Generating Units* in the docket for this rulemaking.

[200] 89 FR 39798, 39881 (May 9, 2024).

[201] 90 FR 25752, 25772 (June 17, 2025).

[202] Commenters cited *Portland Cement Ass'n,* 513 F.2d at 508 (''The industry has not shown inability to adjust itself in a healthy economic fashion to . . . the standards prescribed.'').

[203] Commenters cited *Portland Cement Ass'n,* 486 F.2d at 388, observing that the ruling explained that the ''cost'' analysis is focused on equipment and operating costs and rejected an argument that a broader cost-benefit analysis evaluating impacts was required because that would ''conflict with the specific time constraints imposed on the administrator.''

[204] Commenters cited 576 U.S. at 752–53.

that transfer was counted as a reduction, then much more expensive controls would be considered reasonable as long as the cost of those controls were passed on to the public. As commenters noted, the tax credit does not eliminate costs, it simply transfers costs to the U.S. taxpayer. Thus, the costs paid by the U.S. taxpayer, in the form of the reduction in tax receipts due to the IRC section 45Q tax credit, are part of ''the cost of achieving [the emission] reduction,'' under CAA section 111(a)(1). As commenters also noted, this interpretation treats ''costs'' as consistent with the other factors that CAA section 111(a)(1) directs the EPA to consider because those other factors are not limited to the source. Specifically, CAA section 111(a)(1) directs the EPA to consider ''nonair quality health and environmental impact[s]'' that affect the public and ''energy requirements,'' which include effects on the broader energy system.

Comments: Commenters argued that counting the IRC section 45Q tax credit as a reduction in costs is consistent with Congressional intent. Commenters stated that Congress enacted the IRC section 45Q tax credit specifically to encourage CCS deployment because Congress had determined such deployment as sufficiently valuable to justify the cost, and that Congress amended the CAA in the IRA and directed the EPA to regulate with the expanded tax incentives of the IRA in mind.[205] Commenters stated that if Congress wants to keep a federal funding program from affecting a BSER determination under CAA section 111, Congress would include legislative text stating so, as Congress similarly did for the funding provided as part of the Energy Policy Act of 2005 (EPAct05). Commenters note that no similar provision exists for the IRC section 45Q tax credit. Some commenters took issue with the June 2025 NPRM's observation that there was pending legislation that would have ended the tax credit. Commenters observed that, rather than eliminate the tax credit, Congress in the OBBBA expanded the tax credit by increasing the value for CO_2 used for EOR and implementing a more favorable inflation adjustment.

EPA Response: CAA section 135(a)(6), as adopted by the IRA, provides $18 million to the EPA ''to ensure that reductions in [GHG] emissions are achieved through the use of the existing authorities of [the CAA], incorporating [an] assessment'' that the EPA is required to conduct of reductions in GHG emissions from changes in domestic electricity generation and use through fiscal year 2031.[206] However, this provision does not mention CAA section 111 and thus by its terms is not specific enough to indicate Congressional intent to authorize the EPA to promulgate CAA section 111 regulations based on CCS as the BSER and, in doing so, to account for the cost of CCS after reductions by the IRC section 45Q tax credit.

The EPA further disagrees with commenters' objection that if Congress had intended for the Agency not to consider the reduction in control costs due to the IRC section 45Q tax credit, Congress would have explicitly said so. Commenters note that in the EPAct05, Congress included provisions explicitly precluding the EPA from considering projects that included emissions controls that had been funded through EPAct05 in determining whether those controls are adequately demonstrated under CAA section 111. Absent such provisions, CAA section 111 would have allowed the EPA to consider those projects. As noted in this section of the preamble, the best interpretation of CAA section 111 is that the EPA must consider the costs of the control device, whether the costs are incurred by the facility or the taxpayer through the IRC section 45Q tax credit, and that if Congress had intended that the EPA not to do so, Congress would have included a specific provision to that effect.

Comments: Some commenters stated that in *Michigan* v. *EPA,* the U.S. Supreme Court reiterated that in promulgating rulemakings, Federal agencies ''are required to engage in 'reasoned decisionmaking,' '' [207] and that ''ordinarily requires paying attention to the advantages and the disadvantages of agency decisions.'' [208] Commenters stated that the failure of the EPA to consider the burden on the average U.S. taxpayer of the IRC section 45Q tax credit constituted a failure of reasoned decisionmaking.

EPA Response: The EPA agrees with the commenters, and that considering the burden on U.S. taxpayers tilts this action against adopting CCS as the BSER. The EPA is finalizing that the IRC section 45Q tax credit should not be accounted for as a reduction in costs to the source when evaluating the reasonableness of the costs of the BSER. Without taking into account the IRC section 45Q tax credit as a reduction, the costs of 90 percent CCS as BSER ($77/MWh and $155/ton) are unreasonable for long-term coal-fired steam generating units.[209]

c. Infrastructure

The large, widespread, and third-party infrastructure needed to support CCS is unique as compared to other BSER control technologies the EPA has historically analyzed and adopted under CAA section 111. In the 2024 CPS, the EPA determined that the capture, pipeline, and sequestration infrastructure necessary for the affected sources to meet the standards could be deployed by the compliance date of January 1, 2032. However, that position relied on incorrect assumptions in an unrealistic, best-case scenario that experience has already shown to be inaccurate. Therefore, the EPA proposed that the degree of emission limitation is not achievable because it is unlikely that the necessary infrastructure can be deployed by that compliance date.

In general, the capture, pipeline, and sequestration infrastructure necessary for 90 percent CCS for the fleet of existing coal-fired steam generating units does not currently exist. The necessary infrastructure would need to be broadly deployed, and there are challenges that exist for sources (*e.g.,* pipeline permitting and right-of-way) that may not be able to be resolved. It is highly unlikely, if not impossible, that the infrastructure necessary for CCS can be deployed by the January 1, 2032, compliance date, and the EPA is therefore finalizing that the degree of emission limitation in the 2024 CPS for long-term coal-fired steam generating units is not achievable.

With respect to the timeline for implementing infrastructure that does not currently exist, the EPA is revising both the weight the Agency should place on such future projections and its future projections with respect to 90 percent CCS. In the 2024 CPS, the Agency took the general position that an adequately demonstrated control technology could be selected as the BSER, and therefore the basis for a standard, so long as implementation at the scale required for compliance to be feasible could be projected to a date certain. However, upon further consideration and in light of public

[205] Commenters cited the Inflation Reduction Act, Public Law 117–169, section 13104, 136 Stat. 1818, 1924–29 (2022).

[206] 42 U.S.C. 7435(a)(6).

[207] 576 U.S. at 750 (citing *Allentown Mack Sales & Service, Inc.* v. *NLRB,* 522 U.S. 359, 374 (1998)).

[208] *Id.* at 753 (emphasis omitted).

[209] These costs include the costs of capital equipment, *etc.,* consistent with 90 percent design capture rate, 63 percent actual capture rate, a fixed 70 percent capacity factor, and 15-year booklife (no reduction in cost from 45Q). Costs are expressed in 2019$. See memorandum entitled *Updated Evaluation of Best System of Emission Reduction Costs of Carbon Capture and Sequestration/Storage at Existing Coal-Fired Electric Generating Units* in the docket for this rulemaking.

comments, the EPA is now clarifying that the uncertainty associated with such projections is a reason to disfavor the selection of such BSERs. The eight-year review cycle laid out in CAA section 111(b)(1)(B) is a signal that Congress thought the BSER generally should be capable of being implemented within eight years such that the EPA's review can meaningfully assess the success of the prior rule.[210] [211] In the 2024 CPS, the EPA estimated that it would take approximately seven years to implement 90 percent CCS for existing coal-fired units. The 2024 CPS also provided an exemption under which sources were not subject to the rule if they closed by the date that compliance with the standard based on 90 percent CCS would have commenced (January 1, 2032). However, as explained in section IV.A.1.c of this preamble, the EPA is now determining that the January 1, 2032 compliance date for 90 percent CCS for existing coal-fired steam generating units was overly optimistic. That is, implementing 90 percent CCS would take longer than the seven years provided in the 2024 CPS, bringing it close to CAA section 111(b)(1)(B)'s eight-year benchmark, if not exceeding it.

With respect to the infrastructure itself, the EPA has, upon further review, determined that the novelty of a BSER predicated on widespread infrastructure operated by third parties warns strongly against its selection. Much of the necessary CCS infrastructure requires the involvement, both for initial development and ongoing performance, of external third parties over whom the owners and operators of regulated facilities have limited control. Each of the three components of CCS—capture, transport, and storage—entail distinct infrastructure projects completed and operated in most instances by different sets of third parties, and all three components would need to be timely completed by those different sets of third parties without delay for owners and operators to be able to implement the CCS requirements by the January 1, 2032, compliance date. Construction of a CO_2 capture facility requires years of engineering analysis by third-party experts before ground can be broken and installation of the necessary equipment can commence.[212] Development of a capture facility also includes entering into necessary agreements and procuring permits through processes that may be governed by multiple jurisdictions, including but not limited to federal and state permitting authorities. And construction itself takes two or more years and involves many different activities that require a range of expert third parties.[213] In addition to the CO_2 capture facility, CCS also requires implementation of CO_2 pipeline infrastructure and CO_2 injection and storage infrastructure which involves reliance on engineers, geologists, construction firms, and permitting authorities, at least some of whom are likely separate from those involved in design and construction of the capture facility, as well as being outside of the electricity generation sector.

A BSER based on 90 percent CCS thus requires involvement, at multiple steps, of a complex web of experts and practitioners across a wide range of disciplines, many of whom may not be part of the regulated source category, or even the broader industry of which it is part, *i.e.,* the electric power industry. The implication is that these third parties are not subject to the same regulatory impetus as the owner or operator of a coal-fired steam generating unit that would be subject to requirements under the 2024 2024 CPS. The scale of the ancillary infrastructure required to support implementation of 90 percent CCS and the multitude of parties outside of an owner or operator's control at multiple steps of the process that are necessary to successfully design, permit, construct, test, and operate a CCS system makes it unreasonable to base federally enforceable requirements on the presumption of a best-case scenario for implementation when tardy- or non-performance by a single party has the potential to cause or exacerbate delays that ripple through the deployment of the CCS system.

The tenuousness of timely compliance given the scope of the requisite infrastructure for 90 percent CCS, coupled with the novelty of CCS and the need for a large number of third parties, is especially apparent when it is contrasted with air pollution control technologies that have been in widespread use in the power sector for decades, such as scrubbers for SO_2 emissions and selective catalytic reduction (SCR) for NO_X emissions.[214] Those latter control technologies do not rely on extensive pipeline and sequestration infrastructure. In contrast, the infrastructure to implement CO_2 capture in the power sector at a large scale is extensive, relatively new,[215] and involves a large collection of parties and activities necessary for design, permitting, construction, and implementation. All this compounds the likelihood of delays in implementation as parties work through necessary learning processes, which further supports the unreasonableness of the 2024 CPS's aggressive compliance timeframe. To be sure, CCS has been employed in some industries for certain limited purposes. However, in those instances, CCS has not been required by federal regulation under enforceable timelines or at a similar nationwide scale, meaning that any non-performance by third parties has not resulted in noncompliance with federally enforceable obligations.

In reaching these conclusions, the EPA notes that CAA section 111 anticipates analyses and regulatory requirements that turn on actions by the regulated source. Pursuant to CAA section 111(a)(1), the Agency must promulgate standards that ''reflec[t] the degree of emission limitation achievable through the *application* of the [BSER],'' and the resulting emission standards apply, in turn, to the regulated source. Consistent with the EPA's historical understanding, this language is most naturally read as tying the BSER to results that are achievable through the source's application of the selected

[210] CAA section 111(b)(1)(B) provides that the Administrator shall review and, if appropriate, revise NSPS at least every eight years. However, the Administrator need not review any such standard if the Administrator determines that ''such review is not appropriate in light of readily available information on the efficacy of such standard.'' 42 U.S.C. 7411(b)(1)(B). The EPA believes that the eight-year review cycle is relevant to existing sources regulated under CAA section 111(d) because it speaks to the appropriateness of a system of emission reduction as the BSER, and the BSER considerations under CAA section 111(a)(1) apply to both new and existing sources.

[211] In the event a system of emission reduction would take longer than eight years to implement, the EPA should take a hard look at whether it in fact qualifies as the BSER under CAA section 111(a)(1). The result of this inquiry may depend on whether other, less time-intensive options are available.

[212] Sargent & Lundy, *CO_2 Capture Project Schedule and Operations,* Document ID No. EPA–HQ–OAR–2023–0072–9095, at 2–3 (April 2024).

[213] *Id.* at 3–4.

[214] *See, e.g.,* 44 FR 33580, 33580 (June 11, 1979) (promulgating standards of performance for SO_2 emitted from new, modified, and reconstructed fossil fuel-fired steam generating EGUs under CAA section 111(b) based on use of scrubbers); 63 FR 49442, 49445 (Sept. 16, 1998) (promulgating standards of performance for NO_X emitted from new fossil fuel-fired steam generating units under CAA section 111(b) based on use of SCR).

[215] While CCS has a longer history of implementation in other industries, such as ethanol production, it has not been broadly deployed in the power sector at the capture rates contemplated in the 2024 CPS. Similarly, while the 2015 NSPS for new coal-fired power plants established a standard of performance based on partial-CCS, 80 FR 64510, 64545 (Oct. 23, 2015), no new coal-fired power plants have been constructed that would be subject to this standard. Therefore, the power sector's experience with CCS has been relatively limited compared to other, similarly complex pollution controls.

control technology. While sources commonly rely on third parties in the normal operation of their business, the extensive infrastructure requirements for CCS, coupled with the novelty of the control technology and the high level of dependence on third parties, undermines the ability of sources to achieve the CCS-based emission standards. If any third party provider responsible for any of the many links in the CCS infrastructure chain fails to develop the necessary infrastructure in a particular area, is delayed in such development for any reason, or ceases operation for any reason, the source would no longer be able to comply. These circumstances are different in kind from other BSERs that entail substantially less novel infrastructure.

The EPA is thus finding that the 2024 CPS erred by not considering the extent of the ancillary infrastructure and reliance on third parties needed for 90 percent CCS to be deployable at scale. This lapse is especially salient given the novelty of CCS at this scale and applied to this particular sector. These considerations provide further support for the conclusion that the January 1, 2032, compliance date and the degree of emission limitation are unachievable.

Comments: Some commenters stated that 90 percent CCS is achievable because the necessary infrastructure can be deployed by the compliance deadline. Commenters reiterated the arguments the EPA previously made in the 2024 CPS, including asserting that the timeline for deployment of capture based on the Sargent and Lundy report was achievable.[216] Commenters also stated that sequestration potential is broadly available, and that the 2024 CPS was premised on smaller, often intrastate CO_2 pipelines from the source to those storage sites. Commenters also stated that the EPA has made significant progress toward granting additional States primacy over Class VI injection wells for geologic storage of CO_2.[217] [218]

Other commenters stated that 90 percent CCS is not achievable because the necessary infrastructure cannot be deployed fast enough to meet the compliance deadline. Commenters argued that the timeline for deployment of the capture equipment would take longer than detailed in 2024 CPS. Commenters asserted that FEED studies can require more than 12 months, and DOE FEED studies can require even longer due to additional reporting requirements. Commenters stated that deployment of a capture facility could take up to eight to 10 years. Some commenters noted that permitting for CO_2 pipelines varies by State, and that some States have restrictive policies for CO_2 pipelines. Some commenters stated that the Pipeline Hazardous Materials Safety Administration is still working on updated regulations for CO_2 pipeline safety.

EPA Response: In general, the capture, pipeline, and sequestration infrastructure necessary for 90 percent CCS for the fleet of existing coal-fired steam generating units does not currently exist.

The equipment for the capture of CO_2 takes time to design, permit, and install. In the 2024 CPS, the EPA assumed an aggressive, unrealistic timeline for deployment of capture equipment. The EPA's timeline for installation of capture equipment included a 12-month FEED study in place of an 18-month FEED study, based off the more aggressive project schedule in a report developed by Sargent and Lundy.[219] The EPA further abbreviated that schedule by two months based on its own assumptions by shortening the duration for commercial arrangements from nine months to seven months, assuming sources immediately begin sitework once permitting is complete, and accounting for 13 months (rather than 14) for startup and testing.[220] However, those assumptions ignore any potential delays and do not reflect what is actually achievable.[221] The necessary infrastructure would need to be broadly deployed, and there are significant challenges that could exist for sources that would need to be resolved.

Regarding transport of CO_2, there is no existing network of CO_2 pipelines with the capacity capable of meeting the demands in the 2024 CPS. There are approximately 5,000 miles of CO_2 pipelines operational in the U.S.[222] [223] However, they are largely not located near existing coal-fired sources and additional pipelines would take time to deploy. Planned CO_2 pipelines continue to face delays due to several factors, including state permitting and the challenges associated with eminent domain authority and negotiating rights-of-way. For example, after promulgation of the 2024 CPS, Summit Carbon Solutions paused their application for a pipeline in South Dakota after the State banned eminent domain for CO_2 pipelines.[224] [225] A similar law is progressing through the Iowa legislature.[226]

Furthermore, while the U.S. has broad availability of the geologic formations that are potentially suitable for CO_2 sequestration, existing storage infrastructure for sequestration of CO_2 is limited. Underground CO_2 storage is governed by the Underground Injection Control program as authorized by the Safe Drinking Water Act.[227] Under that program, Class VI wells are used to inject CO_2 thousands of feet underground for geologic storage, and are permitted by the EPA. There are 18 Class VI wells that have been permitted by the EPA and there are six states that have primary enforcement authority (Arizona, Louisiana, North Dakota, Texas, West Virginia, and Wyoming).[228]

[216] Sargent & Lundy, *CO_2 Capture Project Schedule and Operations,* Document ID No. EPA–HQ–OAR–2023–0072–9095, at A–1 (April 2024).

[217] Class VI wells are used to inject CO_2 into deep rock formations and are regulated by the EPA under the Underground Injection Control (UIC) Program as authorized by the Safe Drinking Water Act. Available at: *https://www.epa.gov/uic/class-vi-wells-used-geologic-sequestration-carbon-dioxide#authorities.*

[218] Injection wells are overseen by either a state or tribal agency or one of EPA's regional offices. States and tribes may apply for primary enforcement responsibility to implement the UIC program. Primary enforcement responsibility, often called primacy, refers to State, territory, or Tribal responsibilities associated with implementing EPA approved UIC programs. A State, territory, or Tribe with UIC primacy, or primary enforcement responsibility, oversees the UIC program in that State, territory, or Tribe. Available at: *https://www.epa.gov/uic/class-vi-wells-used-geologic-sequestration-carbon-dioxide.*

[219] Sargent & Lundy, *CO_2 Capture Project Schedule and Operations,* Document ID No. EPA–HQ–OAR–2023–0072–9095, Attachment 17 (April 2024).

[220] 89 FR 39798, 39875 (May 9, 2024).

[221] *See Nat'l Lime Ass'n* v. *EPA,* 627 F.2d 416, 432–33 (D.C. Cir. 1980) (EPA must explain how the standard is ''achievable under the range of relevant conditions'' which sources may experience).

[222] Congressional Research Service. Carbon Dioxide Pipelines: Safety Issues, CRS Reports (June 3, 2022). Available at: *https://www.congress.gov/crs-product/IN11944.*

[223] U.S. Department of Transportation, Pipeline and Hazardous Materials Safety Administration. Annual Report Mileage for Hazardous Liquid or Carbon Dioxide Systems (May 1, 2026). Available at: *https://www.phmsa.dot.gov/data-and-statistics/pipeline/annual-report-mileage-hazardous-liquid-or-carbon-dioxide-systems.*

[224] J. Chilson, *Summit pauses CO_2 pipeline application in South Dakota,* South Dakota Public Broadcasting (March 12, 2025). Available at: *https://www.sdpb.org/business-economics/2025-03-12/summit-pauses-co2-pipeline-application-in-south-dakota.*

[225] An Act to prohibit the exercise of eminent domain for a pipeline that carries carbon oxide, South Dakota Legislature House Bill 1052, 100th Session, H.J. 475 (March 6, 2025). Available at: *https://sdlegislature.gov/Session/Bill/25581.*

[226] C. Koons, *House votes to ban eminent domain for CO_2 pipelines,* Iowa Capital Dispatch (March 26, 2025). Available at: *https://iowacapitaldispatch.com/2025/03/26/house-votes-to-ban-eminent-domain-for-co2-pipelines/.*

[227] EPA. Class VI Wells used for Geologic Sequestration of Carbon Dioxide (May 14, 2026). Available at: *https://www.epa.gov/uic/class-vi-wells-used-geologic-sequestration-carbon-dioxide#ClassVI_PermittingProcess.*

[228] EPA. Current Class VI Projects under Review at EPA. Accessed June 2, 2026. Available at: *https://www.epa.gov/uic/current-class-vi-projects-under-review-epa.*

In the 2024 CPS, the EPA based assumptions on the availability of ''potential'' storage sites. Time is required to characterize those sites to ensure the geology in the project area can receive and contain the CO_2 within the zone where it will be injected. However, the nearest available ''potential'' site may, after further investigation, not ultimately be suitable, *e.g.,* if faults or fractures are detected during site characterization. More time would then be required to find and characterize a new storage site, if another suitable site is even available. The timeline in the 2024 CPS did not take into consideration the prospect of project developers having to pivot to a different storage site should the initial site prove unsuitable. Development of planned storage sites may also face delays due to permitting and other issues. These challenges to deployment of CCS provide further support to the conclusion that the January 1, 2032, compliance date and degree of emission limitation are unachievable.

Moreover, a greater number of sources would likely be subject to CCS-based requirements than previously anticipated. Those sources would be competing to build CCS infrastructure, exacerbating any potential schedule delays or supply constraints, further limiting the achievability of the EPA's infrastructure timeline in the 2024 CPS. As the EPA noted in the June 2025 NPRM, the Agency believes that coal-fired steam generating unit capacity and generation will continue to comprise a substantial portion of the nation's electricity supply due to increasing electricity demand.[229] A number of coal-fired steam generating units are delaying or canceling their scheduled retirements in light of this increasing demand, the changes in tax incentives for various types of electricity-generating resources in the OBBBA, and Administration actions to support the continued operation of coal-fired capacity.[230] [231] Recent changes in the U.S. electricity market affect the amount of coal-fired steam generating units operating in the long-term, as described in section III.C of this preamble, including increased electricity demand from data centers and scaled back tax credits for renewable generation under the OBBBA. The EPA now projects that more existing coal-fired EGUs will operate in the long term and more base load NGCCs will be built than previously anticipated.[232] Specifically, at the end of 2024 there were 174 GW of coal-fired EGUs active in the power sector nationwide.[233] The baseline 2024 analysis for the 2024 CPS projected that, absent requirements, approximately 40 GW of coal capacity would still be active by 2040.[234] Therefore, the 2024 CPS considered the viability and reasonableness of installing and operating CCS at 40 GW of coal capacity. However, the EPA now projects that, as a baseline, approximately 100 GW of coal capacity will be active in 2040.[235] Similarly, under the analysis conducted for the 2024 CPS, the EPA projected approximately 26 GW of incremental NGCC capacity additions by 2035.[236] Under the 2025 analysis, absent the requirements of 2024 CPS, the EPA projects approximately 155 GW of new NGCC builds by 2035. Based on the EPA's updated analytics a much larger number of EGUs would be subject to CCS-based standards than previously estimated in the 2024 CPS. The large amount of CCS infrastructure necessary would likely exacerbate any potential schedule delays or supply chain constraints. Deploying the necessary infrastructure for the affected fleet by the January 1, 2032, compliance date is therefore further unlikely.

Considering these factors, it is unlikely the infrastructure necessary for CCS can be deployed by the January 1, 2032 compliance date, and the EPA is therefore finalizing that the degree of emission limitation in the 2024 CPS for long-term coal-fired steam generating units is not achievable.

d. Conclusion

Because the EPA is finalizing that 90 percent CCS is not adequately demonstrated as the BSER and that the cost of 90 percent CCS for long-term coal-fired steam generating units is not reasonable, the Agency is finalizing the determination that 90 percent CCS is not the BSER for long-term coal-fired steam generating units. Furthermore, because it is extremely unlikely that the extensive infrastructure necessary for CCS can be deployed by the January 1, 2032 compliance date, the EPA is finalizing a determination that the degree of emission limitation in the 2024 CPS for long-term coal-fired steam generating units is not achievable. Additionally, the challenges posed by the scope of the infrastructure are heighted by the involvement of numerous parties external to the owners and operators of the regulated facility, which complicates deployment and exacerbates delays that thus provides further support for the conclusion that the January 1, 2032 compliance date and the degree of emission limitation are unachievable.

Moreover, the EPA is concluding that in light of current information concerning sources' inability to comply with 90 percent CCS by 2032, retaining 90 percent CCS as the BSER for existing coal-fired steam generating units that did not commit to retire before January 1, 2039, coupled with an exemption from the rule for sources that agreed to retire before January 1, 2032, would be a form of generation shifting prohibited by *West Virginia* under the circumstances here.[237] Specifically, because updated projections demonstrate that compliance with 90 percent CCS generally is not feasible by 2032, sources have only one remaining option: retirement by 2032. Failing to revise the standard under these circumstances would therefore amount to forced closures in anticipation of other forms of power generation by facilities not subject to the at-issue 2024 CPS requirements.

In the immediate aftermath of *West Virginia,* the EPA initially focused on the Supreme Court's statement that generation shifting could sometimes be a consequence of regulatory requirements under CAA section 111.[238] The Agency believed at the time that the lesson of *West Virginia* was that generation shifting was appropriate as a *result* of regulation, so long as the regulation did not explicitly *require* it.[239] The EPA therefore selected 90 percent CCS and 40 percent natural gas co-firing, coupled with an exemption contingent on unit retirement by 2032,

[229] *See* 90 FR 25752, 25772, 25774 (June 17, 2025).

[230] D. Proctor, *U.S. Coal Plants Get Reprieve as Market and Policies Change,* Power (February 6, 2025). Available at: *https://www.powermag.com/u-s-coal-plants-get-reprieve-as-market-and-policies-change/.*

[231] *See, e.g.,* U.S. Department of Energy, 2026 DOE 202(c) Orders. Available at: *https://www.energy.gov/ceser/2026-doe-202c-orders.*

[232] See memorandum entitled *Trends Relating to Fossil Fuel-fired Electric Generating Units* in the docket for this rulemaking (Docket ID No. EPA–HQ–OAR–2025–0124).

[233] U.S. Energy Information Administration. EIA Power Monthly (December 2024). Available at: *https://www.eia.gov/electricity/monthly/archive/december2024.pdf.*

[234] Document ID No. EPA–HQ–OAR–2023–0072–8913. Table 3–14.

[235] See memorandum entitled *Trends Relating to Fossil Fuel-fired Electric Generating Units* in the docket for this rulemaking (Docket ID No. EPA–HQ–OAR–2025–0124).

[236] Document ID No. EPA–HQ–OAR–2023–0072–8913. Table 3–14.

[237] 597 U.S. at 735.

[238] *See id.* at 731 n.4 (noting that ''there is an obvious difference between (1) issuing a rule that may end up causing an incidental loss of coal's market share, and (2) simply announcing what the market share of coal, natural gas, wind, and solar must be'').

[239] *See, e.g.,* 91 FR 39798, 39899 (May 9, 2024).

based on the belief that unit closure was an appropriate consequence so long as facilities could also choose to comply with the standards.

However, as detailed in section IV of this preamble, the EPA is now determining that the predictions and analyses underlying 90 percent CCS were overly optimistic. The EPA now concludes that requiring sources either to close by 2032 or comply with 90 percent CCS requirements that have now been determined to be unreasonable and impracticable essentially presents a Hobson's choice. That is, because the EPA's predictions regarding 90 percent CCS have now been determined to be overly optimistic, retaining the 2024 CPS would effectively force generation shifting by leaving regulated sources with no alternative to closure by the compliance deadline in 2032.

Consequently, the EPA is finalizing repeal of the requirements in emission guidelines pertaining to long-term coal-fired steam generating units. As discussed in this section of the preamble, the EPA is addressing only CCS with 90 percent capture and implementation by January 1, 2032, because these were the requirements under the 2024 CPS. This action does not finalize any potential alternative BSERs or implementation timeframes such as CCS with lower rates of capture or a later compliance date. The EPA considered whether to analyze and promulgate potential alternatives and determined it is not necessary to do so under the circumstances presented here.

2. Natural Gas Co-Firing-Based Requirements for Existing Medium-Term Coal-Fired Steam Generating Units

In the 2024 CPS, the EPA determined the BSER for existing medium-term coal-fired steam generating units to be 40 percent natural gas co-firing. Natural gas co-firing can require installation of new gas burners and related boiler modifications. Natural gas co-firing also requires construction of natural gas pipeline infrastructure to supply the necessary amount of natural gas to the unit. The EPA argued in the 2024 CPS that natural gas co-firing qualifies as the BSER for medium-term coal-fired units because, among other things, it does not result in unreasonable adverse consequences related to energy requirements. In the 2024 CPS, the EPA further argued that the degree of emission limitation based on application of the 40 percent natural gas co-firing BSER to the affected sources was achievable by the January 1, 2030, compliance date, considering the time necessary to deploy the necessary natural gas pipeline infrastructure.

The EPA reevaluated the record for and the Agency's determinations in the 2024 CPS and subsequently proposed that 40 percent natural gas co-firing is not the BSER for existing medium-term coal-fired steam generating units based on the potential for significant adverse consequences related to energy requirements. The EPA also proposed that 40 percent natural gas co-firing cannot qualify as the BSER because it constitutes impermissible generation shifting. Finally, the EPA further proposed to determine that the degree of emission limitation based on 40 percent natural gas co-firing is not achievable because it is unlikely that the pipeline infrastructure necessary can be deployed by the compliance date of January 1, 2030. Consequently, the EPA proposed to repeal the requirements for medium-term coal-fired steam generating units.

The EPA is finalizing the determination that 40 percent natural gas co-firing is not the BSER for medium-term coal-fired steam generating units and is repealing the requirements for those sources on that basis. In this section of the preamble, the EPA details the three bases for this determination. The first basis discussed here—that 40 percent natural gas co-firing represents impermissible generation shifting—is sufficient to preclude it from qualifying as the BSER. However, the EPA is also providing two additional bases that provide additional support for this conclusion.

a. 40 Percent Natural Gas Co-Firing is Generation Shifting

The EPA is finalizing its proposed interpretation that 40 percent co-firing with natural gas is not the BSER for existing medium-term coal-fired steam generating EGUs because it constitutes generation shifting and is therefore beyond the EPA's authority to require under CAA section 111. In *West Virginia,* the Supreme Court held that a ''system of emission reduction'' under that section cannot include a forced shift of nationwide electricity generation from one type of energy source to another.[240] That is, the BSER cannot be based on generation shifting. In discussing whether the EPA could effect generation shifting through at-the-source measures by, *e.g.,* ''simply requiring coal plants to become natural gas plants,'' the Court stated that ''EPA has never ordered anything remotely like that, and we doubt it could.'' [241]

In the 2024 CPS, the EPA considered whether co-firing natural gas in a coal-fired boiler would constitute generation shifting and concluded that it would not. There, the Agency argued that, in contrast to impermissible generation shifting, 40 percent natural gas co-firing constitutes at-the-source fuel switching, which is a ''traditional pollution control measure'' as recognized by the Supreme Court in *West Virginia.*[242] The EPA further explained in the 2024 CPS that the Agency interpreted the Court's statements in footnote 3 of that opinion as referring to a complete transformation of a coal-fired unit to a 100 percent natural gas-fired unit and contrasted such complete repowering with natural gas co-firing at 40 percent.[243]

The EPA has reexamined the question of whether 40 percent natural gas co-firing is impermissible generation shifting and has now determined that requiring a utility to use a completely different fuel type runs counter to the Supreme Court's decision in *West Virginia*. Critically, in that decision, the Court found that the EPA lacks authority to decide the appropriate share of different types of electricity generation on a nationwide basis.[244] Requiring a significant portion of the coal-fired fleet to become a different type of electricity generating resource—a hybrid coal and gas-fired fleet that relies on a different set of fuels—has the same effect of dictating the market shares of the different fuel types that comprise the nation's energy supply. The fact that this forced shift would occur within individual sources as opposed to across sources in the electricity generation sector does not rebut this conclusion.

Moreover, a coal-fired steam generating EGU is a fundamentally different type of plant than a steam generating EGU that fires both coal and natural gas. This is evidenced by the modifications and new infrastructure needed to turn a coal-fired EGU into a hybrid coal and gas-fired EGU, including modifications to or additions of burners to the boiler and potential changes to steam superheaters, reheaters, and economizer heating surfaces. The EPA believes that requiring a coal plant to turn itself into a different type of plant in order to burn a completely different fuel (*i.e.,* natural gas) belies the Agency's earlier assertions that 40 percent natural gas co-firing is fuel switching akin to burning

[240] 594 U.S. at 734–35.

[241] *Id.* at 728 n.3.

[242] U.S. EPA, Response to Comments Document (April 2024). Chapter 2.7.2, page 101–02. Document ID No. EPA–HQ–OAR–2023–0072–8914.

[243] *Id.*

[244] *West Virginia,* 594 U.S. at 728.

lower sulfur coal in a coal-fired EGU or ultra-low sulfur diesel in a stationary compression ignition internal combustion engine. In these examples, a source is merely using a particular type of the fuel that the source was always intended to use, as opposed to a different fuel entirely. Therefore, the EPA is finalizing the finding that a BSER based on forcing a coal-fired EGU to become a partially natural gas-fired steam generating units shifts that unit's generation from coal to natural gas and is impermissible under the Court's precedent because it is an attempt to dictate the market share of coal versus natural gas.

The EPA acknowledges that this is a change in position from its earlier interpretation in the 2024 CPS that 40 percent natural gas co-firing is not generation shifting. As explained in the preceding discussion, the Agency believes its updated interpretation of *West Virginia* and its application to natural gas co-firing is the best one because it recognizes the distinction between traditional fuel switching and requiring a switch to different type of fuel. No party will have relied on the EPA's earlier interpretation in the 2024 CPS, given that that regulatory framework was never implemented.

Comments: Many commenters supported the EPA's proposed interpretation that natural gas co-firing constitutes impermissible generation shifting. Commenters stressed that generation shifting occurs whenever a facility is required to switch from burning one type of fuel to an entirely different type of fuel, regardless of the amount or percentage of co-firing required, because the EPA lacks authority either to require a plant to change to a different fuel type or to require it to become a different type of plant (*i.e.,* a hybrid coal and gas plant). Commenters asserted that 40 percent co-firing would require transformation into a different type of source because co-firing natural gas in a coal-fired boiler entails changes to that boiler that could include modifications to millions of dollars of equipment and additional costs associated with pipeline infrastructure needed to support co-firing.

Other commenters opposed to the EPA's interpretation that 40 percent natural gas co-firing is generation shifting argued that natural gas co-firing is a form of fuel switching, which the EPA has historically relied on under CAA section 111. Commenters contrasted fuel switching, a traditional technology-based control measure focused on improving the performance of individual sources, with the generation shifting described by the Supreme Court in *West Virginia,* further asserting that co-firing does not entail a transformative expansion in the Agency's regulatory authority. Commenters explained that any new infrastructure and costs associated with natural gas co-firing are accounted for in the EPA's evaluation of the system's cost, which is a separate factor in the BSER analysis. Additionally, commenters asserted that it is common for a CAA section 111 standard to require extensive modifications to a plant, although the modifications associated with co-firing are relatively minor and far less extensive than those required for other control strategies at coal-fired plants, such as flue gas desulfurization or selective catalytic reduction.

Moreover, according to the commenters, co-firing does not involve the type of grid-wide reshuffling that *West Virginia* prohibits, either in concept or practice. There is no emissions or generation cap on affected sources, and the EPA does not assume any change in generation at co-firing sources. Therefore, commenters argued that the BSER is not premised on a shift of generation from co-firing sources to other sources. In addition, EPA's compliance modeling did not predict such a shift. Commenters also argued that fuel-switching is not generation shifting because a coal plant that is co-firing with 40 percent natural gas does not cease to exist as a coal plant, unlike the generation shifting addressed in *West Virginia*. Further, the EPA has always treated coal- and gas-fired steam generating EGUs as part of the same source category because the underlying type of source burning the fuel (a steam generating utility boiler) is the same, even though co-firing would require the use of some amount of a different fuel (natural gas instead of coal).

EPA Response: The EPA disagrees that co-firing natural gas in a coal-fired boiler is akin to the traditional pollution control measure under CAA section 111. As noted in this section of the preamble, natural gas co-firing is distinguishable from switching to lower sulfur coal or lower sulfur diesel, or from requiring a source to limit itself to one type of fuel. The EPA takes no position in this rule about these forms of fuel switching vis-à-vis *West Virginia*. But the EPA is, in this final rule, finding that it is not permissible for a BSER to be based on the use of an entirely different fuel from what a source was designed and configured to accept. Given that modifications are necessary to accommodate co-firing at 40 percent, this level of co-firing, in particular, is distinct from the traditional forms of fuel switching that the EPA has employed under CAA section 111. The cost of those modifications is not as relevant as the fact that they occur: The EPA considers the need for modifications as part of determining whether 40 percent co-firing is an appropriate system of emission reduction, as opposed to whether it is the *best* system of emission reduction based on cost and the other factors of CAA section 111(a)(1). That is, because a coal-fired source must transform itself to co-fire natural gas at 40 percent, such co-firing is not fuel switching but is rather shifting generation to a different type of source. While commenters countered that natural gas co-firing is not generation shifting because the source remains a fossil fuel-fired steam generating boiler that continues to fire some amount of coal, the EPA does not believe that it is necessary to shift generation from a boiler to a combustion turbine in order to effectuate impermissible generation shifting. Under the commenters' logic, the EPA's requiring 99 percent natural gas co-firing would still not be considered shifting generation because one percent would still be some amount of coal still being utilized. Rather, the EPA's position is that generation shifting occurs when a system of emission reduction requires a source to use an entirely different type of fuel, particularly when the source was not designed to accept the new type of fuel. The effect of such an approach is that the EPA effectively dictates the fuel mix used in the nationwide energy system, which the Supreme Court held in *West Virginia* the EPA is not permitted to do.

b. Energy Requirements

Even if 40 percent natural gas co-firing could be evaluated as a potential BSER, which it cannot be for the reasons discussed in section IV.A.2.a of this preamble, the EPA further determines that the adverse impacts on the energy system are unreasonable and therefore that 40 percent co-firing cannot be the BSER for medium-term coal-fired EGUs. As part of determining the BSER, the EPA considers energy requirements.[245] As discussed in section II.C.3 of this preamble, energy requirements may include the impacts, if any, of the air pollution controls on the source's own energy needs.[246] The EPA may further assess, as part of the energy

[245] 42 U.S.C. 7411(a)(1).

[246] *See, e.g.,* 91 FR 1910, 1937 (January 15, 2026) (energy requirements consideration includes auxiliary/parasitic load requirements to run a potential BSER control for fossil fuel-fired combustion turbines).

requirements consideration, any impacts of a system of emission reduction on the energy system on a sector-wide, regional, or national basis, as appropriate.[247] As part of such assessment, the EPA has considered potential adverse impacts on the reliability of the bulk power system and its ability to deliver affordable and consistent electricity to end users.[248] Similarly, the EPA has considered whether potential BSERs might have adverse impacts on the supply or cost of natural gas, which is used in many applications throughout the nation's energy system, including for electricity generation, industrial applications, and transportation.[249] In this action, the Agency's determination of unreasonable adverse impacts has focused on the sector-wide strain that requirements based on 40 percent natural gas co-firing could place on the availability of natural gas. The demand for natural gas, as explained below, is anticipated to be greater than previously projected. Under these circumstances, diverting natural gas for use in natural gas in steam generating boilers could result in an unreasonable impact on the energy system because it reduces the availability of gas for other, more efficient uses, including for electricity generation in combustion turbines.

The analyses the EPA conducted and relied on to assess the 2024 CPS's projected impacts showed only incremental increases in electricity demand: a 13 percent increase between 2000 and 2022, with demand staying relatively flat over the 2007–2022 period. As discussed in section III.C of this preamble, during this period, the share of coal-fired electricity decreased in both absolute and relative terms, while both natural gas-fired net generation and wind and solar net generation increased. Natural gas surpassed the total net generation from coal on an absolute basis in 2016, while renewables surpassed the total net generation from coal on an absolute basis in 2022.[250] The information that the EPA analyzed for purposes of the 2024 CPS indicated that the sector trend of moving away from coal-fired generation was likely to continue, that the share of electricity generation from natural gas-fired sources would likely decline, and that the share of generation from non-emitting technologies would likely continue to increase. One important data point for purposes of the 2024 CPS was that the Agency anticipated that the recent trend of retirements of coal-fired capacity (at an average annual rate of 10 GW from 2015 to 2023) would continue due to the economics of coal-fired generation. At that time, more than half of the operating coal-fired steam generating units had announced retirement or plans to convert to natural gas by 2039.[251] Thus, the EPA predicated the Agency's consideration of energy requirements associated with 40 percent natural gas co-firing in the 2024 CPS on an assumption of a continued and significant decline in the number of coal-fired EGUs.

In contrast, updated information and analysis of power sector trends indicate a significantly different landscape moving forward. In particular, as outlined in section III.C of this preamble, the projections of electricity markets over the coming decades indicate higher electricity demand due to a number of factors. Recent analyses further predict that this higher electricity demand will, in turn, result in higher utilization of coal and gas fired resources [252] than projected under the 2024 analysis underpinning the 2024 CPS.[253] The EPA's updated baseline projections indicate that coal capacity will level off at 100 GW by 2040, in contrast to the 2024 analysis's prediction of continuing to decline from the current level to 52 GW in 2035 and 42 GW in 2040. Similarly, the updated baseline projections indicate that new NGCC additions would be 155 GW in 2035 and 217 GW by 2040, contrasting earlier projections that total just 26 GW in 2035 and 2040. The EPA's updated baseline modeling in the 2025 analysis also projects significantly higher natural gas consumption, even absent the 2024 CPS requirements, with Henry Hub gas prices projected at 18 percent higher by 2030 and 52 percent higher by 2035.

These significant changes in the power sector complement the EPA's reevaluation of the demands natural gas co-firing puts on both individual coal-fired steam generating units and the energy system more broadly, informing the EPA's analysis and determination here. While coal-fired steam generating units may use small amounts of natural gas for startup purposes, relatively few sources use natural gas in proportions that would have been consistent with the requirements for medium-term coal-fired steam generating units in the 2024 CPS. Therefore, the co-firing-based standards would result in a significant increase in the demand for natural gas. The 2024 CPS failed to adequately address the impacts of this increase, even before the updated projections of coal capacity and natural gas demand that are now available.

Based on the EPA's reexamination of the facts and conclusions in the 2024 CPS and the analysis supporting this rulemaking, the Agency now finds that 40 percent natural gas co-firing is not the BSER because of the potential for unreasonable adverse impacts related to energy requirements.[254] The EPA's two reasons for this determination—diverting the volume of natural gas needed to support 40 percent co-firing from other uses in the energy system could have significant impacts and natural gas is more efficiently used in natural gas-fired combustion turbines—are described in further detail below. The EPA is determining that the collective effect of these two phenomena could result in unreasonable adverse impacts on the energy system by forcing natural gas, the availability of which is anticipated to become more constrained, to be used in a relatively inefficient manner. The EPA has also balanced these energy impacts against the relatively small amount of CO_2 reductions available from 40 percent natural gas co-firing (16 percent) and the other relevant considerations under CAA section 111(a)(1) (*i.e.,* cost and nonair quality health and environmental impacts) in determining that such co-firing could not be the BSER for medium-term coal-fired steam generating units.

i. 2024 CPS Requirements Reduce the Availability of Natural Gas for Other Purposes

The EPA now finds that the potentially large demand for natural gas associated with 40 percent co-firing in coal-fired steam boilers is unreasonable and could produce a significant adverse consequence related to energy requirements. As explained in the June 2025 NPRM, the EPA believes that coal-fired steam generating unit capacity and generation will now continue to comprise a substantial portion of the

[247] *See, e.g., Sierra Club,* 657 F.2d at 330 (interpreting energy requirements factor as including consideration of effects ''on the grand scale''); *see also* 84 FR 32520, 32534 n.152 (July 8, 2019) (''The EPA may consider energy requirements on both a source-specific basis and a sector-wide, region-wide, or nationwide basis.'').

[248] *See, e.g.,* 80 FR 64510, 64594 (October 23, 2015); 80 FR 64662, 64721 (October 23, 2015).

[249] *See* 84 FR 32520, 32544–46 (July 8, 2019).

[250] Document ID No. EPA–HQ–OAR–2023–0072–8920.

[251] 89 FR 39798, 39816–18 (May 9, 2024).

[252] See memorandum entitled *Trends Relating to Fossil Fuel-fired Electric Generating Units* in the docket for this rulemaking (Docket ID No. EPA–HQ–OAR–2025–0124).

[253] U.S. EPA. RIA for 2024 CPS. Document ID No. EPA–HQ–OAR–2023–0072–8913.

[254] For details on the analysis, see memorandum entitled *Trends Relating to Fossil Fuel-fired Electric Generating Units* in the docket for this rulemaking (Docket ID No. EPA–HQ–OAR–2025–0124).

nation's electricity supply.[255] A number of coal-fired steam generating units are delaying or canceling scheduled retirements in light of increasing electricity demand, the changes in tax incentives for various types of electricity-generating resources in the OBBBA, and Administration actions to support the continued operation of coal-fired capacity.[256] [257] Furthermore, the EPA's modeling projections show a substantial capacity of coal-fired steam generating units operating past 2032.[258] The EPA's updated modeling estimates that 100 GW coal capacity will be operational in the 2035 model run year,[259] whereas the EPA projected 52 GW of coal capacity would exist by 2035 in the 2024 CPS analysis.[260] While it is the case that not all 100 GW would necessarily be subject to the 40 percent co-firing based standard, it is very likely that the amount of capacity that would be so subject is significantly higher than the EPA projected in the 2024 CPS. Because much more coal capacity is anticipated to remain operational than was previously projected in the 2024 CPS modeling (almost twice as much in 2035), it is reasonable to expect that more units could be subject to a standard of performance based on 40 percent co-firing with natural gas. Thus, the total volume of natural gas that sources would need to implement co-firing could be both substantial and greater than previously believed.

More specifically, using the latest available data from the EIA, the U.S. electric sector comprised approximately 174 GW of coal-fired EGUs in 2024, which collectively consumed approximately 6.98 quadrillion Btus of energy. According to operation planning data reported to the EIA, 146 GW of this 174 GW coal capacity in the U.S. electric sector are expected to remain in service through 2032.[261] If these 146 GW of units maintained their 2024 utilization levels and co-fired 40 percent natural gas, they would draw more than 2.3 quadrillion Btus of natural gas. For context, the entire U.S. electric sector consumed approximately 13.9 quadrillion Btus of natural gas in 2024 (*i.e.,* implementing the co-firing standard would require an increase of 17 percent of 2024's total gas consumption in the U.S. electric sector).

As noted above, there are many critical demands for natural gas other than for electricity generation, including for industrial uses, residential use, and as a transportation fuel. According to the EIA, total demand for all uses of natural gas was approximately 33 quadrillion Btus in 2024. Furthermore, the EIA projects that the demand for natural gas, driven by domestic consumption and liquefied natural gas exports, will grow both in the near term [262] as well as in the long term.[263] EIA forecasts record high industrial and power sector natural gas consumption by 2027 [264] [265] and projects a 30 percent increase in LNG exports by 2027 as five new LNG export projects begin operation.[266] This increasing demand stresses supply, resulting in an increase of projected costs of natural gas. Henry Hub gas prices in 2024 dollar-years are projected to rise to $4.12/MMBtu by 2030 and $5.26/MMBtu by 2035.[267] In most model run years, EPA's analysis indicates that the cost of natural gas would be higher with the 2024 CPS in place as compared to the scenario absent the requirements of 2024 CPS.[268] Also, updated EPA projections show substantial increases in natural gas combustion turbine generation when compared to prior EPA projections conducted for the 2024 CPS.[269] Using a large volume of natural gas in coal-fired steam generating units when there are already increasing demands on the natural gas supply (from, among other things, higher domestic demand, including due to increased combustion turbine buildout, and greater liquefied natural gas exports) further exacerbates the potential for adverse energy impacts, as evidenced by the natural gas price increases associated with the 2024 CPS requirements. Therefore, the EPA finds that diverting the volume of natural gas necessary to support 40 percent natural gas co-firing from other uses is unreasonable because it could result in a significant adverse impact on the energy system, such that 40 percent natural gas co-firing is not the BSER.

Comments: Some commenters stated that using large quantities of natural gas to fuel steam generating units is extraordinarily wasteful at a societal level. A commenter also argued that the adverse impacts on the energy system are especially unreasonable when compared to the relatively small CO_2 reductions—16 percent—that are available from 40 percent natural gas co-firing.

Other commenters expressed concern that the EPA's objections to the 40-percent co-firing standard based on gas supply were unsupported. Commenters asserted that the EPA lacked data in the June 2025 NPRM to sustain the argument that there is insufficient natural gas supply to support the 40 percent co-firing standard.

EPA Response: The EPA agrees with commenters who stated that the impacts of 40 percent natural gas co-firing on the energy system are unreasonable, especially given the relatively small amount of CO_2 reductions available. The Agency also notes that the Agency has broad discretion in weighing the statutory considerations under CAA section 111(a)(1) to determine the BSER.[270] The rationale included in the June 2025 NPRM and further corroborated by the arguments and data included in this final rule justifies the EPA's finding that 40 percent natural gas co-firing would have adverse consequences for the energy system: the co-firing standard could strain the supply of natural gas and reduce its availability for other purposes. Although several commenters cited projected natural gas use and supply figures from the 2024 CPS to support

[255] 90 FR 25752, 25772, 25774 (June 17, 2025).

[256] D. Proctor, *U.S. Coal Plants Get Reprieve as Market and Policies Change,* Power (February 6, 2025). Available at: *https://www.powermag.com/u-s-coal-plants-get-reprieve-as-market-and-policies-change/.*

[257] *See, e.g.,* U.S. Department of Energy, 2026 DOE 202(c) Orders. Available at: *https://www.energy.gov/ceser/2026-doe-202c-orders.*

[258] Under the CPS, coal-fired steam generating units operating past 2032 and choosing to permanently cease operation before January 1, 2039, would have had a standard of performance based on 40 percent natural gas co-firing.

[259] See memorandum entitled *Trends Relating to Fossil Fuel-fired Electric Generating Units* in the docket for this rulemaking (Docket ID No. EPA–HQ–OAR–2025–0124).

[260] U.S. EPA. RIA for 2024 CPS. Document ID No. EPA–HQ–OAR–2023–0072–8913. Table 3–14.

[261] The survey Form EIA–860 collects generator-level specific information about existing and planned generators and associated environmental equipment at electric power plants, including scheduled retirements. U.S. EIA. Form 860 data. Available at: *https://www.eia.gov/electricity/data/eia860/.*

[262] U.S. Energy Information Administration. EIA expects higher wholesale U.S. natural gas prices as demand increases. Available at: *https://www.eia.gov/todayinenergy/detail.php?id=64344.*

[263] U.S. Energy Information Administration, Annual Energy Outlook 2025. Available at: *https://www.eia.gov/outlooks/aeo/data/browser/#/?id=13-AEO2025&cases=ref2025&sourcekey=0.*

[264] U.S. Energy Information Administration. U.S. industrial natural gas consumption expected to hit records in 2026 and 2027. Available at: *https://www.eia.gov/todayinenergy/detail.php?id=67686.*

[265] U.S. Energy Information Administration. Natural gas for power generation flat this summer, record high expected in 2027. Available at: *https://www.eia.gov/todayinenergy/detail.php?id=67725.*

[266] U.S. Energy Information Administration. U.S. natural gas exports to grow nearly 30% by 2027 as LNG facilities ramp up. Available at: *https://www.eia.gov/todayinenergy/detail.php?id=67484.*

[267] See memorandum entitled *Trends Relating to Fossil Fuel-fired Electric Generating Units* in the docket for this rulemaking (Docket ID No. EPA–HQ–OAR–2025–0124).

[268] *Id.*

[269] *Id.*

[270] *See Lignite Energy Council,* 198 F.3d at 933 (''Because section 111 does not set forth the weight that should be assigned to each of these factors, we have granted the agency a great degree of discretion in balancing them.'').

arguments that ample gas would be available for co-firing, such comments do not consider the changed circumstances of the energy sector. The EPA cited these changed circumstances in the June 2025 NPRM and, in this final rule, is adding further information that has become available since the June 2025 NPRM's publication in Spring 2025. As discussed in this preamble, the EPA's updated analysis shows that the total volume of natural gas that affected sources would require to implement the 2024 CPS's co-firing standard is 17 percent of total power sector gas consumption in 2024. This increase is over 20 percent higher than the percent increase estimated under the 2024 analysis using the same approach (*i.e.,* assuming all units active in 2032 co-fire 40 percent natural gas and maintain 2024 utilization levels). This substantial increase in natural gas demand would place upward pressure on natural gas prices.

Moreover, the increase in natural gas demand from co-firing units would now be occurring in the context of significantly higher natural gas prices. The EPA's updated analysis projects that natural gas prices will increase significantly more than the Agency predicted in its the 2024 analysis of the final 2024 CPS (50 percent higher in 2035 than what was projected under the 2024 analysis), meaning that the impact of the 2024 CPS on the price of natural gas would be greater. The updated analysis projects that, in a scenario with the 2024 CPS remaining in place, the Henry Hub price of gas would increase nine percent in 2035,[271] while the 2024 analysis projected that the Henry Hub price of gas would have increased only three percent as a result of the 2024 CPS in the same year.[272] In sum, the anticipated constraints on natural gas availability combined with substantial increases in natural gas demand mean that diverting a large volume of natural gas to 40 percent natural gas co-firing in coal-fired steam generating units would further exacerbate the already-strained natural gas market.

ii. Inefficiency of 40 Percent Natural Gas Co-Firing

The EPA is further concluding that the energy requirements associated with 40 percent natural gas co-firing in a steam generating EGU are unreasonable because such co-firing would be an inefficient use of the comparatively constrained (relative to previous assumptions) availability of natural gas, particularly compared to use in a combustion turbine. This is a relevant consideration because the two types of units provide the same product—electricity—and because they are being covered by a single regulatory regime.[273] The EPA therefore believes that it should attempt to optimize the use of natural gas amongst the affected sources. Applying 40 percent natural gas co-firing would result in a decrease in boiler efficiency by approximately two percent (to a total boiler efficiency of less than 40 percent) due to the higher hydrogen content of natural gas relative to coal. In the 2024 CPS, the EPA argued that this decline in efficiency could be partially offset by decreases in auxiliary power demand related to coal handling and emissions controls but acknowledged that uncertainty remained about whether this offset would be true in all circumstances.[274] In the EPA's unit-level cost analysis for the 2024 CPS, the Agency assumed a two percent decrease in boiler efficiency would result in one percent overall heat rate penalty for the unit.[275] Thus, for a theoretical coal-fired steam generating unit with a heat rate of 10,000 British thermal units per kilowatt-hour (Btu/kWh), the EPA estimates that the heat rate increases when co-firing to 10,100 Btu/kWh.

Comparatively, the use of large amounts of natural gas for combustion in combined cycle EGUs is more efficient. New natural gas-fired combined cycle EGUs generally have an operating efficiency of greater than 50 percent. If the natural gas that would otherwise be used for co-firing in a steam generating EGU were instead used in a combined cycle unit with a heat rate of 6,700 Btu/kWh, the combined effective heat rate of the coal-fired EGU and gas-fired combined cycle unit would be approximately 8,400 Btu/kWh, which is substantially less than the coal-fired steam generating unit with 40 percent natural gas co-firing. In addition, effective combined heat rates would be lower if the natural gas were used in a simple cycle combustion turbine EGU.[276] As described in section IV.A.2.b.i of this preamble, the availability of natural gas is projected to be relatively constrained due to a combination of increases in domestic demand and increases in liquefied natural gas exports. Given these circumstances, the EPA believes it is reasonable to consider the relative efficiency of natural gas use amongst regulated sources when determining BSER. When looking at the affected source category as a whole, the EPA finds that impacts on the energy system of 40 percent natural gas co-firing are unreasonable because it is significantly more efficient to use natural gas to generate electricity in a combustion turbine, rather than co-firing natural gas in a steam generating boiler.

Comments: Some commenters supported the EPA's proposed determination that the Agency can or must consider the relative efficiency of co-firing natural gas in a coal-fired steam generating unit versus in a combustion turbine. One commenter stated that co-firing natural gas in a boiler is less efficient than burning natural gas in either a combined cycle system or a simple cycle turbine. Another commenter noted that although choosing to co-fire may be reasonable for individual units due to source-specific circumstances, co-firing is not a reasonable practice on a fleetwide basis.

Other commenters refuted the basis of comparison between heat rates of natural gas co-firing units and NGCC due to the technological differences between an NGCC and a steam unit. Some commenters questioned the relevance of this comparison and asserted that the EPA should consider whether natural gas co-firing reduces emissions from the affected units, not whether a different type of unit can use natural gas more efficiently.

EPA Response: The EPA believes the relative efficiency of steam generating boilers and combustion turbines is relevant because the energy requirements factor of CAA section 111(a)(1) requires the Agency to consider adverse impacts on the energy system.[277] The interplay between different potential uses of a limited fuel to generate electricity is pertinent to this inquiry. Moreover, the EPA believes this is a relevant consideration because coal-fired steam generating units and NGCC units were addressed as part of a common regulatory framework under the 2024 CPS.[278] Thus, the Agency's

[271] See memorandum entitled *Trends Relating to Fossil Fuel-fired Electric Generating Units* in the docket for this rulemaking (Docket ID No. EPA–HQ–OAR–2025–0124).

[272] Docket ID No. EPA–HQ–OAR–2023–0072, Table 3–12 in the 2024 RIA.

[273] *See* 40 CFR part 60, subparts TTTT and TTTTa.

[274] 89 FR 39798, 39895 (May 9, 2024).

[275] See spreadsheet entitled *Unit-Level Cost and Reduction Estimates for Natural Gas Co-firing Final Rule* attached to Document ID No. EPA–HQ–OAR–2023–0072–9095.

[276] For a representative combustion turbine with a heat rate of 8,700 Btu/kWh, the combined effective heat rate would be approximately 9,500 Btu/kWh.

[277] *See* preamble sections II.C.3 and IV.A.2.b for discussion of the EPA's interpretation and application of CAA section 111(a)(1)'s ''energy requirements'' factor.

[278] *See* 40 CFR part 60, subparts TTTT and TTTTa.

regulation should acknowledge the competing uses of natural gas by the affected sources. Directing natural gas to be used in a less efficient manner, *i.e.,* in a steam generating boiler, is not a reasonable use of this resource. This is especially the case when the availability of natural gas is anticipated to be relatively constrained due to multiple competing uses, both within and beyond electricity generation. Furthermore, the EPA has considered the decreased efficiency of a coal unit co-firing 40 percent natural gas relative to the CO_2 reductions available from such co-firing and has determined that the adverse impacts are not reasonable given reductions in emission rate (*e.g.,* lb CO_2/MWh-gross) of only 16 percent.

c. Infrastructure

Finally, the EPA is finalizing the determination that a degree of emission limitation based on 40 percent natural gas co-firing is not achievable because it is unlikely the necessary pipeline infrastructure can be deployed by the compliance date of January 1, 2030. In the 2024 CPS, the EPA estimated the maximum aggregate amount of pipeline capacity at nearly 14.7 billion cubic feet per day for implementing 40 percent natural gas co-firing, which would require approximately 3,500 miles of pipeline.[279] The 2024 CPS further assumed that sources could obtain the permits necessary to construct these pipelines in one year and that the actual construction would require one year or less.[280] While the timelines in the 2024 CPS were based on average permitting, approval, and construction timeframes,[281] the EPA now believes that projects facing reasonably foreseeable adverse conditions could take up to five years for approval and construction.[282]

Further, the EPA now projects that much more coal-fired capacity will remain in operation than previously anticipated, meaning that more natural gas pipeline projects would have to be undertaken to support 40 percent natural gas co-firing at a nationwide level.[283] This increase would strain existing permitting, planning, and implementation resources and make completion of these projects by the January 1, 2030, compliance date less likely. Furthermore, the involvement of external parties in deploying such a large amount of infrastructure would necessarily include its own complications and delays. Additionally, the EPA did not consider that the large number of these projects, or that the new pipelines necessary to support co-firing, would be in addition to pipeline projects necessary to meet the increasing demand for natural gas for other purposes (*e.g.,* liquified natural gas exports and other domestic uses like powering AI). Specifically, updated EPA power sector modeling that incorporates higher demand and the impacts of the OBBBA estimates 100 GW installed coal capacity by 2035,[284] almost twice as much as projected in the final 2024 CPS analysis.[285] This would require an estimated 90 percent more gas by volume to meet the 40 percent co-firing standard. By that same year, modeling projections estimate an overall gas demand of 16.4 trillion cubic feet with an average delivered price of $4.92/MMBtu.[286] Under the earlier analysis, the lower demand environment and the impact of the IRA resulted in falling natural gas consumption over time in the power sector. The updated analysis, driven by the current higher demand environment and the impacts of the OBBBA, projects increasing natural gas consumption over the forecast period. As a result, the updated forecast projects total gas consumption in 2035 will be 77 percent higher as compared to the forecast used for the 2024 CPS.

The EPA now believes that these factors make it unlikely for the necessary additional pipeline infrastructure for 40 percent natural gas co-firing to be deployed by the January 1, 2030, compliance date. Therefore, the EPA is finalizing the determination that the degree of emission limitation in the 2024 CPS for medium-term coal-fired steam generating EGUs is not achievable.

Comments: Commenters supporting the EPA's determination generally expressed concern with the feasibility of the January 1, 2030, compliance deadline for 40 percent natural gas co-firing in the 2024 CPS, stating that this deadline was not achievable because of the required time for permitting and construction of natural gas pipelines, particularly interstate pipelines. These commenters explained that the EPA's assumptions in the 2024 CPS about the amount of time it takes to design, permit, and construct natural gas lateral pipelines were unrealistically optimistic. Other commenters, however, supported the compliance deadline for the 40 percent natural gas co-firing based on the examination of national averages in 2024.

EPA Response: The EPA agrees with the former and disagrees with the latter commenters. As detailed in this section of the preamble, the EPA now believes that projects facing reasonably foreseeable adverse conditions could require up to five years for approval and construction, particularly in light of increased demand for natural gas that could further extend approval and construction periods.[287]

As noted by supportive commenters, a longer approval and construction timeline for pipelines would be more appropriate based on the longest project approval timeline for any project reviewed (Carty Lateral Project) combined with the longest construction timeline for any project reviewed (Coastal Bend Header), which totals to 49 days short of five years. Such an implementation timeframe would, in contrast to the timeframe the EPA promulgated in the 2024 CPS, ensure that regulated entities facing reasonably foreseeable delays in both project approval and construction could still timely comply with the applicable requirements. Furthermore, assuming the longer timeline is reasonable because the increase in the use of natural gas for other purposes will likely necessitate additional pipeline buildout for these purposes, which will further delay pipeline approval and construction time for the electric power sector.

The EPA now believes that these factors make deployment of the necessary additional pipeline infrastructure for 40 percent natural gas co-firing by the January 1, 2030, compliance date unlikely. Therefore, the EPA is finalizing the determination that the degree of emission limitation in the 2024 CPS for existing medium-term coal-fired steam generating EGUs is not achievable.

d. Conclusion

In summary, the EPA is finalizing the repeal of the requirements of the emission guidelines pertaining to medium-term coal-fired steam generating units because natural gas co-

[279] 89 FR 39798, 39893 (May 9, 2024).

[280] *Id.* at 39893 n.682.

[281] *Id.* at 39893.

[282] *Documentation for the Lateral Cost Estimation* (2024), *ICF International,* p. 42. Attachment to *Greenhouse Gas Mitigation Measures for Steam Generating Units.* Document ID No. EPA–HQ–OAR–2023–0072–9095.

[283] See memorandum entitled *Trends Relating to Fossil Fuel-fired Electric Generating Units* in the docket for this rulemaking (Docket ID No. EPA–HQ–OAR–2025–0124).

[284] *Id.*

[285] U.S. EPA. RIA for 2024 CPS. Document ID No. EPA–HQ–OAR–2023–0072–8913. Table 3–14.

[286] See memorandum entitled *Trends Relating to Fossil Fuel-fired Electric Generating Units* in the docket for this rulemaking (Document ID No. EPA–HQ–OAR–2025–0124).

[287] *Documentation for the Lateral Cost Estimation* (2024), *ICF International,* p. 42. Attachment to *Greenhouse Gas Mitigation Measures for Steam Generating Units.* Document ID No. EPA–HQ–OAR–2023–0072–9095.

firing in a coal-fired steam generating EGU is impermissible generation shifting, the energy requirements associated with 40 percent natural gas co-firing are unreasonable, and the degree of emission limitation specified in the 2024 CPS is not achievable. As discussed in this section of the preamble, the EPA is addressing only 40 percent natural gas co-firing and implementation by January 1, 2030, because those were the requirements under the 2024 CPS. This action does not address any potential alternative BSERs or implementation timeframes such as lower rates of co-firing or a later implementation date. The EPA considered whether to analyze and promulgate potential alternatives and determined it is not necessary to do so under the circumstances presented here.

3. Requirements for Existing Natural Gas- and Oil-Fired Steam Generating Units

The EPA is finalizing the repeal of the requirements of the emission guidelines pertaining to natural gas- and oil-fired steam generating units. In the 2024 CPS, the EPA finalized routine methods of operation and maintenance as the BSER for intermediate load and base load natural gas- and oil-fired steam generating units and uniform fuels as the BSER for low load natural gas- and oil-fired steam generating units. Because those BSERs were consistent with the current operations at most sources (*i.e.,* business-as-usual), there was no associated additional cost. In addition, those BSERs resulted in a degree of emission limitation that would have led to few, if any, emission reductions for any of the units. The EPA did not propose to repeal the BSER determinations and degrees of emission limitation for those sources. However, the EPA proposed to repeal the requirements in the emission guidelines for natural gas- and oil-fired steam generating units because requiring States to develop, submit, and implement state plans solely for natural gas- and oil-fires steam generating units would be an inefficient use of State resources, as these sources comprise a relatively small part of the source category and regulating them would have little environmental benefit.

Comments: Several commenters supported the EPA's proposal in the June 2025 NPRM to repeal the portions of the emission guidelines applicable to oil- and natural gas-fired steam generating units. These commenters generally agreed that requiring States to develop and submit state plans for these units alone would be an inefficient use of limited State resources that would present an undue administrative burden. Commenters further asserted that, if regulating these sources would have no significant benefit in terms of emission reductions, then such regulation would not be of reasonable cost. Additionally, some commenters explained that there is no need for the EPA to retain the emission guidelines for these units because the BSERs for oil- and natural gas-fired steam generating units are consistent with business-as-usual operation.

Other commenters opposed repealing the emission guidelines for these units for several reasons. Those commenters asserted that CAA section 111(d) requires the EPA to promulgate emission guidelines for existing sources if the Agency has promulgated standards of performance for the corresponding new sources. Commenters argued that standards of performance currently exist for GHG emissions from new oil- and natural gas-fired steam generating units, and that the EPA cannot override the statutory directive to have regulations for existing units based only on the Agency's judgment that state plans would not be prudent. Commenters stated that this is particularly the case because the EPA has not identified any flaw with the BSER determinations or emission guidelines for oil- and natural gas-fired steam generating units. The commenters further asserted that the EPA's justification for repealing the emission guidelines under CAA section 111 (*i.e.,* requiring States to submit plans covering just these units would be ''imprudent'' and an inefficient use of State resources) is not legally cognizable and that, regardless, the presumptive standards for these units would be straightforward and the EPA has not explained why business-as-usual standards would require expenditure of resources on engineering analyses. Commenters suggested that the 2024 CPS standards cover approximately 200 natural gas-fired steam generating units and 30 oil-fired units, that these units contribute an outsized amount of pollution as compared to electricity generation, and that the emission guidelines provide important protections against increased emissions as these units age. Finally, commenters asserted that it is not, in fact, a significant burden for States to prepare plans to regulate these units and that the EPA has not provided evidence to the contrary. Commenters stated that if a State finds preparing a plan too burdensome or otherwise chooses not to submit a plan, the EPA will issue a federal plan instead.

EPA Response: The EPA acknowledges these comments but continues to believe that it is not a reasonable use of States' resources, nor the Agency's (in the case of a federal plan), to develop and submit plans for oil- and natural gas-fired steam generating units while the Agency is repealing the requirements for all other existing fossil fuel-fired power plants. Natural gas- and oil-fired steam generating units represent a very small portion of the source category from both a generation and an emissions perspective. In 2023, natural gas- and oil-fired steam generating units accounted for 1.2 percent of total electric generation and 3.5 percent of power sector CO_2 emissions in the U.S.[288] The EPA's forecasts of power sector behavior using the Integrated Planning Model in the 2025 Reference Case projects that this share of both generation and emissions in the U.S. will decrease even further over the forecast period.[289]

Although the EPA is not finding that the BSERs or presumptive standards in the 2024 CPS were unreasonable or inappropriate for these sources, the Agency believes that it would be unreasonable to require States to develop state plans solely for these units. Throughout the more than 50-year period that the EPA has promulgated CAA section 111 regulations establishing NSPS for new sources and emissions guidelines for existing sources,[290] the EPA's regulatory approach has been to apply a rule of reason in determining which air pollutants and which source categories to regulate. This approach is consistent with CAA section 307(d)(9)(A), which provides that promulgation of standards of performance under CAA section 111 is subject to the CAA section 307(d)(9)(A) arbitrary and capricious standard for judicial review. *See American Electric Power Co.* v. *Connecticut,* 564 U.S. 410, 424, 427 (2011). For example, in 1977, EPA listed the stationary gas turbine source category,[291] and proposed standards of performances for NOX and SO_2 because the source category emitted those pollutants in large quantities and reasonably priced controls for them

[288] Based on eGRID2023 data. Available at: *https://www.epa.gov/egrid/detailed-data.*

[289] EPA 2025 Reference Case. Available at: *https://www.epa.gov/power-sector-modeling.*

[290] The EPA first listed source categories and promulgated standards of performance for them in 1971, 36 FR 5931 (March 31, 1971) (listing initial source categories); 36 FR 24876 (December 23, 1971) (promulgating initial standards of performance).

[291] 42 FR 53657 (October 3, 1977).

were available, but did not propose standards for HC or CO because those emissions were ''relatively low'' when the turbines were operated at peak capacity or PM because those emissions were ''minimal.'' [292] In 1979, EPA finalized the standards for NOX and SO_2.[293] EPA has similarly applied a rule of reason in determining whether to regulate particular source categories. For example, after enactment in the 1977 CAA Amendments of CAA section 111(f), which directed EPA to list source categories of major stationary sources and promulgate NSPS for them on a specified schedule, EPA promulgated a list of source categories and assigned each one a priority for action. However, EPA noted that ''if further study indicates that an NSPS would have little or no effect on emissions, or that an NSPS would be impractical, a source category would be given a lower priority or removed from the list.'' [294]

In applying a standard of reasonableness here, the EPA anticipates that the business-as-usual BSERs and presumptive standards finalized in the 2024 CPS would result in little to no emission reductions, while at the same time the development of state plans involves an expenditure of resources by States and regulated entities, including time and money for developing compliance strategies, conducting public hearings and meaningful engagement, drafting permits or other legal instruments, and getting necessary legislative or other approvals.[295] Therefore, the pragmatic considerations outweigh any potential regulatory benefit: requiring state plans to address only these sources at the same time the Agency is repealing the requirements for all other existing sources, and when the BSERs and presumptive standards of performance in the 2024 CPS would not, in general, have resulted in changes in operations or emissions, would not be reasonable.[296] Thus, the EPA is finalizing the repeal of the requirements of the emission guidelines pertaining to natural gas- and oil-fired steam generating units.

Moreover, as discussed in this section of the preamble, the EPA is simultaneously issuing a supplemental proposal soliciting comment on additional reasons beyond those on which the EPA solicited comment in the primary proposal in the June 2025 NPRM to repeal the legal basis for regulating GHG emissions from fossil fuel-fired power plants under CAA section 111. If finalized as proposed, this subsequent action would abrogate the need to regulate GHG emissions from natural gas- and oil-fired steam generating EGUs entirely. If the EPA does not finalize the determination that the Agency lacks authority to regulate GHG emissions from fossil fuel-fired power plants under CAA section 111 as proposed, the EPA would revisit the need for requirements for natural gas- and oil-fired steam generating EGUs.

4. Conclusion

Because the EPA is finalizing the repeal of the BSER determinations and related requirements for existing long-term and medium-term coal-fired steam generating units and is further finalizing the repeal of the requirements for existing oil- and natural gas-fired steam generating units, the Agency is finalizing repeal of the emission guidelines for steam generating units in 40 CFR part 60, subpart UUUUb, in their entirety.

B. Repeal of the CCS-Based Requirements for Coal-Fired Steam Generating Units Undertaking a Large Modification

In the 2024 CPS, the EPA finalized revisions to the standards of performance for coal-fired steam generating units that undertake a large modification (*i.e.,* a modification that increases the unit's hourly emission rate by more than 10 percent) to be consistent with the 90 percent CCS requirements for existing coal-fired steam generating units. As discussed in section IV.A.1 of this preamble, the EPA is finalizing the determination that 90 percent CCS is not an adequately demonstrated system of emission reduction and that the cost of 90 percent CCS is not reasonable. For these reasons, the EPA is also finalizing repeal of the CCS-based standards of performance for coal-fired steam generating units undertaking a large modification in 40 CFR part 60, subpart TTTT.

C. Partial Repeal of the 2024 Standards for New Combustion Turbine EGUs

The EPA is finalizing the repeal of the phase 2 CCS-based standards for new base load stationary combustion turbine EGUs in 40 CFR part 60, subpart TTTTa. The EPA's basis for this action is that 90 percent CCS has not been adequately demonstrated, and the costs are not reasonable for new base load combustion turbines. The EPA is finalizing the determination that the CCS-based standards are not achievable as it is unlikely that the infrastructure necessary can be deployed by the January 1, 2032, compliance date. In the June 2025 NPRM, the EPA solicited comment in general on the efficiency-based standards for intermediate load and base load turbines. While the EPA received substantial comments that affected sources may not be able to achieve these standards, the EPA is not addressing these comments at this time.

1. Phase 2 CCS-Based Requirements for New Base Load Combustion Turbines

In the 2024 CPS, the EPA determined the second component of the BSER for new base load combustion turbines to be 90 percent CCS. The EPA determined that 90 percent CCS, including the 90 percent CO_2 capture component, was adequately demonstrated based on extrapolation from the evidence for 90 percent CCS on coal-fired steam generating units and additional examples and planned projects on combustion turbines. The EPA also argued the costs were reasonable and that the other considerations for BSER were satisfied. Based on application of the 90 percent CCS BSER to new base load combustion turbines, the EPA established standards of performance and argued these standards were achievable by the compliance date of January 1, 2032, considering the time necessary to deploy capture equipment, transport, and sequestration.

The EPA proposed to repeal the phase 2 CCS-based requirements for new base load combustion turbines based largely on a reassessment of the record underlying the determinations in the 2024 CPS. The EPA proposed that 90 percent CCS is not the BSER for new base load combustion turbines because it has not been adequately demonstrated and the costs are unreasonable. The EPA further proposed that the standards of performance are not achievable because it is unlikely that the infrastructure

[292] 42 FR 53782, 53783 (October 3, 1977).

[293] 44 FR 52792 (September 10, 1979). As another example, the EPA promulgated standards for lime manufacturing plants for particulate matter, but not for NOX, CO, or SO_2, due to their small amount of emissions or concerns about the available controls. *See* 42 FR 22056, 22507 (May 3, 1977); *Nat'l Lime Ass'n,* 627 F.2d at 426 & n.27.

[294] 44 FR 49223 (August 21, 1979).

[295] The EPA's Information Collection Request analysis for the emission guidelines promulgated in the CPS indicates that developing state plans (and negative declarations) would entail a collective cost to the 48 States subject to the rule of approximately $35 million over three years. *See* Document ID No. EPA–HQ–OAR–2023–0072–8836.

[296] One commenter asserted that the presumptive standards of performance, which the EPA determined in the CPS, may not be appropriate given how oil and natural gas-fired steam generating units may operate in the future. Comments of Talen Energy at 16–17, Document ID No. EPA–HQ–OAR–2025–0124–0904. Although the EPA is not repealing the emission guidelines for these sources on the basis of the achievability of the presumptive standards of performance, the Agency does note this concern.

(including capture equipment, pipelines for transport, and sequestration sites) for 90 percent CCS for new base load combustion turbines can be deployed by the January 1, 2032, compliance date.

The EPA is finalizing the determination that CCS with 90 percent capture is not the BSER for base load combustion turbine EGUs because it has not been adequately demonstrated and the costs are not reasonable. Furthermore, because it is unlikely that the infrastructure necessary for CCS can be deployed by the January 1, 2032, compliance date, the EPA is finalizing the determination that the associated standards of performance in the 2024 CPS for new base load combustion turbines are not achievable. Consequently, the EPA is finalizing repeal of the phase 2 standards for base load combustion turbine EGUs.

a. Adequately Demonstrated

For many of the same reasons described in section IV.A.1.a of this preamble for coal-fired steam generating units, CCS with 90 percent capture has not been adequately demonstrated for new combustion turbine EGUs. The 2024 CPS based the 90 percent capture BSER for new base load combustion turbines on the same capture technology as for coal-fired steam generating units.

i. Translation of Experience at Coal-Fired EGUs

The 2024 CPS relied on the translation of amine-based capture at coal-fired EGUs as evidence to support the determination that 90 percent capture on new natural gas-fired combustion turbine EGUs has been adequately demonstrated. However, as noted in section IV.A.1.a of this preamble, the determination for coal-fired EGUs in the 2024 CPS relied on an extrapolation that, on review, fails to show 90 percent capture is adequately demonstrated. Consequently, the EPA has re-assessed the evidence and is finalizing the determination that 90 percent capture and, therefore, 90 percent CCS have not been adequately demonstrated for existing coal-fired steam generating units. Therefore, the record for 90 percent capture on existing coal-fired steam generating units also does not show that 90 percent capture, or 90 percent CCS, is adequately demonstrated for new base load combustion turbine EGUs.

Additionally, the 2024 CPS argued that fewer contaminants (particulates, trace metals, sulfur dioxide (SO_2)) in the post-combustion flue gas of natural gas-fired stationary combustion turbines would result in fewer challenges with CO_2 capture than those experienced with capture at coal-fired steam generating units. However, the exhaust gas composition for natural gas-fired combustion turbines is different in other ways than for coal-fired units (*i.e.,* lower CO_2 concentrations and higher oxygen concentrations), which makes CO_2 capture more challenging. Furthermore, combustion turbines can change loads more rapidly and start and stop more frequently than coal-fired steam generating units. These factors could create additional challenges for operating CO_2 capture equipment, and demonstrated capture rates from coal-fired EGUs do not necessarily demonstrate that base load combustion turbines could achieve the same capture rates. For example, the startup of the CO_2 capture system may be slower than the startup of a combined cycle combustion turbine EGU, so that the system would not capture CO_2 emitted during startup. This shows that directly applying the record for CO_2 capture at coal-fired EGUs to the evaluation of CO_2 capture as adequately demonstrated for natural gas-fired combustion turbine EGUs, without accounting for the differences between these types of units, is inappropriate.

ii. Capture Projects on Combustion Turbine EGUs

The examples of CO_2 capture applied directly on combustion turbine EGUs are also insufficient to conclude that 90 percent capture has been adequately demonstrated. Primarily, there have been limited examples of applications of CCS to combustion turbine EGUs, none of which have been at sufficient scale to demonstrate the specified BSER based on a 90 percent total capture efficiency.

In the 2024 CPS, the argument that 90 percent capture was adequately demonstrated at combustion turbine EGUs relied in part on the capture plant at the Bellingham combined cycle turbine.[297] This capture plant was only 40 MWe, which is smaller than most base load combined cycle turbine EGUs that would have potentially been subject to the requirements of that rule, and processed only approximately 10 percent of the maximum flue gas volume. The project began operation in 1991 before shutting down in 2005 after the host combined cycle unit switched to peak shaving operation.[298] Publicly available data for this project is limited, so that the performance cannot be accurately assessed. The EPA otherwise cited pilot studies.[299] However, such short-duration demonstrations may not be subject to the same variations in conditions that occur in commercial operation. Boundary Dam Unit 3 remains the only relevant commercial scale attempt at applying 90 percent CCS on a fossil fuel-fired power plant. Reasonable extrapolation from the experience at Boundary Dam Unit 3 shows that commercial scale deployments of CO_2 capture solvent technologies on post-combustion flue gas of fossil fuel-fired EGUs will underperform. Similar to coal-fired steam generating units, a capture system on a gas-fired combined cycle unit would achieve far less than 90 percent capture.[300]

The EPA also previously cited planned projects.[301] However, the planned projects are neither operational nor provide measured data. While the equipment for those planned projects may have been designed for 90 or even 95 percent CO_2 capture, simply designing a project for a certain percentage capture does not ensure that the project will achieve that percentage capture in practice. Boundary Dam Unit 3 did not achieve its design percentage capture, as detailed in section IV.A.1.a.i of this preamble. Therefore, because those hypothetical projects have not yet produced any data, they do not mitigate the potential underperformance of CO_2 capture, and, therefore, are not sufficient to show 90 percent CO_2 capture is adequately demonstrated. The EPA also noted the NET Power Cycle (*i.e.,* CO_2 capture based on oxy-combustion) as a potential technology for meeting the standard based on 90 percent capture. However, the technology provider has not operated the technology at scale and a planned project is facing delays.[302] More recently, the technology provider has deprioritized their efforts on oxy-combustion, and acknowledged it requires further development.[303]

[297] 89 FR 39925–26 (May 9, 2024).

[298] Fluor. The U.S. Carbon Capture and Storage Market. Available at: *https://newsroom.fluor.com/featured-stories/blog-details/2025/The-U-S--Carbon-Capture-and-Storage-Market-Fluors-Role-45Qs-Influence-Challenges-for-New-and-Existing-Technologies-and-Which-Projects-Can-Succeed/default.aspx.*

[299] 89 FR 39798, 39927 (May 9, 2024).

[300] Using the same calculation detailed in section IV.A.1.a.i of this preamble, a system could achieve at best 63 to 82 percent capture.

[301] 89 FR 39798, 39927 (May 9, 2024).

[302] Net Power, Press Release: Net Power Reports Fourth Quarter 2024 Results and Provides Business Update (March 10, 2025). Available at: *https://ir.netpower.com/resources/press-releases/detail/37/net-power-reports-fourth-quarter-2024-results-and-provides-business-update.*

[303] Net Power, Press Release: Net Power Reports Third Quarter 2025 Results and Provides Business Update (November 13, 2025). Available at: *https://ir.netpower.com/resources/press-releases/detail/44/net-power-reports-third-quarter-2025-results-and-provides-business-update.*

Similarly, none of the other projects that the EPA cited have yet commenced construction, either on new NGCC units or on retrofits to existing plants.

Comments: Many commenters agreed with the EPA's proposed determination that 90 percent CCS is not adequately demonstrated for new base load natural gas-fired combustion turbines. Other commenters asserted that 90 percent capture is adequately demonstrated for those sources. Those commenters largely reiterated arguments made in the 2024 CPS, which the EPA has refuted in the preceding sections of this preamble. Those commenters also cited references to some new projects that were not in the record for the 2024 CPS and asserted those projects supported the conclusion that 90 percent CCS has been adequately demonstrated for new base load combustion turbine EGUs. One of the projects cited by commenters was the Ravenna CCS project in Italy, a small-scale capture project at a gas processing facility. Commenters argued this project supported the determination that 90 percent CCS was adequately demonstrated for new base load combustion turbines. Commenters similarly cite small-scale pilot projects, such as the pilot plant at the Himeji No. 2 gas-fired power plant in Japan (five metric tons per day), testing on NGCC flue gas at Los Medanos Energy Center (Contra Costa County, California) (1 MWe), and testing on NGCC flue gas at Technology Centre Mongstad (Mongstad, Norway) (10 MWe). In addition, some commenters cited other projects that are not operational, including the Net Zero Teeside Power project (United Kingdom).

EPA Response: The EPA disagrees with commenters' assertions as those projects are insufficient, for various reasons, to conclude that 90 percent CCS has been adequately demonstrated for base load natural gas-fired combustion turbine EGUs. The EPA finds the Ravenna project is insufficient to conclude 90 percent is adequately demonstrated. The project at Ravenna uses an amine solvent to capture CO_2 from the flue gas of a small 5 MW simple cycle combustion turbine, which drives a compressor for natural gas transmission. A heat recovery steam generator produces process steam and renewable generation provides electricity for the capture process. The combustion turbine is therefore not subject to the electricity and steam requirements of the capture process. This is distinct from the premise of the BSER in the 2024 CPS, where the EGU is a combined cycle unit and the capture system uses heat and power from the host EGU, such that changes in operation of the host EGU may impact the capture facility. Moreover, the 2024 CPS applied to units greater than 25 MW, at least five times the size of the project at Ravenna. Considering those factors, the system at Ravenna has limited relevance to the capture system at issue in the 2024 CPS and this action. In addition, from startup in August 2024 through February 2025, the reported monthly average capture efficiency of the treated flue gas (when operating) was 91.8 percent with a peak of 96.1 percent. However, while reports claimed that the GHG emissions of the project were minimal, reports did not specify the amount of flue gas treated relative to the amount emitted from the facility and the amount of time the capture facility was operational. Lacking that information, it is impossible to evaluate the total capture efficiency and the performance of the project in practice. Because of the limited relevance of the Ravenna project to the capture system at issue here, and because of the incomplete information on the performance of the capture system, the EPA concludes that the experience at Ravenna is insufficient to conclude that 90 percent CCS is adequately demonstrated.

Furthermore, for the reasons detailed in section IV.A.1.a.i of this preamble, the EPA reasonably expects that a new capture system would underperform to a similar degree as Boundary Dam Unit 3. Such short term and small-scale projects cited by the commenters are insufficient to mitigate that potential underperformance, and therefore insufficient to show 90 percent capture is adequately demonstrated. Additionally, projects cited by the commenters that are not yet operational have not provided any data on capture performance and are therefore insufficient to that 90 percent capture is adequately demonstrated.

Considering these factors, the EPA is finalizing the determination that CCS with 90 percent capture has not been adequately demonstrated for new base load combustion turbine EGUs.

b. Cost

The EPA has re-evaluated the assumptions underlying the cost analysis of 90 percent CCS on new base load combustion turbines and is finalizing the determination that the costs are not reasonable.

i. Smaller Combustion Turbines

As part of the phase 1 BSER analysis for combustion turbines, the EPA reviewed the performance and costs of efficient generation for combustion turbines with base load ratings ranging from 490 to 6,100 MMBtu/h. Based on the phase 1 BSER analysis, the EPA established higher emission standards for base load turbines with base load ratings of less than 2,000 MMBtu/h. However, when evaluating the phase 2 BSER based on the use of CCS, the EPA evaluated the reasonableness of the cost based only on combustion turbines with base load ratings of 4,600 and 6,100 MMBtu/h.[304] The costs of the capture equipment and the costs to transport and store the captured CO_2 increase on a $/ton basis for smaller base load combustion turbines. The costs of control on a $/MWh and $/ton basis for the smaller model combustion turbine facilities used in the phase 1 analysis are approximately double the highest costs that the EPA reported in the technical support document. Specifically, the estimated compliance costs for the primary case for the 490 and 1,000 MMBtu/h model combined cycle plants are $73/MWh and $200/ton and $55/MWh and $140/ton, respectively, which are significantly higher than the highest costs presented in the 2024 CPS—$19/MWh and $57/ton.[305] Consequently, the EPA now finds that, in the 2024 CPS, the Agency did not establish that the cost of 90 percent CCS is reasonable for smaller base load combustion turbines.

ii. Operating/Availability, Capacity Factor, and Other Assumptions

Even without factoring in the previously cited omissions, the primary costs of 90 percent CCS for combustion turbines were a best-case scenario.[306] As described in section IV.A.1 of this preamble, the EPA assumed in the 2024 CPS that capture equipment has 100 percent operating-availability. Reducing the operating-availability of the capture equipment to 75 percent reduces the CO_2 emission reductions and increases the cost by approximately $2/MWh and $18/ton compared to the estimated costs

[304] The technical support document entitled *Greenhouse Gas Mitigation Measures Carbon Capture and Storage for Combustion Turbines* included estimated costs for combined cycle turbines with base load ratings of 2,400 and 3,400 MMBtu/h in figures 11 through 13. The costs for the primary case are $29/MWh and $95/ton and $22/MWh and $75/ton respectively—approximately 50 percent higher than the costs presented in the CPS. Document ID No. EPA–HQ–OAR–2023–0072–9099.

[305] See memorandum entitled *Updated Evaluation of Best System of Emission Reduction Costs of Carbon Capture and Sequestration/Storage at New and Reconstructed Natural Gas-Fired Combustion Turbine Electric Generating Units* in the docket for this rulemaking (Document ID No. EPA–HQ–OAR–2025–0124).

[306] The EPA discussed multiple advances that could lower the costs of a BSER based on the use of CCS, but currently none of these technologies are commercially available.

presented in the 2024 CPS.[307] While CCS may achieve potential CO_2 emission reductions, these costs exceed the thresholds that the EPA cited as reasonable in previous Agency rulemakings.

In addition, when conducting the BSER analysis, the EPA assumed that the long-term capacity factors of new combined cycle turbines would be the same as historical long-term capacity factors with and without 90 percent CCS (51 percent capacity factor).[308] In the primary policy case, the EPA compared the costs and emissions impacts assuming a new combined cycle turbine with CCS that operates at an 80 percent capacity factor for the first 12 years and a 31 percent capacity factor for the next 18 years.[309] The EPA compared the levelized cost of electricity of this model facility to a combined cycle without CCS that operates at a 62 percent capacity factor for the first 12 years, a 47 percent capacity factor for the next 13 years, and a 37 percent capacity factor for the final five years.[310] However, the capacity factor assumptions in the 2024 CPS do not account for differences in incremental generating cost affecting dispatch. Based on cost information from NETL and EIA's Annual Energy Outlook, and assuming the full value of the IRC section 45Q tax credit, the incremental generating costs of combined cycle turbines with carbon capture are generally higher than those of nuclear EGUs but lower than those of coal-fired EGUs without carbon capture.[311] While the capacity factors of nuclear EGUs are higher (approximately 90 percent) than the 80 percent used by the EPA, the recent capacity factors of coal-fired EGUs are much lower (approximately 40 percent). While these provide an upper and lower bound of what capacity factors could be from a combined cycle turbine with CCS while the tax credit is available, the EPA selected the upper end of the range without conducting a dispatch analysis. Furthermore, even when counting the full value of the IRC section 45Q tax credit as a reduction, the estimated incremental generating costs of the 490 MMBtu/h combined cycle turbine with carbon capture are higher than the incremental generating costs of the model plant without CCS. Generally, combined cycle facilities without CCS that have recently commenced operation have not maintained capacity factors of 80 percent, this calls the capacity factor assumptions into question for smaller combined cycle facilities with CCS.[312] Additionally, during periods when the IRC section 45Q tax credit is not available after the 12-year period of the credit has expired, it is unlikely that combined cycle turbines with carbon capture would operate at the 31 percent capacity factor used in the 2024 CPS costing analysis. The incremental generating costs of all the model combined cycle turbines with carbon capture exceed the incremental generating costs of simple cycle turbines. Simple cycle turbines generally operate at capacity factors of less than 10 percent. A dispatch modeling analysis would likely result in lower capacity factors and higher costs, which does not support the costs of 90 percent CCS as reasonable.

Further, the EPA only conducted the BSER analysis using capacity factors for the average combined cycle facility. The average combined cycle facility has a 30-year capacity factor of 51 percent. On average, new combined cycle facilities operate at a 65 percent capacity factor that steadily decreases to less than 40 percent by year 30. However, a combustion turbine that ever exceeds the base load threshold (40 percent in the 2024 CPS) for a single 12-operating month period would, effectively, have to install 90 percent CCS to comply with the base load emissions standard. Therefore, while the EPA was correct in using the average capacity factor to determine if the costs of 90 percent CCS are reasonable, the maximum 12-calendar month capacity factor is the appropriate value for subcategorization purposes. A base load subcategorization threshold of 65 percent would subject the average combined cycle turbine to the CCS-based BSER. However, the EPA set a base load subcategorization capacity factor threshold of 40 percent. In doing this, the Agency subjects combustion turbines with lifetime capacity factors of less than 51 percent to a 90 percent CCS-based BSER. However, in the 2024 CPS, the EPA did not analyze whether 90 percent CCS qualifies as the BSER at lower capacity factors. For example, the 12-operating month capacity factor will vary over the life of the facility, even assuming a combined cycle facility operates at a relatively constant capacity over the entire 30-year life. If the absolute difference between the maximum 12-operating month and 30-year average capacity factors is five percent, the EPA should have determined whether CCS is the BSER for a combined cycle operating at a 30-year capacity factor of 35 percent. At a capacity factor of 35 percent, the costs of CCS are clearly not reasonable ($36/MWh and $110/ton), and costs are even higher for smaller units ($56/MWh and $170/ton).[313] In addition, if the EPA accounted for both the declining capacity factors as combustion turbines age and the 12-operating month variability, the 30-year capacity factor of a combined cycle turbine with a maximum 12-operating month capacity factor of 40 percent would be less than 35 percent, which calls into question whether the cost of 90 percent CCS at a 40 percent subcategorization threshold is reasonable since the costs are three times higher than the cost ($18.5/MWh) the EPA previously determined to be reasonable.[314]

When conducting the BSER analysis, the EPA failed to account for additional factors that would increase the costs of CCS. First, the Agency did not account for lost revenue due to lower capacity

[307] See memorandum entitled *Updated Evaluation of Best System of Emission Reduction Costs of Carbon Capture and Sequestration/Storage at New and Reconstructed Natural Gas-Fired Combustion Turbine Electric Generating Units* in the docket for this rulemaking (Document ID No. EPA–HQ–OAR–2025–0124).

[308] Based on data submitted to the Clean Air Markets Program, the median annual capacity factor of combined cycle turbines begins at a high of 68 percent and steadily declines to 34 percent in year 30. The median 30-year capacity factor is 51 percent. To avoid impacting the costs due to changes in the overall capacity factors with the base case, the EPA kept the overall 30-year capacity factor at the historical average of 51 percent.

[309] The EPA selected 80 percent to account for the lower variable operating costs when the 45Q tax credits are available. The capacity factor during the final 18 years was adjusted to maintain a 30-year average capacity factor of 51 percent.

[310] The 62/47/37 operating scenario is based on the averaged reported median capacity factors for combined cycle turbines during the three periods of operation—62 percent during years 1 to 12, 47 percent during years 13 to 25, and 37 percent during years 26 to 30.

[311] T. Schmitt, S. Leptinsky, M. Turner, A. Zoelle, M. Woods, T. Shultz, and R. James *Cost and Performance Baseline for Fossil Energy Plants Volume 1: Bituminous Coal and Natural Gas to Electricity, Revision 4a,* U.S. DOE. National Energy Technology Laboratory (NETL). (October 14, 2022). Available at: *https://netl.doe.gov/energy-analysis/details?id=e818549c-a565-4cbc-94db-442a1c2a70a9;* Capital Cost and Performance Characteristics for Utility-Scale Electric Power Generating Technologies. U.S. DOE. U.S. Energy Information Administration (EIA). (January 2024). Available at: *https://www.eia.gov/analysis/studies/powerplants/capitalcost/pdf/capital_cost_AEO2025.pdf.*

[312] Based on information submitted to the EPA's Clean Air Markets Program Data, the 2025 average annual capacity factor of combined cycle turbines that commenced operation between 2020 and 2024 is 65 percent.

[313] The costs for the combustion turbine model plant with a 6,100 MMBtu/h base load rating is $36/MWh ($110/ton) at a 35 percent capacity factor. The costs for the combustion turbine model plant with a 2,400 MMBtu/h base load rating is $56/MWh ($170/ton) at a 35 percent capacity factor.

[314] Assuming an initial capacity factor of 40 percent that declines to 22 percent at year 30 results in an overall capacity factor of 30 percent. Costs are similar to the constant 35 percent capacity factor case.

payments that result from the lower net output of combined cycle facilities with CCS relative to combined cycle facilities without CCS.[315] Assuming a capacity payment of $65/kW, a 1x1 F-class combined cycle facility would lose almost $3 million per year in capacity payments, and a 1x1 H-class combined cycle facility would lose almost $4 million per year in capacity payments.[316]

iii. The IRC Section 45Q Tax Credit

As noted above in connection with the costs of CCS for existing coal-fired plants, the 2024 CPS accounted for the IRC section 45Q tax credits by reducing the direct costs to the source for every ton of CO_2 captured. However, the EPA no longer believes that counting the IRC section 45Q tax credit as a reduction in determining BSER is appropriate, as discussed in section IV.A.1.b of this preamble. Rather, the tax credit shifts the costs of CCS to taxpayers, and in the 2024 CPS, the EPA failed to account for those costs. Removing the tax credit as a reduction in the costs for the 2024 CPS 90 percent CCS case increases the costs for combustion turbines with base load ratings of 4,600 and 6,100 MMBtu/h to $37/MWh ($110/ton) and $32/MWh ($100/ton), respectively. Even using the 2024 CPS primary model plants, the costs of 90 percent CCS for base load stationary combustion turbines are clearly unreasonable.[317]

c. Infrastructure

Consistent with the arguments presented in section IV.A.1.c of this preamble regarding CCS infrastructure for existing coal-fired steam generating units, the necessary infrastructure to meet the requirements for the phase 2 CCS-based requirements for base load combustion turbines cannot likely be deployed by the January 1, 2032, compliance date. While new combustion turbines do not have the additional timeline requirement of state plan development, the timeline in the 2024 CPS for the design, permitting, and installation of capture equipment, pipelines, and sequestration for new combustion turbines assumes an unrealistic best-case scenario. Furthermore, pipeline and sequestration infrastructure remain limited. In the 2024 CPS, the EPA argued that new combustion turbines could site preferentially near potential storage sites. However, the EPA did not consider the availability of sufficient quantities of natural gas or the availability of sufficient transmission capacity (*i.e.,* to transmit power to end users) for new base load combustion turbines specifically located near potential storage sites.[318] In addition, the analysis ignores the associated line loss (*i.e.,* inefficiency) due to potentially longer transmission lines.[319] The analysis further ignores the requirements of siting electricity generating sources in locations necessary to meet local grid reliability considerations. Considering these factors, it is unlikely that the infrastructure necessary for CCS can be deployed by the January 1, 2032, compliance date, and the EPA has therefore determined that phase 2 standards of performance in the 2024 CPS for new base load combustion turbines are not achievable. Additionally, similar to coal-fired steam generating units, much of the necessary CCS infrastructure would likely be developed by external parties over whom the owners and operators of regulated facilities have limited control. This complicates deployment and has the potential to cause or exacerbate delays, providing further support for the conclusion that the January 1, 2032, compliance date and the degree of emission limitation are unachievable.

d. Conclusion

The EPA is finalizing the determination that 90 percent CCS has not been adequately demonstrated nor shown to have reasonable costs and thus is not the BSER for base load stationary combustion turbines. Furthermore, because it is unlikely that the infrastructure necessary for CCS can be deployed by the January 1, 2032, compliance date, the EPA is finalizing the determination that the phase 2 standards of performance in the 2024 CPS for new base load combustion turbines are not achievable. Accordingly, the Agency is finalizing repeal of the phase 2 requirements for base load combustion turbines.

e. Implications for Evaluation of Best Available Control Technology (BACT) for Prevention of Significant Deterioration (PSD) Permitting

Sources subject to 40 CFR part 60, subparts NSPS TTTT and NSPS TTTTa may be subject to a component of the major NSR program known as the PSD program.

Part C of title I of the CAA contains the requirements for the PSD program. This program sets forth procedures for the preconstruction review and permitting of new and modified stationary sources of air pollution locating in areas meeting the NAAQS (''attainment'' areas) and areas for which there is insufficient information to classify an area as either attainment or nonattainment (''unclassifiable'' areas). Sources subject to PSD must, among other requirements, demonstrate that construction or modification will not cause or contribute to a violation of any NAAQS or PSD increment,[320] and comply with the emission limitations that reflect the BACT ''for each pollutant subject to regulations'' under the CAA.[321] The EPA regulations for the PSD program are contained in 40 CFR 51.166 (applicable to air agencies that issue permits under EPA-approved SIPs) and 40 CFR 52.21 (the federal PSD program applicable to permits issued by the EPA or air agencies to which the EPA has delegated authority to implement the federal PSD program). Most PSD permits are issued by State and local air agencies, subject to federally enforceable rules in State Implementation Plans. There are a smaller number of programs where State, local, or Tribal permitting authorities have delegated federal authority to issue permits on behalf of the EPA or where the EPA directly issues PSD permits.

Revisions to the emissions standards in this rulemaking pursuant to CAA

[315] The capacity markets pay owners of generating units based on the ability to provide firm power regardless of if any electricity is actually delivered to the electric grid.

[316] The EPA notes that when the Agency finalized subpart TTTTa, only the most efficient combustion turbines with base load ratings of greater than 850 MMBtu/h would have required the installation of a selective catalytic reduction (SCR) to comply with the criteria pollutant NSPS (subpart KKKK). Less efficient simple cycle turbines could comply with the criteria pollutant NSPS using advanced combustion controls. Since subpart TTTTa is based on the use of the most efficient combustion turbines, the EPA should have accounted for the costs of SCR as part of the BSER evaluation. While the new criteria pollutant NSPS (subpart KKKKa) does not require the use of SCR for any non-base load combustion turbines as a procedural matter, the EPA should have addressed the issue in the final subpart TTTTa rulemaking.

[317] The costs for the 1x1 F-class and 1x1 H-class are $47/MWh ($140/ton) and $39/MWh ($120/ton) respectively.

[318] If a storage site does not have enough available natural gas to fuel a new base load combustion turbine, or enough transmission capacity to deliver the generated electricity to end users, infrastructure would have to be developed prior to the new combustion turbine commencing operation. Developing that infrastructure could result in additional costs to the owner or operator of the new base load combustion turbine.

[319] Although transmission lines conduct electricity, they have some resistance that results in dissipation of the electrical energy in other forms (*e.g.,* heat). As a result, when transmitted over long distances, the electric energy delivered to an end user is less than the electric energy produced at the generating source (in this case, a stationary combustion turbine).

[320] CAA section 165(a)(3), 42 U.S.C. 7475(a)(3).

[321] CAA sections 165(a)(4) and 169(3), 42 U.S.C. 7475(a)(4), 7479(3).

section 111 will impact the minimum requirements of BACT in the PSD program. The BACT requirement is the maximum degree of emission reduction a specific source can achieve on a case-by-case basis considering the energy, environmental, and economic impacts of available control measures. The definition of ''best available control technology'' in CAA section 169(3) states that, ''In no event shall application of 'best available control technology' result in emissions of any pollutants which will exceed the emissions allowed by any applicable standard established pursuant to section 7411 [CAA section 111] or 7412 [CAA section 112] of this title.'' [322] In other words, the CAA specifies that BACT cannot be set at an emission control level that is less stringent than that which any applicable standard of performance under the NSPS requires. An applicable NSPS must always be met and provides a ''floor'' for the BACT requirement; however, a BACT determination could be more stringent than the NSPS. As such, the GHG emission limits the EPA is repealing in this NSPS rulemaking, including the standards for new base load combustion turbines based on 90 percent CCS, will no longer be the ''BACT floor'' for GHG emissions from sources in the applicable category. The EPA acknowledges that sources and air agencies have some flexibility in implementation of BACT and may continue to consider certain limits and/or controls that are more stringent than the BACT floor. The EPA acknowledges that changing applicable standards under the NSPS can result in implementation impacts in the context of PSD and BACT. The EPA provides additional discussion in chapter 5.3 of the RTC on implications to BACT for PSD permitting related to the 2024 efficiency-based standards in 40 CFR part 60, subpart TTTTa.

2. Summary of Substantial Comments on the 2024 Efficiency-Based Requirements for New Intermediate and Base Load Combustion Turbines

In the June 2025 NPRM, the EPA broadly solicited comment on the BSER determinations and standards of performance for all new and reconstructed combustion turbines. While the EPA is not finalizing changes to the requirements for new or reconstructed combustion turbines other than removing the phase 2 CCS-based requirements for new base load combustion turbines as discussed in section IV.C.1 of this preamble, the Agency notes that commenters specifically raised several concerns on the achievability of the 2024 efficiency-based standards for new intermediate load and base load combustion turbines. Those comments are summarized in this section of the preamble. Additional comments are summarized in the RTC.

Comments: Several commenters raised concerns over the achievability of the efficiency-based standards for new combustion turbines. Commenters cited issues including the need to account for variability in operating load and ambient conditions affecting performance and that many combustion turbine models that could be intermediate load or base load would be unable to meet the standards. Commenters also raised concerns about the limited availability of combustion turbines that could meet the standards, particularly considering load growth. Commenters also stated that efficiency can degrade over time due to normal wear. Commenters also cited uncertainty in how turbines will operate in the future.

Response: The EPA acknowledges the commenters' concerns regarding the 2024 efficiency-based standards for new combustion turbine EGUs. While the EPA is not repealing or otherwise revising the 2024 efficiency-based standards in this action, the Agency notes that it is simultaneously issuing a supplemental proposal soliciting additional public comment on the underlying question raised in the primary basis of the June 2025 NPRM: Whether the EPA lacks statutory authority to regulate GHG emissions from fossil fuel-fired power plants under CAA section 111. That action, if finalized as proposed, would repeal all GHG standards for the fossil fuel-fired EGU source category, including the 2015 and 2024 GHG standards, and would thus resolve commenters' concerns.

3. Conclusion

Based on the EPA's review of the BSER and the achievability of the standards, and for the reasons detailed in this section of the preamble, the EPA is repealing the 2024 phase 2 CCS-based emission standards finalized in the 2024 CPS for new base load stationary combustion turbines, codified in 40 CFR part 60, subpart TTTTa.

D. Consideration of Alternatives

The EPA is determining that it is not necessary to analyze and promulgate alternatives to the repeal of the emission guidelines and standards of performance in this action. The purpose of this rule is to provide near-term relief from the 2024 CPS requirements that the EPA now considers unlawful, infeasible, or otherwise unreasonable. This action is not intended to establish replacement standards. Although CAA section 111 generally requires the EPA to regulate existing sources once the EPA has set standards for new sources, the statute does not require the Agency to do so within a particular timeframe. For that reason, the EPA is not legally obligated to promulgate replacement standards in this rulemaking. Nor is it appropriate to do so, for the following reasons:

First, the EPA's approach in this rulemaking is consistent with the incremental way agencies often proceed, and courts have recognized that agencies may act in steps rather than all at once.[323] The EPA's decision not to immediately move forward with alternatives is also supported by its simultaneous proposal to find that it lacks authority under CAA section 111 to regulate GHG emissions from fossil fuel-fired power plants. If that proposal is finalized, any replacement BSER determinations, standards of performance, or compliance schedules would become unnecessary. Thus, promulgating alternatives now could prove to be futile and wasteful. If the EPA does not finalize that separate proposal, the Agency could revisit whether alternatives to the standards repealed in this action should be developed and promulgated. For now, however, the EPA believes it is reasonable to proceed without doing so.

The EPA also notes that it already considered and rejected several alternatives in the 2024 CPS. For long-term coal-fired steam generating units, the EPA evaluated 90 percent CCS, partial CCS at lower capture rates, natural gas co-firing, and heat-rate improvements. The EPA rejected partial CCS because it would produce substantially smaller reductions at higher cost, and because it considered 90 percent CCS achievable. In addition, the IRC section 45Q tax credit might not be available to offset partial CCS costs. In this final rule, the EPA now rejects the conclusion that 90 percent CCS is adequately demonstrated and achievable, and it further concludes that the IRC section 45Q tax credit should not be counted in evaluating the BSER costs of CCS. As a result, the EPA believes partial CCS would be even more expensive than previously thought. The EPA likewise determined

[322] *See also* 40 CFR 51.166(b)(12), 52.21(b)(12) (defining BACT).

[323] *Fox Television Stations,* 556 U.S. at 522; *see also Pub. Safety Spectrum All., supra* (it was reasonable for the FCC to defer making relevant decisions to a subsequent action).

that natural gas co-firing would amount to impermissible generation shifting and therefore cannot serve as BSER. Heat-rate improvements were also rejected because they would provide only limited reductions and could create a rebound effect.

For medium-term coal-fired EGUs, the EPA similarly considered and rejected CCS and heat-rate improvements in the 2024 CPS. That prior analysis reinforces the EPA's conclusion that further consideration of alternatives is unnecessary here. For new baseload combustion turbines, the EPA considered lower-emitting fuels, highly efficient generation, and hydrogen co-firing. The EPA has not changed its prior conclusion that highly efficient generation remains an appropriate BSER for those units. The Agency previously found that lower-emitting fuels would reduce emissions only modestly and that uncertainties about the cost of low-GHG hydrogen prevented the EPA from treating hydrogen as part of the BSER at that time. Taken together, these prior evaluations support the EPA's view that additional alternatives to the repealed standards do not need to be analyzed and promulgated in this rulemaking.

V. Statutory and E.O. Reviews

Additional information about these statutes and E.O.s can be found at *https://www.epa.gov/laws-regulations/laws-and-executive-orders.*

A. E.O. 12866: Regulatory Planning and Review and E.O. 13563: Improving Regulation and Regulatory Review

This action is a significant regulatory action under E.O. 12866 section 3(f)(1) that was submitted to the Office of Management and Budget (OMB) for review. Any changes made in the course of E.O. 12866 review have been documented in the docket. The EPA prepared an analysis of the potential costs and benefits associated with this action. This analysis, *Regulatory Impact Analysis for the Final Partial Repeal of the Carbon Pollution Standards for Fossil Fuel-Fired Electric Generating Units,* is available in the docket.

The EPA presents the estimated present value (PV) and equivalent annualized value (EAV) of the projected cost savings for the power sector of this final repeal for the years 2026 to 2047 in 2024 dollars, discounted to 2025. In addition, the EPA presents the results for specific snapshot years, consistent with historical practice. These snapshot years are 2030, 2035, 2040, and 2045. The benefit-cost analysis, which is in the RIA for this rulemaking, is available in the docket.

The analysis considers the power industry's compliance costs as the change in electric power generation costs due to this final repeal. Table 1 presents the estimates of compliance cost savings of this final rule for the power sector.

TABLE 1—PRESENT VALUE (PV) AND EQUIVALENT ANNUALIZED VALUE (EAV) OF THE COMPLIANCE COST SAVINGS

[Billion 2024$, discounted to 2025]

3% Discount rate		7% Discount rate	
PV	EAV	PV	EAV
160	10	95	8.6

Note: For the reasons the EPA describes in section 4 of the RIA, the Agency has not monetized several impact categories, including the potential health and welfare impacts of changes in emissions. Therefore, this table does not include those impact categories.

The compliance cost savings in Table 1 are the estimated change in expenditures by the power sector due to this final repeal, which include changes in taxes paid and credits received. The analysis also considers the real resource cost savings due to this final repeal, which are the change in the total avoided cost of resources used by the power sector, which includes capital, labor, fuel, and material inputs, that would have been used for compliance. In contrast to the compliance cost savings in Table 1, the real resource cost savings do not include transfers, such as taxes paid or tax credits, that shift who is paying for the inputs for compliance but do not reduce the social cost. The use of tax credits would have reduced costs from the perspective of firms in the power sector but would have led to a use of resources that are a cost from a societal perspective. These societal costs will now be avoided because of this final action. Over the 2026 to 2047 period, the PV of the estimated real resource cost savings is $280 billion using a three percent discount rate and $180 billion using a seven percent discount rate discounted to 2025. Over this same timeframe, the EAV of the estimated real resource cost is $18 billion using a three percent discount rate, and $16 billion using a seven percent discount rate.

Changes in resources used by the power sector may cause economic interactions in other markets that affect other sectors and households. To evaluate the economy-wide social costs and economic impacts of the action, the EPA used the peer-reviewed CGE model SAGE. The PV of the social cost savings estimated in SAGE for the action is approximately $310 billion (2024 dollars) between 2026 and 2047 (discounted to 2025). The EAV is $23 billion. Note that SAGE does not account for the effects of changing environmental quality as a result of this action. The RIA further describes the methodology and the distinctions between compliance costs, real resource costs, and social costs.

The EPA is obligated to present the agency's best scientific understanding and the implications of that science when developing policies and regulations. However, historically, the EPA's analytical practices may not have presented the full range of uncertainties and associated confidence level regarding the potential benefit estimates from reduction in exposure to particulate matter ($PM_{2.5}$) and ozone. In addition, the science regarding the exposure, health effects from exposure and valuation of reduction in health effect are evolving with better data and methods, especially at low concentrations of PM and ozone. Some of the sources of uncertainties include the set of assumptions used in projecting the health impact of reducing PM. These projections are based on a series of models that take into account emissions changes, resulting distributions of changes in ambient air quality, the estimated reductions in health effects from changes in exposure, and the composition of the population that will benefit from the reduced exposure. Each component includes assumptions, each with varying degrees of uncertainty.

In addition, the EPA historically provided point estimates rather than just ranges of emission-related effects or only quantifying emissions when monetizing proved to be too uncertain. Therefore, to address these concerns, the EPA is refraining from providing primary estimates resulting from

changes in $PM_{2.5}$ and ozone exposure resulting from changes in direct $PM_{2.5}$, NO_X and VOC emissions but will continue to quantify the emissions until the Agency is confident enough in the modeling to robustly monetize those impacts.

To illustrate the impacts of the final repeal, including the cost savings of not deploying CCS as a control strategy and the resultant impact on real resource costs through diminished uptake of the IRC section 45Q tax credit, the EPA assumes that 90 percent CCS is allowed in the model's solution set in the modelling supporting the current RIA. However, to illustrate the sensitivity of the results to the viability of 90 percent CCS as a control strategy, the EPA also developed a modeling scenario assuming 90 percent CCS is not allowed in the model's solution set. These model runs and a memorandum describing key results are available in the docket for this action.[324]

B. E.O. 14192: Unleashing Prosperity Through Deregulation

This action is considered an E.O. 14192 deregulatory action. For regulatory accounting purposes, the estimated present value and annualized value of the cost savings of this rule are $102 billion and $7 billion, respectively (7 percent discount rate, 2024 dollars, 2024 present value year, perpetuity time horizon). Details on the estimated cost savings of this final rule can be found in the EPA's analysis of the potential costs and benefits associated with this action. This analysis, *Regulatory Impact Analysis for the Final Partial Repeal of the Carbon Pollution Standards for Fossil Fuel-Fired Electric Generating Units,* is available in the docket.

C. Paperwork Reduction Act (PRA)

The information collection activities in this final action have been submitted for approval to the OMB under the PRA. The EPA is finalizing amendments to the information collection request (ICR) for 40 CFR part 60, subpart UUUUb. Details on the amendments for this subpart are described below. The EPA is not finalizing amendments to the ICRs for 40 CFR part 60, subparts TTTT and TTTTa.

An agency may not conduct or sponsor, and a person is not required to respond to, a collection of information unless it displays a currently valid OMB control number. The OMB control numbers for the EPA's regulations in 40 CFR are listed in 40 CFR part 9. When OMB approves the ICR, the Agency will announce that approval in the FR and publish a technical amendment to 40 CFR part 9 to display the OMB control number for the approved information collection activities contained in this final rule.

1. 40 CFR Part 60, Subpart TTTT

This action does not impose any new information collection burden under the PRA. OMB has previously approved the information collection activities contained in the existing regulations and has assigned OMB control number 2060–0685.

2. 40 CFR Part 60, Subpart TTTTa

This action does not impose any new information collection burden under the PRA.

3. 40 CFR Part 60, Subpart UUUUb

The ICR document that the EPA prepared has been assigned EPA ICR number 2770.04. You can find a copy of the ICR in the docket for this rule, and it is briefly summarized here. The information collection requirements are not enforceable until OMB approves them.

This action repeals requirements on state governments with existing fossil fuel-fired steam generating units. The information collection requirements are based on the recordkeeping and reporting burden reduction associated with developing, implementing, and enforcing a state plan to limit GHG emissions from these existing EGUs.

Respondents/affected entities: States with one or more designated facilities covered under subpart UUUUb.

Respondent's obligation to respond: No longer mandatory.

Estimated number of respondents: 43.

Frequency of response: No response required.

Total estimated burden reduction: 89,000 hours (per year). Burden is defined at 5 CFR 1320.3(b).

Total estimated cost savings: $11.7 million, includes $35,000 annualized capital or operation & maintenance costs.

D. Regulatory Flexibility Act (RFA)

I certify that this action will not have a significant economic impact on a substantial number of small entities under the RFA. In making this determination, the EPA concludes that the impact of concern for this rule is any significant adverse economic impact on small entities and that the Agency is certifying that this final rule will not have a significant economic impact on a substantial number of small entities because this action relieves regulatory burden on the small entities subject to the rule. Emission guidelines established under CAA section 111(d) do not impose any requirements on regulated entities and, thus, will not have a significant economic impact upon a substantial number of small entities. After emission guidelines are promulgated, States establish emission standards on existing sources, and it is those requirements that could potentially impact small entities. Thus, the repeal of the requirements in the emission guidelines will not impose any requirements on small entities. The repeal of requirements for new, modified, and reconstructed fossil fuel-fired EGUs will relieve regulatory burden on the small entities subject to the rule. As outlined in section 5.3 of the RIA for this rulemaking, the EPA identified 14 potentially affected small entities that own NGCC units considered in the analysis. Under the repeal, the EPA projected compliance cost savings of $143 million for these small entities in 2035. Consequently, the EPA expects that this deregulatory action will relieve the regulatory burden for facilities that, absent this repeal, would be affected by the provisions from the 2024 CPS. As a result, this action will not have a significant economic impact on a substantial number of small entities under the RFA. We have therefore concluded that this action will relieve regulatory burden for all directly regulated small entities.

E. Unfunded Mandates Reform Act (UMRA)

This action does not contain an unfunded mandate of $100 million (adjusted annually for inflation) or more (in 1995 dollars) as described in UMRA, 2 U.S.C. 1531–1538, and does not significantly or uniquely affect small governments. The action imposes no enforceable duty on any State, local, or Tribal governments or the private sector.

F. E.O. 13132: Federalism

This action does not have federalism implications. It will not have substantial direct effects on the States, on the relationship between the national government and the States, or on the distribution of power and responsibilities among the various levels of government.

G. E.O. 13175: Consultation and Coordination With Indian Tribal Governments

This action does not have Tribal implications as specified in E.O. 13175. It will not have substantial direct effects on Tribal governments, on the relationship between the Federal Government and Indian Tribes, or on

[324] See memorandum entitled ''IPM Sensitivity Runs Memo'' in the docket for this rulemaking.

the distribution of power and responsibilities between the Federal Government and Indian Tribes, as specified in E.O. 13175. Thus, E.O. 13175 does not apply to this final action.

However, because of Tribal interest on this action and consistent with the EPA Policy on Consultation with Indian Tribes, the EPA offered government-to-government consultation with Tribes. Tribal consultations were completed following the proposal at the request of the Summit Lake Paiute Tribe, the Coeur d'Alene Tribe, the Bois Forte Tribe, and the Ak-Chin Indian Community. Summaries of these consultations are included in the rulemaking docket.

H. E.O. 13045: Protection of Children From Environmental Health Risks and Safety Risks

E.O. 13045 directs Federal agencies to include an evaluation of the health and safety effects of the planned regulation on children in Federal health and safety standards and explain why the regulation is preferable to potentially effective and reasonably feasible alternatives. This action is subject to E.O. 13045 because it is a significant regulatory action under section 3(f)(1) of E.O. 12866. The 2024 CPS was anticipated to reduce emissions of various pollutants and some of the benefits of reducing these pollutants would have accrued to children. This final action is expected to decrease the impact of the emissions reductions estimated from the 2024 CPS on these benefits. However, as discussed in the RIA, the EPA does not quantify the health effects of air pollution in this final rule.

This final action does not affect the level of public health and environmental protection already being provided by existing NAAQS and other mechanisms in the CAA. This final action does not affect applicable local, State, or Federal permitting or air quality management programs that will continue to address areas with degraded air quality and maintain the air quality in areas meeting current standards. Areas that need to reduce criteria air pollution to meet the NAAQS will still need to rely on control strategies to reduce emissions.

I. E.O. 13211: Actions Concerning Regulations That Significantly Affect Energy Supply, Distribution, or Use

This action is not a ''significant energy action'' because it is not likely to have a significant adverse effect on the supply, distribution or use of energy over the analysis period (2026–2047) based on the results presented in the RIA accompanying this rulemaking.

J. National Technology Transfer and Advancement Act (NTTAA) and 1 CFR Part 51

This rulemaking does not involve technical standards; however, with the removal of 40 CFR part 60 subpart UUUUb, the EPA is also removing ANSI No. C12.20–2010 from § 60.5860b that has been approved for incorporation by reference.

K. Congressional Review Act (CRA)

This action is subject to the CRA, and the EPA will submit the rule report to each House of the Congress and to the Comptroller General of the United States. This action meets the criteria set forth in 5 U.S.C. 804(2).

List of Subjects in 40 CFR Part 60

Environmental protection, Administrative practice and procedures, Air pollution control, Incorporation by reference, Reporting and recordkeeping requirements.

Lee Zeldin,

Administrator.

For the reasons stated in the preamble, the Environmental Protection Agency amends part 60 of title 40, chapter I, of the Code of Federal Regulations as follows:

PART 60—STANDARDS OF PERFORMANCE FOR NEW STATIONARY SOURCES

■ 1. The authority citation for part 60 continues to read as follows:

Authority: 42 U.S.C. 7401 *et seq.*

Subpart A—General Provisions

■ 2. Amend § 60.17 by revising paragraph (d)(1) to read as follows:

§ 60.17 Incorporations by reference.

* * * * *

(d) * * *

(1) ANSI No. C12.20–2010 American National Standard for Electricity Meters—0.2 and 0.5 Accuracy Classes (Approved August 31, 2010); IBR approved for §§ 60.5535(d); 60.5535a(d).

* * * * *

Subpart TTTT—Standards of Performance for Greenhouse Gas Emissions for Electric Generating Units

■ 3. Revise § 60.5508 to read as follows:

§ 60.5508 What is the purpose of this subpart?

This subpart establishes emission standards and compliance schedules for the control of greenhouse gas (GHG) emissions from a steam generating unit or an integrated gasification combined cycle (IGCC) facility that commences construction after January 8, 2014, commences reconstruction after June 18, 2014, or commences modification after January 8, 2014. This subpart also establishes emission standards and compliance schedules for the control of GHG emissions from a stationary combustion turbine that commences construction after January 8, 2014, but on or before May 23, 2023, or commences reconstruction after June 18, 2014, but on or before May 23, 2023. An affected steam generating unit, IGCC, or stationary combustion turbine shall, for the purposes of this subpart, be referred to as an affected electric generating unit (EGU).

■ 4. Amend § 60.5580 by revising the definition of *System emergency* to read as follows:

§ 60.5580 What definitions apply to this subpart?

* * * * *

System emergency means periods when the Reliability Coordinator has declared an Energy Emergency Alert level 2 or 3 which should follow NERC Reliability Standard EOP–011–2, its successor, or equivalent.

* * * * *

Subpart TTTTa—Standards of Performance for Greenhouse Gas Emissions for New Construction and Reconstruction Stationary Combustion Turbine Electric Generating Units

■ 5. Revise the heading of subpart TTTTa to read as set forth above.

■ 6. Revise § 60.5508a to read as follows:

§ 60.5508a What is the purpose of this subpart?

This subpart establishes emission standards and compliance schedules for the control of GHG emissions from a stationary combustion turbine that commences construction or reconstruction after May 23, 2023. An affected stationary combustion turbine shall, for the purposes of this subpart, be referred to as an affected electric generating unit (EGU).

■ 7. Amend § 60.5509a by:

■ a. Revising the introductory text of paragraph (a);

■ b. Removing and reserving paragraph (b)(1);

■ c. Revising paragraph (b)(4); and

■ d. Removing and reserving paragraph (b)(7).

The revisions read as follows:

§ 60.5509a Am I subject to this subpart?

(a) Except as provided for in paragraph (b) of this section, the GHG standards included in this subpart apply to any stationary combustion turbine that commences construction or reconstruction after May 23, 2023, that meets the relevant applicability conditions in paragraphs (a)(1) and (2) of this section.

* * * * *

(b) * * *

(4) Your EGU serves a generator along with other stationary combustion turbine(s) where the effective generation capacity (determined based on a prorated output of the base load rating of each stationary combustion turbine) is 25 MW or less.

* * * * *

■ 8. Amend § 60.5525a by revising paragraphs (a)(3) and (c)(2) and (3) to read as follows:

§ 60.5525a What are my general requirements for complying with this subpart?

* * * * *

(a) * * *

(3) Owners/operators of a base load combustion turbine with a base load rating of less than 2,110 GJ/h (2,000 MMBtu/h) and/or an intermediate or base load combustion turbine burning fuels other than natural gas may elect to determine a site-specific emissions rate using one of the following equations. Combustion turbines firing fuels with a lower CO_2 emissions rate than natural gas (*e.g.,* hydrogen) are not required to use the fuel adjustment parameter.

(i) For base load combustion turbines:

Equation 2 to Paragraph (a)(3)(i)

$$CO_2 \text{ emissions standard} = \left[BLER_L + \frac{BLER_S - BLER_L}{BLR_L - BLR_S} \times (BLR_L - BLR_A)\right] \times \left[\frac{HIER_A}{HIER_{NG}}\right] \text{(Eq. 2)}$$

Where:

CO_2 emission standard = the emission standard during the compliance period in units of kg/MWh (or lb/MWh).

$BLER_L$ = Base load emissions standard for natural gas-fired combustion turbines with base load ratings greater than 2,110 GJ/h (2,000 MMBtu/h). 360 kg CO_2/MWh-gross (800 lb CO_2/MWh-gross) or 370 kg CO_2/MWh-net (820 lb CO_2/MWh-net).

$BLER_S$ = Base load emissions standard for natural gas-fired combustion turbines with a base load rating of 260 GJ/h (250 MMBtu/h). 410 kg CO_2/MWh-gross (900 lb CO_2/MWh-gross) or 420 kg CO_2/MWh-net (920 lb CO_2/MWh-net).

BLR_L = Minimum base load rating of large combustion turbines 2,110 GJ/h (2,000 MMBtu/h).

BLR_S = Base load rating of smallest combustion turbine 260 GJ/h (250 MMBtu/h).

BLR_A = Base load rating of the actual combustion turbine in GJ/h (or MMBtu/h).

$HIER_A$ = Heat input-based emissions rate of the actual fuel burned in the combustion turbine (lb CO_2/MMbtu). Not to exceed 69 kg/GJ (160 lb CO_2/MMBtu).

$HIER_{NG}$ = Heat input-based emissions rate of natural gas 50 kg/GJ (120 lb CO_2/MMBtu).

(ii) For intermediate load combustion turbines:

Equation 3 to Paragraph (a)(3)(ii)

$$CO_2 \text{ emissions standard} = ILER \times \left[\frac{HIER_A}{HIER_{NG}}\right] \text{(Eq. 3)}$$

Where:

CO_2 emission standard = the emission standard during the compliance period in units of kg/MWh (or lb/MWh).

ILER = Intermediate load emissions rate for natural gas-fired combustion turbines. 530 kg/MWh-gross (1,170 lb CO_2/MWh-gross) or 540 kg CO_2/MWh-net (1,190 lb CO_2/MWh-net).

$HIER_A$ = Heat input-based emissions rate of the actual fuel burned in the combustion turbine (lb CO_2/MMBtu). Not to exceed 69 kg/GJ (160 lb CO_2/MMBtu).

$HIER_{NG}$ = Heat input-based emissions rate of natural gas 50 kg/GJ (120 lb CO_2/MMBtu).

* * * * *

(c) * * *

(2) For a reconstructed EGU that becomes subject to this subpart, the first month of the initial compliance period shall be the first operating month (as defined in § 60.5580a) after the calendar month in which emissions reporting is required to begin under § 60.5555a(c)(3)(iii).

(3) Emissions of CO_2 emitted by your affected facility and the output of the affected facility generated when it operated during a system emergency as defined in § 60.5580a are excluded for both applicability and compliance with the relevant standards of performance if you can sufficiently provide the documentation listed in § 60.5560a(i). The relevant standard of performance for affected EGUs that operate during a system emergency depends on the subcategory, as described in paragraph (c)(3)(i) of this section.

(i) For intermediate and base load combustion turbines that operate during a system emergency, you must comply with the standard for low load combustion turbines specified in table 1 to this subpart.

(ii) [Reserved]

■ 9. Amend § 60.5535a by revising paragraphs (b)(1) and (g) to read as follows:

§ 60.5535a How do I monitor and collect data to demonstrate compliance?

* * * * *

(b) * * *

(1) For affected EGUs, you may install, certify, operate, maintain, and calibrate a CO_2 continuous emission monitoring system (CEMS) to directly measure and record hourly average CO_2 concentrations in the affected EGU exhaust gases emitted to the atmosphere, and a flow monitoring system to measure hourly average stack gas flow rates, according to 40 CFR 75.10(a)(3)(i). As an alternative to direct measurement of CO_2 concentration, provided that your EGU does not use carbon separation (*e.g.,* carbon capture and storage), you may use data from a certified oxygen (O_2) monitor to calculate hourly average CO_2 concentrations, in accordance with 40 CFR 75.10(a)(3)(iii). If you measure CO_2 concentration on a dry basis, you must also install, certify, operate, maintain, and calibrate a continuous moisture monitoring system, according to 40 CFR 75.11(b). Alternatively, you may either use an appropriate fuel-specific default moisture value from 40 CFR 75.11(b) or submit a petition to the Administrator under 40 CFR 75.66 for a site-specific default moisture value.

* * * * *

(g) In accordance with §§ 60.13(g) and 60.5520a if the exhaust gases from an affected EGU that implements the continuous emission monitoring provisions in paragraph (b) of this

section are emitted to the atmosphere through multiple stacks (or if the exhaust gases are routed to a common stack through multiple ducts and you elect to monitor in the ducts), you must monitor the hourly CO_2 mass emissions and the ''stack operating time'' (as defined in 40 CFR 72.2) at each stack or duct separately. In this case, you must determine compliance with the applicable emissions standard in table 1 to this subpart by summing the CO_2 mass emissions measured at the individual stacks or ducts and dividing by the total gross or net energy output for the affected EGU.

■ 10. Amend § 60.5540a by:
■ a. Revising paragraphs (a)(5)(i) and (a)(8); and
■ b. Removing paragraph (c).
The revisions read as follows:

§ 60.5540a How do I demonstrate compliance with my CO_2 emissions standard and determine excess emissions?

(a) * * *

(5) * * *

(i) Calculate $P_{gross/net}$ for your affected EGU using the following equation. All terms in the equation must be expressed in units of MWh. To convert each hourly gross or net energy output (consistent with § 60.5520a) value reported under part 75 of this chapter to MWh, multiply by the corresponding EGU or stack operating time.

Equation 1 to Paragraph (a)(5)(i)

$$P_{gross/net} = \frac{(Pe)_{ST} + (Pe)_{CT} + (Pe)_{IE} - (Pe)_{A}}{TDF} + [(Pt)_{PS} + (Pt)_{HR} + (Pt)_{IE}] \quad \text{(Eq. 1)}$$

Where:

$P_{gross/net}$ = In accordance with § 60.5520a, gross or net energy output of your affected EGU for each valid operating hour (as defined in paragraph (a)(1) of this section) in MWh.

$(Pe)_{ST}$ = Electric energy output plus mechanical energy output (if any) of steam turbines in MWh.

$(Pe)_{CT}$ = Electric energy output plus mechanical energy output (if any) of stationary combustion turbine(s) in MWh.

$(Pe)_{IE}$ = Electric energy output plus mechanical energy output (if any) of your affected EGU's integrated equipment that provides electricity or mechanical energy to the affected EGU or auxiliary equipment in MWh.

$(Pe)_{A}$ = Electric energy used for any auxiliary loads in MWh. Not applicable for determining P_{gross}.

$(Pt)_{PS}$ = Useful thermal output of steam (measured relative to standard ambient temperature and pressure (SATP) conditions, as applicable) that is used for applications that do not generate additional electricity, produce mechanical energy output, or enhance the performance of the affected EGU. This is calculated using the equation specified in paragraph (a)(5)(ii) of this section in MWh.

$(Pt)_{HR}$ = Non steam useful thermal output (measured relative to SATP conditions, as applicable) from heat recovery that is used for applications other than steam generation or performance enhancement of the affected EGU in MWh.

$(Pt)_{IE}$ = Useful thermal output (relative to SATP conditions, as applicable) from any integrated equipment is used for applications that do not generate additional steam, electricity, produce mechanical energy output, or enhance the performance of the affected EGU in MWh.

TDF = Electric Transmission and Distribution Factor of 0.95 for a combined heat and power affected EGU where at least on an annual basis 20.0 percent of the total gross or net energy output consists of useful thermal output on a 12-operating-month rolling average basis, or 1.0 for all other affected EGUs.

* * * * *

(8) You may exclude CO_2 mass emissions and output generated from your affected EGU from your calculations for hours during which the affected EGU operated during a system emergency, as defined in § 60.5580a, if you can provide the information listed in § 60.5560a(i). While operating during a system emergency, your compliance determination depends on your subcategory or unit type, as listed in paragraph (a)(8)(i) of this section.

(i) For affected combustion turbines in the intermediate or base load subcategory, your CO_2 emission standard while operating during a system emergency is the applicable emission standard for low load combustion turbines.

(ii) [Reserved]

* * * * *

■ 11. Amend § 60.5555a by:
■ a. Revising paragraphs (a)(2)(v) and (c)(3)(iii); and
■ b. Removing paragraphs (f) and (g).
The revisions read as follows:

§ 60.5555a What reports must I submit and when?

(a) * * *

(2) * * *

(v) Consistent with § 60.5520a, the CO_2 emissions standard (as identified in table 1 to this subpart) with which your affected EGU must comply; and

* * * * *

(c) * * *

(3) * * *

(iii) For reconstructed units, reporting of emissions data shall begin at the date on which the EGU becomes an affected unit under this subpart, provided that the ECMPS Client Tool is able to receive and process net energy output data on that date. Otherwise, emissions data reporting shall be on a gross energy output basis until the date that the Client Tool is first able to receive and process net energy output data.

* * * * *

■ 12. Amend § 60.5560a by revising paragraph (f) to read as follows:

§ 60.5560a What records must I maintain?

* * * * *

(f) You must keep records of the calculations you performed to assess compliance with each applicable CO_2 mass emissions standard in table 1 to this subpart.

* * * * *

■ 13. Amend § 60.5580a by:
■ a. Removing the definition of *Coal-fired Electric Generating Unit;*
■ b. Revising the definitions of *Electric Generating Units or EGU* and *Gross energy output;*
■ c. Removing the definition of *Integrated gasification combined cycle facility or IGCC;* and
■ d. Revising the definitions of *Intermediate load combustion turbine, Low load combustion turbine, Net-electric sales,* and *System emergency.*
The revisions read as follows:

§ 60.5580a What definitions apply to this subpart?

* * * * *

Electric Generating Units or EGU means any stationary combustion turbine that is subject to this rule (*i.e.,* meets the applicability criteria).

* * * * *

Gross energy output means:

(1) For stationary combustion turbines, the gross electric or direct mechanical output from both the EGU (including, but not limited to, output from steam turbine(s), combustion turbine(s), and gas expander(s)) plus 100 percent of the useful thermal output.

(2) [Reserved]

(3) For combined heat and power facilities, where at least 20.0 percent of

the total gross energy output consists of useful thermal output on a 12-operating-month rolling average basis, the gross electric or mechanical output from the affected EGU (including, but not limited to, output from steam turbine(s), combustion turbine(s), and gas expander(s)) minus any electricity used to power the feedwater pumps, that difference divided by 0.95, plus 100 percent of the useful thermal output.

* * * * *

Intermediate load combustion turbine means a stationary combustion turbine that is not a low load or base load combustion turbine. An intermediate load combustion turbine supplies more than 20 percent of its potential electric output as net-electric sales on both a 12-operating month and a 3-year rolling average basis and supplies 40 percent or less of its potential electric output as net-electric sales on either a 12-operating month or a 3-year rolling average basis.

* * * * *

Low load combustion turbine means a stationary combustion turbine that supplies 20 percent or less of its potential electric output as net-electric sales on either a 12-operating month or a 3-year rolling average basis.

* * * * *

Net-electric sales means:

(1) The gross electric sales to the utility power distribution system minus purchased power; or

(2) For combined heat and power facilities, where at least 20.0 percent of the total gross energy output consists of useful thermal output on a 12-operating month basis, the gross electric sales to the utility power distribution system minus purchased power and the applicable percentage of purchased power of the thermal host facility or facilities. The applicable percentage of purchased power for CHP facilities is determined based on the percentage of the total thermal load of the host facility supplied to the host facility by the CHP facility. For example, if a CHP facility serves 50 percent of a thermal host's thermal demand, the owner/operator of the CHP facility would subtract 50 percent of the thermal host's electric purchased power when calculating net-electric sales.

(3) Electricity supplied to other facilities that produce electricity to offset auxiliary loads are included when calculating net-electric sales.

(4) Electric sales during a system emergency are not included when calculating net-electric sales.

* * * * *

System emergency means periods when the Reliability Coordinator has declared an Energy Emergency Alert level 2 or 3 which should follow NERC Reliability Standard EOP–011–2, its successor, or equivalent.

* * * * *

■ 14. Revise table 1 to subpart TTTTa to read as follows:

TABLE 1 TO SUBPART TTTTa OF PART 60—CO_2 EMISSION STANDARDS FOR AFFECTED STATIONARY COMBUSTION TURBINES THAT COMMENCED CONSTRUCTION OR RECONSTRUCTION AFTER MAY 23, 2023 (GROSS OR NET ENERGY OUTPUT-BASED STANDARDS APPLICABLE AS APPROVED BY THE ADMINISTRATOR)

[Note: Numerical values of 1,000 or greater have a minimum of 3 significant figures and numerical values of less than 1,000 have a minimum of 2 significant figures]

Affected EGU category	CO_2 emission standard
Base load combustion turbines	360 to 560 kg CO_2/MWh (800 to 1,250 lb CO_2/MWh) of gross energy output; or 370 to 570 kg CO_2/MWh (820 to 1,280 lb CO_2/MWh) of net energy output as determined by the procedures in § 60.5525a.
Intermediate load combustion turbines	530 to 710 kg CO_2/MWh (1,170 to 1,560 lb CO_2/MWh) of gross energy output; or 540 to 720 kg CO_2/MWh (1,190 to 1,590 lb CO_2/MWh) of net energy output as determined by the procedures in § 60.5525a.
Low load combustion turbines	Between 50 to 69 kg CO_2/GJ (120 to 160 lb CO_2/MMBtu) of heat input as determined by the procedures in § 60.5525a.

Table 2 to Subpart TTTTa of Part 60 [Removed and Reserved]

■ 15. Remove and reserve table 2 to subpart TTTTa.

■ 16. Revise table 3 to subpart TTTTa to read as follows:

TABLE 3 TO SUBPART TTTTa OF PART 60—APPLICABILITY OF SUBPART A OF THIS PART TO THIS SUBPART

General provisions citation	Subject of citation	Applies to subpart TTTTa	Explanation
§ 60.1	Applicability	Yes.	
§ 60.2	Definitions	Yes	Additional terms defined in § 60.5580a.
§ 60.3	Units and Abbreviations	Yes.	
§ 60.4	Address	Yes	Does not apply to information reported electronically through ECMPS. Duplicate submittals are not required.
§ 60.5	Determination of construction or modification.	Yes.	
§ 60.6	Review of plans	Yes.	
§ 60.7	Notification and Recordkeeping	Yes	Only the requirements to submit the notifications in § 60.7(a)(1) and (3) and to keep records of malfunctions in § 60.7(b), if applicable.
§ 60.8(a)	Performance tests	No.	
§ 60.8(b)	Performance test method alternatives	Yes	Administrator can approve alternate methods.
§ 60.8(c)–(f)	Conducting performance tests	No.	

TABLE 3 TO SUBPART TTTTa OF PART 60—APPLICABILITY OF SUBPART A OF THIS PART TO THIS SUBPART—Continued

General provisions citation	Subject of citation	Applies to subpart TTTTa	Explanation
§ 60.9	Availability of Information	Yes.	
§ 60.10	State authority	Yes.	
§ 60.11	Compliance with standards and maintenance requirements.	No.	
§ 60.12	Circumvention	Yes.	
§ 60.13 (a)–(h), (j)	Monitoring requirements	No	All monitoring is done according to part 75.
§ 60.13 (i)	Monitoring requirements	Yes	Administrator can approve alternative monitoring procedures or requirements.
§ 60.14	Modification	No.	
§ 60.15	Reconstruction	Yes.	
§ 60.16	Priority list	No.	
§ 60.17	Incorporations by reference	Yes.	
§ 60.18	General control device requirements	No.	
§ 60.19	General notification and reporting requirements.	Yes	Does not apply to notifications under § 75.61 of this chapter or to information reported through ECMPS.

Subpart UUUUb—[Removed and Reserved]

■ 17. Remove and reserve subpart UUUUb, consisting of §§ 60.5700b through 60.5880b.

[FR Doc. 2026–19071 Filed 9–16–26; 8:45 am]

BILLING CODE 6560–50–P

UNITED STATES OF AMERICA
BEFORE THE
UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Craig Unit 1	)	Order No. 202-26-49

The State Of Colorado's Request for Rehearing,
Motion To Intervene, And Stay Request

Exhibit NNNN: *SPP Address Resource Adequacy Issues in West BAA* (Oct. 23, 2026)

This is one of your three complimentary articles.

SPP Addresses Resource Adequacy Issues in West BAA

Staff Draft Tariff Change to Incent Physical Supply After 2 EEAs

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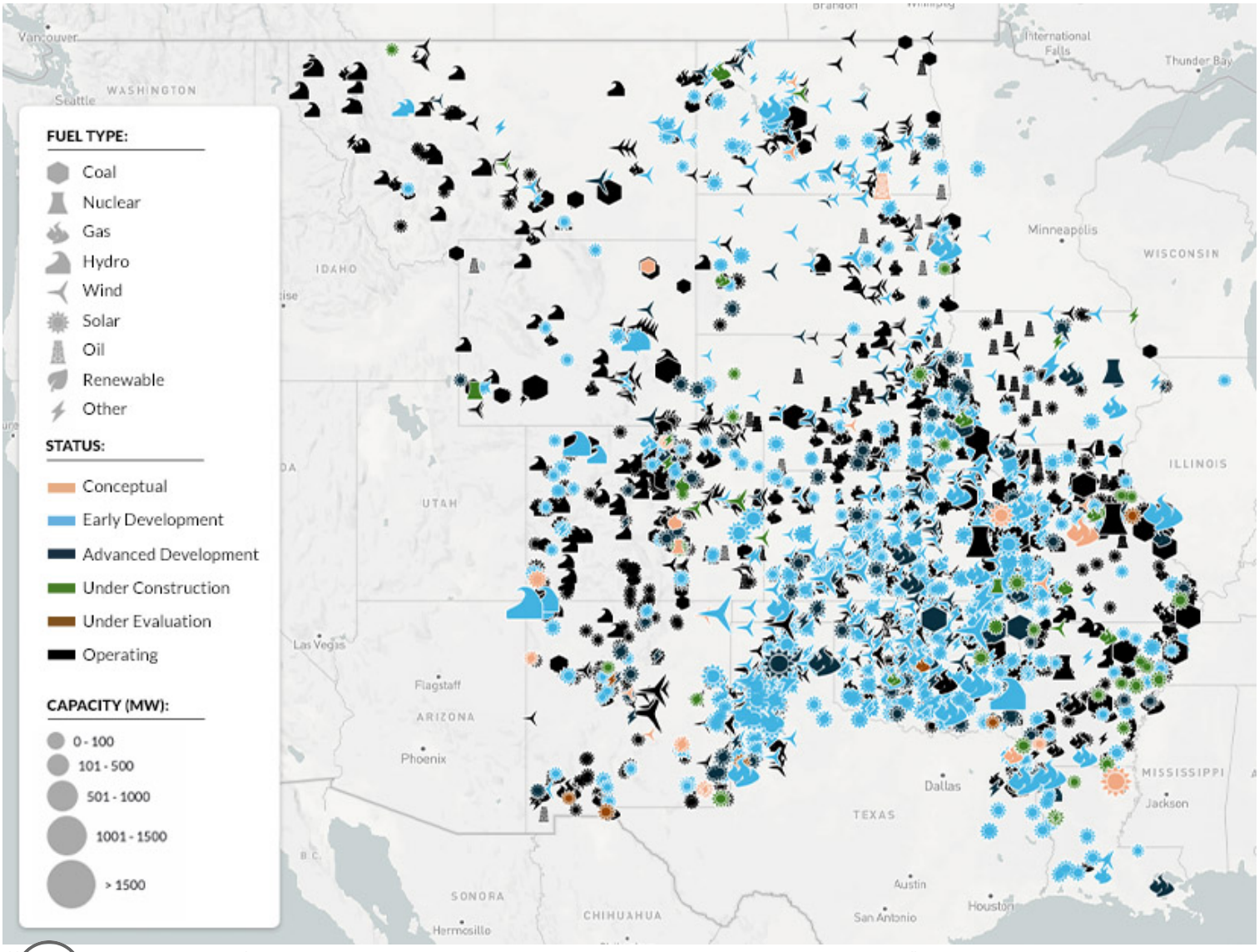

(//www.rtoinsider.com/137925-spp-addressing-western-resource-adequacy-issues/)

SPP generation | *Yes Energy*

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After calling two energy emergency alerts and coming close to a third within eight days in its Western footprint, *SPP (https://www.rtoinsider.com/category/rto/rto-spp/)* is moving quickly with a tariff change that it hopes will address its resource adequacy challenges there.

The grid operator's staff have drafted a revision request (*RR801 (https://spp.org/documents/77351/rtoe%20user%20forum%207.29.26.pdf)*) that proposes an interim market adequacy evaluation to determine whether market participants in the West balancing authority area are providing "sufficient generation for their load obligations."

The evaluation would take place after the operating day and consider energy that each participant made available before real-time market operations and their market obligations. Market participants would be considered deficient when their available energy is less than their market obligations and be assessed a charge.

Why This Matters

The RTO is proposing an interim market adequacy evaluation to determine whether market participants in the West are providing "sufficient generation for their load obligations."

SPP says this will provide a mechanism to incent adequate physical supply ahead of the day-ahead reliability unit commitment (RUC) process and prod load-responsible entities to bring sufficient supply to cover their load obligation earlier.

RR801 will expire June 1, 2027. SPP exempted the expansion members from its resource adequacy requirement until the 2027 summer season when the RTO Expansion became effective April 1.

Carrie Simpson, SPP's markets vice president, said during a *webinar (http://click.spplist.spp.org/?qs=ABB7InYiOjEsImQiOjQ5NTJ9AAwAAAAAAggaWXb-wWfAaPIA1wBsnMVa-h7nXpkfFJ1NRDm7kTEr4S5ja0XPlMdXEjamhupuCr9k33sTty-fbuEZpiic8T86cLATcqbBPmITcw)* with Western entities July 29 that the Western RTO's current construct is leading participants to either not procure energy for supply "or to offer into the market and waiting until close to real time to secure energy to offer to the market to hedge themselves or not hedging themselves at all."

"Going out and procuring energy ahead of time is also a hedge against what's happening in the real-time market and the spot market," Simpson said. "What we're doing in the proposal is basically saying, 'OK, bring that energy earlier, bring it at the day-ahead RUC process because we can then commit around it. We can optimize around that for everyone and for that entity.' It puts the whole system in a better condition."

Simpson plans to conduct an education session on RR801 during the quarterly Joint Stakeholder Briefing before state commissioners and staffs, and SPP's Board of Directors on Aug. 3 in St. Paul, Minn. She said staff could request board approval during its Aug. 4 meeting or, more likely, request an urgent revision request process to move things along.

“We recognize that there’s a lot of moving parts here, including *FERC (https://www.rtoinsider.com/category/rto/rto-public-policy/rto-ferc-federal/)*,” Simpson said. “At a minimum, having this ready for the winter is definitely a high priority.”

SPP issued an EEA Level 3 that lasted less than an hour July 20 and an EEA Level 2 on July 24 that lasted more than two and a half hours. The grid operator cited a risk of high loads during both events along with the uncertainty of a 257-MW unit’s forced outage and variable energy, or intermittent, resources. (The unit forced offline is still out of service.) (See *SPP West Exits 2nd EEA in 5 Days (https://www.rtoinsider.com/137473-spp-west-exits-2nd-eea-in-5-days/)*.)

C.J. Brown, SPP’s operations vice president, told the webinar’s attendees that the RTO was on the verge of declaring another EEA on July 27 when strong imports during the afternoon peak disappeared during the off-peak hours.

“We would prefer that if we’re going to have to depend on non-firm interchange, that we know that way ahead of time,” he said. “We’re not seeing the reaction in real time, and that’s got us concerned.”

“While we’ve had two events where we’ve had to go into EEAs, there’s many other events where we’re right on the cusp,” added SPP’s Ryan Ziegler, director of operations policy and performance. “Until we have some change and mitigation, we’re going to continue to have to rely on those emergency tools, which we don’t want to.”

Stakeholders have until close of business Aug. 11 to file comments on RR801. They will then be considered by the Market Working Group.

“It’s a real reliability concern that we’re trying to address. That’s the only reason we would ever try to do something this expedient,” Brown said.

Mark Gabriel, CEO of Colorado-based United Power, a member of the West BAA, cautioned against staff moving too quickly in response to the EEAs. He noted the BAA has about 9.4 GW of nameplate capacity in the market — “Much of which is not being bid on,” Gabriel said — and that it peaks at just over 5 GW.

“It feels like jamming something to the Board of Directors in a week or less violates the sort of the fundamental principle of SPP about going through a full process,” he said. “Jamming something through without fully vetting and understanding this, especially for something which I understand really ends June 1, [2027], doesn’t feel like the right way to do this, not in the SPP process world. I don’t like to see things rush through. That’s not the SPP way.”

Conservative Ops Extended

The grid operator on July 30 extended the West BAA’s conservative operations advisory until 12 a.m. Aug. 6 because of potential forecast uncertainty, including higher-than-normal loads and outages, seasonally high temperatures, and the potential for lower wind and solar output. The advisory initially was issued July 19 and was to expire July 21, but it has been extended several times since.

The RTO considers conservative operations as a stable operating condition. The advisories do not require public conservation or action. SPP issues them to raise awareness by transmission and generation facilities of potential threats to grid reliability.

Since the expansion, the grid operator also has issued 10 resource advisories in the West BAA to manage interchange and generation uncertainty. The advisories generally are declared because of forecasts of potential high peak loads and low output from wind and solar resources, and possible increases in resource outages.

Even the U.S. Department of Energy has jumped in, issuing an *emergency order (https://www.energy.gov/articles/energy-secretary-secures-grid-across-17-states-amid-period-hot-weather)* July 26 authorizing SPP to direct backup generation resources as a last resort before declaring an EEA Level 3. The order, which came after a request from SPP, directs the grid operator to dispatch specified generation units and to order their operation as needed to maintain reliability in its 17-state footprint.

In a July 26 message to stakeholders, SPP said the recent events "illuminate" that resource adequacy challenges "have become particularly heightened" in the Western Interconnection since the April 1 expansion. It said it is "actively" partnering with member utilities, neighboring systems and policymakers to design and deploy solutions that will strengthen the Western grid's resilience."

"Until these solutions and necessary infrastructure are in place, our West BAA is likely to continue to experience advisories and energy emergency alert conditions, particularly during periods of high customer demand."

One possible long-term solution is the recent agreement between the Western Transmission Expansion Coalition and the Western Transmission Consortium to explore opportunities for interregional transmission projects in the West. The WestTEC effort, jointly facilitated by Western Power Pool and WECC, released a 10-year outlook in February that found the West must spend about $60 billion to build or upgrade 12,600 miles of transmission to meet the region's forecast 30% increase in peak demand and other needs by 2035. (See *WestTEC, TWTC Launch Effort to Build Interregional Tx Infrastructure (https://www.rtoinsider.com/132177-wpp-twtc-collaborate-interregional-tx-initiative/)*.)

SPP spokesperson Meghan Sever told *RTO Insider* that the RTO Expansion is an example of its partnerships with Western utilities and operators to strengthen grid reliability.

"That expansion has allowed SPP and Western operators to work together in real time to balance supply and demand and respond to emergencies," she said in an email. "These collaborative relationships were essential during the July 24 energy emergency alert. SPP and Western utilities coordinated conservation appeals and worked with neighboring regions to avoid service interruptions."

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